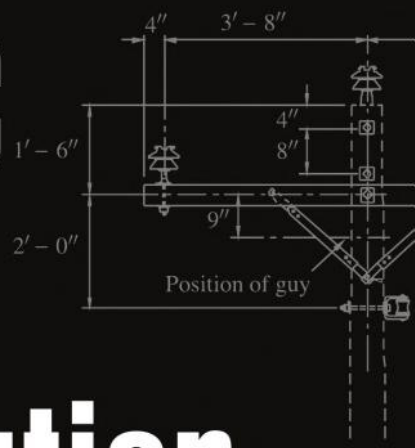
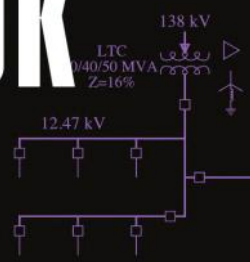
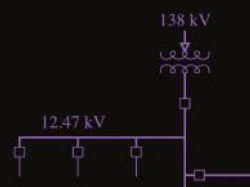
SECOND EDITION

Electric Power Distribution Handbook





T. A. Short
Electric Power Research Institute



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To the future. To Jared. To Logan.

Contents

Foreword		ix
Preface		xi
Acknowledgments		xiii
Author		xv
Credits		xvii
1	Fundamentals of Distribution Systems	1
2	Overhead Lines	33
3	Overhead Line Performance	91
4	Underground Distribution	137
5	Transformers	203
6	Voltage Regulation	271
7	Capacitor Application	319
8	Faults	367
9	Short-Circuit Protection	425
10	Reliability	491
11	Voltage Sags and Momentary Interruptions	557
12	Other Power Quality Issues	613
13	Lightning Protection	659
14	Grounding and Safety	725
15	Distributed Generation	797
Index		851

Foreword

In 2003, the National Academy of Engineering listed the development of the electric power system infrastructure as the greatest engineering achievement of the twentieth century. Now, we are embarking on a new challenge to rethink and re-engineer the electric power system to handle the challenges of the twenty-first century. This effort starts with the electric distribution system, where we connect the customer to the interconnected grid. It is important to note that the challenges of the next-generation distribution system are not unique to distribution systems in North America, but are international in scope.

Some of the important new challenges that must be dealt with include

- Maintaining the reliability of the distribution system with an aging infrastructure and continuous efforts to reduce both maintenance and capital investment costs.
- Improving the resiliency of the system during major storms.
- Developing a smart grid infrastructure with communications, automation, and security to facilitate integration of widespread distributed resources, like photovoltaic systems that continue to become more cost competitive.
- Using the distribution system to improve efficiency through measures like advanced voltage and var control systems.
- Integrating customer systems like electric vehicle charging, smart appliances, and home energy management systems to improve the performance of both local systems and the overall grid.
- Maintaining the power quality required by customer equipment that is increasingly digitally controlled and automated.
- Assuring the safety of the system, both for customers and for utility personnel that must build and maintain the system.

These challenges have resulted in one of the most exciting times ever for our distribution research program at Electric Power Research Institute (EPRI) and for the electric distribution system engineer. The strong collaboration in the electric utility industry to tackle these challenges is resulting in tremendous advancements that will continue to transform the distribution system of the future. In our white paper on the costs and benefits of the smart grid [1], we estimated that additional investments in the range of $230–440B will be required in the electric distribution system (besides normal investments to meet load requirements and replace aging infrastructure) to meet the requirements of the next-generation grid (and, by the way, the benefits of

these investments far exceed the costs). Obviously, we want to make these investments as intelligently as possible.

This handbook does an excellent job of bringing together information for the electric distribution engineer from a wide variety of resources, including EPRI research efforts. The result is a very complete guidebook for designing and maintaining the electric distribution system, including recognition of the new challenges that we are facing. I am very proud to have Tom as part of our research team at EPRI, and we are proud to be associated with this resource for the electric power industry.

With my own background in the field of power quality, I am particularly excited about the understanding that Tom shows in relating the design and maintenance of the distribution system to the power quality that is experienced by the customer. The treatment of areas like fault management, protection, voltage sags, and other power quality concerns are much more complete and understandable than you will find in other texts on distribution systems.

Overall, I think you will find that Tom's expertise comes through in every chapter in a way that is both useful and understandable as you deal with your own distribution system challenges. I want to personally thank Tom for the effort put into this extremely valuable resource for the industry.

Mark McGranaghan
Vice President—Power Delivery and Utilization
Electric Power Research Institute (EPRI)
Palo Alto, California

Reference

1. Estimating the Costs and Benefits of the Smart Grid—A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid, EPRI Report 1022519, 2011.

Preface

In industrialized countries, distribution systems deliver electricity literally everywhere, taking power generated at many locations and delivering it to end users. Generation, transmission, and distribution—of these three big components of the electricity infrastructure, the distribution system gets the least attention. Yet, it is often the most critical component in terms of its effect on reliability and quality of service, cost of electricity, and aesthetic (mainly visual) impacts on society.

Like much of the electric utility industry, several political, economic, and technical changes are pressuring the way distribution systems are built and operated. Deregulation has increased pressures on electric power utilities to cut costs and has focused emphasis on reliability and quality of electric service. The great fear of deregulation is that service will suffer because of cost cutting. Regulators and utility consumers are paying considerable attention to reliability and quality. Another change that is brewing is the introduction of distributed generation on the distribution system. Generators at the distribution level can cause problems (and have benefits if properly applied). New loads such as plug-in vehicles may be on the horizon. Customers are pressing for lower costs, better reliability, and lesser visual impacts from utility distribution systems.

Deregulation and technical changes increase the need by utility engineers for better information. This book helps fill some of those needs in the area of electric distribution systems. The first few chapters of the book focus on equipment-oriented information and applications such as choosing transformer connections, sizing and placing capacitors, and setting regulators.

The middle portion of this handbook contains many sections targeting reliability and power quality. The performance of the distribution system determines greater than 90% of the reliability of service to customers (the high-voltage transmission and generation system determines the rest). If performance is increased, it will have to be done on the distribution system.

Near the end, we tackle lightning protection, grounding, and safety. Safety is a very important consideration in the design, operation, and maintenance of distribution facilities. The last chapter on distributed generation provides information to help utilities avoid problems caused by the introduction of distributed generation.

I hope you find useful information in this book. If it is not in here, hopefully one of the many bibliographic references will lead you to what you are looking for. Please feel free to email me feedback on this book including errors, comments, or new sources of

information. Also, if you need my help with any interesting research opportunities, I would love to hear from you.

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Acknowledgments

First and foremost, I would like to thank my wife, Kristin—thank you again for your strength, thank you for your help, thank you for your patience, and thank you for your love. My play buddies during the first edition, Logan and Jared, are now growing into fine young men. My family was a source of inspiration. I would like to thank my parents, Bob and Sandy, for their influence and education over the years.

EPRI provided a great deal of support on this project, both during the first edition and again for this second edition. I would like to thank Matt Olearczyk and Mark McGranaghan for their support. I really enjoy working with the EPRI Distribution Systems team (program 180) and with all of our utility participants. The Knoxville crew has also been supportive on a number of projects.

Many other people reviewed portions of the first edition, including Phil Barker (Nova Energy Specialists), Dave Smith (consultant, formerly with Power Technologies, Inc.), Dan Ward (Dominion Virginia Power), Jim Stewart (Consultant, Scotia, NY), Conrad St. Pierre (Electric Power Consultants), Karl Fender (Cooper Power Systems), John Leach (Hi-Tech Fuses, Inc.), and Rusty Bascom (Power Delivery Consultants).

Thanks to Van Holsomback (Georgia Power), John Goodfellow (BioCompliance Consulting, Inc.), Stu Hanebuth (Power Survey Co.), and Marcia Eblen (consultant, formerly with PG&E) for providing material for the second edition. Lee Taylor of Duke Energy provided a lot of great material for the second edition, particularly for Chapters 3 and 10. I am a big fan of Lee's approach to managing reliability, particularly Duke Energy's use of reliability data and outage follow-ups.

Thanks to Power Technologies, Inc., for opportunities and mentoring during my early career with the help of several talented, helpful engineers, including Jim Burke, Phil Barker, Dave Smith, Jim Stewart, and John Anderson. Over the years, several clients have also educated me in many ways; two that stand out are Ron Ammon (Keyspan, retired) and Clay Burns (National Grid). Now with EPRI in a collaborative research environment, many utility engineers—too many to name—have helped guide projects and educate me. During the Green Circuits project, Ron Belvin (Duke Energy) and Don Parker (Alabama Power) were great supporters. I've enjoyed working with Marcia Eblen on arc flash.

As a side-note, I would like to recognize the efforts of line workers in the electric power industry. These folks do the real work of building the lines and keeping the power on. As a tribute to them, a trailer at the end of each chapter reveals a bit of the lineman's character and point of view.

Author

Tom Short is a technical executive at the Electric Power Research Institute (EPRI). His research and study activities have included distribution system studies, reliability, power quality, distributed generation, lightning protection, and capacitor application. Before joining EPRI PEAC in 2000 (later merged into EPRI), he worked for Power Technologies, Inc., for 10 years.

Tom earned an MS in electrical engineering from Montana State University in 1990.

As chair of the IEEE Working Group on the Lightning Performance of Electric Power Overhead Distribution Lines, he led the development of IEEE Std. 1410-1997, Improving the Lightning Performance of Electric Power Overhead Distribution Lines. In the 1990s, he led several studies evaluating and monitoring lightning performance on distribution circuits.

Tom is past chair of the IEEE Schenectady Section. He also chaired the IEEE Task Force on Weather Normalization of Reliability Data.

Tom was awarded the 2008 IEEE/PES Award for Excellence in Power Distribution Engineering.

Tom is currently researching distribution system resiliency and reliability, efficiency improvements, fault location, arc flash, and AMI (advanced metering infrastructure) data for distribution applications. He was a technical lead on EPRI's Green Circuits project, investigating options to improve the efficiency of distribution circuits. His leadership on the EPRI arc flash collaborative research has led to changes in the NESC based on realistic research.

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1

Fundamentals of Distribution Systems

Contents

1.1 Primary Distribution Configurations 4
1.2 Urban Networks 9
1.3 Primary Voltage Levels 12
1.4 Distribution Substations 15
1.5 Subtransmission Systems 18
1.6 Differences between European and North American Systems 20
1.7 Loads 23
1.8 Efficiency 25
1.9 The Past and the Future 28
References 30

Electrification in the early twentieth century dramatically improved productivity and increased the well-being of the industrialized world. No longer a luxury—now a necessity—electricity powers the machinery, the computers, the health-care systems, and the entertainment of modern society. Given its benefits, electricity is inexpensive, and its price continues to slowly decline (after adjusting for inflation—see Figure 1.1).

Electric power distribution is the portion of the power delivery infrastructure that takes the electricity from the highly meshed, high-voltage transmission circuits and delivers it to customers. Primary distribution lines are "medium-voltage" circuits, normally thought of as 600 V to 35 kV. At a distribution substation, a substation transformer takes the incoming transmission-level voltage (35 to 230 kV) and steps it down to several distribution primary circuits, which fan out from the substation. Close to each end user, a distribution transformer takes the primary distribution voltage and steps it down to a low-voltage secondary circuit (commonly 120/240 V; other utilization voltages are used as well). From the distribution transformer, the secondary distribution circuits connect to the end user where the connection is made at the service entrance. Figure 1.2 shows an overview of the power generation and delivery infrastructure and where distribution fits in. Functionally, distribution circuits are those that feed customers (this is how the term is used in this book, regardless of voltage or configuration). Some also think of distribution as anything that is radial or anything that is below 35 kV.

The distribution infrastructure is extensive; after all, electricity has to be delivered to customers concentrated in cities, customers in the suburbs, and customers in very remote regions; few places in the industrialized world do not have electricity from a distribution system readily available. Distribution circuits are found along most

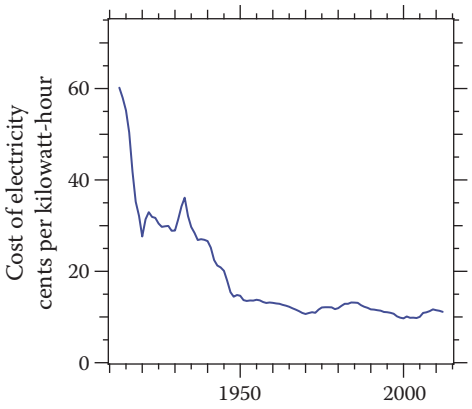

Figure 1.1 Cost of U.S. electricity adjusted for inflation to year 2000 U.S. dollars. (Data from U.S. city average electricity costs from the U.S. Bureau of Labor Statistics.)

secondary roads and streets. Urban construction is mainly underground; rural construction is mainly overhead. Suburban structures are a mix, with a good deal of new construction going underground.

A mainly urban utility may have less than 50 ft of distribution circuit for each customer. A rural utility can have over 300 ft of primary circuit per customer.

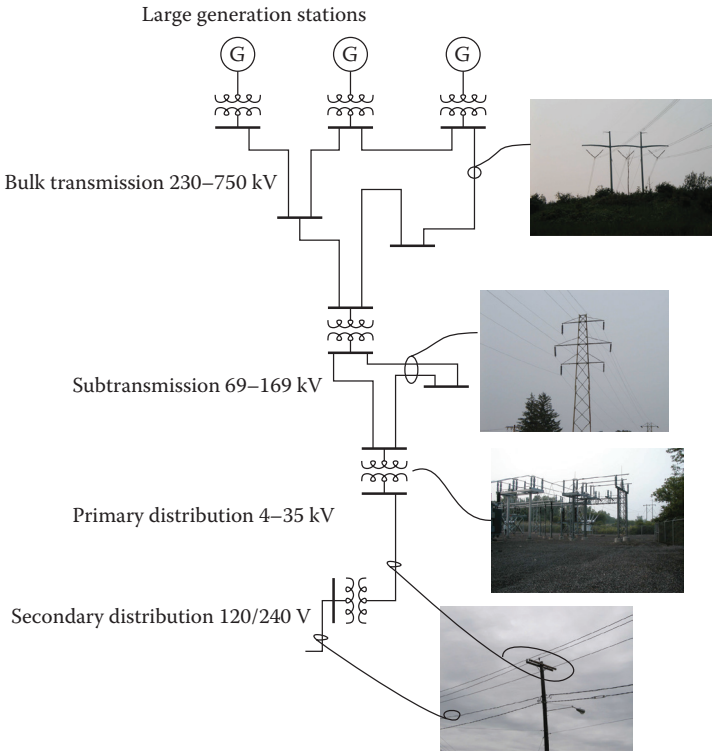

Figure 1.2 Overview of the electricity infrastructure.

Several entities may own distribution systems: municipal governments, state agencies, federal agencies, rural cooperatives, or investor-owned utilities. In addition, large industrial facilities often need their own distribution systems. While there are some differences in approaches by each of these types of entities, the engineering issues are similar for all.

For all the action regarding deregulation, the distribution infrastructure remains a natural monopoly. As with water delivery or sewers or other utilities, it is difficult to imagine duplicating systems to provide true competition, so it will likely remain highly regulated.

Because of the extensive infrastructure, distribution systems are capital-intensive businesses. An Electric Power Research Institute (EPRI) survey found that the distribution plant asset carrying cost averages 49.5% of the total distribution resource (EPRI TR-109178, 1998). The next largest component is labor at 21.8%, followed by materials at 12.9%. Utility annual distribution budgets average about 10% of the capital investment in the distribution system. On a kilowatt-hour basis, utility distribution budgets average 0.89 cents per kilowatt-hour (see Table 1.1 for budgets shown relative to other benchmarks).

Low cost, simplification, and standardization are all important design characteristics of distribution systems. Few components and/or installations are individually engineered on a distribution circuit. Standardized equipment and standardized designs are used wherever possible. "Cookbook" engineering methods are used for much of distribution planning, design, and operations.

Distribution planning is the study of future power delivery needs. Planning goals are to provide service at low cost and high reliability. Planning requires a mix of geographic, engineering, and economic analysis skills. New circuits (or other solutions) must be integrated into the existing distribution system within a variety of economic, political, environmental, electrical, and geographic constraints. The planner needs estimates of load growth, knowledge of when and where development is occurring, and local development regulations and procedures. While this book has some material that should help distribution planners, many of the tasks of a planner, such as load forecasting, are not discussed. For more information on distribution planning, see Willis's *Power Distribution Planning Reference Book* (2004), IEEE's *Power Distribution Planning* tutorial (1992), and the *CEA Distribution Planner's Manual* (1982).

TABLE 1.1 Surveyed Annual Utility Distribution Budgets in U.S. Dollars

	Average	Range
Per dollar of distribution asset	0.098	0.0916 to 0.15
Per customer	195	147 to 237
Per 1000 kWh	8.9	3.9 to 14.1
Per mile of circuit	9400	4800 to 15,200
Per substation	880,000	620,000 to 1,250,000

Source: Adapted from EPRI TR-109178, *Distribution Cost Structure—Methodology and Generic Data*, Electric Power Research Institute, Palo Alto, CA, 1998.

1.1 Primary Distribution Configurations

Distribution circuits come in many different configurations and circuit lengths. Most share many common characteristics. Figure 1.3 shows a "typical" distribution circuit, and Table 1.2 shows the typical parameters of a distribution circuit. A *feeder* is one of the circuits out of the substation. The main feeder is the three-phase backbone of the circuit, which is often called the *mains* or *mainline*. The mainline is normally a

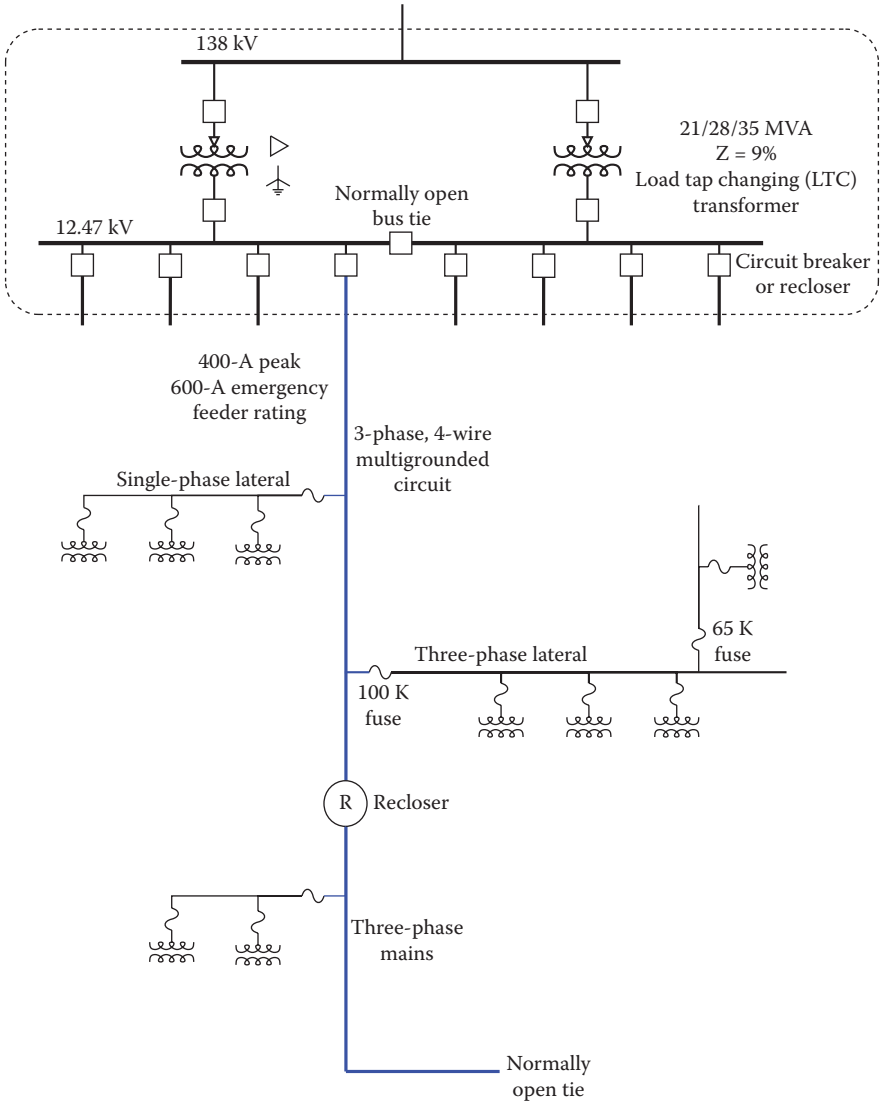

Figure 1.3 Typical distribution substation with one of the several feeders shown (many lateral taps are left off). (From EPRI 1000419, *Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems*, Electric Power Research Institute, Palo Alto, CA, 2000. Copyright 2000. Reprinted with permission.)

TABLE 1.2 Typical Distribution Circuit Parameters

	Most Common Value	Other Common Values
Substation Characteristics		
Voltage	12.47 kV	4.16, 4.8, 13.2, 13.8, 24.94, and 34.5 kV
Number of station transformers	2	1 to 6
Substation transformer size	21 MVA	5 to 60 MVA
Number of feeders per bus	4	1 to 8
Feeder Characteristics		
Peak current	400 A	100 to 600 A
Peak load	7 MVA	1 to 15 MVA
Power factor	0.98 lagging	0.8 lagging to 0.95 leading
Number of customers	400	50 to 5000
Length of feeder mains	4 mi	2 to 15 mi
Length including laterals	8 mi	4 to 25 mi
Area covered	25 mi^2	0.5 to 500 mi^2
Mains wire size	500 kcmil	4/0 to 795 kcmil
Lateral tap wire size	1/0	#4 to 2/0
Lateral tap peak current	25 A	5 to 50 A
Lateral tap length	0.5 mi	0.2 to 5 mi
Distribution transformer size (1 ph)	25 kVA	10 to 150 kVA

Source: From EPRI 1000419, *Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems*, Electric Power Research Institute, Palo Alto, CA, 2000. Copyright 2000. Reprinted with permission.

modestly large conductor, such as a 500- or 750-kcmil aluminum conductor. Utilities often design the main feeder for 400 A and often allow an emergency rating of 600 A. Branching from the mains are one or more *laterals*, which are also called taps, lateral taps, branches, or branch lines. These laterals may be single phase, two phase, or three phase. The laterals normally have fuses to separate them from the mainline if they are faulted.

The most common distribution primaries are four-wire, multigrounded systems: three-phase conductors plus a multigrounded neutral. Single-phase loads are served by transformers connected between one phase and the neutral. The neutral acts as a return conductor and as an equipment safety ground (it is grounded periodically and at all equipment). A single-phase line has one phase conductor and the neutral, and a two-phase line has two phases and the neutral. Some distribution primaries are three-wire systems (with no neutral). On these, single-phase loads are connected phase to phase, and single-phase lines have two of the three phases.

There are several configurations of distribution systems. Most distribution circuits are radial (both primary and secondary). Radial circuits have many advantages over networked circuits including

- Easier fault current protection
- Lower fault currents over most of the circuit

- Easier voltage control
- Easier prediction and control of power flows
- Lower cost

Distribution primary systems come in a variety of shapes and sizes (Figure 1.4). The arrangements depend on street layouts, the shape of the area covered by the circuit, obstacles (such as lakes), and where the big loads are. A common suburban layout has the main feeder along a street with laterals tapped down side streets or into developments. Radial distribution feeders may also have extensive branching—whatever it takes to get to the loads. An *express feeder* serves load concentrations some distance from the substation. A three-phase mainline runs a distance before tapping loads off to customers. With many circuits coming from one substation, a number of the circuits may have express feeders; some feeders cover areas close to the substation, and express feeders serve areas farther from the substation.

For improved reliability, radial circuits are often provided with normally open tie points to other circuits as shown in Figure 1.5. The circuits are still operated radially, but if a fault occurs on one of the circuits, the tie switches allow some portion of the faulted circuit to be restored quickly. Normally, these switches are manually operated, but some utilities use automated switches or reclosers to perform these operations automatically.

A primary-loop scheme is an even more reliable service that is sometimes offered for critical loads such as hospitals. Figure 1.6 shows an example of a primary loop. The key feature is that the circuit is "routed through" each critical customer transformer.

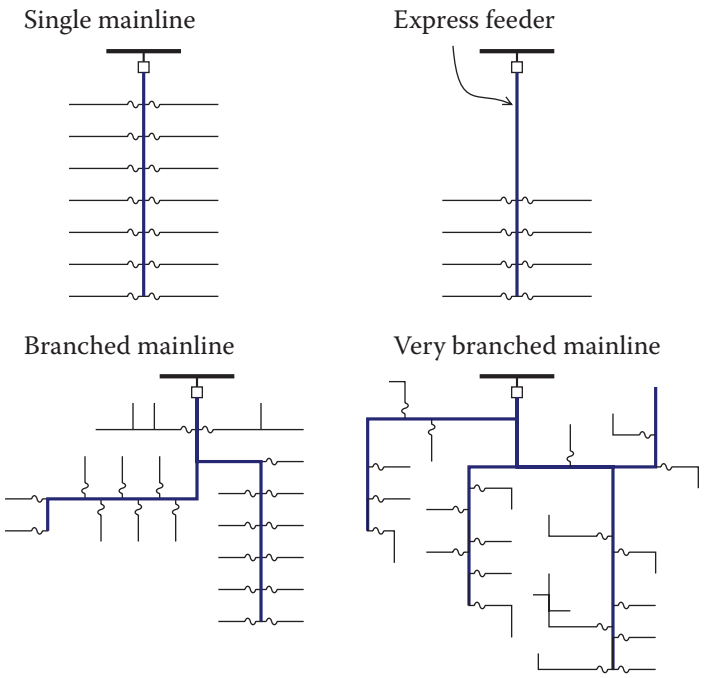

Figure 1.4 Common distribution primary arrangements.

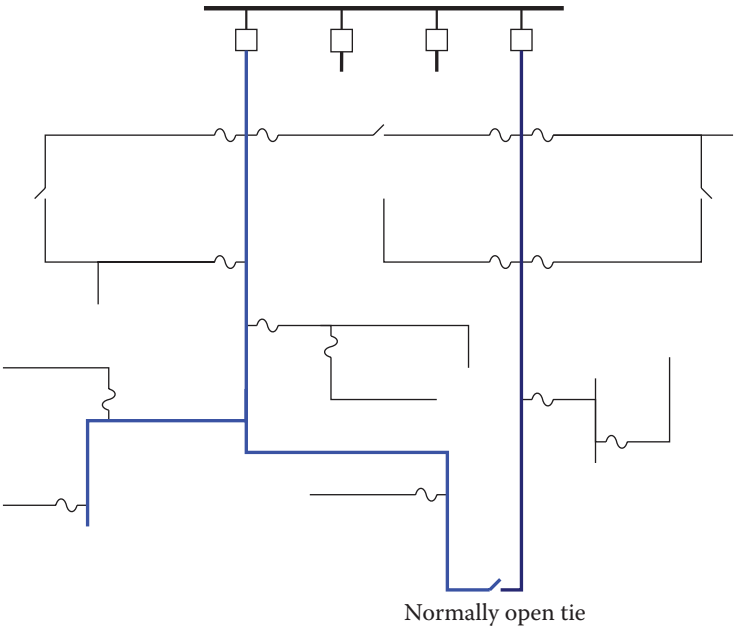

Figure 1.5 Two radial circuits with normally open ties to each other. (From EPRI 1000419, *Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems*, Electric Power Research Institute, Palo Alto, CA, 2000. Copyright 2000. Reprinted with permission.)

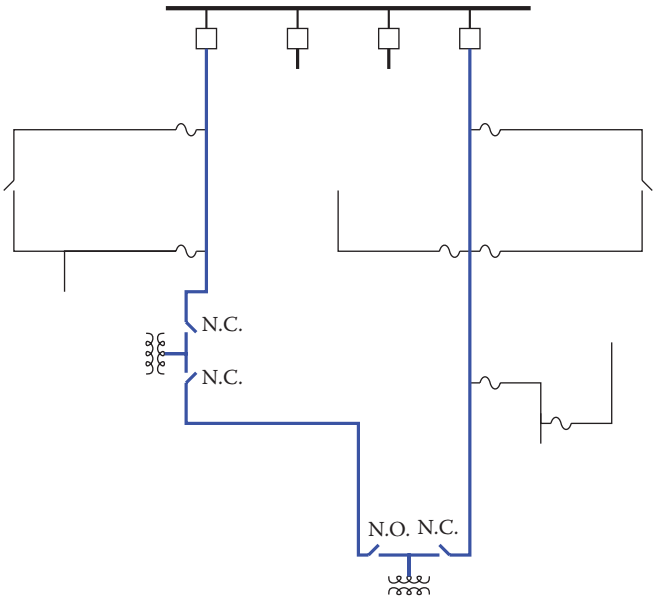

Figure 1.6 Primary-loop distribution arrangement. (From EPRI 1000419, *Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems*, Electric Power Research Institute, Palo Alto, CA, 2000. Copyright 2000. Reprinted with permission.)

If any part of the primary circuit is faulted, all critical customers can still be fed by reconfiguring the transformer switches.

Primary-loop systems are sometimes used on distribution systems for areas needing high reliability (meaning limited long-duration interruptions). In the open-loop design where the loop is normally left open at some point, primary-loop systems have almost no benefits for momentary interruptions or voltage sags. They are rarely operated in a closed loop. A widely reported installation of a sophisticated *closed* system has been installed in Orlando, FL, by Florida Power Corporation (Pagel, 2000). An example of this type of closed-loop primary system is shown in Figure 1.7. Faults on any of the cables in the loop are cleared in less than six cycles, which reduces the duration of the voltage sag during the fault (enough to help many computers). Advanced relaying similar to transmission-line protection is necessary to coordinate the protection and operation of the switchgear in the looped system. The relaying scheme uses a transfer trip with permissive overreaching (the relays at each end of the cable must agree that there is a fault between them with communications done on fiber-optic lines). A backup scheme uses directional relays, which will trip for a fault in a certain direction unless a blocking signal is received from the remote end (again over the fiber-optic lines).

Critical customers have two more choices for more reliable service where two primary feeds are available. Both primary selective and secondary selective schemes are

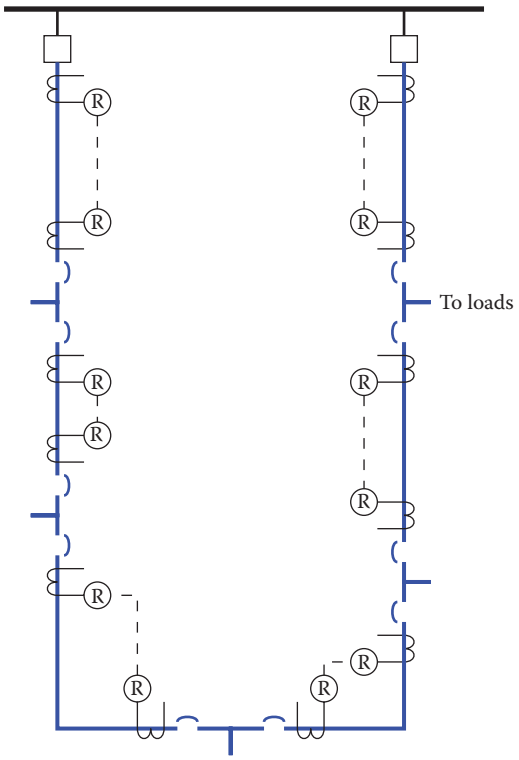

Figure 1.7 Example of a closed-loop distribution system.

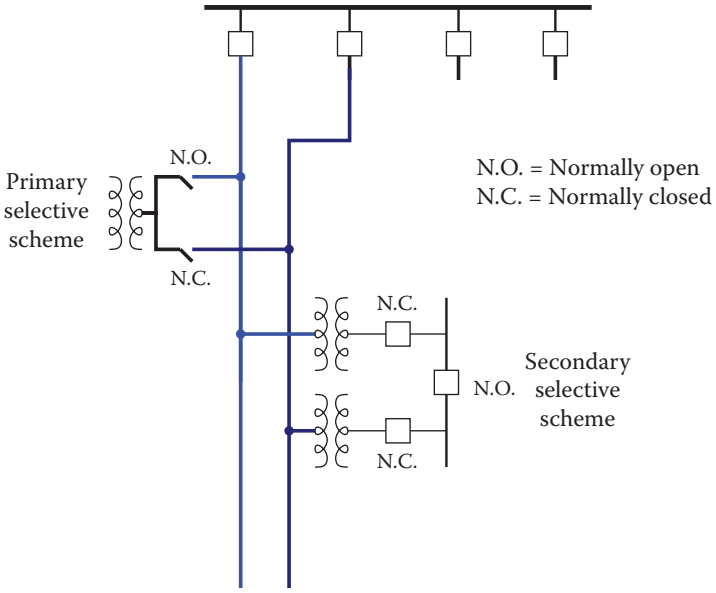

Figure 1.8 Primary and secondary selective schemes. (From EPRI 1000419, *Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems*, Electric Power Research Institute, Palo Alto, CA, 2000. Copyright 2000. Reprinted with permission.)

normally fed from one circuit (see Figure 1.8). So, the circuits are still radial. In the event of a fault on the primary circuit, the service is switched to the backup circuit. In the primary selective scheme, the switching occurs on the primary, and in the secondary selective scheme, the switching occurs on the secondary. The switching can be done manually or automatically, and there are even static transfer switches that can switch in less than a half-cycle to reduce momentary interruptions and voltage sags.

Today, the primary selective scheme is preferred mainly because of the cost associated with the extra transformer in a secondary selective scheme. The normally closed switch on the primary-side transfer switch opens after sensing a loss of voltage. It normally has a time delay on the order of seconds—enough to ride through the distribution circuit's normal reclosing cycle. The opening of the switch is blocked if there is an overcurrent in the switch (the switch does not have fault interrupting capability). Transfer is also disabled if the alternate feed does not have proper voltage. The switch can return to normal through either an open or a closed transition; in a closed transition, both distribution circuits are temporarily paralleled.

1.2 Urban Networks

Some distribution circuits are not radial. The most common are the grid and spot secondary networks. In these systems, the secondary is networked together and has feeds from several primary distribution circuits. The spot network feeds one load such as a high-rise building. The grid network feeds several loads at different points in an

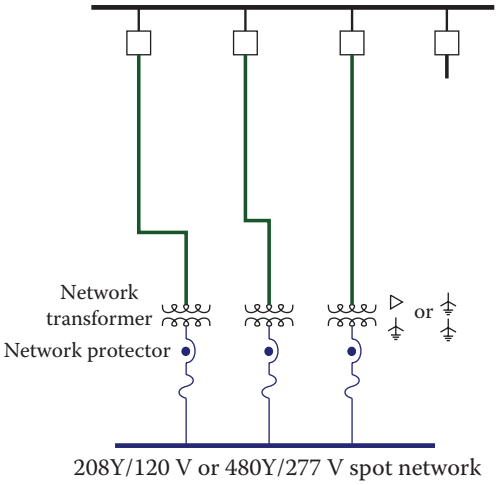

Figure 1.9 Spot network. (From EPRI 1000419, *Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems*, Electric Power Research Institute, Palo Alto, CA, 2000. Copyright 2000. Reprinted with permission.)

area. Secondary networks are very reliable; if any of the primary distribution circuits fail, the others will carry the load without causing an outage for any customer.

The spot network is generally fed by three to five primary feeders (see Figure 1.9). The circuits are generally sized to be able to carry all the load with the loss of either one or two of the primary circuits. Secondary networks have network protectors between the primary and the secondary network. A network protector is a low-voltage circuit breaker that will open when there is reverse power through it. When a fault occurs on a primary circuit, fault current backfeeds from the secondary network(s) to the fault. When this occurs, the network protectors will trip on reverse power. A spot network operates at 480Y/277 V or 208Y/120 V in the United States.

Secondary grid networks are distribution systems that are used in most major cities. The secondary network is usually 208Y/120 V in the United States. Five to 10 primary distribution circuits (e.g., 12.47-kV circuits) feed the secondary network at multiple locations. Figure 1.10 shows a small part of a secondary network. As with a spot network, network protectors provide protection for faults on the primary circuits. Secondary grid networks can have peak loads of 5 to 50 MVA. Most utilities limit networks to about 50 MVA, but some networks are over 250 MVA. Loads are fed by tapping into the secondary networks at various points. Grid networks (also called street networks) can supply residential or commercial loads, either single or three phase. For single-phase loads, a three-wire service is provided to give 120 and 208 V (rather than the standard three-wire residential service, which supplies 120 and 240 V).

Networks are normally fed by feeders originating from one substation bus. Having one source reduces circulating current and gives better load division and distribution among circuits. It also reduces the chance that network protectors stay open under light load (circulating current can trip the protectors). Given these difficulties, it is

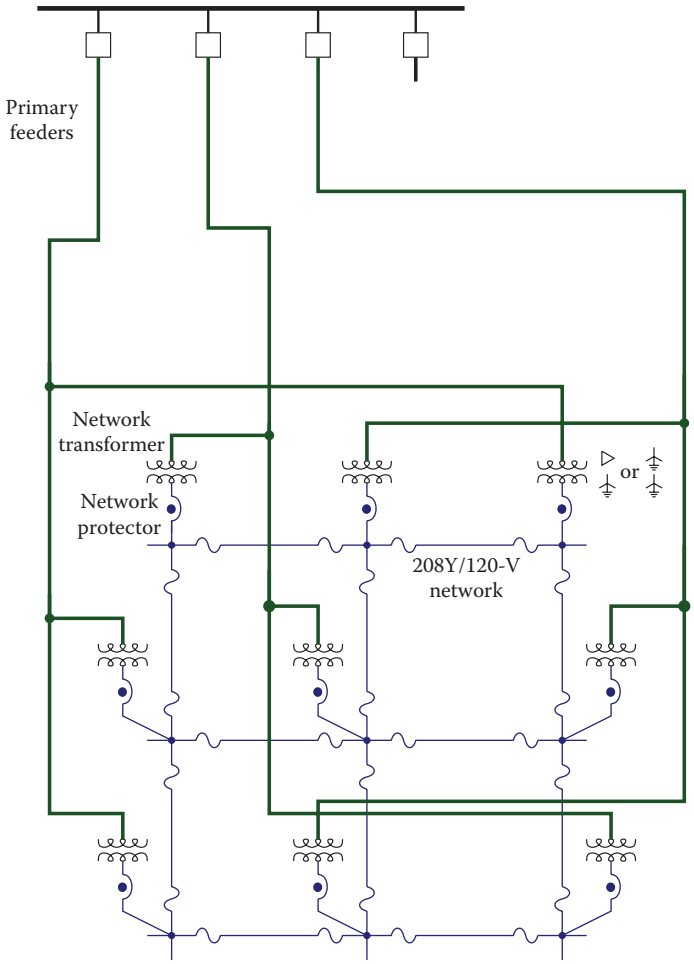

Figure 1.10 Portion of a grid network. (From EPRI 1000419, *Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems*, Electric Power Research Institute, Palo Alto, CA, 2000. Copyright 2000. Reprinted with permission.)

still possible to feed grid or spot networks from different substations or electrically separate buses.

The network protector is the key to automatic isolation and continued operation. The network protector is a three-phase low-voltage air circuit breaker with controls and relaying. The network protector is mounted on the network transformer or on a vault wall. Standard units are available with continuous ratings from 800 to 5000 A. Smaller units can interrupt 30 kA symmetrical, and larger units have interrupt ratings of 60 kA (IEEE Std. C57.12.44–2000). A network protector senses and operates for reverse power flow (it does not have forward-looking protection). Protectors are available for either 480Y/277 V or 216Y/125 V.

The tripping current on network protectors can be changed, with low, nominal, and high settings, which are normally 0.05 to 0.1%, 0.15 to 0.20%, and 3 to 5% of the network protector rating. For example, a 2000-A network protector has a low setting of

1 A, a nominal setting of 4 A, and a high setting of 100 A (IEEE Std. C57.12.44–2000). Network protectors also have fuses that provide backup in case the network protector fails to operate, and as a secondary benefit, provide protection to the network protector and transformer against faults in the secondary network that are close.

The closing voltages are also adjustable: a 216Y/125-V protector has low, medium, and high closing voltages of 1, 1.5, and 2 V, respectively; a 480Y/277-V protector has low, medium, and high closing voltages of 2.2, 3.3, and 4.4 V, respectively.

1.3 Primary Voltage Levels

Most distribution voltages are between 4 and 35 kV. In this book, unless otherwise specified, voltages are given as line-to-line voltages; this follows the normal industry practice, but it is sometimes a source of confusion. The four major voltage classes are 5, 15, 25, and 35 kV. A voltage class is a term applied to a set of distribution voltages and the equipment common to them; it is not the actual system voltage. For example, a 15-kV insulator is suitable for application on any 15-kV class voltage, including 12.47, 13.2, and 13.8 kV. Cables, terminations, insulators, bushings, reclosers, and cutouts all have a voltage class rating. Only voltage-sensitive equipment such as surge arresters, capacitors, and transformers have voltage ratings dependent on the actual system voltage.

Utilities most widely use the 15-kV voltages as shown by the survey results of North American utilities in Figure 1.11. The most common 15-kV voltage is 12.47 kV, which has a line-to-ground voltage of 7.2 kV.

The dividing line between distribution and subtransmission is often gray. Some lines act as both subtransmission and distribution circuits. A 34.5-kV circuit may feed a few 12.5-kV distribution substations, but it may also serve some load directly. Some utilities would refer to this as subtransmission; others would refer to this as distribution.

The last half of the twentieth century saw a move to higher-voltage primary distribution systems. Higher-voltage distribution systems have advantages and disadvantages

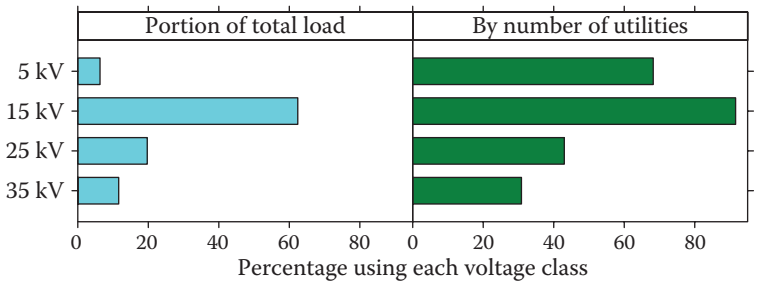

Figure 1.11 Usage of different distribution voltage classes ($n = 107$). (Data from IEEE Working Group on Distribution Protection, Distribution line protection practices industry survey results, *IEEE Transactions on Power Delivery*, vol. 10, no. 1, pp. 176–86, January 1995.)

TABLE 1.3 Advantages and Disadvantages of Higher-Voltage Distribution

Advantages	Disadvantages
Voltage drop—A higher-voltage circuit has less voltage drop for a given power flow.	*Reliability*—An important disadvantage of higher voltages: longer circuits mean more customer interruptions.
Capacity—A higher-voltage system can carry more power for a given ampacity.	*Crew safety and acceptance*—Crews do not like working on higher-voltage distribution systems.
Losses—For a given level of power flow, a higher-voltage system has fewer line losses.	*Equipment cost*—From transformers to cable to insulators, higher-voltage equipment costs more.
Reach—With less voltage drop and more capacity, higher-voltage circuits can cover a much wider area.	
Fewer substations—Because of longer reach, higher-voltage distribution systems need fewer substations.	

(see Table 1.3 for a summary). The great advantage of higher-voltage systems is that they carry more power for a given current (Table 1.4 shows maximum power levels typically supplied by various distribution voltages). Less current means lower voltage drop, fewer losses, and more power-carrying capability. Higher-voltage systems need fewer voltage regulators and capacitors for voltage support. Utilities can use smaller conductors on a higher-voltage system or can carry more power on the same size conductor. Utilities can run much longer distribution circuits at a higher primary voltage, which means fewer distribution substations. Some fundamental relationships are

- *Power*—For the same current, power changes linearly with voltage.

$$P_2 = \frac{V_1}{V_1} P_1$$

  when $I_2 = I_1$
- *Current*—For the same power, increasing the voltage decreases current linearly.

$$I_2 = \frac{V_1}{V_2} I_1$$

  when $P_2 = P_1$

TABLE 1.4 Power Supplied by Each Distribution Voltage for a Current of 400 A

System Voltage (kV)	Total Power (MVA)
4.8	3.3
12.47	8.6
22.9	15.9
34.5	23.9

- *Voltage drop*—For the same power delivered, the percentage voltage drop changes as the ratio of voltages squared. A 12.47-kV circuit has 4 times the percentage voltage drop as a 24.94-kV circuit carrying the same load.

$$V_{\%2} = \left(\frac{V_1}{V_2}\right)^2 V_{\%1}$$

  when $P_2 = P_1$
- *Area coverage*—For the same load density, the area covered increases linearly with voltage: a 24.94-kV system can cover twice the area of a 12.47-kV system; a 34.5-kV system can cover 2.8 times the area of a 12.47-kV system.

$$A_2 = \frac{V_2}{V_1} A_1$$

  where
  V_1 and V_2 = voltage on circuits 1 and 2
  P_1 and P_2 = power on circuits 1 and 2
  I_1 and I_2 = current on circuits 1 and 2
  $V_{\%1}$ and $V_{\%2}$ = voltage drop per unit length in percent on circuits 1 and 2
  A_1 and A_2 = area covered by circuits 1 and 2

The squaring effect on voltage drop is significant. It means that doubling the system voltage quadruples the load that can be supplied over the same distance (with equal percentage voltage drop); or, twice the load can be supplied over twice the distance; or, the same load can be supplied over 4 times the distance.

Resistive line losses are also lower on higher-voltage systems, especially in a voltage-limited circuit. Thermally limited systems have more equal losses, but even in this case, higher-voltage systems have fewer losses.

Line crews do not like higher-voltage distribution systems as much. In addition to the widespread perception that they are not as safe, gloves are thicker, and procedures are generally more stringent. Some utilities will not glove 25- or 35-kV voltages and only use hotsticks.

The main disadvantage of higher-voltage systems is reduced reliability. Higher voltages mean longer lines and more exposure to lightning, wind, dig-ins, car crashes, and other fault causes. A 34.5-kV, 30-mi mainline is going to have many more interruptions than a 12.5-kV system with an 8-mi mainline. To maintain the same reliability as a lower-voltage distribution system, a higher-voltage primary must have more switches, more automation, more tree trimming, or other reliability improvements. Higher-voltage systems also have more voltage sags and momentary interruptions. More exposure causes more momentary interruptions. Higher-voltage systems have more voltage sags because faults further from the substation can pull down the station's voltage (on a higher-voltage system, the line impedance is lower relative to the source impedance).

TABLE 1.5 Costs of 34.5 kV Relative to 12.5 kV

Item	Underground	Overhead
Subdivision without bulk feeders	1.25	1.13
Subdivision with bulk feeders	1.00	0.85
Bulk feeders	0.55	0.55
Commercial areas	1.05 to 1.25	1.05 to 1.25

Source: Adapted from Jones, A. I., Smith, B. E., and Ward, D. J., *IEEE Transactions on Power Delivery*, vol. 7, no. 2, pp. 782–8, April 1992.

Cost comparison between circuits is difficult (see Table 1.5 for one utility's cost comparison). Higher-voltage equipment costs more—cables, insulators, transformers, arresters, cutouts, and so on. But higher-voltage circuits can use smaller conductors. The main savings of higher-voltage distribution are fewer substations. Higher-voltage systems also have lower annual costs from losses. As far as ongoing maintenance, higher-voltage systems require less substation maintenance, but higher-voltage systems should have more tree trimming and inspections to maintain reliability.

Conversion to a higher voltage is an option for providing additional capacity in an area. Conversion to higher voltages is most beneficial when substation space is hard to find and load growth is high. If the existing subtransmission voltage is 34.5 kV, then using that voltage for distribution is attractive; additional capacity can be met by adding customers to the existing 34.5-kV lines (a neutral may need to be added to the 34.5-kV subtransmission line).

Higher-voltage systems are also more prone to ferroresonance. Radio interference is also more common at higher voltages.

Overall, the 15-kV class voltages provide a good balance between cost, reliability, safety, and reach. Although a 15-kV circuit does not naturally provide long reach, with voltage regulators and feeder capacitors, it can be stretched to reach 20 mi or more. That said, higher voltages have advantages, especially for rural lines and for high-load areas, particularly where substation space is expensive.

Many utilities have multiple voltages (as shown by the survey data in Figure 1.11). Even one circuit may have multiple voltages. For example, a utility may install a 12.47-kV circuit in an area currently served by 4.16 kV. Some of the circuit may be converted to 12.47 kV, but much of it can be left as it is and coupled through 12.47/4.16-kV step-down transformer banks.

1.4 Distribution Substations

Distribution substations come in many sizes and configurations. A small rural substation may have a nominal rating of 5 MVA while an urban station may be over 200 MVA. Figures 1.12 through 1.14 show examples of small, medium, and large substations. As much as possible, many utilities have standardized substation layouts, transformer sizes, relaying systems, and automation and SCADA (supervisory

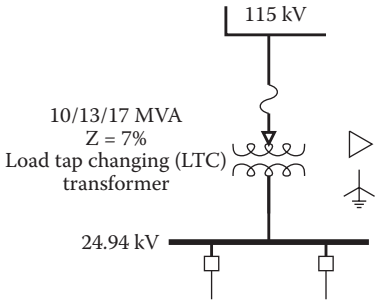

Figure 1.12 Example of a rural distribution substation.

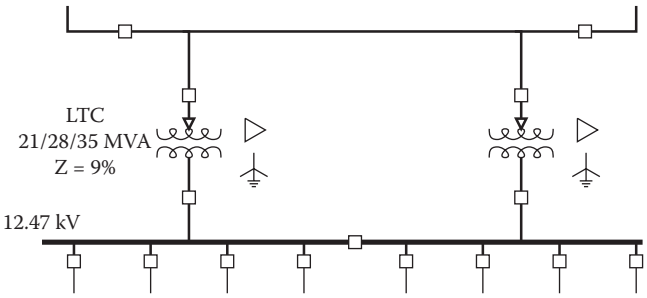

Figure 1.13 Example of a suburban distribution substation.

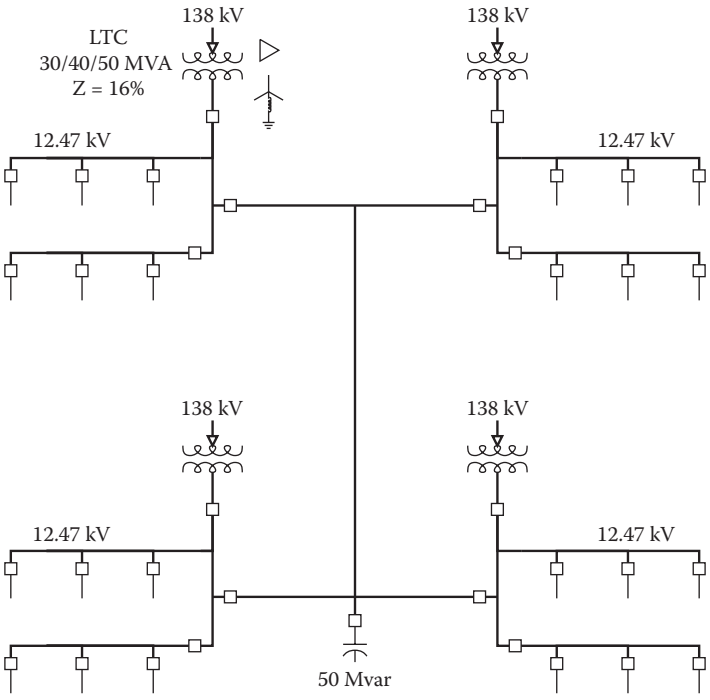

Figure 1.14 Example of an urban distribution substation.

control and data acquisition) facilities. Most distribution substation bus configurations are simple with limited redundancy.

Transformers smaller than 10 MVA are normally protected with fuses, but fuses are also used for transformers to 20 or 30 MVA. Fuses are inexpensive and simple; they do not need control power and take up little space. Fuses are not particularly sensitive, especially for evolving internal faults. Larger transformers normally have relay protection that operates a circuit switcher or a circuit breaker. Relays often include differential protection, sudden-pressure relays, and overcurrent relays. Both the differential protection and the sudden-pressure relays are sensitive enough to detect internal failures and clear the circuit to limit additional damage to the transformer. Occasionally, relays operate a high-side grounding switch instead of an interrupter. When the grounding switch engages, it creates a bolted fault that is cleared by an upstream device or devices.

The feeder interrupting devices are normally relayed circuit breakers, either free-standing units or metal-enclosed switchgear. Many utilities also use reclosers instead of breakers, especially at smaller substations.

Station transformers are normally protected by differential relays that trip if the current into the transformer is not very close to the current out of the transformer. Relaying may also include pressure sensors. The high-side protective device is often a circuit switcher but may also be fuses or a circuit breaker.

Two-bank stations are very common (Figure 1.13); these are the standard design for many utilities. Normally, utilities size the transformers so that if either transformer fails, the remaining unit can carry the entire substation's load. Utility practices vary on how much safety margin is built into this calculation, and load growth can eat into the redundancy.

Most utilities normally use a split bus: a bus tie between the two buses is normally left open in distribution substations. The advantages of a split bus are

- *Lower fault current*—This is the main reason that bus ties are open. For a two-bank station with equal transformers, opening the bus tie cuts fault current into half.
- *Circulating current*—With a split bus, current cannot circulate through both transformers.
- *Bus regulation*—Bus voltage regulation is also simpler with a split bus. With the tie closed, the control of paralleled tap changers is more difficult.

Having the bus tie closed has some advantages, and many utilities use closed ties under some circumstances. A closed bus tie is better for

- *Secondary networks*—When feeders from each bus supply either spot or grid secondary networks, closed bus ties help prevent circulating current through the secondary networks.
- *Unequal loading*—A closed bus tie helps balance the loading on the transformers. If the set of feeders on one bus has significantly different loading patterns (either seasonal or daily), then a closed bus tie helps even out the loading (and aging) of the two transformers.

Whether the bus tie is open or closed has little impact on reliability. In the uncommon event that one transformer fails, both designs allow the station to be reconfigured

so that one transformer supplies both bus feeders. The closed-tie scenario is somewhat better in that an automated system can reconfigure the ties without total loss of voltage to customers (customers do see a very large voltage sag). In general, both designs perform about the same for voltage sags.

Urban substations are more likely to have more complicated bus arrangements. These could include ring buses or breaker-and-a-half schemes. Figure 1.14 shows an example of a large urban substation with feeders supplying secondary networks. If feeders are supplying secondary networks, it is not critical to maintain continuity to each feeder, but it is important to prevent the loss of any one bus section or piece of equipment from shutting down the network (an *N*-1 design).

For more information on distribution substations, see RUS 1724E-300 (2001) and Westinghouse Electric Corporation (1965).

1.5 Subtransmission Systems

Subtransmission systems are those circuits that supply distribution substations. Several different subtransmission systems can supply distribution substations. Common subtransmission voltages include 34.5, 69, 115, and 138 kV. Higher-voltage subtransmission lines can carry more power with less losses over greater distances. Distribution circuits are occasionally supplied by high-voltage transmission lines such as 230 kV; such high voltages make for expensive high-side equipment in a substation. Subtransmission circuits are normally supplied by bulk transmission lines at subtransmission substations. For some utilities, one transmission system serves as both the subtransmission function (feeding distribution substations) and the transmission function (distributing power from bulk generators). There is much crossover in functionality and voltage. One utility may have a 23-kV subtransmission system supplying 4-kV distribution substations. Another utility right next door may have a 34.5-kV distribution system fed by a 138-kV subtransmission system. And within utilities, one can find a variety of different voltage combinations.

Of all the subtransmission circuit arrangements, a radial configuration is the simplest and least expensive (see Figure 1.15). But radial circuits provide the most unreliable supply; a fault on the subtransmission circuit can force an interruption of several distribution substations and service to many customers. A variety of redundant subtransmission circuits are available, including dual circuits and looped or meshed circuits (see Figure 1.16). The design (and evolution) of subtransmission configurations depends on how the circuit developed, where the load is needed now and in the future, what the distribution circuit voltages are, where bulk transmission is available, where rights-of-way are available, and, of course, economic factors.

Most subtransmission circuits are overhead. Many are built right along roads and streets just like distribution lines. Some—especially higher-voltage subtransmission circuits—use a private right-of-way such as bulk transmission lines use. Some new subtransmission lines are put underground, as the development of solid-insulation cables has made costs more reasonable.

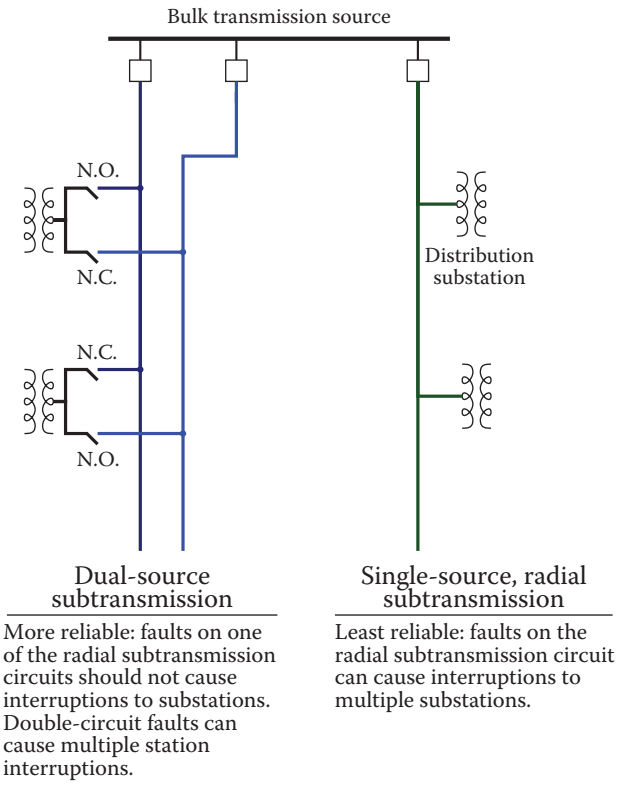

Figure 1.15 Radial subtransmission systems.

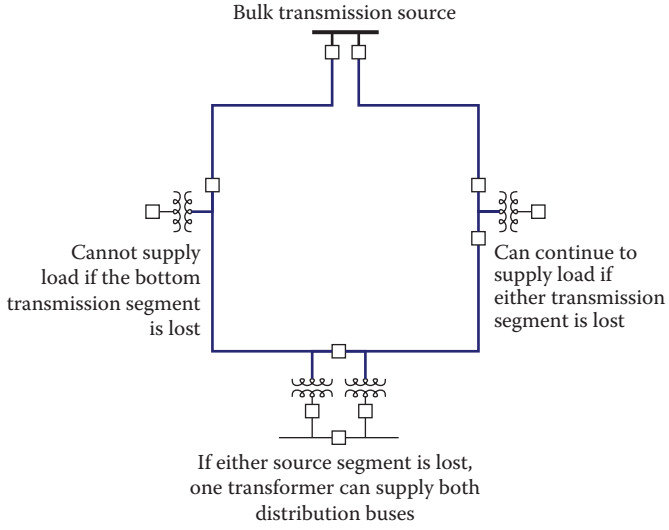

Figure 1.16 Looped subtransmission system.

Lower-voltage subtransmission lines (69, 34.5, and 23 kV) tend to be designed and operated as are distribution lines, with radial or simple loop arrangements, using wood-pole construction along roads, with reclosers and regulators, often without a shield wire, and with time–overcurrent protection. Higher-voltage transmission lines (115, 138, and 230 kV) tend to be designed and operated like bulk transmission lines, with loop or mesh arrangements, tower configurations on a private right-of-way, a shield wire or wires for lightning protection, and directional or pilot-wire relaying from two ends. Generators may or may not interface at the subtransmission level (which can affect protection practices).

1.6 Differences between European and North American Systems

Distribution systems around the world have evolved into different forms. The two main designs are North American and European. This book mainly deals with North American distribution practices; for more information on European systems, see Lakervi and Holmes (1995). For both forms, hardware is much the same: conductors, cables, insulators, arresters, regulators, and transformers are very similar. Both systems are radial, and voltages and power carrying capabilities are similar. The main differences are in layouts, configurations, and applications.

Figure 1.17 compares the two systems. Relative to North American designs, European systems have larger transformers and more customers per transformer. Most European transformers are three phase and on the order of 300 to 1000 kVA, much larger than the typical North American 25- or 50-kVA single-phase units.

Secondary voltages have motivated many of the differences in distribution systems. North America has standardized on a 120/240-V secondary system; on these, voltage drop constrains how far utilities can run secondaries, typically not more than 250 ft. In European designs, higher secondary voltages allow secondaries to stretch to almost 1 mi. European secondaries are largely three phase and most European countries have a standard secondary voltage of 220, 230, or 240 V, twice the North American standard. With twice the voltage, a circuit feeding the same load can reach 4 times the distance. And, because three-phase secondaries can reach over twice the length of a single-phase secondary, overall, a European secondary can reach 8 times the length of an American secondary for a given load and voltage drop. Although it is rare, some European utilities supply rural areas with single-phase taps made of two phases with single-phase transformers connected phase to phase.

In the European design, secondaries are used much like primary laterals in the North American design. In European designs, the primary is not tapped frequently, and primary-level fuses are not used as much. European utilities also do not use reclosing as religiously as North American utilities.

Some of the differences in designs center around the differences in loads and infrastructure. In Europe, the roads and buildings were already in place when the electrical system was developed, so the design had to "fit in." Secondary is often attached to buildings. In North America, many of the roads and electrical circuits were developed

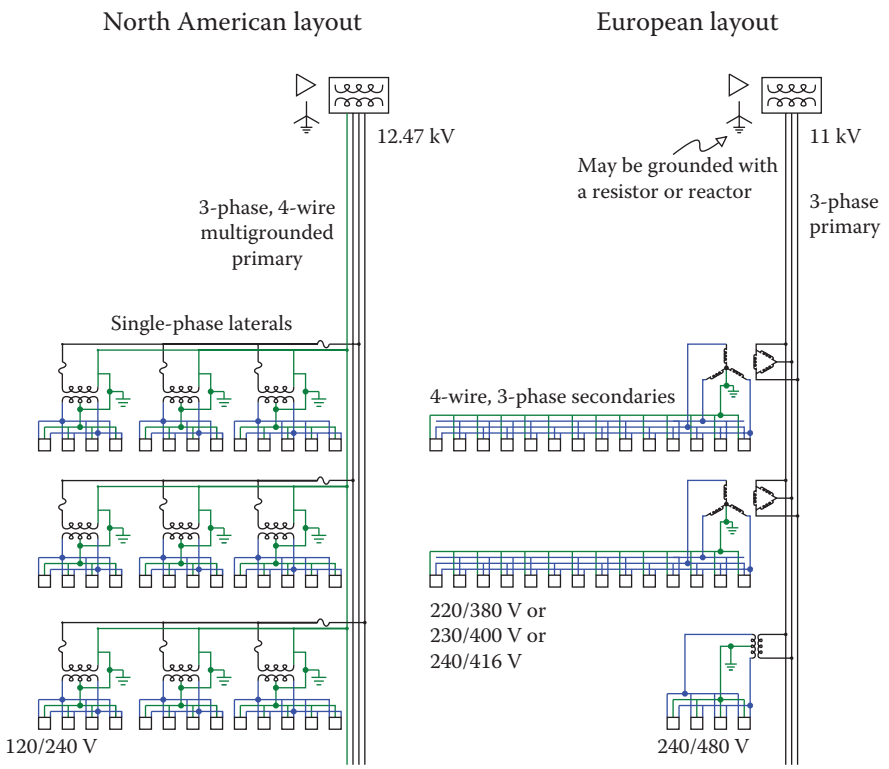

Figure 1.17 North American versus European distribution layouts.

at the same time. Also, in Europe, houses are packed together more and are smaller than houses in America.

Each type of system has its advantages. Some of the major differences between systems are the following (see also Carr and McCall, 1992; Meliopoulos et al., 1998; Nguyen et al., 2000):

- *Cost*—The European system is generally more expensive than the North American system, but there are so many variables that it is hard to compare them on a one-to-one basis. For the types of loads and layouts in Europe, the European system fits quite well. European primary equipment is generally more expensive, especially for areas that can be served by single-phase circuits.
- *Flexibility*—The North American system has a more flexible primary design, and the European system has a more flexible secondary design. For urban systems, the European system can take advantage of the flexible secondary; for example, transformers can be sited more conveniently. For rural systems and areas where load is spread out, the North American primary system is more flexible. The North American primary is slightly better suited for picking up new load and for circuit upgrades and extensions.
- *Safety*—The multigrounded neutral of the North American primary system provides many safety benefits; protection can more reliably clear faults, and the neutral acts as a physical barrier, as well as helps to prevent dangerous touch voltages during

faults. The European system has the advantage that high-impedance faults are easier to detect.

- *Reliability*—Generally, North American designs result in fewer customer interruptions. Nguyen et al. (2000) simulated the performance of the two designs for a hypothetical area and found that the average frequency of interruptions was over 35% higher on the European system. Although European systems have less primary, almost all of it is on the main feeder backbone; loss of the main feeder results in an interruption for all customers on the circuit. European systems need more switches and other gear to maintain the same level of reliability.
- *Power quality*—Generally, European systems have fewer voltage sags and momentary interruptions. On a European system, less primary exposure should translate into fewer momentary interruptions compared to a North American system that uses fuse saving. The three-wire European system helps to protect against sags from line-to-ground faults. A squirrel across a bushing (from line to ground) causes a relatively high-impedance fault path that does not sag the voltage much compared to a bolted fault on a well-grounded system. Even if a phase conductor faults to a low-impedance return path (such as a well-grounded secondary neutral), the delta–wye customer transformers provide better immunity to voltage sags, especially if the substation transformer is grounded through a resistor or reactor.
- *Aesthetics*—Having less primary, the European system has an aesthetic advantage: the secondary is easier to underground or to blend in. For underground systems, fewer transformer locations and longer secondary reach make siting easier.
- *Theft*—The flexibility of the European secondary system makes power much easier to steal. Developing countries especially have this problem. Secondaries are often strung along or on top of buildings; this easy access does not require great skill to attach into.

Outside Europe and North America, both systems are used, and usage typically follows colonial patterns with European practices being more widely used. Some regions of the world have mixed distribution systems, using bits of North American and bits of European practices. The worst mixture is 120-V secondaries with European-style primaries; the low-voltage secondary has limited reach along with the more expensive European primary arrangement.

Higher secondary voltages have been explored (but not implemented to my knowledge) for North American systems to gain flexibility. Higher secondary voltages allow extensive use of the secondary, which makes undergrounding easier and reduces costs. Westinghouse engineers contended that both 240/480-V three-wire single-phase and 265/460-V four-wire three-phase secondaries provide cost advantages over a similar 120/240-V three-wire secondary (Lawrence and Griscom, 1956; Lokay and Zimmerman, 1956). Higher secondary voltages do not force higher utilization voltages; a small transformer at each house converts 240 or 265 V into 120 V for lighting and standard outlet use (air conditioners and major appliances can be served directly without the extra transformation). More recently, Bergeron et al. (2000) outlined a vision of a distribution system where primary-level distribution voltage is stepped down to an extensive 600-V, three-phase secondary system. At each house, an electronic transformer converts 600 V into 120/240 V.

1.7 Loads

Distribution systems obviously exist to supply electricity to end users, so loads and their characteristics are important. Utilities supply a broad range of loads, from rural areas with load densities of 10 kVA/mi^2 to urban areas with 300 MVA/mi^2. A utility may feed houses with a 10- to 20-kVA peak load on the same circuit as an industrial customer peaking at 5 MW. The electrical load on a feeder is the sum of all individual customer loads. And, the electrical load of a customer is the sum of the load drawn by the customer's individual appliances. Customer loads have many common characteristics. Load levels vary through the day, peaking in the afternoon or early evening. Several definitions are used to quantify load characteristics at a given location on a circuit:

- *Demand*—The load average over a specified time period, is often 15, 20, or 30 min. Demand can be used to characterize real power, reactive power, total power, or current. Peak demand over some period of time is the most common way utilities quantify a circuit's load. In substations, it is common to track the current demand.
- *Load factor*—The ratio of the average load over the peak load. Peak load is normally the maximum demand but may be the instantaneous peak. The load factor is between zero and one. A load factor close to 1.0 indicates that the load runs almost constantly. A low load factor indicates a more widely varying load. From the utility point of view, it is better to have high load-factor loads. Load factor is normally found from the total energy used (kilowatt-hours) as

$$\mathrm{LF} = \frac{\mathrm{kWh}}{d_{\mathrm{kW}} \times h}$$

  where
  LF = load factor
  kWh = energy use in kilowatt-hours
  d_{kW} = peak demand in kilowatts
  h = number of hours during the time period

- *Coincident factor*—The ratio of the peak demand of a whole system to the sum of the individual peak demands within that system. The peak demand of the whole system is referred to as the peak *diversified* demand or as the peak *coincident* demand. The individual peak demands are the *noncoincident* demands. The coincident factor is less than or equal to one. Normally, the coincident factor is much lesser than one because each of the individual loads do not hit their peak at the same time (they are not coincident).
- *Diversity factor*—The ratio of the sum of the individual peak demands in a system to the peak demand of the whole system. The diversity factor is greater than or equal to one and is the reciprocal of the coincident factor.
- *Responsibility factor*—The ratio of a load's demand at the time of the system peak to its peak demand. A load with a responsibility factor of one peaks at the same time as the overall system. The responsibility factor can be applied to individual customers, customer classes, or circuit sections.

The loads of certain customer classes tend to vary in similar patterns. Commercial loads are highest from 8 a.m. to 6 p.m. Residential loads peak in the evening. Weather significantly changes loading levels. On hot summer days, air conditioning increases the demand and reduces the diversity among loads. At the transformer level, load factors of 0.4 to 0.6 are typical (Gangel and Propst, 1965).

Several groups have evaluated coincidence factors as a function of the number of customers. Nickel and Braunstein (1981) determined that one curve roughly fell in the middle of several curves evaluated. Used by Arkansas Power and Light, this curve fits the following:

$$F_{co} = \frac{1}{2}\left(1 + \frac{5}{2n+3}\right)$$

where n is the number of customers (see Figure 1.18).

At the substation level, coincidence is also apparent. A transformer with four feeders, each peaking at 100 A, will peak at less than 400 A because of diversity between feeders. The coincident factor between four feeders is normally higher than coincident factors at the individual customer level. Expect coincident factors to be above 0.9. Each feeder is already highly diversified, so not much more is gained by grouping more customers together if the sets of customers are similar. If the customer mix on each feeder is different, then multiple feeders can have significant differences. If some feeders are mainly residential and others are commercial, the peak load of the feeders together can be significantly lower than the sum of the peaks. For distribution transformers, the peak responsibility factor ranges from 0.5 to 0.9 with 0.75 being typical (Nickel and Braunstein, 1981).

Different customer classes have different characteristics (see Figure 1.19 for an example). Residential loads peak more in the evening and have a relatively low load factor. Commercial loads tend to run from 8 a.m. to 6 p.m., and the industrial loads tend to run continuously; and as a class, they have a higher load factor.

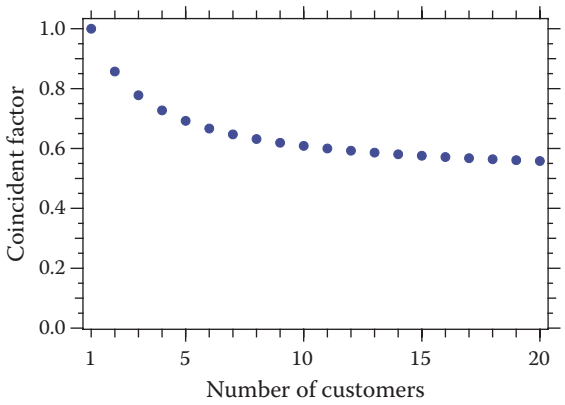

Figure 1.18 Coincident factor average curve for utilities.

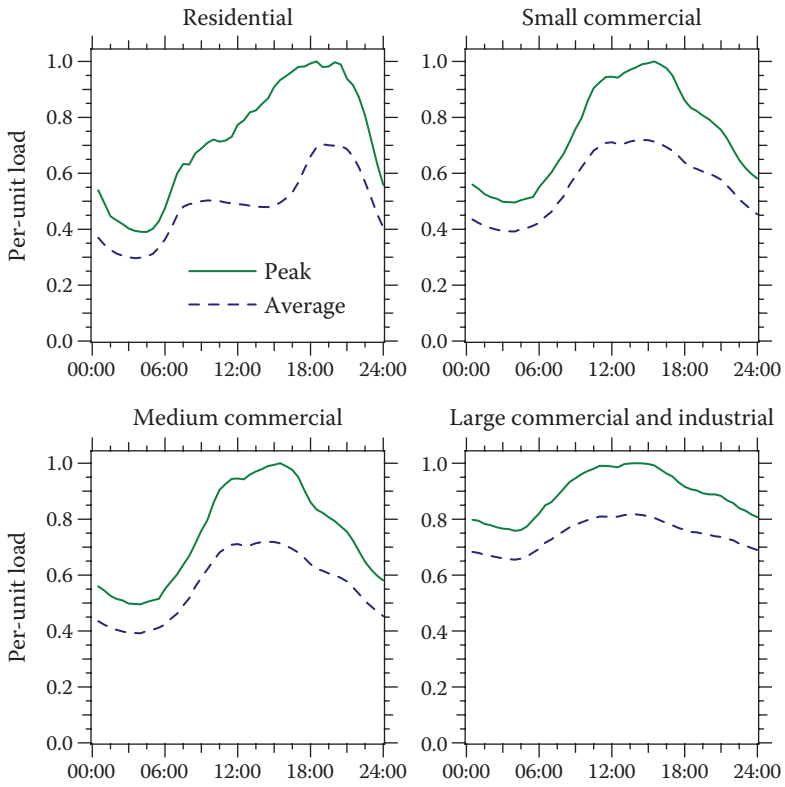

Figure 1.19 Daily load profiles for Pacific Gas and Electric (2002 data).

Electric vehicles are another load that could change customer load characteristics, and if adoptions happen quickly, it could impact the loading of infrastructure. EPRI 1024101 (2012) describes several evaluations of the impacts of plug-in vehicles. Distribution transformers are the main equipment that might be overloaded, especially when clustering is considered. Secondary voltage drop is another issue. Delayed charging tends to reduce distribution system impacts.

1.8 Efficiency

Distribution efficiency has always been a consideration for distribution planners (CEA, 1982; IEEE Tutorial Course, 1992). Most distribution planning projects include efficiency evaluations. Efficiency is normally considered in specifications for transformer purchases, guidelines for applying transformers, conductor selection, and loading criteria.

See Table 1.6 for losses estimated by several utilities as part of loss studies. These loss studies are not all directly comparable because of different categorizations and because of differing approaches to performing loss studies. Some utilities used computer models to calculate primary losses, while others used average loading for each size of the conductor. Some utilities included substation transformers losses as transmission losses, while others classified these as distribution losses.

TABLE 1.6 Losses from Several Utility Studies

	Electric System Energy Losses			
Utility	Transmission (%)	Distribution (%)	Secondary (%)	Total Distribution (%)
B	0.62	2.73	3.75	6.49
C	N/A	1.91	0.92	2.84
D	2.53	1.79	0.89	2.68
E	3.71	2.40	0.35	2.76
F	2.25	1.84	1.75	3.59
G	3.76	1.53	1.71	3.24
H	4.20	0.82	0.89	1.71
I	3.51	1.20	1.24	2.44
J	3.70	1.28	1.28	2.56
K	1.10	6.40	1.56	7.96
O	1.80	3.67	0.38	4.05
P	1.38	1.58	1.80	3.38
Q	2.53	1.14	1.83	2.96
R	2.69	4.69	0.30	4.99

Source: From EPRI 1016097, *Distribution System Losses Evaluation*, Electric Power Research Institute, Palo Alto, CA, 2008. Copyright 2008. Reprinted with permission.

Note: Losses reported as provided in reports. No attempt was made to normalize losses due to the differences in the way each utility categorized and reported losses.

Losses also vary by system configuration. Rural circuits tend to have higher losses because circuits are longer. Higher-voltage distribution systems generally have lower losses because currents are lower, and line losses are a function of I^2R. For transformer losses, historical specifications for purchasing transformers and the cost of losses play a role as well as how transformers are utilized.

Table 1.7 summarizes the losses estimated in the EPRI Green Circuit project (EPRI 1023518, 2011; Arritt et al., 2012). The 66-project circuits encompassed many different types of distribution circuits that varied in design practices, load types, voltage class, voltage-regulation techniques, and var control practices. In addition, the circuits covered many different geographical locations and urban and rural environments of

TABLE 1.7 Distribution Circuit Loss Statistics (Percent)

		Quartiles		
	Average	25%	50%	75%
Primary line losses	1.40	0.61	1.04	1.84
Transformer load losses	0.38	0.24	0.34	0.46
Transformer no-load losses	1.59	1.03	1.49	1.89
Secondary line losses	0.31	0.16	0.27	0.44
Total losses	3.64	2.52	3.09	4.32

Source: From EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright 2011. Reprinted with permission.

varying degrees. Since the circuits were analyzed and modeled similarly, the dataset provides a good way to compare losses on a wide range of circuits and evaluate various efficiency improvements. Overall, 75% of circuits had losses exceeding 2.52%, and 25% of circuits had losses exceeding 4.32%, not including the substation transformer. See Figure 1.20 for a breakdown by the circuit and the type of loss. Transformer

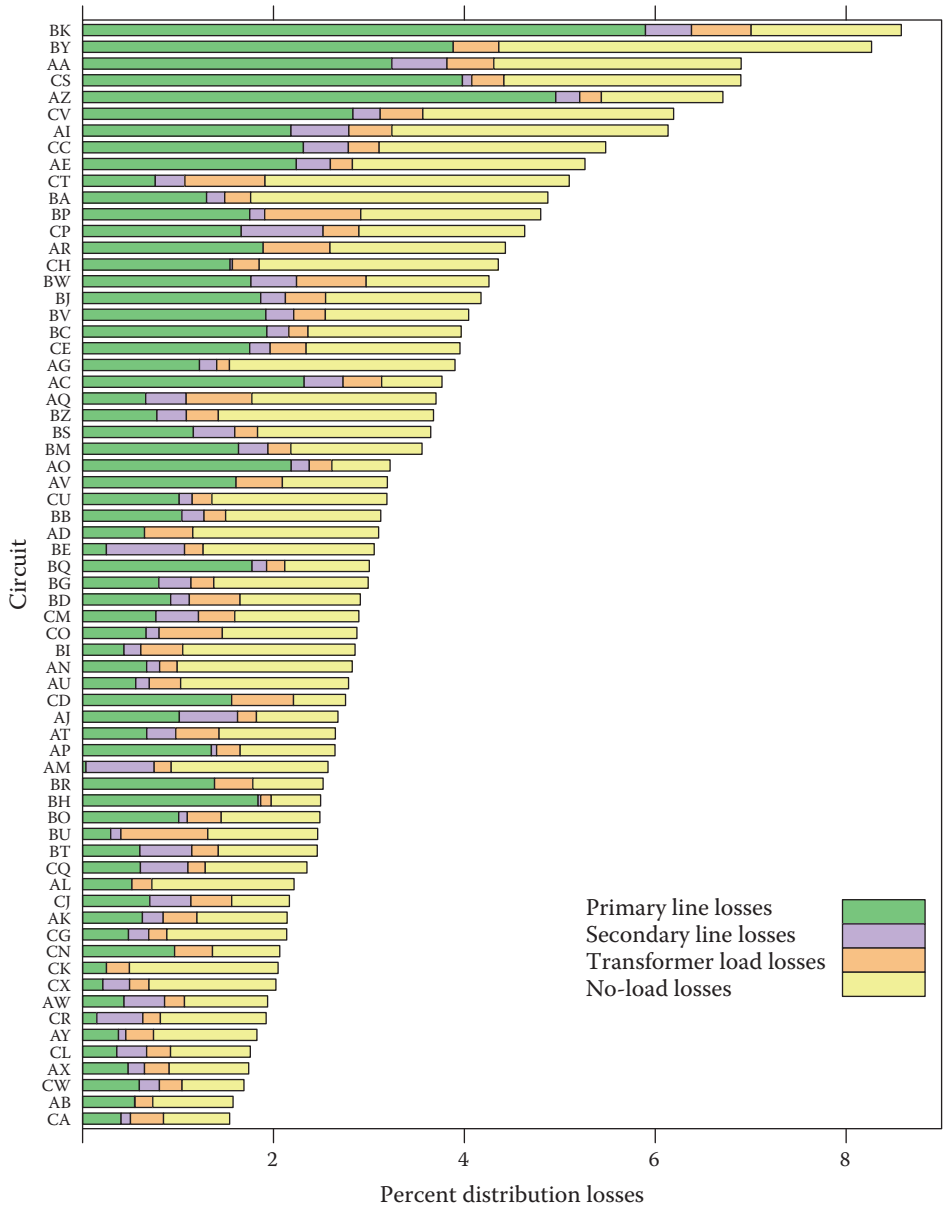

Figure 1.20 Circuit loss breakdowns in average percentage. (From EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright 2011. Reprinted with permission.)

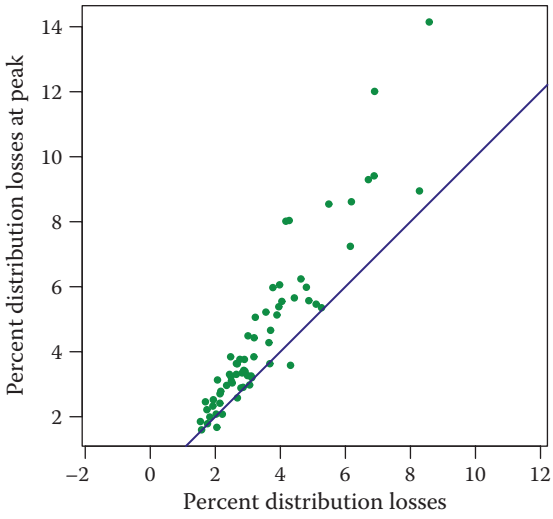

Figure 1.21 Peak versus average losses. (From EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright 2011. Reprinted with permission.)

no-load losses averaged about 1.6% of the total energy consumption and ranged from approximately 0.5% to 3.5%. These losses were the most consistent across circuits, depending mainly on transformer age and transformer utilization (connected kVA versus load).

At peak load, losses averaged 4.8% of peak demand and ranged from approximately 1.6% to 16.5%. Losses at peak load were predominantly primary line losses. Seventy-five percent of circuits had peak losses exceeding 3.0%, and 25% of circuits had losses exceeding 5.8%. See Figure 1.21 for comparisons of the average energy losses versus losses at peak.

In the EPRI study, losses on some circuits could be economically reduced by phase balancing and reactive power improvements (adding capacitor banks or applying more efficient control to existing units). Other projects such as reconductoring, circuit reconfigurations, and voltage upgrades cannot be justified through loss savings alone, but savings from losses can add to the value of such projects when they are considered along with other factors such as capacity limitations and reliability. For more information on efficiency improvement programs, see NRECA (2004). The Green Circuits project also showed economic benefits from improvements that reduce losses and flatten voltage profiles as part of voltage optimization projects. See Chapter 6 for more information.

1.9 The Past and the Future

Looking at Seelye's *Electrical Distribution Engineering* book (1930), we find more similarities to than differences from present-day distribution systems. The basic layout

and operations of distribution infrastructure at the beginning of the twenty-first century are much the same as in the middle of the twentieth century. The equipment has undergone steady improvements, transformers are more efficient, cables are much less expensive and easier to use, and protection equipment is better (see Figure 1.22 for some development milestones). Utilities operate more distribution circuits at higher voltages and use more underground circuits. But the concepts are much the same: alternating current (ac), three-phase systems, radial circuits, fused laterals, overcurrent relays, and so on. Advances in computer technology have opened up possibilities for more automation and more effective protection.

How will future distribution systems evolve? Given the fact that distribution systems of the year 2000 look much the same as distribution systems in 1950, a good guess is that the distribution system of 2050 (or at least 2025) will look much like today's systems. More and more of the electrical infrastructure will be placed underground. Designs and equipment will continue to be standardized. Gradually, the distribution system will evolve to take advantage of computer and communication gains: more advanced metering, more automation, more communication between equipment, and smarter switches and controllers. EPRI outlined a vision of a future distribution system that was no longer radial, a distribution system that evolves to support widespread distributed generation and storage along with the ability to charge

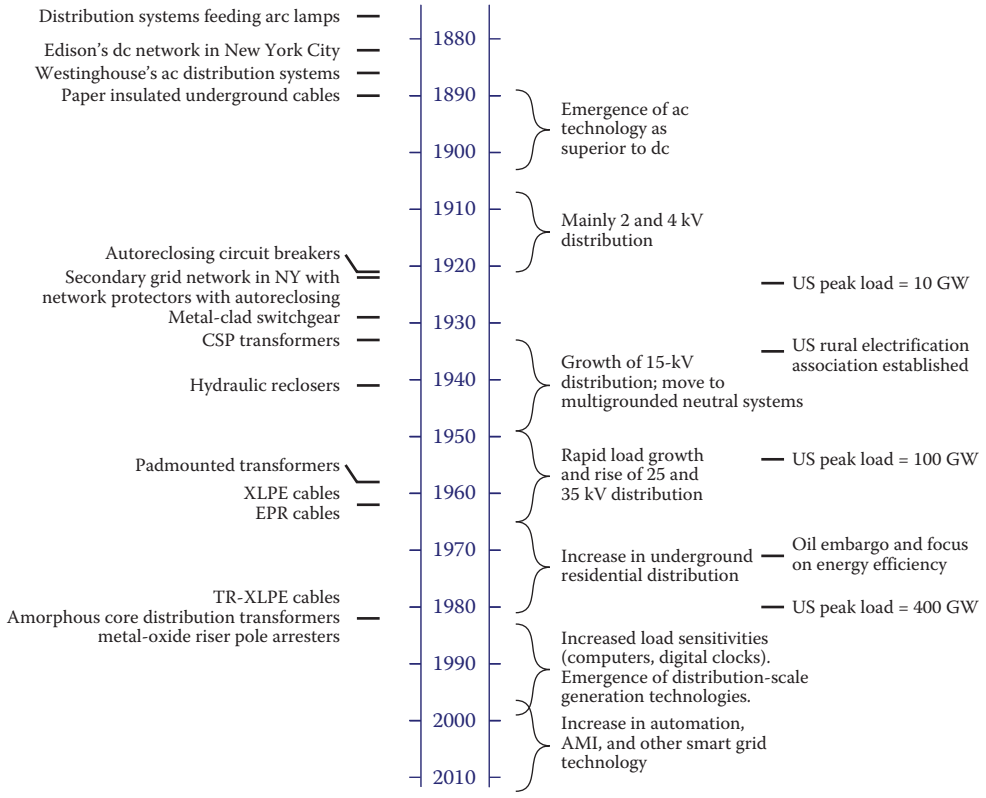

Figure 1.22 Electric power distribution development timeline.

electric vehicles (EPRI TR-111683, 1998). Such a system needs directional relaying for reclosers, communication between devices, regulators with advanced controls, and information from and possibly control of distributed generators. Such "smart grid" approaches will continue to evolve and be integrated into distribution systems.

Advances in power electronics make more radical changes such as conversion into direct current (dc) possible. Advances in power electronics allow flexible conversion between different frequencies, phasings, and voltages while still producing ac voltage to the end user at the proper voltage. While possible, radical changes are unlikely, given the advantages to evolving an existing system rather than replacing it. Whatever the approach, the future has challenges; utilities will be expected to deliver more reliable power with minimal pollution while keeping the distribution system hidden from view and causing the least disruption possible. And, of course, costs are expected to stay the same or go down.

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2
Overhead Lines

Contents

2.1 Typical Constructions 33
2.2 Conductor Data 37
2.3 Line Impedances 42
2.4 Simplified Line Impedance Calculations 49
2.5 Line Impedance Tables 54
2.6 Conductor Sizing 54
2.7 Ampacities 56
2.7.1 Neutral Conductor Sizing 69
2.8 Secondaries 70
2.9 Fault Withstand Capability 71
2.9.1 Conductor Annealing 72
2.9.2 Burndowns 74
2.10 Other Overhead Issues 82
2.10.1 Conductor Slapping 82
2.10.2 Connectors and Splices 84
2.10.3 Radio-Frequency Interference 86
References 88

Along streets, alleys, through woods, and in backyards, many of the distribution lines that feed customers are overhead structures. Because overhead lines are exposed to trees and animals, to wind and lightning, and to cars and kites, they are a critical component in the reliability of distribution circuits. This chapter discusses many of the key electrical considerations of overhead lines: conductor characteristics, impedances, ampacity, and other issues.

2.1 Typical Constructions

Overhead constructions come in a variety of configurations (see Figures 2.1 through 2.4). Normally one primary circuit is used per pole, but utilities sometimes run more than one circuit per structure. For a three-phase circuit, the most common structure is a horizontal layout with an 8- or 10-ft wood crossarm on a pole (see Figure 2.5). Armless constructions are also widely found where fiberglass insulator standoffs or post insulators are used in a tighter configuration. Utilities normally use 30- to 45-ft poles, set 6 to 8 ft deep. Vertical construction is also occasionally

Figure 2.1 Three-phase 34.5-kV armless construction with covered wire.

Figure 2.2 Single-phase circuit, 7.2 kV line-to-ground.

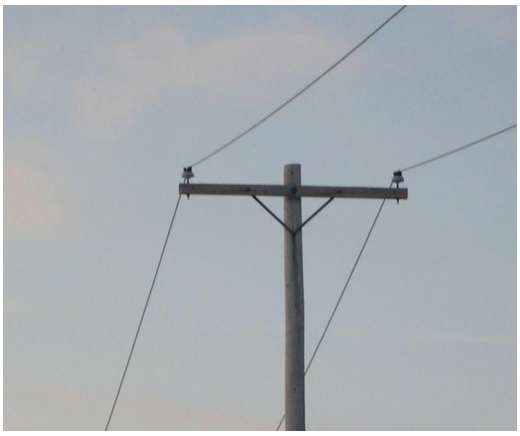


Figure 2.3 Single-phase, 4.8-kV circuit.

Figure 2.4 13.2-kV spacer cable.

used. Span lengths vary from 100 to 150 ft in suburban areas to as much as 300 or 400 ft in rural areas.

Distribution circuits normally have an underbuilt neutral—the neutral acts as a safety ground for equipment and provides a return path for unbalanced loads and for line-to-ground faults. The neutral is 3 to 5 ft below the phase conductors. Utilities in very high lightning areas may run the neutral wire above the phase conductors to act as a shield wire. Some utilities also run the neutral on the crossarm. Secondary circuits are often run under the primary. The primary and the secondary may share the neutral, or they may each have their own neutral. Many electric utilities share their space

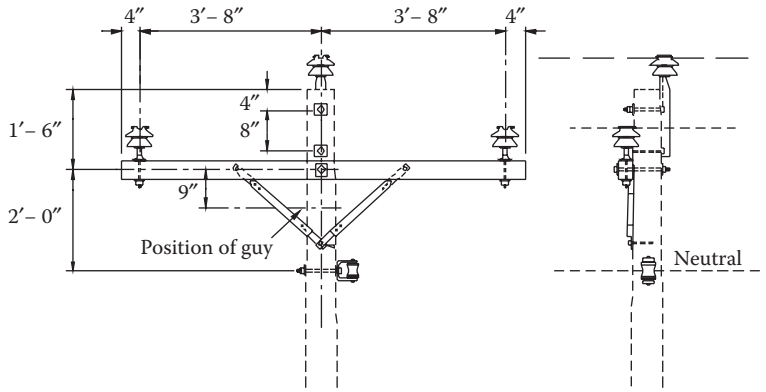


Figure 2.5 Example crossarm construction. (From RUS 1728F-803, *Specifications and Drawings for 24.9/14.4 kV Line Construction*, United States Department of Agriculture, Rural Utilities Service, 1998.)

with other utilities; telephone or cable television cables may run under the electric secondary.

Wood is the main pole material, although steel, concrete, and fiberglass are also used. Treated wood lasts a long time, is easy to climb and attach equipment to, and also augments the insulation between the energized conductors and ground. Conductors are primarily aluminum. Insulators are pin type, post type, or suspension, either porcelain or polymer.

The National Electrical Safety Code (IEEE C2-2012) governs many of the safety issues that play important roles in overhead design issues. Poles must have space for crews to climb them and work safely in the air. All equipment must have sufficient strength to stand up to "normal" operations. Conductors must carry their weight, the weight of any accumulated ice, plus withstand the wind pressure exerted on the wire. We are not going to discuss mechanical and structural issues in this book. For more information, see the *Lineman's and Cableman's Handbook* (Kurtz et al., 1997), the *Mechanical Design Manual for Overhead Distribution Lines* (RUS 160-2, 1982), the *NESC* (IEEE C2-2012), the *NESC Handbook* (Clapp, 2012), and the *National Electrical Safety Handbook* (Marne, 2012).

Overhead construction can cost $10,000/mi to $250,000/mi, depending on the circumstances. Some of the major variables are labor costs, how developed the land is, natural objects (including rocks in the ground and trees in the way), whether the circuit is single or three phase, and how big the conductors are. Suburban three-phase mains are typically about $60,000 to $150,000/mi; single-phase laterals are often in the $40,000 to $75,000/mi range. Construction is normally less expensive in rural areas; in urban areas, crews must deal with traffic and set poles in concrete. As Willis (2004) notes, upgrading a circuit normally costs more than building a new line. Typically this work is done live: the old conductor has to be moved to standoff brackets while the new conductor is strung, and the poles may have to be reinforced to handle heavier conductors.

2.2 Conductor Data

A *wire* is metal drawn or rolled to long lengths, normally understood to be a solid wire. Wires may or may not be insulated. A *conductor* is one or more wires suitable for carrying electric current. Often the term *wire* is used to mean conductor. Table 2.1 shows some characteristics of common conductor metals.

Most conductors are either aluminum or copper. Utilities use aluminum for almost all new overhead installations. Aluminum is lighter and less expensive for a given current-carrying capability. Copper was installed more in the past, so significant lengths of copper are still in service on overhead circuits.

Aluminum for power conductors is alloy 1350, which is 99.5% pure and has a minimum conductivity of 61.0% IACS [for more complete characteristics, see the *Aluminum Electrical Conductor Handbook* (Aluminum Association, 1989)]. Pure aluminum melts at 660°C. Aluminum starts to anneal (soften and lose strength) above 100°C. It has good corrosion resistance; when exposed to the atmosphere, aluminum oxidizes, and this thin, invisible film of aluminum oxide protects against most chemicals, weathering conditions, and even acids. Aluminum can corrode quickly through electrical contact with copper or steel. This galvanic corrosion (dissimilar metals corrosion) accelerates in the presence of salts.

TABLE 2.1 Nominal or Minimum Properties of Conductor Wire Materials

Property	International Annealed Copper Standard	Commercial Hard-Drawn Copper Wire	Standard 1350-H19 Aluminum Wire	Standard 6201-T81 Aluminum Wire	Galvanized Steel Core Wire	Aluminum Clad Steel
Conductivity, % IACS at 20°C	100.0	97.0	61.2	52.5	8.0	20.3
Resistivity at 20°C, $\Omega \cdot in.^2/1000$ ft	0.008145	0.008397	0.013310	0.015515	0.101819	0.04007
Ratio of weight for equal dc resistance and length	1.00	1.03	0.50	0.58	9.1	3.65
Temp. coefficient of resistance, per °C at 20°C	0.00393	0.00381	0.00404	0.00347	0.00327	0.00360
Density at 20°C, $lb/in.^3$	0.3212	0.3212	0.0977	0.0972	0.2811	0.2381
Coefficient of linear expansion, 10^{-6} per °C	16.9	16.9	23.0	23.0	11.5	13.0
Modulus of elasticity, 10^6 psi	17	17	10	10	29	23.5
Specific heat at 20°C, cal/g-°C	0.0921	0.0921	0.214	0.214	0.107	0.112
Tensile strength, 10^3 psi	62.0	62.0	24.0	46.0	185	175
Minimum elongation, %	1.1	1.1	1.5	3.0	3.5	1.5

Source: Data from Southwire Company, *Overhead Conductor Manual*, 1994.

Several variations of aluminum conductors are available:

- *AAC—all-aluminum conductor*—Aluminum grade 1350-H19 AAC has the highest conductivity-to-weight ratio of all overhead conductors. See Table 2.2 for characteristics.
- *ACSR—aluminum conductor, steel reinforced*—Because of its high mechanical strength-to-weight ratio, ACSR has equivalent or higher ampacity for the same size conductor (the kcmil size designation is determined by the cross-sectional area of the aluminum; the steel is neglected). The steel adds extra weight, normally 11 to 18% of the weight of the conductor. Several different strandings are available to provide different strength levels. Common distribution sizes of ACSR have twice the breaking strength of AAC. High strength means the conductor can withstand higher ice and wind loads. Also, trees are less likely to break this conductor. See Table 2.3 for characteristics.
- *AAAC—all-aluminum alloy conductor*—This alloy of aluminum, the 6201-T81 alloy, has high strength and equivalent ampacities of AAC or ACSR. AAAC finds good use in coastal areas where use of ACSR is prohibited because of excessive corrosion.
- *ACAR—aluminum conductor, alloy reinforced*—Strands of aluminum 6201-T81 alloy are used along with standard 1350 aluminum. The alloy strands increase the strength of the conductor. The strands of both are of the same diameter, so they can be arranged in a variety of configurations.

For most urban and suburban applications, AAC has sufficient strength and has good thermal characteristics for a given weight. In rural areas, utilities can use smaller conductors and longer pole spans, so ACSR or another of the higher-strength conductors is more appropriate.

Copper has very low resistivity and is widely used as a power conductor, although its use as an overhead conductor has become rare because copper is heavier and more expensive than aluminum. It has significantly lower resistance than aluminum by volume—a copper conductor has equivalent ampacity (resistance) of an aluminum conductor that is two AWG sizes larger. Copper has very good resistance to corrosion. It melts at 1083°C, starts to anneal at about 100°C, and anneals most rapidly between 200°C and 325°C (this range depends on the presence of impurities and amount of hardening). When copper anneals, it softens and loses tensile strength.

Different sizes of conductors are specified with gage numbers or area in circular mils. Smaller wires are normally referred to using the American wire gage (AWG) system. The gage is a numbering scheme that progresses geometrically. A number 36 solid wire has a defined diameter of 0.005 in. (0.0127 cm), and the largest size, a number 0000 (referred to as 4/0 and pronounced "four-ought") solid wire has a 0.46-in. (1.17-cm) diameter. The larger gage sizes in sequence of increasing conductor size are: 4, 3, 2, 1, 0 (1/0), 00 (2/0), 000 (3/0), 0000 (4/0). Going to the next bigger size (smaller gage number) increases the diameter by 1.1229. Some other useful rules are:

- An increase of three gage sizes doubles the area and weight and halves the dc resistance.
- An increase of six gage sizes doubles the diameter.

Larger conductors are specified in circular mils of cross-sectional area. One circular mil is the area of a circle with a diameter of one mil (one mil is one-thousandth of

TABLE 2.2 Characteristics of All-Aluminum Conductor (AAC)

					Resistance, Ω/1000 ft					
					dc	60-Hz ac				
AWG	kcmil	Strands	Diameter, in.	GMR, Ft	20°C	25°C	50°C	75°C	Breaking. Strength, lb	Weight, lb/1000 ft
6	26.24	7	0.184	0.0056	0.6593	0.6725	0.7392	0.8059	563	24.6
4	41.74	7	0.232	0.0070	0.4144	0.4227	0.4645	0.5064	881	39.1
2	66.36	7	0.292	0.0088	0.2602	0.2655	0.2929	0.3182	1350	62.2
1	83.69	7	0.328	0.0099	0.2066	0.2110	0.2318	0.2527	1640	78.4
1/0	105.6	7	0.368	0.0111	0.1638	0.1671	0.1837	0.2002	1990	98.9
2/0	133.1	7	0.414	0.0125	0.1299	0.1326	0.1456	0.1587	2510	124.8
3/0	167.8	7	0.464	0.0140	0.1031	0.1053	0.1157	0.1259	3040	157.2
4/0	211.6	7	0.522	0.0158	0.0817	0.0835	0.0917	0.1000	3830	198.4
	250	7	0.567	0.0171	0.0691	0.0706	0.0777	0.0847	4520	234.4
	250	19	0.574	0.0181	0.0693	0.0706	0.0777	0.0847	4660	234.3
	266.8	7	0.586	0.0177	0.0647	0.0663	0.0727	0.0794	4830	250.2
	266.8	19	0.593	0.0187	0.0648	0.0663	0.0727	0.0794	4970	250.1
	300	19	0.629	0.0198	0.0575	0.0589	0.0648	0.0705	5480	281.4
	336.4	19	0.666	0.0210	0.0513	0.0527	0.0578	0.0629	6150	315.5
	350	19	0.679	0.0214	0.0494	0.0506	0.0557	0.0606	6390	327.9
	397.5	19	0.724	0.0228	0.0435	0.0445	0.0489	0.0534	7110	372.9
	450	19	0.769	0.0243	0.0384	0.0394	0.0434	0.0472	7890	421.8
	477	19	0.792	0.0250	0.0363	0.0373	0.0409	0.0445	8360	446.8
	477	37	0.795	0.0254	0.0363	0.0373	0.0409	0.0445	8690	446.8
	500	19	0.811	0.0256	0.0346	0.0356	0.0390	0.0426	8760	468.5
	500	37	0.813	0.0260	0.0346	0.0356	0.0390	0.0426	9110	468.3
	556.5	19	0.856	0.0270	0.0311	0.0320	0.0352	0.0383	9750	521.4
	556.5	37	0.858	0.0275	0.0311	0.0320	0.0352	0.0383	9940	521.3
	600	37	0.891	0.0285	0.0288	0.0297	0.0326	0.0356	10700	562.0
	636	37	0.918	0.0294	0.0272	0.0282	0.0309	0.0335	11400	596.0
	650	37	0.928	0.0297	0.0266	0.0275	0.0301	0.0324	11600	609.8
	700	37	0.963	0.0308	0.0247	0.0256	0.0280	0.0305	12500	655.7
	700	61	0.964	0.0310	0.0247	0.0256	0.0280	0.0305	12900	655.8
	715.5	37	0.974	0.0312	0.0242	0.0250	0.0275	0.0299	12800	671.0
	715.5	61	0.975	0.0314	0.0242	0.0252	0.0275	0.0299	13100	671.0
	750	37	0.997	0.0319	0.0230	0.0251	0.0263	0.0286	13100	703.2
	750	61	0.998	0.0321	0.0230	0.0251	0.0263	0.0286	13500	703.2
	795	37	1.026	0.0328	0.0217	0.0227	0.0248	0.0269	13900	745.3
	795	61	1.028	0.0331	0.0217	0.0227	0.0248	0.0269	14300	745.7
	874.5	37	1.077	0.0344	0.0198	0.0206	0.0227	0.0246	15000	820.3
	874.5	61	1.078	0.0347	0.0198	0.0206	0.0227	0.0246	15800	820.6
	900	37	1.092	0.0349	0.0192	0.0201	0.0220	0.0239	15400	844.0
	900	61	1.094	0.0352	0.0192	0.0201	0.0220	0.0239	15900	844.0
	954	37	1.124	0.0360	0.0181	0.0191	0.0208	0.0227	16400	894.5
	954	61	1.126	0.0362	0.0181	0.0191	0.0208	0.0225	16900	894.8
	1000	37	1.151	0.0368	0.0173	0.0182	0.0199	0.0216	17200	937.3
	1000	61	1.152	0.0371	0.0173	0.0182	0.0199	0.0216	17700	936.8

Data sources: Aluminum Association, *Aluminum Electrical Conductor Handbook*, 1989; Southwire Company, *Overhead Conductor Manual*, 1994.

TABLE 2.3 Characteristics of Aluminum Conductor, Steel Reinforced (ACSR)

					Resistance, Ω/1000 ft					
					dc	60-Hz ac				
AWG	kcmil	Strands	Diameter, in.	GMR, ft	20°C	25°C	50°C	75°C	Breaking. Strength, lb	Weight, lb/1000 ft
6	26.24	6/1	0.198	0.0024	0.6419	0.6553	0.7500	0.8159	1190	36.0
4	41.74	6/1	0.250	0.0033	0.4032	0.4119	0.4794	0.5218	1860	57.4
4	41.74	7/1	0.257	0.0045	0.3989	0.4072	0.4633	0.5165	2360	67.0
2	66.36	6/1	0.316	0.0046	0.2534	0.2591	0.3080	0.3360	2850	91.2
2	66.36	7/1	0.325	0.0060	0.2506	0.2563	0.2966	0.3297	3640	102
1	83.69	6/1	0.355	0.0056	0.2011	0.2059	0.2474	0.2703	3550	115
1/0	105.6	6/1	0.398	0.0071	0.1593	0.1633	0.1972	0.2161	4380	145
2/0	133.1	6/1	0.447	0.0077	0.1265	0.1301	0.1616	0.1760	5300	183
3/0	167.8	6/1	0.502	0.0090	0.1003	0.1034	0.1208	0.1445	6620	230
4/0	211.6	6/1	0.563	0.0105	0.0795	0.0822	0.1066	0.1157	8350	291
	266.8	18/1	0.609	0.0197	0.0644	0.0657	0.0723	0.0788	6880	289
	266.8	26/7	0.642	0.0217	0.0637	0.0652	0.0714	0.0778	11300	366
	336.4	18/1	0.684	0.0221	0.0510	0.0523	0.0574	0.0625	8700	365
	336.4	26/7	0.721	0.0244	0.0506	0.0517	0.0568	0.0619	14100	462
	336.4	30/7	0.741	0.0255	0.0502	0.0513	0.0563	0.0614	17300	526
	397.5	18/1	0.743	0.0240	0.0432	0.0443	0.0487	0.0528	9900	431
	397.5	26/7	0.783	0.0265	0.0428	0.0438	0.0481	0.0525	16300	546
	477	18/1	0.814	0.0263	0.0360	0.0369	0.0405	0.0441	11800	517
	477	24/7	0.846	0.0283	0.0358	0.0367	0.0403	0.0439	17200	614
	477	26/7	0.858	0.0290	0.0357	0.0366	0.0402	0.0438	19500	655
	477	30/7	0.883	0.0304	0.0354	0.0362	0.0389	0.0434	23800	746
	556.5	18/1	0.879	0.0284	0.0309	0.0318	0.0348	0.0379	13700	603
	556.5	24/7	0.914	0.0306	0.0307	0.0314	0.0347	0.0377	19800	716
	556.5	26/7	0.927	0.0313	0.0305	0.0314	0.0345	0.0375	22600	765
	636	24/7	0.977	0.0327	0.0268	0.0277	0.0300	0.0330	22600	818
	636	26/7	0.990	0.0335	0.0267	0.0275	0.0301	0.0328	25200	873
	795	45/7	1.063	0.0352	0.0216	0.0225	0.0246	0.0267	22100	895
	795	26/7	1.108	0.0375	0.0214	0.0222	0.0242	0.0263	31500	1093
	954	45/7	1.165	0.0385	0.0180	0.0188	0.0206	0.0223	25900	1075
	954	54/7	1.196	0.0404	0.0179	0.0186	0.0205	0.0222	33800	1228
	1033.5	45/7	1.213	0.0401	0.0167	0.0175	0.0191	0.0208	27700	1163

Data sources: Aluminum Association, *Aluminum Electrical Conductor Handbook*, 1989; Southwire Company, *Overhead Conductor Manual*, 1994.

an inch). Conductor sizes are often given in kcmil, thousands of circular mils. In the past, the abbreviation MCM was used, which also means thousands of circular mils (M is thousands, not mega, in this case). By definition, a solid 1000-kcmil wire has a diameter of 1 in. The diameter of a solid wire in mils is related to the area in circular mils by $d = \sqrt{A}$.

Outside of America, most conductors are specified in mm^2. Some useful conversion relationships are:

$$1 \text{ kcmil} = 1000 \text{ cmil} = 785.4 \times 10^{-6} \text{ in}^2 = 0.5067 \text{ mm}^2$$

Stranded conductors increase flexibility. A two-layer arrangement has seven wires; a three-layer arrangement has 19 wires, and a four-layer arrangement has 37 wires. The cross-sectional area of a stranded conductor is the cross-sectional area of the metal, so a stranded conductor has a larger diameter than a solid conductor of the same area.

The area of an ACSR conductor is defined by the area of the aluminum in the conductor.

Utilities with heavy tree cover often use covered conductors—conductors with a thin insulation covering. The covering is not rated for full conductor line-to-ground voltage, but it is thick enough to reduce the chance of flashover when a tree branch falls between conductors. Covered conductor is also called *tree wire* or weatherproof wire. Insulation thicknesses typically range from 30 to 150 mils (1 mil = 0.001 in. = 0.00254 cm); see Table 2.4 for typical thicknesses. Covered conductors are also used in Australia to reduce the threat of bush fires (Barber, 1999).

While covered wire helps with trees, it has some drawbacks compared with bare conductors. Covered wire is much more susceptible to burndowns caused by fault arcs. Covered-wire systems increase the installed cost somewhat. Covered conductors are heavier and have a larger diameter, so the ice and wind loading is higher than a comparable bare conductor. The covering may be susceptible to degradation due to ultraviolet radiation, tracking, and mechanical effects that cause cracking.

Spacer cables and aerial cables are also alternatives that perform well in treed areas. Spacer cables are a bundled configuration using a messenger wire holding up three

TABLE 2.4 Typical Covering Thicknesses of Covered All-Aluminum Conductor

Size AWG or kcmil	Strands	Cover Thickness, mil	Diameter, in.	
			Bare	Covered
6	7	30	0.184	0.239
4	7	30	0.232	0.285
2	7	45	0.292	0.373
1	7	45	0.328	0.410
1/0	7	60	0.368	0.480
2/0	7	60	0.414	0.524
3/0	7	60	0.464	0.574
4/0	7	60	0.522	0.629
266.8	19	60	0.593	0.695
336.4	19	60	0.666	0.766
397.5	19	80	0.724	0.857
477	37	80	0.795	0.926
556.5	37	80	0.858	0.988
636	61	95	0.918	1.082
795	61	95	1.028	1.187

TABLE 2.5 Characteristics of Steel Conductors

Size	Diameter, in.	Conductor Area, in.²	Weight, lb/1000 ft	Strength, lb	Resistance, Ω/1000 ft: dc 25°C	60-Hz ac at the Given Current Level (A): 10	40	70	100
High-Strength Steel—Class A Galvanizing									
5/8	0.621	0.2356	813	29,600	0.41	0.42	0.43	0.46	0.49
1/2	0.495	0.1497	517	18,800	0.65	0.66	0.68	0.73	0.77
7/16	0.435	0.1156	399	14,500	0.84	0.85	0.88	0.94	1.00
3/8	0.360	0.0792	273	10,800	1.23	1.25	1.28	1.38	1.46
Utilities Grade Steel									
7/16	0.435	0.1156	399	18,000	0.87	0.88	0.90	0.95	1.02
3/8	0.380	0.0882	273	11,500	1.23	1.25	1.28	1.38	1.46
Extra-High-Strength Steel—Class A Galvanizing									
5/8	0.621	0.2356	813	42,400	0.43	0.43	0.44	0.47	0.50
1/2	0.495	0.1497	517	26,900	0.67	0.68	0.69	0.73	0.78
7/16	0.435	0.1156	399	20,800	0.87	0.88	0.90	0.95	1.02
3/8	0.360	0.0792	273	15,400	1.28	1.29	1.31	1.39	1.48
Extra-High-Strength Steel—Class C Galvanizing									
7/16	0.435	0.1156	399	20,800		0.70	0.70	0.71	0.71
3/8	0.360	0.0792	273	15,400		1.03	1.03	1.03	1.04
5/16	0.312	0.0595	205	11,200		1.20	1.30	1.30	1.30

Source: Adapted from EPRI, *Transmission Line Reference Book: 345 kV and Above*, 2nd ed., Electric Power Research Institute, Palo Alto, CA, 1982.

phase wires that use covered wire. Because the spacer cable has significantly smaller spacings than normal overhead constructions, its reactive impedance is smaller.

Guy wires, messenger wires, and other wires that require mechanical strength but not current-carrying capability are often made of steel. Steel has high strength (see Table 2.5). Steel corrodes quickly, so most applications use galvanized steel to slow down the corrosion. Because steel is a magnetic material, steel conductors also suffer hysteresis losses. Steel conductors have much higher resistances than copper or aluminum. For some applications requiring strength and conductivity, steel wires coated with copper or aluminum are available. A copperweld conductor has copper-coated steel strands, and an alumoweld conductor has aluminum-coated steel strands. Both have better corrosion protection than galvanized steel.

2.3 Line Impedances

Overhead lines have resistance and reactance that impedes the flow of current. These impedance values are necessary for voltage drop, power flow, short circuit, and line-loss calculations.

The dc resistance is inversely proportional to the area of a conductor; doubling the area halves the resistance. Several units are used to describe a conductor's resistance. Conductivity is often given as % IACS, the percent conductivity relative to the International Annealed Copper Standard, which has the following volume resistivities:

$$0.08145\ \Omega\text{-in.}^2/1000\ \text{ft} = 17.241\ \Omega\text{-mm}^2/\text{km} = 10.37\ \Omega\text{-cmil/ft}$$

And with a defined density of 8.89 g/cm^3 at 20°C, the copper standard has the following weight resistivities:

$$875.2\ \Omega\text{-lb/mi}^2 = 0.15328\ \Omega\text{-g/m}^2$$

Hard-drawn copper has 97.3% IACS. Aluminum varies, depending on type; alloy 1350-H19 has 61.2% conductivity.

Temperature and frequency—these change the resistance of a conductor. A hotter conductor provides more resistance to the flow of current. A higher frequency increases the internal magnetic fields. Current has a difficult time flowing in the center of a conductor at high frequency, as it is being opposed by the magnetic field generated by current flowing on all sides of it. Current flows more easily near the edges. This *skin effect* forces the current to flow in a smaller area of the conductor.

Resistance changes with temperature as

$$R_{t2} = R_{t1}\frac{M + t_2}{M + t_1}$$

where

R_{t2} = resistance at temperature t_2 given in °C
R_{t1} = resistance at temperature t_1 given in °C
M = a temperature coefficient for the given material
= 228.1 for aluminum
= 241.5 for annealed hard-drawn copper

For a wide range of temperatures, resistance rises almost linearly with temperature for both aluminum and copper. The effect of temperature is simplified as a linear equation as

$$R_{t2} = R_{t1}[1 + \alpha(t_2 - t_1)]$$

where

α = a temperature coefficient of resistance
= 0.00404 for 61.2% IACS aluminum at 20°C
= 0.00347 for 6201-T81 aluminum alloy at 20°C
= 0.00383 for hard-drawn copper at 20°C
= 0.0036 for aluminum-clad steel at 20°C

So, the resistance of aluminum with a 61.2% conductivity rises 4% for every 10°C rise in temperature.

We can also linearly interpolate using resistances provided at two different temperatures as

$$R(T_c) = R(T_{\text{low}}) + \frac{R(T_{\text{high}}) - R(T_{\text{low}})}{T_{\text{high}} - T_{\text{low}}}(T_c - T_{\text{low}})$$

where

$R(T_c)$ = conductor resistance at temperature T_c
$R(T_{\text{high}})$ = resistance at the higher temperature T_{high}
$R(T_{\text{low}})$ = resistance at the lower temperature T_{low}

With alternating current, skin effects raise the resistance of a conductor relative to its dc resistance. At 60 Hz, the resistance of a conductor is very close to its dc resistance except for very large conductors. Skin effects are much more important for high-frequency analysis such as switching surges and power-line carrier problems. They play a larger role in larger conductors.

The internal resistance of a solid round conductor including skin effects is [for details, see Stevenson (1962)]

$$\frac{R_{\text{ac}}}{R_{\text{dc}}} = \frac{x}{2}\frac{\text{ber}(x)\text{bei}'(x) - \text{bei}(x)\text{ber}'(x)}{(\text{bei}'(x))^2 + (\text{ber}'(x))^2}$$

where

$$x = 0.02768\sqrt{\frac{f\mu}{R_{\text{dc}}}}$$

f = frequency in Hz
μ = relative permeability = 1 for nonmagnetic conductors (including aluminum and copper)
R_{dc} = dc resistance of the conductor in ohms/1000 ft

ber, bei, ber′, and bei′ are real and imaginary modified Bessel functions and their derivatives (also called Kelvin functions).

For x greater than 3 (frequencies in the kilohertz range), the resistance increases linearly with x (Clarke, 1950) approximately as

$$\frac{R_{\text{ac}}}{R_{\text{dc}}} = \frac{x}{2\sqrt{2}} + \frac{1}{4} = 0.009786\sqrt{\frac{f\mu}{R_{\text{dc}}}} + 0.25$$

So, for higher frequencies, the ac resistance increases as the square root of the frequency. For most distribution power-frequency applications, we can ignore skin effects (and they are included in ac resistance tables).

For most cases, we can model a stranded conductor as a solid conductor with the same cross-sectional area. ACSR with a steel core is slightly different. Just as in a transformer, the steel center conductor has losses due to hysteresis and eddy currents. If an ACSR conductor has an even number of layers, the axial magnetic field produced by one layer tends to cancel that produced by the next layer. We can model these as a tubular conductor for calculating skin effect. For odd numbers of layers, especially single-layered conductors like 6/1 or 7/1, the 60-Hz/dc ratio is higher than normal, especially at high current densities. These effects are reflected in the resistances included in tables (such as Table 2.3).

The reactance part of the impedance usually dominates the impedances on overhead circuit for larger conductors; below 4/0, resistance plays more of a role. For all-aluminum conductors on a 10-ft crossarm, the resistance approximately equals the reactance for a 2/0 conductor. Reactance is proportional to inductance; and inductance causes a voltage that opposes the change in the flow of current. Alternating current is always changing, so a reactance always creates a voltage due to current flow.

Distance between conductors determines the external component of reactance. Inductance is based on the area enclosed by a loop of current; a larger area (more separation between conductors) has more inductance. On overhead circuits, reactance of the line is primarily based on the separations between conductors—not the size of the conductor, not the type of metal in the conductor, not the stranding of the conductor.

The reactance between two parallel conductors in ohms per mile is

$$X_{ab} = 0.2794 \frac{f}{60} \log_{10} \frac{d_{ab}}{\text{GMR}}$$

where

f = frequency in hertz
d_{ab} = distance between the conductors
GMR = geometric mean radius of both conductors

d_{ab} and GMR must have the same units, normally feet. More separation—a bigger loop—gives larger impedances.

The geometric mean radius (GMR) quantifies a conductor's internal inductance—by definition, the GMR is the radius of an infinitely thin tube having the same internal inductance as the conductor out to a one-foot radius. The GMR is normally given in feet to ease calculations with distances measured in feet. GMR is less than the actual conductor radius. Many conductor tables provide x_a, the inductive reactance due to flux in the conductor and outside the conductor out to a one-foot radius. The GMR in feet at 60 Hz relates to x_a as

$$x_a = 0.2794 \log_{10} \frac{1}{\text{GMR}}$$

where GMR is in feet, and x_a is in ohms/mile.

For a solid, round, nonmagnetic conductor, the relationship between the actual radius and the GMR is

$$\frac{\text{GMR}}{r} = e^{-1/4} = 0.779$$

For stranded conductors, the GMR is

$$\text{GMR} = k \cdot r$$

where
k = the GMR factor from Table 2.6
r = conductor radius

For ACSR conductors (which are layered), the GMR factor is more complicated.

Current flowing in a conductor induces a reactive voltage drop on the conductor it is flowing through. By the same induction, current flow in one conductor creates a voltage gradient along parallel conductors (see Figure 2.6). This voltage is of the same polarity as the voltage on the current-carrying conductor. Closer conductors have larger induced voltages. This induction is significant for several reasons:

- *Opposite flow*—Current flows more easily when a parallel conductor has flow in the opposite direction. The magnetic field from the other conductor creates a voltage drop that encourages flow in the opposite direction. Conductors carrying current in opposite directions have lower impedance when they are closer together.
- *Parallel flow*—A conductor carrying current in the same direction as a parallel conductor faces more impedance because of the current in the other conductor. Conductors carrying current in the same direction have higher impedance when they are closer together.
- *Circulating current*—Current flow in the vicinity of a shorted current loop induces currents to circulate in the loop.

For balanced conditions—balanced voltages, balanced loads, and balanced impedances—we can analyze power systems just with positive-sequence voltages,

TABLE 2.6 GMR Factor

Strands	GMR Factor, k
1 (solid)	0.7788
3	0.6778
7	0.7256
19	0.7577
37	0.7678
61	0.7722

Data source: Aluminum Association, *Ampacities for Aluminum and ACSR Overhead Electrical Conductors*, 1986.

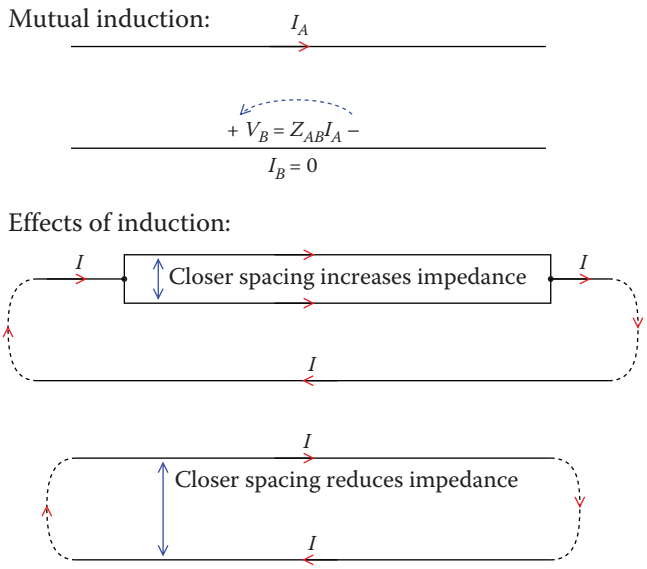


Figure 2.6 Mutual induction.

currents, and impedances. This is regularly done in transmission-planning and industrial load-flow studies. Using just positive-sequence quantities simplifies analysis; it's like a single-phase circuit rather than a three-phase circuit. For distribution circuits, unbalanced loading is quite common, so we normally need more than just positive-sequence parameters—we need the zero-sequence parameters as well. We also need unbalanced analysis approaches for phase-to-ground or phase-to-phase faults.

With symmetrical components, the phasors of circuit quantities on each of the three phases resolve to three sets of phasors. For voltage, the symmetrical components relate to the phase voltages as

$$V_a = V_0 + V_1 + V_2 \quad V_0 = 1/3\ (V_a + V_b + V_c)$$

$$V_b = V_0 + a^2V_1 + aV_2 \quad \text{and} \quad V_1 = 1/3\ (V_a + aV_b + a^2V_c)$$

$$V_c = V_0 + aV_1 + a^2V_2 \quad V_2 = 1/3\ (V_a + a^2V_b + aV_c)$$

where $a = 1\angle 120°$ and $a^2 = 1\angle 240°$.

These phase-to-symmetrical conversions apply for phase-to-ground as well as phase-to-phase voltages. The same conversions apply for converting line currents to sequence currents:

$$I_a = I_0 + I_1 + I_2 \quad I_0 = 1/3\ (I_a + I_b + I_c)$$

$$I_b = I_0 + a^2I_1 + aI_2 \quad \text{and} \quad I_1 = 1/3\ (I_a + aI_b + a^2I_c)$$

$$I_c = I_0 + aI_1 + a^2I_2 \quad I_2 = 1/3\ (I_a + a^2I_b + aI_c)$$

The voltage drop along each of the phase conductors depends on the currents in each of the phase conductors and the self-impedances (such as Z_{aa}) and the mutual impedances (such as Z_{ab}) as

$$V_a = Z_{aa}I_a + Z_{ab}I_b + Z_{ac}I_c$$

$$V_b = Z_{ba}I_a + Z_{bb}I_b + Z_{bc}I_c$$

$$V_c = Z_{ca}I_a + Z_{cb}I_b + Z_{cc}I_c$$

Likewise, when we use sequence components, we have voltage drops of each sequence in terms of the sequence currents and sequence impedances:

$$V_0 = Z_{00}I_0 + Z_{01}I_1 + Z_{02}I_2$$

$$V_1 = Z_{10}I_0 + Z_{11}I_1 + Z_{12}I_2$$

$$V_2 = Z_{20}I_0 + Z_{21}I_1 + Z_{22}I_2$$

This is not much of a simplification until we assume that all of the self-impedance terms are equal ($Z_S = Z_{aa} = Z_{bb} = Z_{cc}$) and that all of the mutual impedances are equal ($Z_M = Z_{ab} = Z_{ac} = Z_{bc} = Z_{ba} = Z_{ca} = Z_{cb}$). With this assumption, the sequence impedances decouple; the mutual terms of the zero-sequence matrix (such as Z_{12}) become zero. Zero-sequence current only causes a zero-sequence voltage drop. This is a good enough approximation for many distribution problems and greatly simplifies hand and computer calculations. Now, the sequence voltage drop equations are

$$V_0 = Z_{00}I_0 = (Z_S + 2Z_M)I_0$$

$$V_1 = Z_{11}I_1 = (Z_S \boxtimes Z_M)I_1$$

$$V_2 = Z_{22}I_2 = (Z_S \boxtimes Z_M)I_2$$

Now, we have the sequence terms as

$$Z_0 = Z_S + 2Z_M$$

$$Z_1 = Z_2 = Z_S \boxtimes Z_M$$

And likewise,

$$Z_S = (Z_0 + 2Z_1)/3$$

$$Z_M = (Z_0 \boxtimes Z_1)/3$$

Note Z_S, the self-impedance term. Z_S is also the "loop impedance"—the impedance to current through one phase wire and returning through the ground return

path. This loop impedance is important because it is the impedance for single-phase lines and the impedance for single line-to-ground faults.

Engineers normally use three methods to find impedances of circuits. In order of least to most accurate, these are

- Table lookup
- Hand calculations
- Computer calculations

This book provides data necessary for the first two approaches. Table lookups are quite common. Even though table lookup is not the most accurate approach, its accuracy is good enough for analyzing most common distribution problems. Computer calculations are quite accessible and allow easier analysis of more complicated problems.

2.4 Simplified Line Impedance Calculations

The positive-sequence impedance of overhead lines is

$$Z_1 = R_\phi + jk_1 \log_{10} \frac{\text{GMD}_\phi}{\text{GMR}_\phi}$$

where

R_ϕ = resistance of the phase conductor in Ω/distance
$k_1 = 0.2794f/60$ for outputs in Ω/mi
$= 0.0529f/60$ for outputs in Ω/1000 ft
f = frequency in hertz
GMR_ϕ = geometric mean radius of the phase conductor in ft
GMD_ϕ = geometric mean distance between the phase conductors in ft
$\text{GMD}_\phi = \sqrt[3]{d_{AB}d_{BC}d_{CA}}$ for three-phase lines
$\text{GMD}_\phi = 1.26\ d_{AB}$ for a three-phase line with flat configuration, either horizontal or vertical, where $d_{AB} = d_{BC} = 0.5d_{CA}$
$\text{GMD}_\phi = d_{AB}$ for two-phase lines*
$\text{GMD}_\phi = d_{AN}$ for single-phase lines*
d_{ij} = distance between the center of conductor i and the center of conductor j, in feet

For 60 Hz and output units of Ω/1000 ft, this is

$$Z_1 = R_\phi + j0.0529 \log_{10} \frac{\text{GMD}_\phi}{\text{GMR}_\phi}$$

* The two-phase circuit has two out of the three phases; the single-phase circuit has one phase conductor with a neutral return. While it may seem odd to look at the positive-sequence impedance of a one- or two-phase circuit, the analysis approach is useful. This approach uses fictitious conductors for the missing phases to model the one- or two-phase circuit as an equivalent three-phase circuit (no current flows on these fictitious phases).

Zero-sequence impedance calculations are more complicated than positive-sequence calculations. Carson's equations are the most common way to account for the ground return path in impedance calculations of overhead circuits. Carson (1926) derived an expression including the earth return path. We will use a simplification of Carson's equations; it includes the following assumptions (Smith, 1980)

- Since distribution lines are relatively short, the height-dependent terms in Carson's full model are small, so we neglect them.
- The multigrounded neutral is perfectly coupled to the earth (this has some drawbacks for certain calculations as discussed in Chapter 14).
- End effects are neglected.
- The current at the sending end equals that at the receiving end (no leakage currents).
- All phase conductors have the same size conductor.
- The ground is infinite and has uniform resistivity.

Consider the circuit in Figure 2.7; current flows in conductor *a* and returns through the earth. The voltage on conductor *a* equals the current times Z_{aa}, which is the self-impedance with an earth return path. The current in conductor *a* induces a voltage drop along conductor *b* equaling the phase-*a* current times Z_{ab}, which is the mutual impedance with an earth return path. These two impedances are found (Smith, 1980) with

$$Z_{aa} = R_\phi + R_e + jk_1 \log_{10} \frac{D_e}{GMR_\phi}$$

$$Z_{ab} = R_e + jk_1 \log_{10} \frac{D_e}{d_{ab}}$$

where

R_e = resistance of the earth return path
= 0.0954f/60 Ω/mi
= 0.01807f/60 Ω/1000 ft

$D_e = 2160\sqrt{\rho/f}$ = equivalent depth of the earth return current in ft

ρ = earth resistivity in Ω-m

d_{ab} = distance between the centers of conductors *a* and *b*

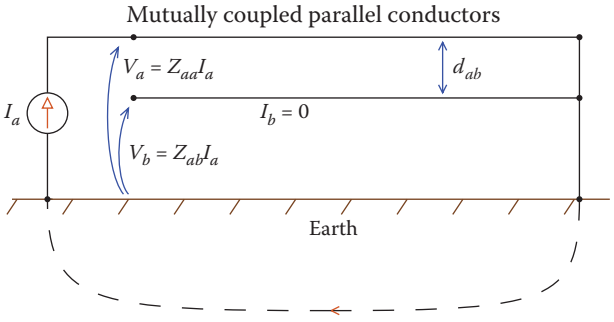


Figure 2.7 Depiction of Carson's impedances with earth return.

For 60 Hz and output units of Ω/1000 ft,

$$Z_{aa} = R_\phi + 0.01807 + j0.0529 \log_{10} \frac{278.9\sqrt{\rho}}{GMR_\phi}$$

$$Z_{ab} = 0.01807 + j0.0529 \log_{10} \frac{278.9\sqrt{\rho}}{d_{ab}}$$

These equations lead to different formulations for the zero-sequence impedance of circuits depending on the grounding configuration. They are also useful in their own right in many circumstances. Single-phase circuits with a phase and a neutral are often easier to analyze using these equations rather than using sequence components. Consider a single-phase circuit that is perfectly grounded with a current of I_A in the phase conductor. As Figure 2.8 shows, we can find the neutral current as a function of the mutual impedance between the two conductors divided by the self-impedance of the neutral conductor.

Now, let us look at the zero-sequence impedances—these change depending on grounding configuration. Figure 2.9 shows the configurations that we will consider.

A three-wire overhead line has a zero-sequence impedance of (Smith, 1980)

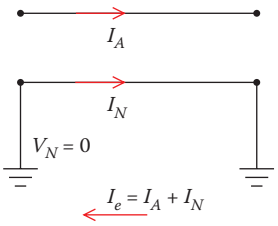
$$Z_0 = R_\phi + 3R_e + j3k_1 \log_{10} \frac{D_e}{\sqrt[3]{\text{GMR}_\phi \cdot \text{GMD}_\phi^2}}$$

For a four-wire multigrounded system, the zero-sequence self-impedance is

$$Z_0 = R_\phi + 3R_e + j3k_1 \log_{10} \frac{D_e}{\sqrt[3]{\text{GMR}_\phi \cdot \text{GMD}_\phi^2}} - 3\frac{Z_{\phi N}^2}{Z_{NN}}$$

where Z_{NN} is the self-impedance of the neutral conductor with an earth return, and $Z_{\phi N}$ is the mutual impedance between the phase conductors as a group and the neutral. For 60 Hz and output units of Ω/1000 ft, the zero-sequence self-impedance is

$$Z_0 = R_\phi + 0.0542 + j0.1587 \log_{10} \frac{278.9\sqrt{\rho}}{\sqrt[3]{\text{GMR}_\phi \cdot \text{GMD}_\phi^2}} - 3\frac{Z_{\phi N}^2}{Z_{NN}}$$



$$V_N = 0 = Z_{AN} I_A + Z_{NN} I_N$$

$$\text{So, } I_N = -\frac{Z_{AN}}{Z_{NN}} I_A$$

Figure 2.8 Current flow in a neutral conductor based on self-impedances and mutual impedances.

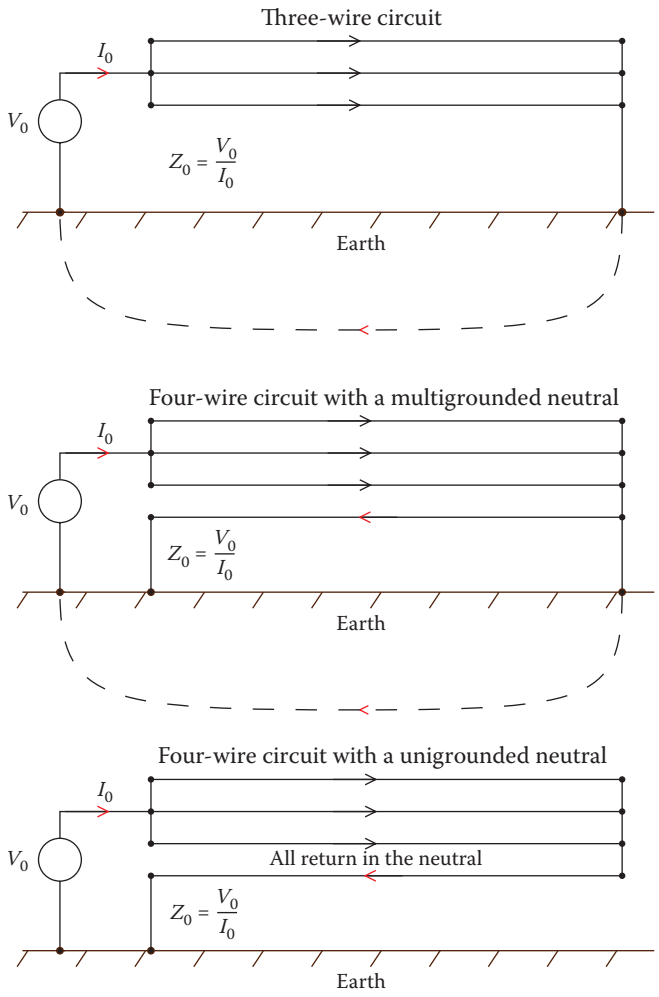


Figure 2.9 Different zero-sequence impedances depending on the grounding configuration.

$$Z_{NN} = R_N + 0.01807 + j0.0529 \log_{10} \frac{278.9\sqrt{\rho}}{\text{GMR}_N}$$

$$Z_{\phi N} = 0.01807 + j0.0529 \log_{10} \frac{278.9\sqrt{\rho}}{\text{GMD}_{\phi N}}$$

where

GMR_N = geometric mean radius of the neutral conductor in ft

$\text{GMD}_{\phi N}$ = geometric mean distance between the phase conductors as a group and the neutral in ft

$\text{GMD}_{\phi N} = \sqrt[3]{d_{AN} d_{BN} d_{CN}}$ for three-phase lines

$\text{GMD}_{\phi N} = \sqrt{d_{AN} d_{BN}}$ for two-phase lines
$\text{GMD}_{\phi N} = d_{AN}$ for single-phase lines

A special case is for a four-wire unigrounded circuit where the return current stays in the neutral, which has a zero-sequence impedance of (Ender et al., 1960)

$$Z_0 = R_\phi + 3R_n + j3k_1 \log_{10} \frac{\text{GMD}_{\phi N}^2}{\text{GMR}_N \sqrt[3]{\text{GMR}_\phi \cdot \text{GMD}_\phi^2}}$$

This is for a four-wire unigrounded circuit where there are no connections between the neutral conductor and earth. We can also use this as an approximation for a multigrounded neutral line that is very poorly grounded. Remember that the equation given above for a multigrounded circuit assumes perfect grounding. For some calculations, that is not accurate. This is the opposite extreme, which is appropriate for some calculations. Lat (1990) used this as one approach to estimating the worst-case overvoltage on unfaulted phases during a line-to-ground fault.

So, what does all of this mean? Some of the major effects are

- *Conductor size*—Mainly affects resistance—larger conductors have lower positive-sequence resistance. Positive-sequence reactance also lowers with larger conductor size, but since it changes with the logarithm of conductor radius, changes are small.
- *Conductor spacings*—Increasing spacing (higher GMD_ϕ) increases Z_1. Increasing spacing reduces Z_0. Both of these changes with spacing are modest given the logarithmic effect.
- *Neutral*—Adding the neutral always reduces the total zero-sequence impedance, $|Z_0|$. Adding a neutral always reduces the reactive portion of this impedance. But adding a neutral may increase or may decrease the resistive portion of Z_0. Adding a small neutral with high resistance increases the resistance component of Z_0.
- *Neutral spacing*—Moving the neutral closer to the phase conductors reduces the zero-sequence impedance (but may increase the resistive portion, depending on the size of the neutral).
- *Earth resistivity*—The earth resistivity does not change the earth return resistance (R_e only depends on frequency). The current spreads to wider areas of the earth in high-resistivity soil. Earth resistivity does change the reactance. Higher earth resistivities force current deeper into the ground (larger D_e), raising the reactance.
- *Grounding*—The positive-sequence impedance Z_1 stays the same regardless of the grounding, whether four-wire multigrounded, ungrounded, or unigrounded.
- *Negative sequence*—Equals the positive-sequence impedance.

Figures 2.10 and 2.11 show the effects of various parameters on the positive and zero-sequence impedances. Many of the outputs are not particularly sensitive to changes in the inputs. Since many parameters are functions of the logarithm of the variable, major changes induce only small changes in the impedance.

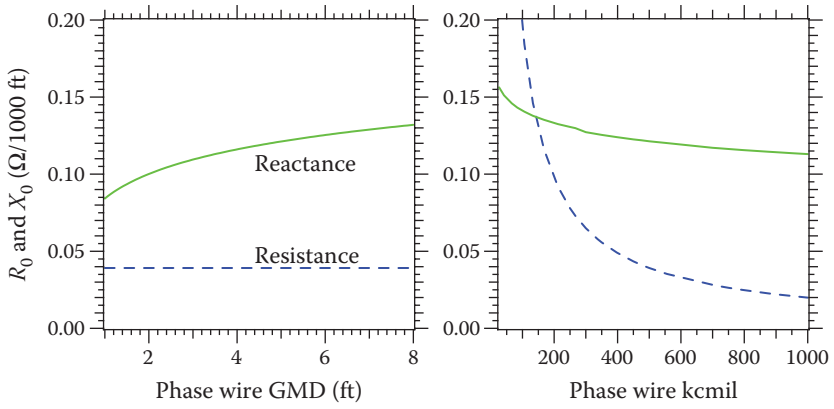


Figure 2.10 Effect of spacings and conductor size on the positive-sequence impedance with 500-kcmil AAC phases (GMR = 0.0256 ft) and GMD_{ϕ} = 5 ft.

When do we need more accuracy or more sophistication? For power flows, fault calculations, voltage flicker calculations, and voltage sag analysis, we normally do not need more sophistication. For switching surges, lightning, or other higher frequency transient analysis, we normally need more sophisticated line models.

Most unbalanced calculations can be done with this approach, but some cases require more sophistication. Distribution lines and most lower-voltage subtransmission lines are not transposed. On some long circuits, even with balanced loading, the unbalanced impedances between phases create voltage unbalance.

2.5 Line Impedance Tables

Tables 2.7 through 2.12 show impedances for all-aluminum, ACSR, and copper constructions. All are based on the equations in the previous section and assume GMD = 4.8 ft, conductor temperature = 50°C, $GMD_{\phi N}$ = 6.3 ft, and earth resistivity = 100 Ω-m. All zero-sequence values are for a four-wire multigrounded neutral circuit.

2.6 Conductor Sizing

We have an amazing variety of sizes and types of conductors. Several electrical, mechanical, and economic characteristics affect conductor selection:

- *Ampacity*—The peak current-carrying capability of a conductor limits the current (and power) carrying capability.
- *Economics*—Often we will use a conductor that normally operates well below its ampacity rating. The cost of the extra aluminum pays for itself with lower I^2R losses; the conductor runs cooler. This also leaves room for expansion.

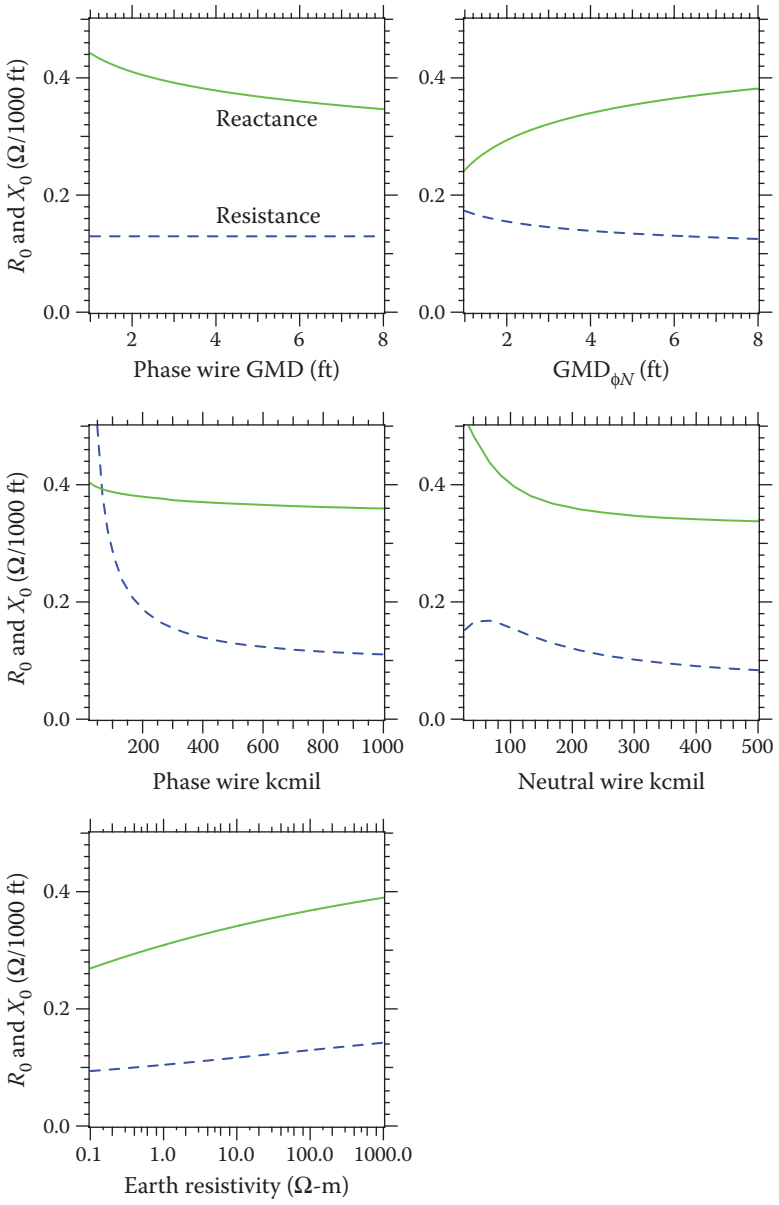


Figure 2.11 Effect of various parameters on the zero-sequence impedance with a base case of AAC 500-kcmil phases, 3/0 neutral (168 kcmil), GMD_{ϕ} = 5 ft, $GMD_{\phi N}$ = 6.3 ft, and ρ = 100 Ω-m.

- *Mechanical strength*—Especially on rural lines with long span lengths, mechanical strength plays an important role in size and type of conductor. Stronger conductors like ACSR are used more often. Ice and wind loadings must be considered.
- *Corrosion*—While not usually a problem, corrosion sometimes limits certain types of conductors in certain applications.

TABLE 2.7 Positive-Sequence Impedances of All-Aluminum Conductor

Phase Size	Strands	R_1	X_1	Z_1
6	7	0.7405	0.1553	0.7566
4	7	0.4654	0.1500	0.4890
2	7	0.2923	0.1447	0.3262
1	7	0.2323	0.1420	0.2723
1/0	7	0.1839	0.1394	0.2308
2/0	7	0.1460	0.1367	0.2000
3/0	7	0.1159	0.1341	0.1772
4/0	7	0.0920	0.1314	0.1604
250	7	0.0778	0.1293	0.1509
266.8	7	0.0730	0.1286	0.1478
300	19	0.0649	0.1261	0.1418
336.4	19	0.0580	0.1248	0.1376
350	19	0.0557	0.1242	0.1361
397.5	19	0.0490	0.1229	0.1323
450	19	0.0434	0.1214	0.1289
477	19	0.0411	0.1208	0.1276
500	19	0.0392	0.1202	0.1265
556.5	19	0.0352	0.1189	0.1240
700	37	0.0282	0.1159	0.1192
715.5	37	0.0277	0.1157	0.1190
750	37	0.0265	0.1151	0.1181
795	37	0.0250	0.1146	0.1173
874.5	37	0.0227	0.1134	0.1157
900	37	0.0221	0.1130	0.1152
954	37	0.0211	0.1123	0.1142
1000	37	0.0201	0.1119	0.1137

Note: Impedances, Ω/1000 ft (×5.28 for Ω/mi or ×3.28 for Ω/km). GMD = 4.8 ft, conductor temp. = 50°C.

As with many aspects of distribution operations, many utilities standardize on a set of conductors. For example, a utility may use 500-kcmil AAC for all mainline spans and 1/0 AAC for all laterals. While many circuit locations are overdesigned, the utility saves from reduced stocking, fewer tools, and standardized connectors. While many utilities have more than just two conductors, most use just a handful of standard conductors; four to six economically covers the needs of most utilities.

2.7 Ampacities

The ampacity is the maximum designed current of a conductor. This current-carrying capacity is normally given in amperes. A given conductor has several ampacities, depending on its application and the assumptions used. House and Tuttle (1958) derive the ampacity calculations described below, which are used in IEEE Std.

TABLE 2.8 AAC Zero-Sequence, Z_0, and Ground-Return Loop Impedances, $Z_S = (2Z_1 + Z_0)/3$

Phase Size	Neutral Size	R_0	X_0	Z_0	R_S	X_S	Z_S
6	6	0.8536	0.5507	1.0158	0.7782	0.2871	0.8294
2	6	0.4055	0.5401	0.6754	0.3301	0.2765	0.4306
2	2	0.4213	0.4646	0.6272	0.3353	0.2513	0.4190
1	6	0.3454	0.5374	0.6389	0.2700	0.2738	0.3845
1	1	0.3558	0.4405	0.5662	0.2734	0.2415	0.3648
1/0	6	0.2971	0.5348	0.6117	0.2216	0.2712	0.3502
1/0	1/0	0.2981	0.4183	0.5136	0.2220	0.2323	0.3213
2/0	6	0.2591	0.5321	0.5919	0.1837	0.2685	0.3253
2/0	2/0	0.2487	0.3994	0.4705	0.1802	0.2243	0.2877
3/0	2	0.2449	0.4540	0.5158	0.1589	0.2407	0.2884
3/0	3/0	0.2063	0.3840	0.4359	0.1461	0.2174	0.2619
4/0	1	0.2154	0.4299	0.4809	0.1331	0.2309	0.2665
4/0	4/0	0.1702	0.3716	0.4088	0.1180	0.2115	0.2422
250	2/0	0.1805	0.3920	0.4316	0.1120	0.2169	0.2441
250	250	0.1479	0.3640	0.3929	0.1012	0.2075	0.2309
266.8	2/0	0.1757	0.3913	0.4289	0.1072	0.2161	0.2413
266.8	266.8	0.1402	0.3614	0.3877	0.0954	0.2062	0.2272
300	2/0	0.1675	0.3888	0.4234	0.0991	0.2137	0.2355
300	300	0.1272	0.3552	0.3773	0.0856	0.2025	0.2198
336.4	2/0	0.1607	0.3875	0.4195	0.0922	0.2123	0.2315
336.4	336.4	0.1157	0.3514	0.3699	0.0772	0.2003	0.2147
350	2/0	0.1584	0.3869	0.4181	0.0899	0.2118	0.2301
350	350	0.1119	0.3499	0.3674	0.0744	0.1994	0.2129
397.5	2/0	0.1517	0.3856	0.4143	0.0832	0.2105	0.2263
397.5	397.5	0.1005	0.3463	0.3606	0.0662	0.1974	0.2082
450	2/0	0.1461	0.3841	0.4109	0.0776	0.2089	0.2229
450	450	0.0908	0.3427	0.3545	0.0592	0.1951	0.2039
477	2/0	0.1438	0.3835	0.4096	0.0753	0.2084	0.2216
477	477	0.0868	0.3414	0.3522	0.0563	0.1943	0.2023
500	4/0	0.1175	0.3605	0.3791	0.0653	0.2003	0.2107
500	500	0.0835	0.3401	0.3502	0.0540	0.1935	0.2009
556.5	4/0	0.1135	0.3591	0.3766	0.0613	0.1990	0.2082
556.5	556.5	0.0766	0.3372	0.3458	0.0490	0.1917	0.1978
700	4/0	0.1064	0.3561	0.3717	0.0542	0.1960	0.2033
700	700	0.0639	0.3310	0.3371	0.0401	0.1876	0.1918
715.5	4/0	0.1060	0.3559	0.3714	0.0538	0.1958	0.2030
715.5	715.5	0.0632	0.3306	0.3366	0.0395	0.1873	0.1915
750	4/0	0.1047	0.3553	0.3705	0.0526	0.1952	0.2022
750	750	0.0609	0.3295	0.3351	0.0380	0.1866	0.1904
795	4/0	0.1033	0.3548	0.3695	0.0511	0.1946	0.2012
795	795	0.0582	0.3283	0.3335	0.0361	0.1858	0.1893

continued

TABLE 2.8 (*Continued*) AAC Zero-Sequence, Z_0, and Ground-Return Loop Impedances, $Z_S = (2Z_1 + Z_0)/3$

Phase Size	Neutral Size	R_0	X_0	Z_0	R_S	X_S	Z_S
874.5	4/0	0.1010	0.3536	0.3678	0.0488	0.1935	0.1996
874.5	874.5	0.0540	0.3261	0.3305	0.0332	0.1843	0.1873
900	4/0	0.1004	0.3533	0.3672	0.0482	0.1931	0.1990
900	900	0.0529	0.3254	0.3296	0.0324	0.1838	0.1866
954	4/0	0.0993	0.3525	0.3662	0.0471	0.1924	0.1981
954	954	0.0510	0.3239	0.3279	0.0310	0.1828	0.1854
1000	4/0	0.0983	0.3521	0.3656	0.0462	0.1920	0.1975
1000	1000	0.0491	0.3232	0.3269	0.0298	0.1823	0.1847

Note: Impedances, Ω/1000 ft (×5.28 for Ω/mi or ×3.28 for Ω/km). GMD = 4.8 ft, $GMD_{\phi N}$ = 6.3 ft, Conductor temp. = 50°C, Earth resistivity = 100 Ω-m.

TABLE 2.9 Positive-Sequence Impedances of ACSR

Phase Size	Strands	R_1	X_1	Z_1
6	6/1	0.7500	0.1746	0.7700
4	6/1	0.4794	0.1673	0.5077
2	6/1	0.3080	0.1596	0.3469
1	6/1	0.2474	0.1551	0.2920
1/0	6/1	0.1972	0.1496	0.2476
2/0	6/1	0.1616	0.1478	0.2190
3/0	6/1	0.1208	0.1442	0.1881
4/0	6/1	0.1066	0.1407	0.1765
266.8	18/1	0.0723	0.1262	0.1454
336.4	18/1	0.0574	0.1236	0.1362
397.5	18/1	0.0487	0.1217	0.1311
477	18/1	0.0405	0.1196	0.1262
556.5	18/1	0.0348	0.1178	0.1228
636	18/1	0.0306	0.1165	0.1204
795	36/1	0.0247	0.1140	0.1167

Note: Impedances, Ω/1000 ft (×5.28 for Ω/mi or ×3.28 for Ω/km). GMD = 4.8 ft, Conductor temp. = 50°C.

738-1993 and most other published ampacity tables (Aluminum Association, 1986; Southwire Company, 1994).

Sun, wind, and ambient temperature change a conductor's ampacity. A conductor's temperature depends on the thermal balance of heat inputs and losses. Current driven through a conductor's resistance creates heat (I^2R). The sun is another source of heat into the conductor. Heat escapes from the conductor through radiation and from convection. Considering the balance of inputs and outputs, the ampacity of a conductor is

TABLE 2.10 ACSR Zero-Sequence, Z_0, and Ground-Return Loop Impedances, $Z_S = (2Z_1 + Z_0)/3$

Phase Size	Neutral Size	R_0	X_0	Z_0	R_S	X_S	Z_S
4	4	0.6030	0.5319	0.8040	0.5206	0.2888	0.5953
2	4	0.4316	0.5242	0.6790	0.3492	0.2812	0.4483
2	2	0.4333	0.4853	0.6505	0.3498	0.2682	0.4407
1	4	0.3710	0.5197	0.6385	0.2886	0.2766	0.3998
1	1	0.3684	0.4610	0.5901	0.2877	0.2571	0.3858
1/0	4	0.3208	0.5143	0.6061	0.2384	0.2712	0.3611
1/0	1/0	0.3108	0.4364	0.5357	0.2351	0.2452	0.3397
2/0	2	0.2869	0.4734	0.5536	0.2034	0.2563	0.3272
2/0	2/0	0.2657	0.4205	0.4974	0.1963	0.2387	0.3090
3/0	2	0.2461	0.4698	0.5304	0.1626	0.2527	0.3005
3/0	3/0	0.2099	0.4008	0.4524	0.1505	0.2297	0.2746
4/0	1	0.2276	0.4465	0.5012	0.1469	0.2426	0.2836
4/0	4/0	0.1899	0.3907	0.4344	0.1344	0.2240	0.2612
266.8	2/0	0.1764	0.3990	0.4362	0.1070	0.2171	0.2421
266.8	266.8	0.1397	0.3573	0.3836	0.0948	0.2032	0.2242
336.4	2/0	0.1615	0.3963	0.4280	0.0921	0.2145	0.2334
336.4	336.4	0.1150	0.3492	0.3676	0.0766	0.1988	0.2130
397.5	2/0	0.1528	0.3944	0.4230	0.0834	0.2126	0.2284
397.5	397.5	0.1002	0.3441	0.3584	0.0659	0.1958	0.2066
477	2/0	0.1446	0.3923	0.4181	0.0752	0.2105	0.2235
477	477	0.0860	0.3391	0.3498	0.0557	0.1927	0.2006
556.5	2/0	0.1389	0.3906	0.4145	0.0695	0.2087	0.2200
556.5	556.5	0.0759	0.3351	0.3436	0.0485	0.1902	0.1963

Note: Impedances, Ω/1000 ft (×5.28 for Ω/mi or ×3.28 for Ω/km). GMD = 4.8 ft, $GMD_{\phi N}$ = 6.3 ft, conductor temp. = 50°C, Earth resistivity = 100 Ω-m.

$$I = \sqrt{\frac{q_c + q_r - q_s}{R_{ac}}}$$

where

q_c = convected heat loss, W/ft
q_r = radiated heat loss, W/ft
q_s = solar heat gain, W/ft
R_{ac} = Nominal ac resistance at operating temperature t, Ω/ft

The convected heat loss with no wind is

$$q_c = 0.283\sqrt{\rho_f}\, D^{0.75}(t_c - t_a)^{1.25}$$

TABLE 2.11 Positive-Sequence Impedances of Hard-Drawn Copper

Phase Size	Strands	R_1	X_1	Z_1
4	3	0.2875	0.1494	0.3240
2	3	0.1809	0.1441	0.2313
1	7	0.1449	0.1420	0.2029
1/0	7	0.1150	0.1393	0.1807
2/0	7	0.0911	0.1366	0.1642
3/0	12	0.0723	0.1316	0.1501
4/0	12	0.0574	0.1289	0.1411
250	12	0.0487	0.1270	0.1360
300	12	0.0407	0.1250	0.1314
350	19	0.0349	0.1243	0.1291
400	19	0.0307	0.1227	0.1265
450	19	0.0273	0.1214	0.1244
500	19	0.0247	0.1202	0.1227

Note: Impedances, Ω/1000 ft (×5.28 for Ω/mi or ×3.28 for Ω/km). GMD = 4.8 ft, conductor temp. = 50°C.

Wind increases convection losses. The losses vary based on wind speed. The IEEE method uses the maximum q_c from the following two equations:

$$q_{c1} = \left[1.01 + 0.371\left(\frac{D\rho_f V}{\mu_f}\right)^{0.52}\right] K_f (t_c - t_a)$$

$$q_{c2} = 0.1695\left(\frac{D\rho_f V}{\mu_f}\right)^{0.6} K_f (t_c - t_a)$$

where

D = conductor diameter, in.
t_c = conductor operating temperature, °C
t_a = ambient temperature, °C
$t_f = (t_c + t_c)/2$
V = air velocity, ft/h
ρ_f = air density at t_f, lb/ft^3
μ_f = absolute viscosity of air at t_f, lb/h-ft
K_f = thermal conductivity of air at t_f, W/ft^2/°C

The density, viscosity, and thermal conductivity of air all depend on temperature (actually the film temperature T_f near the surface of the conductor, which is taken as the average of the conductor and ambient temperatures). Tables of these are available in the references (IEEE Std. 738-1993; Southwire Company, 1994). We may also use the following polynomial approximations (IEEE Std. 738-1993):

TABLE 2.12 Copper Zero-Sequence, Z_0, and Ground-Return Loop Impedances, $Z_S = (2Z_1 + Z_0)/3$

Phase Size	Neutral Size	R_0	X_0	Z_0	R_S	X_S	Z_S
3	3	0.3515	0.4459	0.5678	0.2707	0.2468	0.3663
3	3	0.3515	0.4459	0.5678	0.2707	0.2468	0.3663
6	6	0.5830	0.5157	0.7784	0.4986	0.2751	0.5695
6	6	0.5830	0.5157	0.7784	0.4986	0.2751	0.5695
4	6	0.4141	0.5104	0.6572	0.3297	0.2697	0.4260
4	4	0.4146	0.4681	0.6253	0.3299	0.2556	0.4173
2	6	0.3075	0.5051	0.5913	0.2231	0.2644	0.3460
2	2	0.2924	0.4232	0.5143	0.2181	0.2371	0.3221
1	4	0.2720	0.4606	0.5349	0.1873	0.2482	0.3109
1	1	0.2451	0.4063	0.4745	0.1783	0.2301	0.2911
1/0	4	0.2421	0.4580	0.5180	0.1574	0.2455	0.2916
1/0	1/0	0.2030	0.3915	0.4410	0.1443	0.2234	0.2660
2/0	3	0.2123	0.4352	0.4842	0.1315	0.2362	0.2703
2/0	2/0	0.1672	0.3796	0.4148	0.1165	0.2176	0.2468
3/0	2	0.1838	0.4106	0.4498	0.1095	0.2246	0.2498
3/0	3/0	0.1383	0.3662	0.3915	0.0943	0.2098	0.2300
4/0	2	0.1689	0.4080	0.4415	0.0946	0.2219	0.2412
4/0	4/0	0.1139	0.3584	0.3760	0.0762	0.2054	0.2191
250	1	0.1489	0.3913	0.4187	0.0821	0.2151	0.2303
250	250	0.0993	0.3535	0.3671	0.0656	0.2025	0.2128
300	1	0.1409	0.3893	0.4140	0.0741	0.2131	0.2256
300	300	0.0856	0.3487	0.3590	0.0557	0.1995	0.2071
350	1	0.1351	0.3886	0.4115	0.0683	0.2124	0.2231
350	350	0.0754	0.3468	0.3549	0.0484	0.1985	0.2043
400	1	0.1309	0.3871	0.4086	0.0641	0.2109	0.2204
400	400	0.0680	0.3437	0.3503	0.0431	0.1964	0.2011
450	1/0	0.1153	0.3736	0.3910	0.0566	0.2055	0.2131
450	450	0.0620	0.3410	0.3466	0.0389	0.1946	0.1984
500	1/0	0.1127	0.3724	0.3891	0.0540	0.2043	0.2113
500	500	0.0573	0.3387	0.3435	0.0356	0.1930	0.1963

Note: Impedances, Ω/1000 ft (×5.28 for Ω/mi or ×3.28 for Ω/km). GMD = 4.8 ft, $GMD_{\phi N}$ = 6.3 ft, conductor temp. = 50°C, Earth resistivity = 100 Ω-m.

$$\rho_f = \frac{0.080695 - (0.2901 \times 10^{-5})H_c + (0.37 \times 10^{-10})H_c^2}{1 + 0.00367T_f}$$

where H_c is the altitude above sea level in feet.

$$k_f = 0.007388 + 2.27889 \times 10^{-5} T_f - 1.34328 \times 10^{-9} T_f^2$$
$$\mu_f = 0.0415 + 1.2034 \times 10^{-4} T_f - 1.1442 \times 10^{-7} T_f^2 + 1.9416 \times 10^{-10} T_f^3$$

A conductor radiates heat as the absolute temperature to the fourth power as

$$q_r = 0.138 D \varepsilon \left[\left(\frac{T_c + 273}{100} \right)^4 - \left(\frac{T_a + 273}{100} \right)^4 \right]$$

where

D = conductor diameter, in.
ε = emissivity (normally 0.23 to 0.91 for bare wires)
T_c = conductor temperature, °C
T_a = ambient temperature, °C

A conductor absorbs heat from the sun as

$$q_s = \alpha Q_s \frac{D}{12} \sin\theta$$

where

α = solar absorptivity
Q_s = total solar heat in W/ft^2
θ = effective angle of incidence of the sun's rays
D = conductor diameter, in.

The angles and total solar heat depend on the time of day and the latitude. Since the solar input term does not change the output significantly, we can use some default values. For a latitude of 30 °N at 11 a.m. in clear atmosphere, Q_s = 95.2 W/ft^2, and θ = 78.6°.

Emissivity (ε) is the ability of a conductor to radiate heat into the air. Absorptivity (α) quantifies how much heat a conductor can absorb. Emissivity and absorptivity are interrelated; a nice shiny conductor reflects away much of the sun's heat but does not radiate heat well. Commonly, both are assumed to be 0.5 for bare wire. More conservative assumptions, possibly overconservative, are 0.7 for emissivity and 0.9 for absorptivity.

Some of the main factors impacting ampacity are

- *Allowable conductor temperature*—Ampacity increases significantly with higher allowed temperatures.
- *Ambient temperature*—Ampacity increases about 1% for each 1°C decrease in ambient temperature.
- *Wind speed*—Even a small wind helps cool conductors significantly. With no wind, ampacities are significantly lower than with a 2-ft/sec crosswind.

Tables 2.13 through 2.15 show ampacities of all-aluminum, ACSR, and copper conductors. All assume the following:

TABLE 2.13 Ampacities of All-Aluminum Conductor

		Conductor Temp. = 75°C				Conductor Temp. = 100°C			
		Ambient = 25°C		Ambient = 40°C		Ambient = 25°C		Ambient = 40°C	
Conductor	Stranding	No Wind	Wind	No Wind	Wind	No Wind	Wind	No Wind	Wind
6	7	60	103	46	85	77	124	67	111
4	7	83	138	63	114	107	166	92	148
2	7	114	185	86	152	148	223	128	199
1	7	134	214	101	175	174	258	150	230
1/0	7	157	247	118	203	204	299	176	266
2/0	7	184	286	139	234	240	347	207	309
3/0	7	216	331	162	271	283	402	243	358
4/0	7	254	383	190	313	332	466	286	414
250	7	285	425	213	347	373	518	321	460
250	19	286	427	214	348	375	519	322	462
266.8	7	298	443	223	361	390	539	335	479
266.8	19	299	444	224	362	392	541	337	481
300	19	325	479	243	390	426	584	367	519
336.4	19	351	515	262	419	461	628	397	559
350	19	361	527	269	428	474	644	408	572
397.5	19	394	571	293	464	517	697	445	619
450	19	429	617	319	501	564	755	485	671
477	19	447	640	332	519	588	784	506	697
477	37	447	641	333	520	589	785	507	697
500	19	461	658	342	534	606	805	521	716
556.5	19	496	704	368	571	654	864	562	767
556.5	37	496	705	369	571	654	864	563	768
600	37	522	738	388	598	688	905	592	804
636	37	545	767	404	621	720	943	619	838
650	37	556	782	413	633	737	965	634	857
700	37	581	814	431	658	767	1000	660	888
715.5	37	590	825	437	667	779	1014	670	901
715.5	61	590	825	437	667	780	1014	671	901
750	37	609	848	451	686	804	1044	692	927
795	37	634	881	470	712	840	1086	722	964
795	61	635	882	470	713	840	1087	723	965
800	37	636	884	471	714	841	1087	723	965
874.5	61	676	933	500	754	896	1152	770	1023
874.5	61	676	934	500	754	896	1152	771	1023
900	37	689	950	510	767	913	1172	785	1041
954	37	715	983	529	793	946	1210	813	1074
954	61	719	988	532	797	954	1221	821	1084
1000.0	37	740	1014	547	818	981	1252	844	1111

TABLE 2.14 Ampacities of ACSR

		Conductor Temp. = 75°C				Conductor Temp. = 100°C			
		Ambient = 25°C		Ambient = 40°C		Ambient = 25°C		Ambient = 40°C	
Conductor	Stranding	No Wind	Wind	No Wind	Wind	No Wind	Wind	No Wind	Wind
6	6/1	61	105	47	86	79	126	68	112
4	6/1	84	139	63	114	109	167	94	149
4	7/1	85	141	64	116	109	168	94	149
2	6/1	114	184	86	151	148	222	128	197
2	7/1	117	187	88	153	150	224	129	199
1	6/1	133	211	100	173	173	255	149	227
1/0	6/1	156	243	117	199	202	294	174	261
2/0	6/1	180	277	135	227	235	337	203	300
3/0	6/1	208	315	156	258	262	370	226	329
4/0	6/1	243	363	182	296	319	443	274	394
266.8	18/1	303	449	227	366	398	547	342	487
266.8	26/7	312	458	233	373	409	559	352	497
336.4	18/1	356	520	266	423	468	635	403	564
336.4	26/7	365	530	272	430	480	647	413	575
336.4	30/7	371	536	276	435	487	655	419	582
397.5	18/1	400	578	298	469	527	708	453	629
397.5	26/7	409	588	305	477	538	719	463	639
477	18/1	453	648	337	525	597	793	513	705
477	24/7	461	656	343	532	607	804	523	714
477	26/7	464	659	345	534	611	808	526	718
477	30/7	471	667	350	540	615	810	529	720
556.5	18/1	504	713	374	578	664	874	571	777
556.5	24/7	513	722	380	585	677	887	582	788
556.5	26/7	517	727	383	588	682	893	587	793
636	24/7	562	785	417	635	739	962	636	854
636	26/7	567	791	420	639	748	972	644	863
795	45/7	645	893	478	721	855	1101	735	977
795	26/7	661	910	489	734	875	1122	753	996
954	45/7	732	1001	541	807	971	1238	835	1099
954	54/7	741	1010	547	814	983	1250	846	1109
1033.5	45/7	769	1048	568	844	1019	1294	877	1148

- Emissivity = 0.5, absorptivity = 0.5
- 30 °N at 11 a.m. in clear atmosphere
- Wind speed = 2 ft/sec
- Elevation = sea level

The solar heating input has modest impacts on the results. With no sun, the ampacity increases by only a few percent.

TABLE 2.15 Ampacities of Copper Conductors

		Conductor Temp. = 75°C				Temp. = 100°C			
		Ambient = 25°C		Ambient = 40°C		Ambient = 25°C		Ambient = 40°C	
Conductor	Stranding	No Wind	Wind	No Wind	Wind	No Wind	Wind	No Wind	Wind
6	3	83	140	63	116	107	169	92	150
6	1	76	134	58	110	98	160	85	143
5	3	97	162	73	134	125	195	108	174
5	1	90	155	68	127	115	185	99	165
4	3	114	188	86	154	147	226	127	201
4	1	105	179	80	147	136	214	117	191
3	7	128	211	97	174	166	254	143	226
3	3	133	217	101	178	173	262	149	233
3	1	123	206	93	170	159	248	137	221
2	7	150	244	114	201	195	294	168	262
2	3	157	251	118	206	203	303	175	270
2	1	145	239	110	196	187	287	161	256
1	3	184	291	138	238	239	351	206	313
1	7	177	282	133	232	229	340	197	303
1/0	7	207	326	156	267	269	394	232	351
2/0	7	243	378	183	309	317	457	273	407
3/0	12	292	444	219	362	381	539	328	479
3/0	7	285	437	214	357	373	530	321	472
4/0	19	337	507	252	414	440	617	379	549
4/0	12	342	513	256	418	448	624	386	555
4/0	7	335	506	251	413	438	615	377	547
250	19	377	563	282	459	493	684	424	608
250	12	384	569	287	464	502	692	432	615
300	19	427	630	319	513	559	767	481	682
300	12	435	637	324	519	569	776	490	690
350	19	475	694	355	565	624	847	537	753
350	12	484	702	360	571	635	858	546	763
400	19	520	753	387	612	682	920	587	817
450	19	564	811	420	659	742	993	639	883
500	37	606	865	450	702	798	1061	686	942
500	19	605	865	450	701	797	1059	685	941
600	37	685	968	509	784	905	1190	779	1057
700	37	759	1062	563	860	1003	1308	863	1161
750	37	794	1107	588	895	1051	1364	904	1211
800	37	826	1147	612	927	1092	1412	939	1253
900	37	894	1233	662	995	1189	1527	1023	1356
1000	37	973	1333	719	1075	1313	1676	1129	1488

Some simplifying equations help for evaluating some of the significant impacts on ampacity. We can estimate changes in ambient and allowable temperature variations (Black and Rehberg, 1985; Southwire Company, 1994) with

$$I_{\text{new}} = I_{\text{old}} \sqrt{\frac{T_{\text{c,new}} - T_{\text{a,new}}}{T_{\text{c,old}} - T_{\text{a,old}}}}$$

where I_{new} is the new ampacity based on a new conductor limit $T_{c,\text{new}}$ and a new ambient temperature $T_{a,\text{new}}$. Likewise, I_{old} is the original ampacity based on a conductor limit $T_{c,\text{old}}$ and an ambient temperature $T_{a,\text{old}}$.

This approach neglects solar heating and the change in conductor resistance with temperature (both have small impacts). Doing this simplifies the ampacity calculation to a constant (dependent on weather and conductor characteristics) times the difference between the conductor temperature and the ambient temperature: $I^2 = K(T_c - T_a)$. We do not use this simplification for the original ampacity calculation, but it helps us evaluate changes in temperatures or currents.

We use this approach in Figure 2.12 to show the variation in ampacity with ambient conductor assumptions along with two conductor operating limits. Also, Figure 2.13 shows the conductor temperature vs. loading for several AAC conductors. This graph

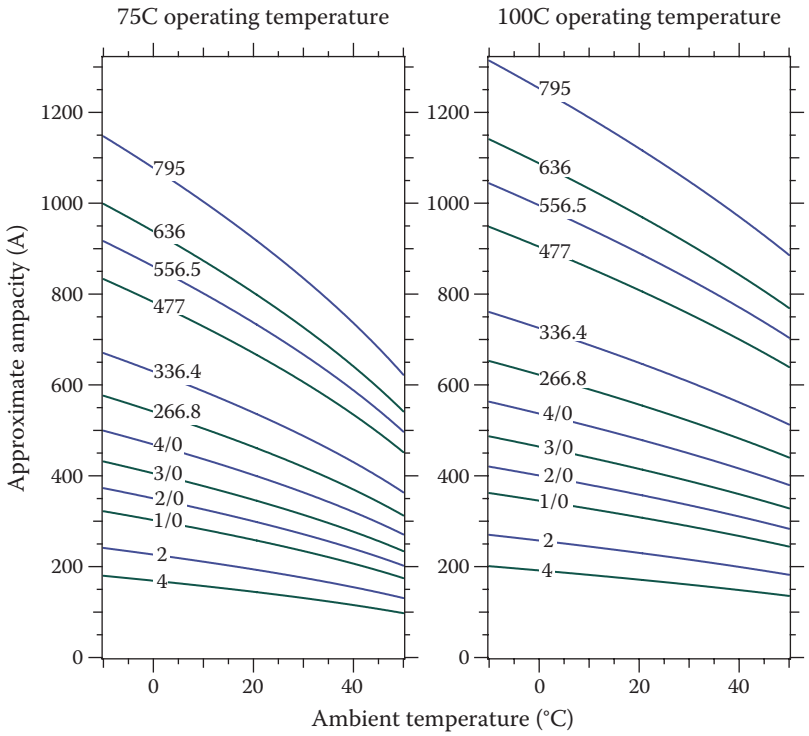


Figure 2.12 AAC ampacity with ambient temperature variations, using adjustments from base ampacity data in Table 2.13 (2 ft/sec wind, with sun).

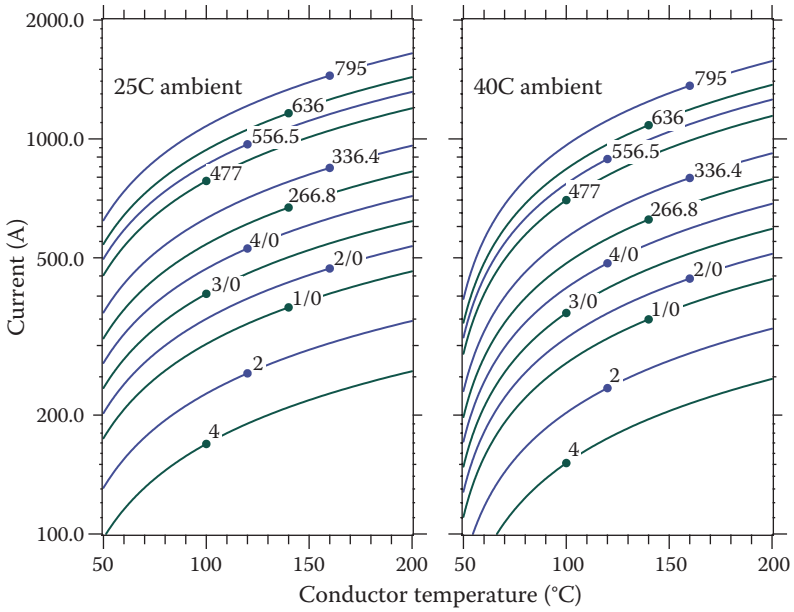


Figure 2.13 Conductor temperatures based on the given currents for selected AAC conductors, using adjustments from base ampacity data in Table 2.13 (2 ft/sec wind).

highlights the major impact of operating temperature on ampacity. If we are overly conservative on a conductor limit, we end up with an overly restrictive ampacity.

We can also use the simplified ampacity equation to estimate the conductor temperature at a current higher or lower than the rated ampacity as (and at a different ambient temperature if we wish)

$$T_{c,\text{new}} = T_{a,\text{new}} + \left(\frac{I_{\text{new}}}{I_{\text{old}}}\right)^2 (T_{c,\text{old}} - T_{a,\text{old}})$$

When examining a line's ampacity, always remember that the overhead wire may not be the weakest link; substation exit cables, terminations, reclosers, or other gear may limit a circuit's current before the conductors do. Also, with currents near a conductor's rating, voltage drop is high.

The maximum operating temperature is an important consideration. Higher designed operating temperatures allow higher currents. But at higher temperatures, we have a higher risk of damage to the conductors. Aluminum strands are strain hardened during manufacturing (the H19 in aluminum's 1350-H19 designation means "extra hard"). Heating relaxes the strands—the aluminum elongates and weakens. This damage is called *annealing*. As aluminum anneals, it reverts back to its natural, softer state: fully annealed 1350 aluminum wire elongates by 30% and loses 58% of its strength (10,000 psi vs. 24,000 psi fully hardened). Even fully annealed, failure may not be immediate; the next ice load or heavy winds may break a conductor. Slow

annealing begins near 100°C. Aluminum anneals rapidly above 200°C. Annealing damage is permanent and accumulates over time. Remaining strength for AAC conductors varies with conductor temperature and duration of exposure as approximately (Harvey, 1971)

$$R_S = k_1 t^{-\frac{0.1}{d}(0.001T_c - 0.095)}$$

where

R_S = remaining strength, percent of initial strength
d = strand diameter, in.
t = exposure time, h
T_c = conductor temperature, °C
$k_1 = (-0.24T_c + 135)$, but if $k_1 > 100$, use $k_1 = 100$

Figure 2.14 shows the loss of strength with time for high-temperature operation using this approximation.

ACSR may be loaded higher than the same size AAC conductor. As the aluminum loses strength, the steel carries more of the tension. The steel does not lose strength until reaching higher temperatures.

Covered conductors are darker, so they absorb more heat from the sun but radiate heat better; the Aluminum Association (1986) uses 0.91 for both the emissivity and the absorptivity of covered wire. Table 2.16 shows ampacities of covered wire. Covered conductors have ampacities that are close to bare-conductor ampacities. The most significant difference is that covered conductors have less ability to withstand higher temperatures; the insulation degrades. Polyethylene is especially prone to damage, so it should not be operated above 75°C. EPR and XLPE may be operated up to 90°C.

Some utilities use two ratings, a "normal" ampacity with a 75°C design temperature and an "emergency" ampacity with a 90°C or 100°C design. Conductors are selected for the normal rating, but operation is allowed to the emergency rating.

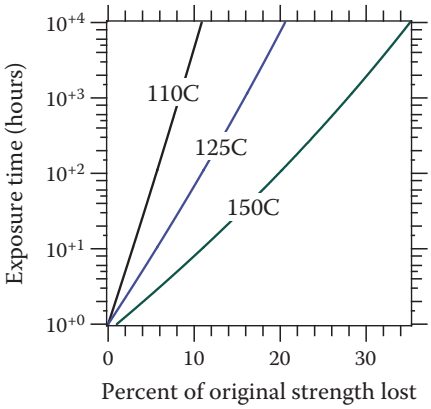


Figure 2.14 Loss of strength of all-aluminum conductors due to exposure to high temperatures.

TABLE 2.16 Ampacities of All-Aluminum Conductor Covered with PE, XLPE, or EPR

AWG or kcmil	Stranding	Cover Thickness (mil)	Conductor Temp. = 75°C		Conductor Temp. = 90°C	
			25°C Ambient	40°C Ambient	25°C Ambient	40°C Ambient
6	7	30	105	85	120	105
4	7	30	140	110	160	135
2	7	45	185	145	210	180
1	7	45	210	170	245	210
1/0	7	60	240	195	280	240
2/0	7	60	280	225	325	280
3/0	7	60	320	255	375	320
4/0	7	60	370	295	430	370
4/0	19	60	375	295	430	370
266.8	19	60	430	340	500	430
336.4	19	60	500	395	580	495
397.5	19	80	545	430	635	545
477	37	80	615	480	715	610
556.5	37	80	675	530	785	675
636	61	95	725	570	850	725
795	61	95	835	650	980	835
1033.5	61	95	980	760	1150	985

Data source: Aluminum Association, *Ampacities for Aluminum and ACSR Overhead Electrical Conductors*, 1986.

Notes: Emissivity = 0.91, absorptivity = 0.91; 30°N at 12 noon in clear atmosphere; wind speed = 2 ft/s; elevation = sea level.

Overhead circuits have considerable capability for overload, especially during cooler weather. We do not use relaying to trip "overloaded" circuits. At higher temperatures, conductors age more quickly but do not usually fail immediately.

2.7.1 Neutral Conductor Sizing

Because the neutral conductor carries lesser current than the phase conductors, utilities can use smaller neutral conductors. On three-phase circuits with balanced loading, the neutral carries almost no current. On single-phase circuits with a multigrounded neutral, the neutral normally carries 40 to 60% of the current (the earth carries the remainder).

On single-phase circuits, some utilities use fully rated neutrals, where the neutral and the phase are the same size. Some use reduced neutrals. The resistance of the neutral should be no more than twice the resistance of the phase conductor, and we are safer with a resistance less than 1.5 times the phase conductor, which is a conductivity or cross-sectional area of 2/3 the phase conductor. Common practice is to drop one to three gage sizes for the neutral: a 4/0 phase has a 2/0 neutral, or a 1/0 phase has

a number 2 neutral. Dropping three gage sizes doubles the resistance, so we do not want to go any smaller than that.

On three-phase circuits, most utilities use reduced neutrals, dropping the area to about 25 to 70% of the phase conductor (and multiplying the resistance by 1.4 to 4).

Several other factors besides ampacity play a role in how small neutral conductors are

- *Grounding*—A reduced neutral increases the overvoltages on the unfaulted phases during single line-to-ground faults (see Chapter 14). It also increases stray voltages.
- *Faults*—A reduced neutral reduces the fault current for single line-to-ground faults, which makes it more difficult to detect faults at far distances. Also, the reduced neutral is subjected to the same fault current as the phase, so impacts on burning down the neutral should be considered for smaller neutrals.
- *Secondary*—If the primary and secondary neutral are shared, the neutral must handle the primary and secondary unbalanced current (and have the mechanical strength to hold up the secondary phase conductors in triplex or quadraplex construction).
- *Mechanical*—On longer spans, the sag of the neutral should coordinate with the sag of the phases and the minimum ground clearances to ensure that spacing rules are not violated.

2.8 Secondaries

Utilities most commonly install *triplex* secondaries for overhead service to single-phase customers, where two insulated phase conductors are wrapped around the neutral. The neutral supports the weight of the conductors. Phase conductors are normally all-aluminum, and the neutral is all-aluminum, aluminum-alloy, or ACSR, depending on strength needs. Insulation is normally polyethylene, high-molecular weight polyethylene, or cross-linked polyethylene with thickness ranging from 30 to 80 mils (1.1 to 2 mm) rated for 600 V. Similarly for three-phase customers, quadraplex has three insulated phase conductors wrapped around a bare neutral. Table 2.17 shows characteristics of polyethylene triplex with an AAC neutral.

Triplex secondary ampacities depend on the temperature capability of the insulation. Polyethylene can operate up to 75°C. Cross-linked polyethylene and EPR can operate higher, up to 90°C. Table 2.18 shows ampacities for triplex when operated to each of these maximum temperatures. Quadraplex has ampacities that are 10 to 15% less than triplex of the same size conductor. Ampacities for open-wire secondary are the same as that for bare primary conductors.

Table 2.19 shows impedances of triplex. Two impedances are given: one for the 120-V loop and another for a 240-V loop. The 240-V loop impedance is the impedance to current flowing down one hot conductor and returning on the other. The 120-V loop impedance is the impedance to current down one hot conductor and returning in the neutral (and assuming no current returns through the earth). If the phase conductor and the neutral conductor are the same size, these impedances are the same. With a reduced neutral, the 120-V loop impedance is higher. Table 2.19

TABLE 2.17 Typical Characteristics of Polyethylene-Covered AAC Triplex

Phase Conductor		Neutral Options (Bare)					
		ACSR Neutral Messenger		Reduced ACSR Neutral Messenger		AAC Neutral Messenger	
Size (Stranding)	Insulation Thickness, mil	Size (Stranding)	Rated Strength, lb	Size (Stranding)	Rated Strength, lb	Size (Stranding)	Rated Strength, lb
6 (1)	45	6 (6/1)	1190				
6 (7)	45	6 (6/1)	1190				
4 (1)	45	4 (6/1)	1860	6 (6/1)	1190	6 (7)	563
4 (7)	45	4 (6/1)	1860	6 (6/1)	1190	4 (7)	881
2 (7)	45	2 (6/1)	2850	4 (6/1)	1860	2 (7)	1350
1/0 (7)	60	1/0 (6/1)	4380	2 (6/1)	2853	1/0 (7)	1990
1/0 (19)	60	1/0 (6/1)	4380	2 (6/1)	2853	1/0 (7)	1990
2/0 (7)	60	2/0 (6/1)	5310	1 (6/1)	3550	2/0 (7)	2510
2/0 (19)	60	2/0 (6/1)	5310	1 (6/1)	3550		
3/0 (19)	60	3/0 (6/1)	6620	1/0 (6/1)	4380	3/0 (19)	3310
4/0 (19)	60	4/1 (6/1)	8350	2/0 (6/1)	5310	4/0 (19)	4020
336.4 (19)	80	336.4 (18/1)	8680	4/0 (6/1)	8350	336.4 (19)	6146

TABLE 2.18 Ampacities of All-Aluminum Triplex

Phase Conductor AWG	Strands	Conductor Temp = 75°C		Conductor Temp = 90°C	
		25°C Ambient	40°C Ambient	25°C Ambient	40°C Ambient
6	7	85	70	100	85
4	7	115	90	130	115
2	7	150	120	175	150
1/0	7	200	160	235	200
2/0	7	230	180	270	230
3/0	7	265	210	310	265
4/0	7	310	240	360	310

Data source: Aluminum Association, *Ampacities for Aluminum and ACSR Overhead Electrical Conductors*, 1986.

Note: Emissivity = 0.91, absorptivity = 0.91; 30°N at 12 noon in clear atmosphere; wind speed = 2 ft/s; elevation = sea level.

shows impedances for the reduced neutral size given; for a fully rated neutral, use the 240-V impedance for the 120-V impedance.

2.9 Fault Withstand Capability

When a distribution line short circuits, very large currents can flow for a short time until a fuse or breaker or other interrupter breaks the circuit. One important aspect

TABLE 2.19 Typical Impedances of All-Aluminum Triplex Secondaries, Ω/1000 ft

Phase		Neutral		120-V Loop Impedance[a]		240-V Loop Impedance	
Size	Strands	Size	Strands	R_{S1}	X_{S1}	R_S	X_S
2	7	4	7	0.691	0.0652	0.534	0.0633
1	19	3	7	0.547	0.0659	0.424	0.0659
1/0	19	2	7	0.435	0.0628	0.335	0.0616
2/0	19	1	19	0.345	0.0629	0.266	0.0596
3/0	19	1/0	19	0.273	0.0604	0.211	0.0589
4/0	19	2/0	19	0.217	0.0588	0.167	0.0576
250	37	3/0	19	0.177	0.0583	0.142	0.0574
350	37	4/0	19	0.134	0.0570	0.102	0.0558
500	37	300	37	0.095	0.0547	0.072	0.0530

Data source: ABB Inc., *Distribution Transformer Guide*, 1995.
[a]With a full-sized neutral, the 120-V loop impedance is equal to the 240-V loop impedance.

of overcurrent protection is to ensure that the fault arc and fault currents do not cause further, possibly more permanent, damage. The two main considerations are

- *Conductor annealing*—From the substation to the fault location, all conductors in the fault-current path must withstand the heat generated by the short-circuit current. If the relaying or fuse does not clear the fault in time, the conductor anneals and loses strength.
- *Burndowns*—Right at the fault location, the hot fault arc can burn the conductor. If a circuit interrupter does not clear the fault in time, the arc will melt the conductor until it breaks apart.

For both annealing and arcing damage, we should design protection to clear faults before more damage is done. To do this, make sure that the time–current characteristics of the relay or fuse are faster than the time–current damage characteristics. Characteristics of annealing and arcing damage are included in the next two sections.

2.9.1 Conductor Annealing

During high currents from faults, conductors can withstand significant temperatures for a few seconds without losing strength. For all-aluminum conductors, assuming a maximum temperature of 340°C during faults is common. ACSR conductors can withstand even higher temperatures because short-duration high temperature does not affect the steel core. An upper limit of 645°C, the melting temperature of aluminum, is often assumed. For short-duration events, we ignore convection and radiation heat losses and assume that all heat stays in the conductor. With all heat staying in the conductor, the temperature is a function of the specific heat of the conductor material. Specific heat is the heat per unit mass required to raise the temperature by

1°C (the specific heat of aluminum is 0.214 cal/g-°C). Considering the heat inputs and the conductor characteristics, the conductor temperature during a fault is related to the current (Southwire Company, 1994) as

$$\left(\frac{I}{1000A}\right)^2 t = K \log_{10}\left(\frac{T_2 + \lambda}{T_1 + \lambda}\right)$$

where

I = fault current, A
t = fault duration, sec
A = cross-sectional area of the conductor, kcmil
T_2 = conductor temperature from the fault, °C
T_1 = conductor temperature before the fault, °C
K = constant depending on the conductor, which includes the conductor's resistivity, density, and specific heat (see Table 2.20)
λ = inferred temperature of zero resistance, °C below zero (see Table 2.20)

If we set T_2 to the maximum allowable conductor temperature, we can find the maximum allowable I^2t characteristic for a given conductor. For all-aluminum conductors, with a maximum temperature, $T_2 = 340$°C, and an ambient of 40°C, the maximum allowable time–current characteristic for a given conductor size (Southwire Company, 1994) is

$$I^2t = (67.1A)^2$$

For ACSR with a maximum temperature of 640°C, the maximum allowable time–current characteristic for a given conductor size (Southwire Company, 1994) is

$$I^2t = (86.2A)^2$$

Covered conductors have more limited short-circuit capability because the insulation is damaged at lower temperatures. Thermoplastic insulations like polyethylene have a maximum short-duration temperature of 150°C. The thermoset insulations EPR and XLPE have a maximum short-duration temperature of 250°C. With these

TABLE 2.20 Conductor Thermal Data for Short-Circuit Limits

Conductor Material	λ,°C	K
Copper (97%)	234.0	0.0289
Aluminum (61.2%)	228.1	0.0126
6201 (52.5%)	228.1	0.0107
Steel	180.0	0.00327

Data source: Southwire Company, *Overhead Conductor Manual*, 1994.

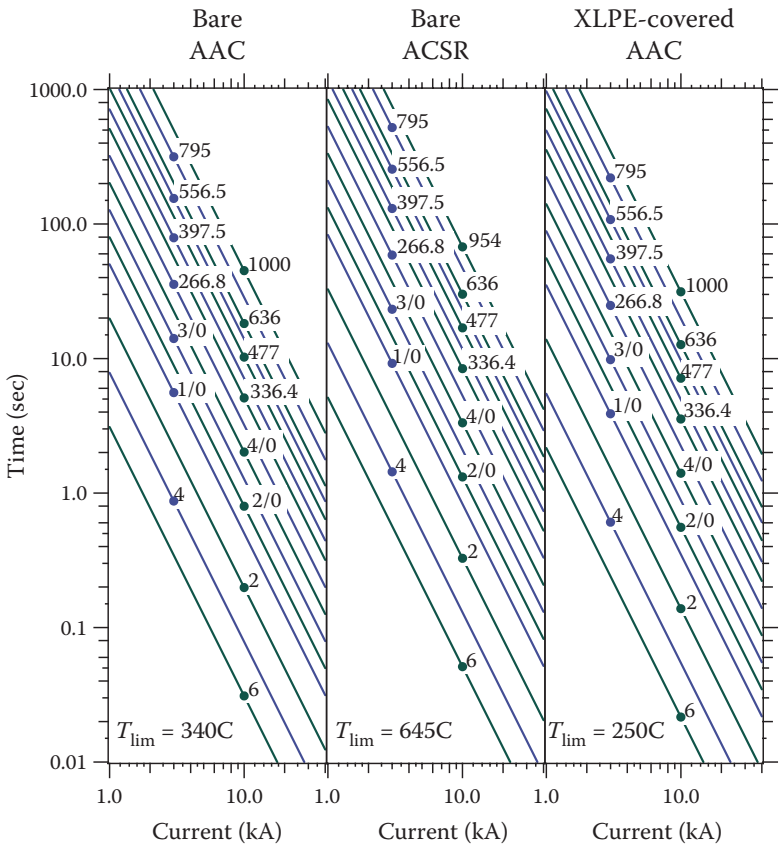


Figure 2.15 Annealing curves of bare AAC, ACSR, and covered AAC.

upper temperature limits (and $T_1 = 40°C$), the allowable time–current characteristics of aluminum conductors are

$$\text{Polyethylene:} \quad I^2t = (43A)^2$$
$$\text{XLPE or EPR:} \quad I^2t = (56A)^2$$

Figure 2.15 compares short-circuit damage curves for various conductors.

2.9.2 Burndowns

Fault-current arcs can damage overhead conductors. The arc itself generates tremendous heat, and where an arc attaches to a conductor, it can weaken or burn conductor strands. On distribution circuits, two problem areas stand out:

1. *Covered conductor*—Covered conductor (also called tree wire or weatherproof wire) holds an arc stationary. Because the arc cannot move, burndowns happen faster than with bare conductors.

2. *Small bare wire on the mains*—Small bare wire (less than 2/0) is also susceptible to wire burndowns, especially if laterals are not fused.

Covered conductors are widely used to limit tree faults. Several utilities have had burndowns of covered conductor circuits when the instantaneous trip was not used or was improperly applied (Barker and Short, 1996; Short and Ammon, 1997). If a burndown on the main line occurs, all customers on the circuit will have a long interruption. In addition, it is a safety hazard. After the conductor breaks and falls to the ground, the substation breaker may reclose. After the reclosure, the conductor on the ground will probably not draw enough fault current to trip the station breaker again. This is a high-impedance fault that is difficult to detect.

A covered conductor 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 conductor itself, so the arc gets very hot. On bare conductors, 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; this is called *motoring*). The covering constricts the arc to one location, so the heating and melting is concentrated on one part of the conductor. If the covering is stripped at the insulators and a fault arcs across an insulator, the arc motors until it reaches the covering, stops, and burns the conductor apart at the junction. A party balloon, lightning, a tree branch, a squirrel—any of these can initiate the arc that burns the conductor down. Burndowns are most associated with lightning-caused faults, but it is the fault current arc, not the lightning, that burns most of the conductor.

Conductor damage is a function of the duration of the fault and the current magnitude. Burndown damage occurs much more quickly than conductor annealing that was analyzed in the previous section.

Although they are not as susceptible as covered conductors, bare conductors can also have burndowns. In tests of smaller bare conductors, Florida Power & Light Co. (FP&L) found that the hot gases from the arc anneal the conductor (Lasseter, 1956). They found surprisingly little burning from the arc; in fact, arcs could seriously degrade conductor strength even when there is no visible damage.

What we would like to do is plot the arc damage characteristic as a function of time and current along with the time–current characteristics of the protective device (whether it be a fuse or a recloser or a breaker). Doing this, we can check that the protective device will clear the fault before the conductor is damaged. Figure 2.16 shows burndown damage characteristics for small bare ACSR conductors along with a 100 K lateral fuse element and a typical ground relay element. The fuse protects the conductors shown, but the ground relay does not provide adequate protection against damage for these conductors. These damage curves are based on FP&L's tests, where Lasseter reported that the threshold-of-damage was 25 to 50% of the average burndown time (see Table 2.21).

Such arc damage data for different conductor sizes as a function of time and current is limited. Table 2.22 summarizes burndown characteristics of some bare and covered conductors based on tests by Baltimore Gas & Electric (Goode and Gaertner, 1965). Figure 2.17 shows this same data on time–current plots along with a 100 K fuse

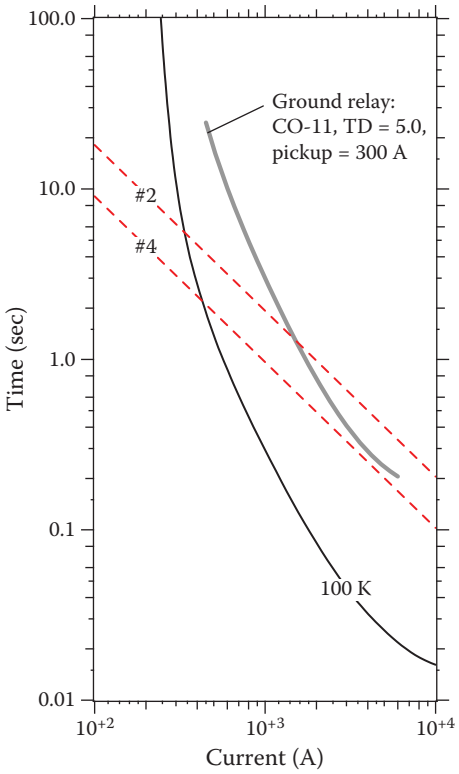


Figure 2.16 Bare-conductor ACSR threshold-of-damage curves along with the 100-K lateral fuse total clearing time and a ground relay characteristic. (Damage curves from Lasseter, J. A., *Electric Light & Power*, pp. 94–100, December 1956.)

TABLE 2.21 The Burndown Characteristics of Several Small Bare Conductors

Conductor	Threshold of Damage	Average Burndown Time
#4 AAAC	$t = \frac{4375}{I^{1.235}}$	$t = \frac{17500}{I^{1.235}}$
#4 ACSR	$t = \frac{800}{I^{0.973}}$	$t = \frac{3350}{I^{0.973}}$
#2 ACSR	$t = \frac{1600}{I^{0.973}}$	$t = \frac{3550}{I^{0.973}}$
#6 Cu	$t = \frac{410}{I^{0.909}}$	$t = \frac{1440}{I^{0.909}}$
#4 Cu	$t = \frac{500}{I^{0.909}}$	$t = \frac{1960}{I^{0.909}}$

Data source: Lasseter, J. A., *Electric Light & Power*, pp. 94–100, December 1956.

Note: I = rms fault current, A; t = fault duration, sec.

TABLE 2.22 Burndown Characteristics of Various Conductors

		Duration, 60-Hz Cycles			
	Current, A	Min	Max	Other	Curvefit
#6 Cu covered	100	48.5	55.5	51	$t = 858/I^{1.51}$
	200	20.5	24.5	22	
	360	3.5	4.5	4.5	
	1140	1.5	1.5	1.5	
#4 Cu covered	200	26.5	36.5	28	$t = 56.4/I^{0.92}$
	360	11	12.5	12	
	1400	4.5	5.5	5.5	
	4900	1	1.5	1.5	
#4 Cu bare	380	24.5	32.5	28.5	$t = 641/I^{1.25}$
	780	6	9	8	
	1300	3.5	7	4.5	
	4600	1	1.5	1	
#2 ACSR covered	750	8	9	14	$t = 15.3/I^{0.65}$
	1400	10	9	14	
	4750	3.5	4.5	4	
	9800	2	2	NA	
#2 ACSR bare	1350	38	39	40	$t = 6718/I^{1.26}$
	4800	10	11.5	10	
	9600	4.5	5	6	
	15,750	1	1.5	NA	
1/0 Cu covered	480	13.5	20	18	$t = 16.6/I^{0.65}$
	1300	7	15.5	9	
	4800	4	5	4.5	
	9600	2	2.5	2.5	
1/0 Cu bare	1400	20.5	29.5	22.5	$t = 91/I^{0.78}$
	4800	3.5	7	4.5	
	9600	4	6	6	
	15,000	3	4	3.5	
3/0 ACSR covered	1400	35	38	37	$t = 642600/I^{1.92}$
	1900	16	17	16.5	
	3300	10	12	11	
	4800	2	3	3	
3/0 ACSR bare	4550	26	30.5	28.5	$t = 1460/I^{0.95}$
	9100	14	16	15	
	15,500	8	9.5	8	
	18,600	7	9	7	
4/0 ACAR bare	2100	24	29	28	$t = 80.3/I^{0.68}$
	4800	16	18	17.5	
	9200	8	9.5	8.5	
	15,250	8	8	NA	
4/0 ACSR bare	4450	53	66	62	$t = 68810/I^{1.33}$

continued

TABLE 2.22 (*Continued*) Burndown Characteristics of Various Conductors

		Duration, 60-Hz Cycles			
	Current, A	Min	Max	Other	Curvefit
	8580	21	26	25	
	15,250	10	14	NA	
	18,700	8	10	8.5	
336.4-kcmil ACAR bare	4900	33	38.5	33	$t = 6610/I^{1.10}$
	9360	12	17.5	17	
	15,800	8	8.5	8	
	18,000	7	14	7.5	
336.4-kcmil ACSR bare	8425	25	26	26	$t = 2690/I^{0.97}$
	15,200	10	15	14	
	18,800	12	13	12	
350-kcmil AAC bare	4800	29	21	20	$t = 448/I^{0.84}$
	9600	11.5	13.5	12	
	15,200	8	9	8.5	
	18,200	8	7.5	7.5	
500-kcmil AAC bare	4800	42	43	42.5	$t = 2776/I^{0.98}$
	8800	22.5	23	22	
	15,400	13	14.5	14	
	18,400	11	12	10.5	

Data source: Goode, W. B. and Gaertner, G. H., *EEI T&D Meeting, Clearwater*, FL, Oct. 14–15, 1965.

total clearing characteristic. For conductor sizes not given, take the closest size given in Table 2.22, and scale the burndown time by the ratio of the given conductor area to the area of the desired conductor.

EPRI tested burndown scenarios for both small bare conductors and larger covered conductors (EPRI 1017839, 2009). Table 2.23 summarizes burndown curves estimated from these tests. The EPRI tests found similar results to those by Goode and Gaertner (1965) for covered conductors as shown in Figure 2.18. Figure 2.19 shows typical damage from arcs on covered conductors. For small bare conductors, the EPRI burndown times were closer to those of Goode and Gaertner than those of Lasseter (1956). Lasseter reported longer times to burndown than the EPRI work or the Goode and Gaertner work.

Conductor line hose inhibits arc movement in similar fashion to covered conductors: the arc motors until it reaches the line hose and burns down there (see Figure 2.20). The implication for live-line work is that arcs can be stopped in the vicinity of workers, possibly increasing arc flash hazard, and also introducing the hazard of conductor breakage from an arc. Both risks decrease by using faster relaying during maintenance.

Because arc movement is so important to burndown, EPRI tested a number of scenarios to see what might inhibit arc movement. In 15 opportunities, arcs motored right past automatic splices with no damage to the conductors. Hotline clamps also

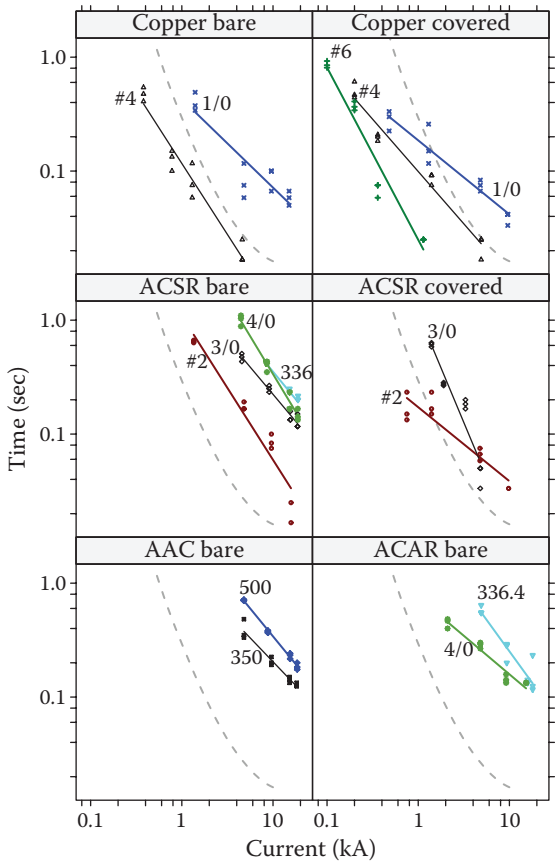


Figure 2.17 Burndown characteristics of various conductors. The dashed line is the total clearing time for a 100-K fuse. (Data from Goode, W. B. and Gaertner, G. H., *EEI T&D Meeting, Clearwater*, FL, Oct. 14–15, 1965.)

TABLE 2.23 Typical and Worst-Case Burndown Characteristics for Several Common Conductors

Conductor	Typical Burndown Characteristics	Severe Case Burndown Characteristics
#4 ACSR Bare	$t = \frac{5074.3}{I^{1.2772}}$	$t = \frac{2682}{I^{1.211}}$
#2 ACSR Bare	$t = \frac{185.1}{I^{0.7407}}$	$t = \frac{117.64}{I^{0.7358}}$
336.4 kcmil Al covered	$t = \frac{24106}{I^{1.3254}}$	$t = \frac{22253}{I^{1.3335}}$
556.4 kcmil Al covered	$t = \frac{41549}{I^{1.3222}}$	$t = \frac{26878}{I^{1.2839}}$

Source: From EPRI 1017839, *Distribution Conductor Burndown Test Results: Small Bare and Large Covered Conductor*, Electric Power Research Institute, Palo Alto, CA, 2009. Copyright 2009. Reprinted with permission.

Note: I = rms fault current, A; t = fault duration, sec.

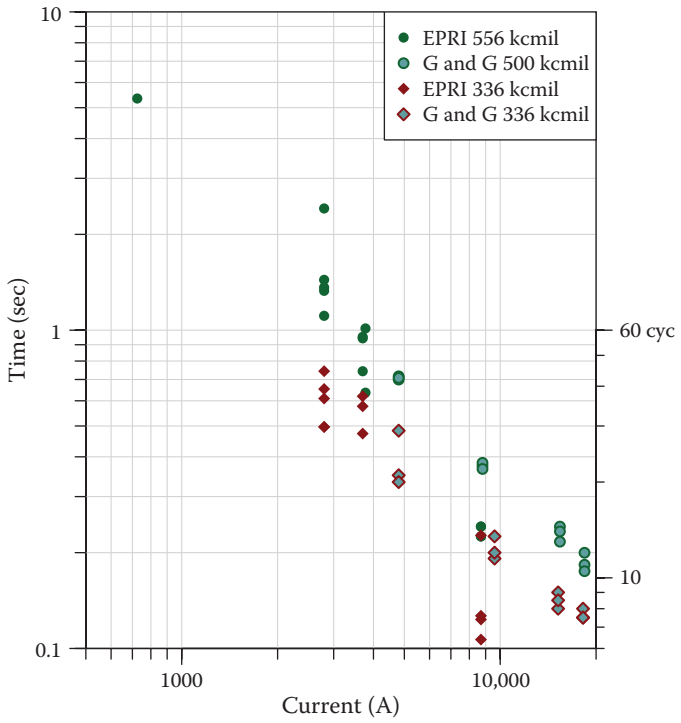


Figure 2.18 Burndown tests of covered, aluminum conductors. (Data from Goode, W. B. and Gaertner, G. H., *EEI T&D Meeting, Clearwater*, FL, Oct. 14–15, 1965 and EPRI 1017839, 2010.)

Figure 2.19 Example of burndown damage on covered 336–kcmil AL conductors. (Electric Power Research Institute. 1017839, Distribution Conductor Burndown Test Results. Copyright 2009. Reprinted with permission.)

did not inhibit arc movement in several tests. A porcelain pin-top insulator with an aluminum hand tie did not fully inhibit movement, but it slowed it down enough that there was visual pitting on the conductor. A polymer vise-top insulator also slowed down travel enough to cause significant damage to the conductor underneath. If the arc is slowed, "bird-caging" was observed on ACSR conductors where the aluminum strands bulge out from around the steel core.

Figure 2.20 Burndown test with line hose. (Electric Power Research Institute. 1017839, Distribution Conductor Burndown Test Results. Copyright 2009. Reprinted with permission.)

If covered conductor is used, consider the following options to limit burndowns:

- *Fuse saving*—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. With fuse saving, the instantaneous relay element trips the circuit faster and reduces conductor damage.
- *Arc protective devices* (APDs)—These sacrificial masses of metal attach to the ends where the covering is stripped (Lee et al., 1980). The arc end attaches to the mass of metal, which has a large enough volume to withstand much more arcing than the conductor itself. EPRI testing showed that arc protective devices are effective at eliminating conductor damage if they are applied right where the covering is stripped (EPRI 1017839, 2009); the arc anchors on the device and protects the conductor. If there is a gap between the device and the covering, the arc will motor past the device and burn down the wire where the arc attaches in the gap. Crews should place these on the downstream side of the exposed conductor, or place them on both ends for scenarios where the line could be fed from either end.
- *Fuse all taps*—Leaving smaller covered conductors unprotected is a sure way of burning down conductors.
- *Tighter fusing*—Not all fuses protect some of the conductor sizes used on taps. Faster fuses reduce the chance of burndowns.
- *Bigger conductors*—Bigger conductors take longer to burn down. Doubling the conductor cross-sectional area approximately doubles the time it takes to burn the conductor down.

Larger bare conductors are fairly immune to burndown. Smaller conductors used on taps are normally safe if protected by a fuse. The solutions for small bare conductor are

- *Fuse all taps*—This is the best option.
- *Fuse saving*—The time-delay relay element may not protect smaller tap conductors. Faults cleared by an instantaneous element with fuse saving will not damage bare

conductor. If fuse blowing is used, consider an alternative such as a high-set instantaneous or a delayed instantaneous (see Chapter 9 for more information).

2.10 Other Overhead Issues

2.10.1 Conductor Slapping

Conductor clashing or conductor slapping from faults is a consideration for overhead systems. The magnetic field from fault current produces forces between conductors all along the circuit from the substation to the initial fault location. These forces can cause conductors to swing. If they swing together, a second fault can occur upstream of the initial fault. The main scenario that causes the most issues is where the initial fault is downstream of a recloser, and a follow-on fault occurs upstream of the recloser and trips the circuit breaker. This can cause more customers to be affected by momentary and/or permanent interruptions. The arcing can also damage conductors. With digital relays, utilities have found that this issue is much more common than previously thought. The signature of conductor slapping is easy to identify in a history of relay events: look for a line-to-line fault followed by another line-to-line fault of higher magnitude within 1 to 2 sec. Using fault locating can also help find spans with conductor slapping issues.

Conductor motion is a function of fault current, fault duration, phase spacings, span lengths, and conductor sag. A line-to-line fault causes the most force between two conductors. The force from fault current pushes conductors away from each other. Once the fault is cleared, the conductors can swing into each other. The force between two conductors is (Aluminum Association, 1989)

$$F = M\frac{5.4I^2}{d10^7}$$

where

F = force in pounds per linear foot of conductor
M = short-circuit force multiplier based on dc offset of fault current. Use 2 for a symmetrical fault and 8 for a fully offset fault.
I = line-to-line short-circuit current in each conductor in amperes
d = spacing between centerlines of conductors in inches

Ward (2003) developed an approach to modeling conductor slapping for distribution lines. His results compared well with previous work on compact transmission lines (EPRI, 1978). Ward developed curves for the critical clearing time, the minimum duration for a fault that will cause conductors to clash. These curves can be compared to recloser curves to coordinate tripping time; in some cases, the recloser can be set to clear the fault before conductors clash. Figure 2.21 shows critical clearing times for several span lengths based on a phase spacing of 44-in (1.1-m) on an 8-ft (2.4-m) horizontal crossarm. Figure 2.22 shows similar curves for two different

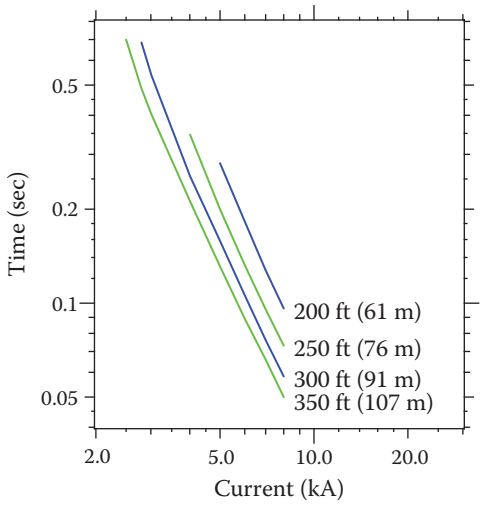


Figure 2.21 Critical clearing time for conductor slapping for several span lengths based on a 44-in (1.1-m) conductor spacing. (Data from Ward, D. J., *IEEE Transactions on Power Delivery*, vol. 18, no. 4, pp. 1534–8, 2003.)

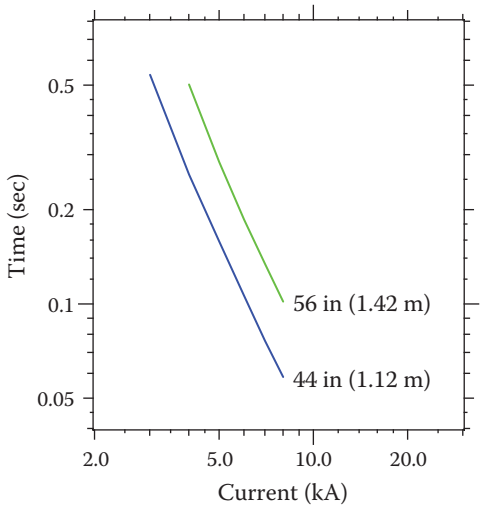


Figure 2.22 Critical clearing time for conductor slapping for two conductor spacings based on a 300-ft (91-m) span length. (Data from Ward, D. J., *IEEE Transactions on Power Delivery*, vol. 18, no. 4, pp. 1534–8, 2003.)

conductor spacings. The conductor slapping threshold curve is approximately an I^2t relationship.

Conductor slapping should be more common on higher-voltage systems because fault currents decrease less with distance. Based on the critical clearing curves in Figures 2.21 and 2.22, if a circuit is having problems with conductor slapping, it is likely that there are spans with tight spacings and long spans.

Two of the main solution options for existing conductor slapping issues are

- *Faster tripping*—As shown in Figures 2.21 and 2.22, faster tripping reduces the likelihood of conductor slapping faults.
- *Fiberglass spacers*—These effectively cut the span length in half.

Increased phase spacings, shorter spans, and removing slack are also solutions. These are expensive to retrofit, but consider these variables when designing new construction. For horizontal crossarm designs, instead of installing the center phase on the crossarm, installing the center phase on a ridge pin on the pole adds more horizontal spacing but more importantly, it adds vertical clearance that significantly reduces this type of conductor-slapping fault.

2.10.2 Connectors and Splices

Connectors and splices are often weak links in the overhead system, either due to hostile environment or bad designs or, most commonly, poor installation. Utilities have had problems with connectors, especially with higher loadings (Jondahl et al., 1991).

Most primary connectors use some sort of compression to join conductors (see Figure 2.23 for common connectors). Compression splices join two conductors

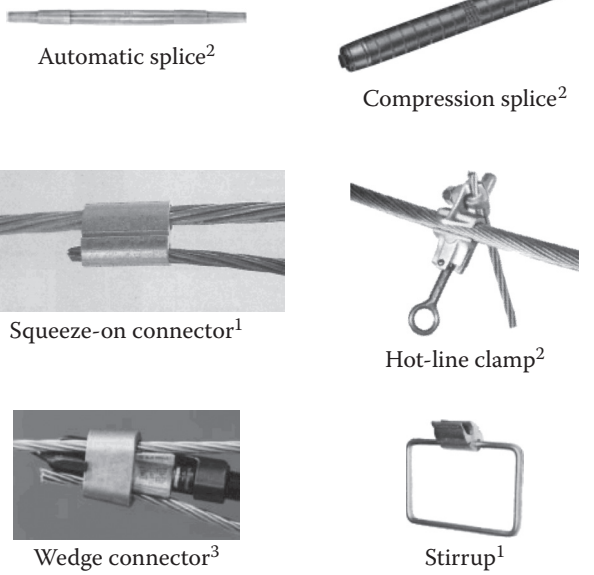


Figure 2.23 Common distribution connectors. (1—Reprinted with the permission of Cooper Industries, Inc. 2—Reprinted with the permission of Hubbell Power Systems, Inc. 3—Reprinted with the permission of Tyco Electronics Corporation.)

together—two conductors are inserted in each end of the sleeve, and a compression tool is used to tighten the sleeve around the conductors. For conductors under tension, automatic splices are also available. Crews just insert the conductors in each end, and serrated clamps within the splice grip the conductor; with higher tension, the wedging action holds tighter.

For tapping a smaller conductor off of a larger conductor, many options are available. Hot-line clamps use a threaded bolt to hold the conductors together. Wedge connectors have a wedge driven between conductors held by a C-shaped body. Compression connectors (commonly called *squeeze-ons*) use dies and compression tools to squeeze together two conductors and the connector.

Good cleaning is essential to making a good contact between connector surfaces. Both copper and aluminum develop a hard oxide layer on the surface when exposed to air. While very beneficial in preventing corrosion, the oxide layer has high electrical resistance. Copper is relatively easy to brush clean. Aluminum is tougher; crews need to work at it harder, and a shiny surface is no guarantee of a good contact. Aluminum oxidizes quickly, so crews should clean conductors just before attaching the connector. Without good cleaning, the temperatures developed at the hotspot can anneal the conductor, possibly leading to failure. Joint compounds are important; they inhibit oxidation and help maintain a good contact between joint surfaces.

Corrosion at interfaces can prematurely fail connectors and splices. Galvanic corrosion can occur quickly between dissimilar metals. For this reason, aluminum connectors are used to join aluminum conductors. Waterproof joint compounds protect conductors and joints from corrosion.

Aluminum expands and contracts with temperature, so swings in conductor temperature cause the conductor to creep with respect to the connector. This can loosen connectors and allow oxidation to develop between the connector and conductor. ANSI specifies a standard for connectors to withstand thermal cycling and mechanical stress (ANSI C119.4-1998).

Poor quality work leads to failures. Not using joint compound (or not using enough), inadequate conductor cleaning, misalignments, not fully inserting the conductor prior to compression, or using the wrong dies—any of these mistakes can cause a joint to fail prematurely.

Infrared thermography is the primary way utilities spot bad connectors. A bad connection with a high contact resistance operates at significantly higher temperatures than the surrounding conductor. While infrared inspections are easier for crews to do, they are not foolproof; they can miss bad connectors and falsely target good conductors. Infrared measurements are very sensitive to sunlight, line currents, and background colors. Temperature differences are most useful (but still not perfect indicators). Experience and visual checks of the connector can help identify false readings (such as glare due to sunlight reflection). A bad connector can become hot enough to melt the conductor, but often the conductor can resolidify, temporarily at a lower resistance. Infrared inspections can miss these bad connectors if they are in the resolidified stage. For compression splices, EPRI laboratory tests and field inspections found high success rates using hotstick-mounted resistance measuring devices that measure the resistance across a short section of the conductor (EPRI 1001913, 2001).

Short-circuit current can also damage inline connectors. Mechanical stresses and high currents can damage some splices and connectors. If an inline connector does not make solid contact at its interfaces to the conductor, hotspots can weaken and possibly break the connector or conductor. If the contact is poor enough to cause arcing, the arcing can quickly eat the connection away. Mechanical forces can also break an already weakened or corroded connector.

Hot-line clamps are popular connectors that crews can easily apply with hot-line tools. Threaded bolts provide compression between conductors. Hot-line clamps can become loose, especially if not installed correctly. Utilities have had problems with hot-line clamps attached directly to primary conductors, especially in series with the circuit (rather than tapped for a jumper to equipment) where they are subjected to the heat and mechanical forces of fault currents. Loose or high-resistance hot-line clamps can arc across the interface, quickly burning away the primary conductor.

Stirrups are widely used between the main conductor and a jumper to a transformer or capacitor bank. A stirrup is a bail or loop of wire attached to the main conductor with one or two compression connectors or hot-line connectors. Crews can quickly make a connection to the stirrup with hot-line clamps. The main reason for using the stirrup is to protect the main conductor from burndown. If tied directly to the main conductor, arcing across a poor connection can burn the main conductor down. If a poor hot-line clamp is connected to a stirrup, the stirrup may burn down, but the main line is protected. Also, any arcing when crews attach or detach the connector does not damage the main conductor, so stirrups are especially useful where jumpers may be put on and taken off several times. Using stirrups is reliable; a survey by the National Rural Electric Cooperative Association (NRECA) found that less than 10% of utilities have annual failure rates between 1% and 5%, and almost all of the remainder have failure rates less than 1% (RUS, 1996).

2.10.3 Radio-Frequency Interference

Distribution line hardware can generate radio-frequency interference (RFI). Such interference can impact the AM and FM bands as well as VHF television broadcasts. Ham radio frequencies are also affected.

Most power-line noise is from arcs—arcs across gaps on the order of 1 mm, usually at poor contacts. These arcs can occur between many metallic junctions on power-line equipment. Consider two metal objects in close proximity but not quite touching. The capacitive voltage divider between the conducting parts determines the voltage differences between them. The voltage difference between two metallic pieces can cause an arc across a small gap. After arcing across, the gap can clear easily, and after the capacitive voltage builds back up, it can spark over again. These sparkovers radiate radio-frequency noise. Stronger RFI is more likely from hardware closer to the primary conductors.

Arcing generates broadband radio-frequency noise from several kilohertz to over 1000 MHz. Above about 50 MHz, the magnitude of arcing RFI drops off. Power-line interference affects lower frequency broadcasts more than higher frequencies. The

most common from low to high frequency are: AM radio (0.54 to 1.71 MHz), low-band VHF TV (channels 2 to 6, 54 to 88 MHz), FM radio (88.1 to 107.9 MHz), and high-band VHF TV (channels 7 to 13, 174 to 216 MHz). UHF (ultra-high frequencies, about 500 MHz) are only created right near the sparking source.

On an oscilloscope, arcing interference looks like a series of noise spikes clustered around the peaks of the sinusoidal power-frequency driving voltage (see Figure 2.24). Often power-line noise causes a raspy sound, usually with a 120-Hz characteristic. The "sound" of power-line noise varies depending on the length of the arcing gap, so interference cannot always be identified by a specific characteristic sound (Loftness, 1997).

Arcing across small gaps accounts for almost all RFI created by utility equipment on distribution circuits. Arcing from corona can also cause interference, but distribution circuit voltages are too low for corona to cause significant interference. Radio interference is more common at higher distribution voltages.

Some common sources and solutions include [for more detail, see (Loftness, 1996; NRECA 90-30, 1992; Vincent et al., 2007)]

- *Loose or corroded hot-line clamps*—Replace the connector. After cleaning the conductor and applying fresh inhibitor replace the clamp with a new hot-line clamp or a wedge connector or a squeeze-on connector.
- *Loose nut and washer on a through bolt*—Commonly a problem on double-arming bolts between two crossarms; use lock washers and tighten.
- *Loose or broken insulator tie wire or incorrect tie wire*—Loose tie wires can cause arcing, and conducting ties on covered conductors generate interference; in either case, replace the tie wire.
- *Loose dead-end insulator units*—Replace, preferably with single-unit types. Semiconductive grease provides a short-term solution.
- *Loose metal staples on bonding or ground wires, especially near the top*—Replace with insulated staples (hammering in existing staples may only help for the short term).
- *Loose crossarm lag screw*—Replace with a larger lag screw or with a through bolt and lock washers.
- *Bonding conductors touching or nearly touching other metal hardware*—Separate by at least 1 in. (2.54 cm).
- *Broken or contaminated insulators*—Clean or replace.
- *Defective lightning arresters, especially gapped units*—Replace.

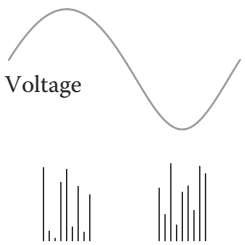


Figure 2.24 Arcing source creating RFI.

Most of these problems have a common characteristic: gaps between metals, often from loose hardware. Crews can fix most problems by tightening connections, separating metal hardware by at least 1 in., or bonding hardware together. Metal-to-wood interfaces are less likely to cause interference; a tree branch touching a conductor usually does not generate RFI.

While interference is often associated with overhead circuits, underground lines can also generate interference. Again, look for loose connections, either primary or secondary such as in load-break elbows.

Interference from an arcing source can propagate in several ways: radiation, induction, and conduction. RFI can radiate from the arcing source just like a radio transmitter. It can conduct along a conductor and also couple inductively from one conductor to parallel conductors. Lower frequencies propagate farther; AM radio is affected over larger distances. Interference is roughly in inverse proportion to frequency at more than a few poles from the source.

Many different interference detectors are available; most are radios with directional antennas. Closer to the source, instruments can detect radio-frequency noise at higher and higher frequencies, so higher frequencies can help pinpoint sources. As you get closer to the source, follow the highest frequency that you can receive. (If you cannot detect interference at higher and higher frequencies as you drive along the line, you are probably going in the wrong direction.) Once a problem pole is identified, an ultrasonic detector with a parabolic dish can zero in on problem areas to identify where the arcing is coming from. Ultrasonic detectors measure ultra-high-frequency sound waves (about 20 to 100 kHz) and give accurate direction to the source. Ultrasonic detectors almost require line-of-sight to the arcing source, so they do not help if the arcing is hidden. In such cases, the sparking may be internal to an enclosed device, or the RF could be conducted to the pole by a secondary conductor or riser pole. For even more precise location, crews can use hot-stick mounted detectors to identify exactly what's arcing.

Note that many other nonutility sources of RFI exist. Many of these also involve intermittent arcing. Common power-frequency-type sources include fans, light dimmers, fluorescent lights, loose wiring within the home or facility, and electrical tools such as drills. Other sources include defective antennas, amateur or CB radios, spark-plug ignitions from vehicles or lawn mowers, home computers, and garage door openers.

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3

Overhead Line Performance

Contents

3.1 Vegetation Management 91
3.1.1 Outages and Damage from Trees 92
3.1.2 Physics of Tree Faults 96
3.1.3 Utility Tree Maintenance Programs 99
3.1.4 Hazard-Tree Programs 104
3.1.5 Vegetation Program Performance 106
3.2 Covered Conductors 108
3.3 Animal Protection 114
3.3.1 Animal-Fault Basics 115
3.3.2 Animal Guards, Wire Coverings, and Other Protective Equipment 117
3.4 Inspections and Maintenance 123
3.5 Pole Inspections and Maintenance 125
3.6 Hardening and Resiliency 131
References 133

Wind, fungi, ultraviolet light, tree branches, whole trees, and animals of various sizes—each of these can stress overhead distribution lines, electrically and/or mechanically. In this chapter, we explore several programs or options that utilities use to maintain and/or improve the performance of their distribution infrastructure. Poles, conductor, and line hardware all have long life, often exceeding 50 years, but many utilities have aging infrastructure. The deterioration and replacement of equipment must be monitored and managed to continue providing safe, reliable service.

Major storms increase stresses on overhead infrastructure, and damage to the overhead distribution system can overwhelm a utility's normal response and repair, leading to customer interruptions lasting days. Hardening of overhead infrastructure or resiliency improvements to reduce damage and reduce times to repair can reduce customer impacts. Many of the programs discussed in this chapter also have applications for resiliency as well as for normal performance.

3.1 Vegetation Management

Trees are the source of many reliability issues on circuits, and vegetation management is expensive. For many utilities, trees are the number one or number two cause of interruptions. When trees contact utility equipment, damage is often extensive, and repair is expensive and time consuming. In addition to long-duration interruptions,

the faults from trees cause voltage sags and can cause momentary interruptions. During major storms, trees are particularly damaging to distribution infrastructure.

For most utilities, vegetation management is by far the largest maintenance item in the budget. So, in addition to improving performance, more efficient vegetation maintenance and more tree-resistant designs can also reduce maintenance costs.

3.1.1 Outages and Damage from Trees

Understanding how trees cause outages and damage will help utilities design more tree-resistant lines and help utilities more efficiently manage vegetation maintenance. A great deal of work on tree faults has been done since the 1990s that should help utilities design more tree-resistant structures and optimize vegetation management. Faults caused by trees generally occur from a handful of conditions:

- Falling trees or major limbs knock down poles or break pole hardware (Figure 3.1 shows a common pole breakage just above the third-party telecom attachment point)
- Tree branches blown by the wind push conductors together
- A branch falls across the wires and forms a bridge from conductor to conductor
- Natural tree growth causes a bridge across conductors

Utility studies of tree outages have shown that most outages are caused from trees or branches bridging conductors or breaking equipment. Rees et al. (1994) examined

Figure 3.1 Video sequence of a falling tree causing a fault and breaking a pole. (Courtesy of Alexander Kirichenko. http://youtu.be/-gUD31Bqnuo.)

over 3000 tree-related outages over 7 years and found the following breakdown of tree-caused outages:

- 75% were caused by dead shorts across a limited distance
- 23% were from mechanical damage to utility equipment
- 98% of tree-caused outages were from trees or tree parts falling on lines; less than 2% were due to natural growth or burning branch tips beneath the lines

Simpson (1997) reported on a survey of tree-caused faults at Eastern Utilities Associates (a small utility in Massachusetts that is now a part of National Grid). The main results were that tree-caused outages broke down as follows: 63% from broken branches, 11% from falling trees, and 2% from tree growth.

EPRI 1008480 (2004) documents surveys by BC Hydro of their tree-related interruptions were as follows: 70% from tree failure, 18% from branch failure, and 12% from growth.

Finch (2001) reported on a survey that Niagara Mohawk Power Corporation (now a part of National Grid) performed in 2000. 86% of permanent tree faults were from outside their maintenance zone covering out to 10 ft (3 m). Growth only accounted for 14% of outages (Figure 3.2), and Finch also reported that most of these were outages on services. In a sample of 250 tree-caused outages from 1995, 36% were from dead trees, and 64% were from live trees. In this sample, 75% came from outside the maintenance zone, and 62% were caused by a broken trunk or branch.

Taylor (2003) reported on a 1995 sample survey of tree-caused outages where 73% of tree outages occurred when an entire tree fell on the line. 86% of these were from outside of a 30-ft (9-m) right-of-way. Dead limbs or trees caused 45% of tree outages. In addition, Duke Energy's investigations of this sample outage set found that 25% of outages reported as tree caused were *not* caused by trees. This highlights the importance of good outage code recording when investigating fault causes.

Finch (2003a) reported on results of a 1995 Environmental Consultants Inc. (ECI) survey of over 20 utilities and a total of 2328 tree outages. The ECI survey found that tree failures and limbs caused the most tree outages (see Figure 3.3).

Detailed tree outage codes allow utilities to target causes more precisely. See Table 3.1 for a breakdown of tree faults and their impact on outages for one utility. Note that

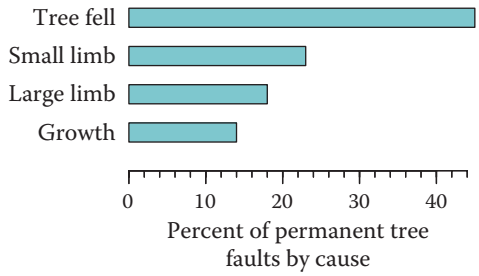

Figure 3.2 Niagara Mohawk survey of tree outage causes. (Data from Finch, K., Understanding tree outages, *EEI Vegetation Managers Meeting*, Palm Springs, CA, May 1, 2001.)

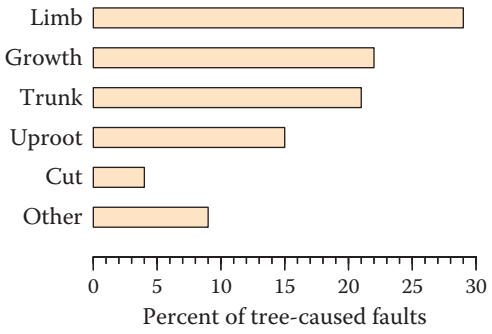

Figure 3.3 ECI survey of tree outage causes. (Data from Finch, K., *Understanding Line Clearance and Tree Caused Outages*, EEI Natural Resources Workshop, April 1, 2003a.)

trees falling (whether from inside or outside of the right-of-way) cause a much larger impact on the customer minutes of interruption relative to the actual number of outages. Likewise, vines and tree growth have relatively less impact on outage duration.

Duke Energy has done considerable work on using its outage database as a resource to learn about tree-caused faults to help guide vegetation management. Chow and Taylor (1993) developed a strategy to analyze Duke Energy's outage database to learn more about specific causes of faults. They found the following trends:

- *Weather*—When looking at the likelihood of tree-caused faults, weather strongly affects tree faults, especially wind and also rain, snow, and ice.
- *Season and time of day*—The most tree faults occurred during summer and the least occurred during winter. More tree faults occurred during the afternoon and evening. Tree faults were not greatly influenced by the day of the week.
- *Phasing and protective device*— Multiple-phase faults are more likely to be caused by trees. Along these same lines, lockouts of a substation circuit breaker or a line recloser were more likely to be caused by trees than were operations of other protective devices. Of circuit breaker and recloser lockouts, trees caused 35 to 50% of the lockouts, which is over twice the rate of all tree outage events (trees cause 15 to 20% of all of Duke's outages).

TABLE 3.1 Percentage of Tree Faults in Each Category

	Outages	CI	CMI
Tree outside right-of-way (fall/lean on primary)	26.0	37.2	42.5
Tree/limb growth	21.1	14.4	13.3
Limb fell from outside right-of-way	18.0	20.1	18.1
Tree inside right-of-way (fall/lean on primary)	12.6	14.8	15.2
Vines	10.0	3.6	3.1
Limb fell from inside right-of-way	8.7	9.8	7.5
Tree on multiplex cable or open-wire secondary	3.6	0.2	0.2

Source: Data from a Southeastern U.S. utility, 2003–2004.
Note: CI = customer interruptions; CMI = customer minutes of interruptions.

More recent work reported by Xu et al. (2003) found many of the same trends and extended the concept to include a statistical regression analysis to identify the variables that mostly influence the likelihood of a tree-caused interruption. They found that weather, time of day, and protective device were most statistically significant indicators of the likelihood of a tree-caused interruption.

Niagara Mohawk (a National Grid company) used several investigations to restructure its vegetation management programs for distribution systems (Finch, 2001, 2003a). Niagara Mohawk used its outage cause codes to categorize the source of tree-caused interruptions, and also used sample studies to provide more in-depth details on tree-caused interruptions. Niagara Mohawk also staged live tests with trees in contact with distribution lines to learn more about momentary interruptions. They also reviewed a sample of tree-caused outages for tree defects. On the basis of these results, Niagara Mohawk modified its program to target the worst circuits, the 13.2-kV system, the circuit backbone, and hazard-tree removal.

Being highly correlated with weather, season has a large impact on tree fault rates. Duke Energy has the most tree-caused faults during summer and the least during fall (Chow and Taylor, 1993; Xu et al., 2003). Another southeastern U.S. utility also has the most outages during summer as shown in Figure 3.4.

Circuit voltage can also impact tree-caused faults. Tree-caused faults cause much less impact to customers on 5-kV class circuits. Finch reported that tree-caused outages on 2.4 to 4.16-kV circuits averaged 79 customers per tree outage, but 7.6 to 13.2-kV circuits averaged 206 customers out per outage. Table 3.2 shows similar trends for another northeastern utility. Contrary to the widely held belief that 5-kV class circuits have much lower fault rates from trees, this utility had similar fault rates;

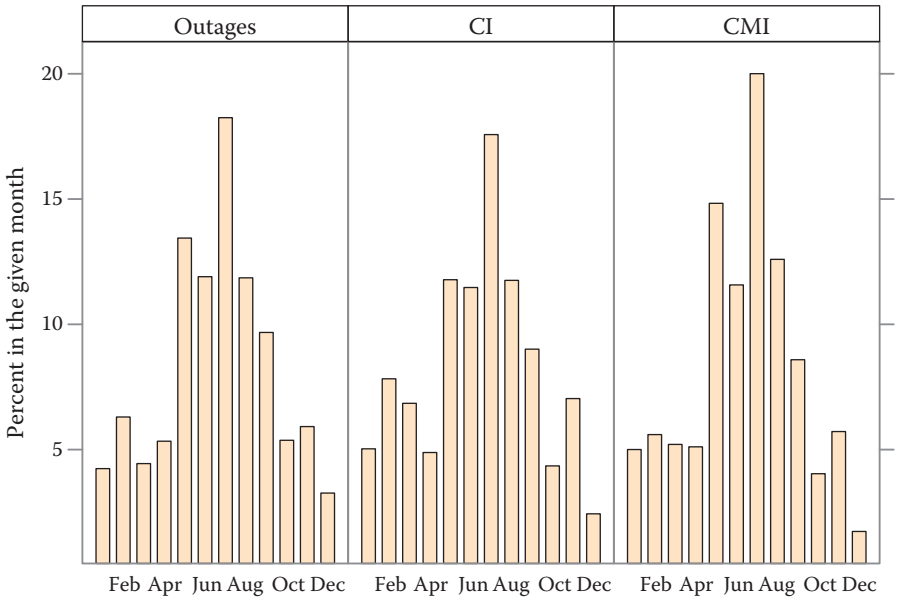

Figure 3.4 Tree-caused outage impacts by month.

TABLE 3.2 Tree Faults by Voltage Class for a Northeastern U.S. Utility

Voltage (kV)	Tree SAIDI (min)	Tree Fault Rate per 100 miles per Year
2.4	4	11.6
4.16	22	9.6
13.8	34	10.8

Note: Includes major storms.

TABLE 3.3 Tree Faults by Voltage Class for a Southeastern U.S. Utility

	Tree Fault Rate per 100 miles per Year	
Voltage Class (kV)	With Major Storms	Without Major Storms
15	68	27
25	51	16

the main difference is that faults impact less customers on the lower-voltage circuits. Table 3.3 shows data from a southeastern utility that shows similar tree-caused fault rates on 15- and 25-kV class systems.

These findings strongly suggest that targeting of vegetation management should help improve performance and more efficiently manage tree maintenance budgets. Target tree maintenance and other tree-improvement strategies (such as covered wire or increased spacings) to circuits with the most outages. To do that, focus on the following:

- Mainline portion of circuits
- Circuits with more customers
- Circuits with a history of tree faults
- Circuits with higher voltage

Trees are often associated with momentary interruptions, but trees are probably not a major contributor to momentary interruptions. As shown in Chapter 14, trees in contact with just one phase conductor do not cause high-current faults. There may be burning near the contact point, but the contact normally draws less than 1 A, and that is well below what is needed to trip reclosers or circuit breakers. So, if temporary faults regularly occur from trees, they must be across *conductor-to-conductor* contacts in close proximity, and not just conductor to tree. There are plausible mechanisms for this: wind could push trees into conductors and cause them to slap together. Once the conductors come apart, the insulation is restored, and the breaker or recloser can reclose successfully.

3.1.2 Physics of Tree Faults

For a tree branch to cause a fault, the branch must bridge the gap between two conductors in close proximity, which usually must be sustained for more than one minute. A tree touching just one conductor will not fault at distribution voltages. The tree branch must cause a connection between two bare conductors (it can be phase to

phase or phase to neutral). A tree branch into one phase conductor normally draws less than 1 A of current under most conditions; this may burn some leaves, but it would not fault. On small wires in contact with a tree, the arcing to the tree may be enough to burn the wire down under the right conditions. Baltimore Gas and Electric (Rees et al., 1994) staged some revealing tests that showed how tree branches can cause faults. ECI (Appelt and Goodfellow, 2004; Finch, 2001, 2003a; Goodfellow, 2000, 2005) tested over 2000 tree branch samples covering over 20 species and a range of voltage gradients.

A fault across a tree branch between two conductors takes some time to develop. If a branch falls across two conductors, arcing occurs at each end where the wire is in contact with the branch. At this point in the process, the current is small (the tree branch is a relatively high impedance). The arcing burns the branch and creates carbon by oxidizing organic compounds. The carbon provides a good conducting path. Arcing then occurs from the carbon to the unburned portion of the branch. A carbon track develops at each end and moves inward. See Figure 3.5 for an example of a test on a 0.5-in. (1.3-cm) diameter red alder energized at 3 kV/ft (10 kV/m) that faulted in 80 sec.

Once the carbon path is established completely across the branch, the fault is a low-impedance path. Now, the current is high—it is effectively a bolted fault. It is also a permanent fault. If a circuit breaker or recloser is opened and then reclosed, the

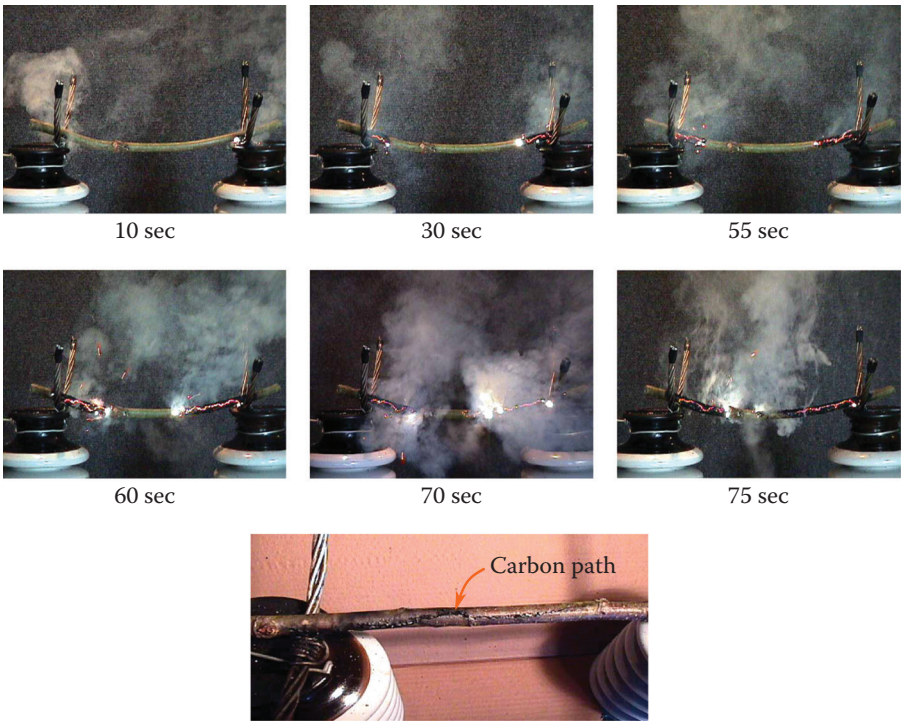

Figure 3.5 Progression of arcing and carbonization of a branch. (From Goodfellow, J., *BioCompliance Consulting, Inc*. With permission.)

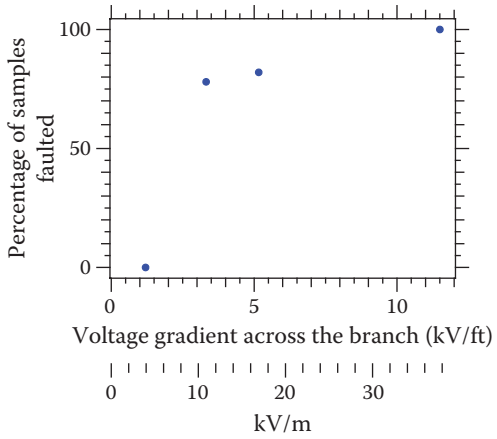

Figure 3.6 Percentage of samples faulted based on the voltage gradient across the tree branch. (Data from Goodfellow, J., *Understanding the Way Trees Cause Outages*, 2000.)

low-impedance carbon path will still be there unless the branch burns enough to fall off of the wires.

Some notable electrical effects include

- The likelihood of a fault depends on the voltage gradient along the branch (see Figure 3.6).
- The time it takes for a fault to occur depends on the voltage gradient (see Figure 3.7).
- It makes little difference if the branch is wet or dry. Live branches are more likely to fault for a given voltage gradient, but dead branches are more likely to break and come in contact with the line.
- Thicker branches are more likely to cause faults because their impedance is lower. Thin branches can also burn through and fall off before the full carbon track develops. So, minor leaf and branch burning does not cause faults.

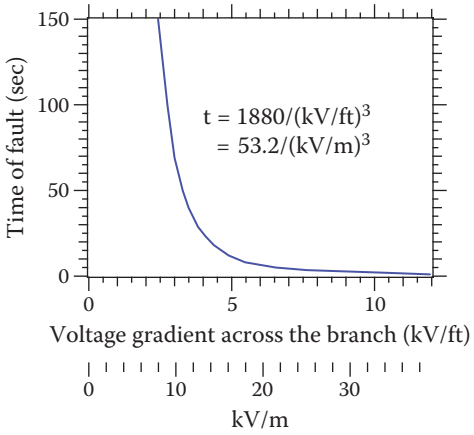

Figure 3.7 Time to fault based on the voltage gradient across the tree branch. (Data from Goodfellow, J., *Understanding the Way Trees Cause Outages*, 2000 with the curve fit added.)

- Lower-voltage circuits are more immune to flashovers from branches across conductors. A 4.8-kV circuit on a 10-ft (3-m) crossarm has about a phase-to-phase voltage gradient of 1 kV/ft (3 kV/m), very unlikely to fault from tree contact. A 12.47-kV circuit has a 2.7 kV/ft (9 kV/m) gradient, which is more likely to fault.

ECI found that branch characteristics affected the probability of failure (Goodfellow, 2000, 2005). Thicker branches were more likely to flashover, and live branches were also more likely to flashover for a given voltage gradient. ECI found "no significant difference" between naturally occurring growth and suckers (a secondary shoot produced from the base that often grows quickly). Moisture factor was "less of a factor than one might guess." Surface moisture was "less of a factor": it may make the fault occur more quickly but does not make the fault more likely. ECI did find some differences between species. Florida Power Corp. (Williams, 1999) also found variation: in their tests, palm limbs faulted the fastest (1 min in their setup), and pine limbs lasted the longest (15 min).

These effects reveal some key issues:

- Pruning around the conductors in areas with a heavy canopy does not prevent tree faults. Traditionally, crews trim a "hole" around the conductors with about a 10-ft (3-m) radius. If there is a heavy canopy of trees above the conductors, this pruning strategy performs poorly since most tree faults are caused by branches falling from above.
- Vertical construction may help since the likelihood of a phase-to-phase contact by falling branches is reduced.
- Candlestick or armless designs are more likely to flashover because of tighter conductor-to-conductor spacings.
- Three-phase construction is more at risk than single-phase construction.

3.1.3 Utility Tree Maintenance Programs

Vegetation management is expensive—see Figure 3.8 for results of a survey showing annual costs vegetation management costs averaging $1039/mi ($646/km). Tree maintenance can also irritate communities. It is always a dilemma that people do not want their trees pruned, but they also do not want interruptions and other disturbances.

A similar survey data showed a median cost of $4754 per mile managed with upper and lower quartiles of $7981 and $2497 per mile managed based on average costs from 2005 to 2010 (CNUC, 2013). Costs vary significantly from utility to utility and reflect differences in tree coverage, load density (urban and suburban pruning is more difficult than rural tree maintenance), vegetation management cycle, and tree growth rates.

Figure 3.9 shows data on the costs of vegetation management programs and ties that to performance using the SAIDI index. There is little direct correlation between spending and SAIDI between utilities. This is not surprising given wide variances in tree coverage, load and customer densities, and weather between utilities.

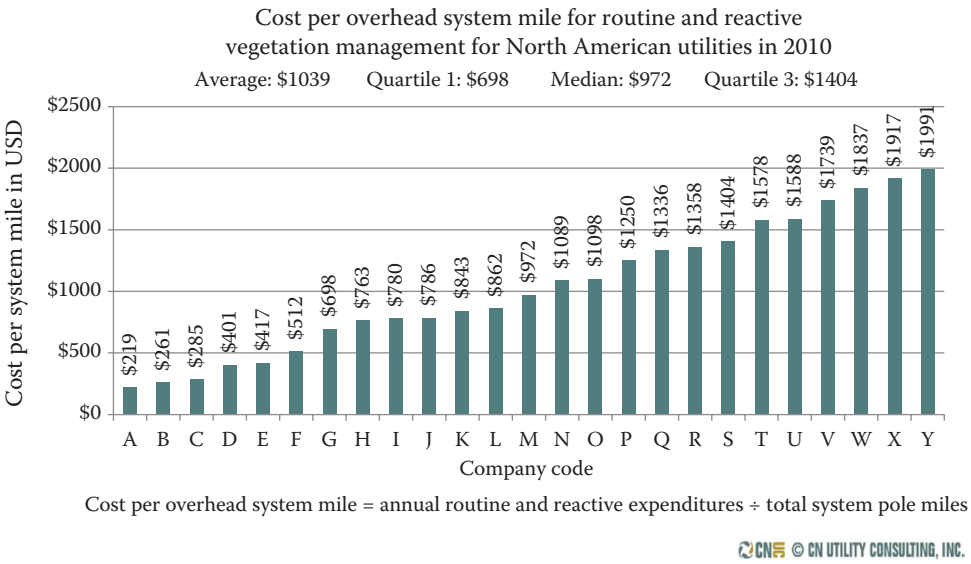

Figure 3.8 Vegetation management costs. (From CNUC, *CN Utility Consulting Distribution Utility Vegetation Management Report 2011–2012*, 2nd ed, CN Utility Consulting, Sebastopol, California, 2013. With permission; Courtesy of CN Utility Consultants, Inc.)

Most utilities use a fixed vegetation maintenance cycle time. Choosing a cycle time is tricky. Many utilities use a 3-year to 5-year cycle. One might expect that longer tree maintenance cycles should lead to higher fault rates. The optimal pruning cycle depends on

- Tree clearance specifications and historical clearing approaches
- Type of trees, growth rates, and growing conditions
- Community tolerance for pruning
- Economic assumptions

Correlating the effect of tree maintenance and performance can help utilities optimize vegetation maintenance, but this can be tricky. Some effects that can interfere with correlations between performance metrics and maintenance include

- *Targeting*—Targeting poorly performing circuits for maintenance can help improve customer satisfaction, but it makes it difficult to gauge the effects of maintenance programs.
- *Maintenance approach*—Some utilities schedule vegetation maintenance using map sections, not by circuit, so it is impossible to correlate circuits to their performance.
- *Budget and tree maintenance*—Vegetation management budgets often vary and pruning specifications or contractors sometimes change. Both can impact different years differently.
- *Reconfigurations*—Circuit reconfigurations can make it difficult to reliably judge the history of tree fault impacts.

Figure 3.10 characterizes one utility's impact of vegetation from 1999 to 2003, including major storms. These are primary events with a vegetation cause. Each

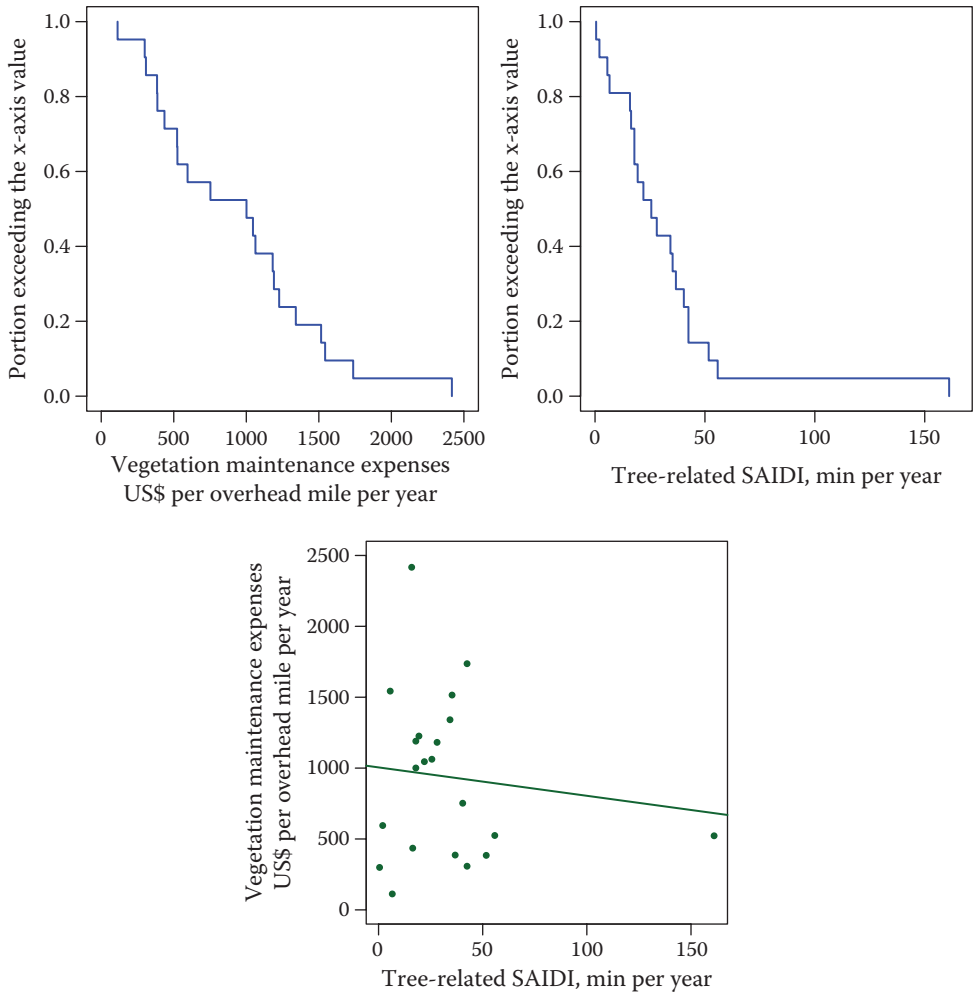

Figure 3.9 Vegetation management costs versus performance. (Data from 2003 PA Consulting Benchmarking survey; BC Hydro, Revenue requirement application 2004/05 and 2005/06, Chapter 7. Electricity distribution and non-integrated areas, 2003; from EPRI 1008506, *Power Quality Implications of Transmission and Distribution Construction: Tree Faults and Equipment Issues*, Electric Power Research Institute, Palo Alto, CA, Copyright 2005. Reprinted with permission.)

graph shows the effect of the time since the last tree pruning. So, the first datapoint in each graph is the given reliability metric based on all circuits that had tree maintenance during the previous year. One might naively expect that tree-caused outages would decrease steadily following tree maintenance, but the data does not show this. There is no strong trend over this short time period.

Figure 3.11 shows the average annual tree-caused event rates for one of Duke Energy's operating regions based on outages from 2009 to 2011. These are primary events, including major storms, but excluding days above a 3.5-beta threshold. These

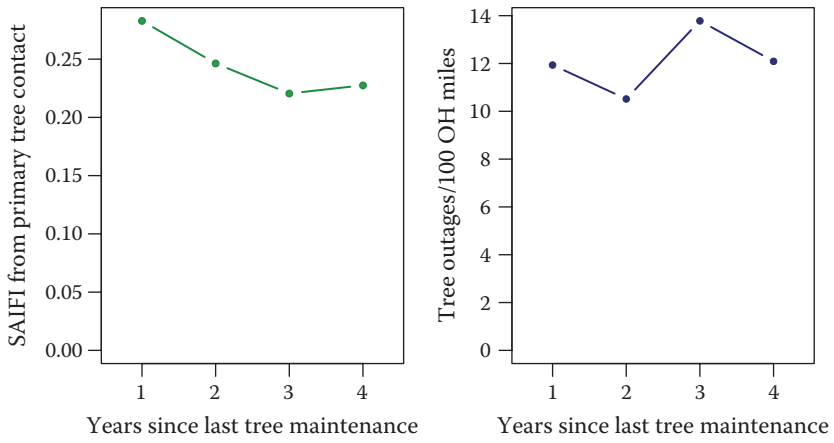

Figure 3.10 Tree maintenance effect on performance.

are normalized by overhead line miles. The fault event rate is relatively flat for most of the first 10 years after maintenance.

Overall, tree-caused outage events do not increase dramatically with longer times between tree maintenance when analyzed over reasonable time periods. Quoting Guggenmoos (2003b): "Only a trim program that is substantially behind cycle results in increased outages. Might say that cycle trimming is not for reliability but public safety and the avoidance of higher costs associated with heavily pruning systems that have grown into conductors."

Vegetation maintenance cycles are tied with maintenance specifications and historical clearance approaches. Table 3.4 shows results for several operating regions for Duke Energy. These regions have historically had different approaches to vegetation management. Areas X and Y have common vegetation approaches. Area Z

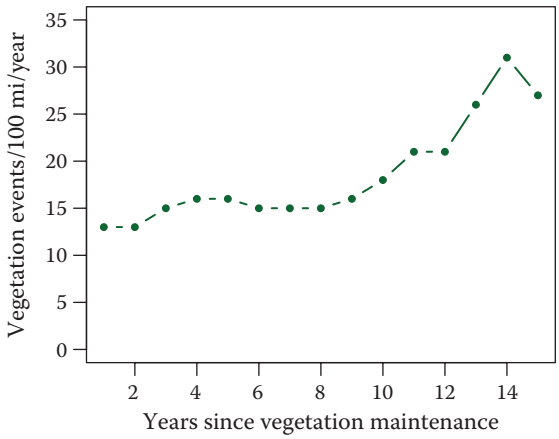

Figure 3.11 Vegetation fault rate versus time since maintenance for Duke Energy area Z. (Analysis courtesy of Lee Taylor, Duke Energy.)

TABLE 3.4 Duke Energy Cycle Times and Vegetation Specifications with Performance Metrics

Region	Cycle Time (Years)	Vegetation Specification	Maintenance Cost per Vegetation Mile per Year ($)	Customer Interruptions from Vegetation per Vegetative Mile	Average Vegetation Incidents/100 Vegetation Miles
X	4	10 ft (3 m) to sides and down to neutral	1998	39.7	25.5
Y	6	10 ft (3 m) to sides and down to neutral	1154	26.8	29.5
Z	13	30 ft (9.1 m) ground to sky and herbicide	672	24.2	20.8

Source: Courtesy of Lee Taylor, Duke Energy.

has longer-than-normal maintenance intervals but maintains larger-than-normal clearances. Area Z has lower vegetation fault rates at lower cost. Area Z's performance challenges recent industry trends to shorter maintenance intervals. This area achieves performance partially by maintaining more clearance. With more clearance, fewer trees and branches are at risk of falling into the line. Costs are less because of longer cycle times, even though more vegetation is generally cut at a given location. Herbicides also help control undergrowth to allow this longer cycle. Larger clearances are easier to maintain if the clearance zone or right-of-way has been established and maintained consistently. The public will resist the major changes to clearance, but if clearance can be established, the public will accept the status quo, and it is easier for the utility to keep that clearance. Another factor contributing to area Z's performance is a hazard-tree program for the three-phase mainline with annual inspections.

The effect on faults and interruptions is not the only reason for selecting a maintenance cycle. Several other factors include

Shock hazard—See Chapter 14.

Fire hazard—For areas in high fire-danger areas, tree clearance requirements may be more severe, requiring more frequent maintenance. The State of California Rules for Overhead Electric Line Construction specifies at least an 18-in. (0.46-m) spacing between conductors and vegetation for all distribution and transmission circuits. In addition, California (Public Resource Code Section 4293) requires a clearance of 4 ft (1.2 m) for circuits in any mountainous land, or in forest-covered land, brush-covered land, or grass-covered land operating between 2.4 and 72 kV. Meeting such spacing requirements normally requires more frequent vegetation maintenance.

Cost—Longer maintenance cycles may actually cost more as the catch-up phase can be more expensive than maintaining a consistent budget. In a survey of three utilities, ECI found that extending tree maintenance cycles beyond the optimum can increase the overall costs (Browning and Wiant, 1997; Massey, 1998). If cycles are increased, costs are higher because (1) it takes more time for crews to prune when trees are in close proximity to conductors, (2) crews must do more hot-spot maintenance in response to trouble calls, and (3) crews have more mass of debris to clear and dispose off. ECI estimated that for each $1 saved by extending maintenance

cycles would require from $1.16 to $1.23 in spending if the cycle was extended 1 year past its optimum, and if the circuit is 4 years past the optimum; the "catch-up" cost is 1.47 to 1.69 times the cost originally saved.

Storm repair—Trees cause considerable damage during storms. Duke Energy discovered that during the ice storm of 2002 that impacted their service territory, the circuits that had not been maintained in 13 years had 5 times the damage of circuits that had been maintained from 1 to 6 years prior (Taylor, 2004, personal communication). Because of this, Duke justified increasing the vegetation management budget based on reducing storm repair costs.

Regulations—Regulatory bodies are paying more attention to performance and vegetation management. Tree maintenance cycle is an easy indicator for regulators to understand. If a utility decreases budgets and/or increases tree maintenance cycles and if that coincides with decreased reliability or customer satisfaction, regulators may impose fines or mandate changes.

On many subtransmission lines, critical distribution lines, or circuit backbones, clearing a right-of-way is an effective way to reduce the chance of tree contacts from falling limbs or trees. Such right-of-ways are regularly maintained for high-voltage transmission lines. Even if a wide ground-to-sky clearance is not possible for complete circuits, where you can get clearance, it is advantageous to maintain what you can claim.

With normal distribution/subtransmission tree maintenance programs, many tree faults still occur. Even with hazard-tree programs, many tree faults will occur, either from healthy trees brought down by severe weather or from trees that die or are missed between maintenance cycles. The only way to drastically reduce tree faults is to clear a right-of-way. Then, the probability of a tree fault is determined by the width of the right-of-way and other factors, including tree density, tree mortality rates, and tree heights. Guggenmoos (2003a) outlines a methodology for estimating the risk of trees striking lines based on these factors. This approach can be used to estimate the benefit of a tree clearance program to establish a right-of-way or to widen an existing right-of-way.

3.1.4 Hazard-Tree Programs

Hazard-tree programs target those trees that are the largest threats to utility circuits. Tree pruning within a zone (e.g., ±10 ft) targets tree growth, but most tree outages are from trees or branches from outside of typical utility trim zones. Hazard-tree programs target dead trees or trees with significant defects, even if they are out of the normal maintenance zone or right-of-way. Consider hazard-tree inspections that are more frequent than the pruning cycle to catch death or deterioration in trees before they fall and cause damage.

Dead trees are the most obvious candidates for hazard-tree removals. In a sample of permanent tree faults, Niagara Mohawk Power Corporation (now National Grid) found 36% were from dead trees (Finch, 2001), and in another sample, Duke Energy found 45% were from dead trees (Taylor, 2003).

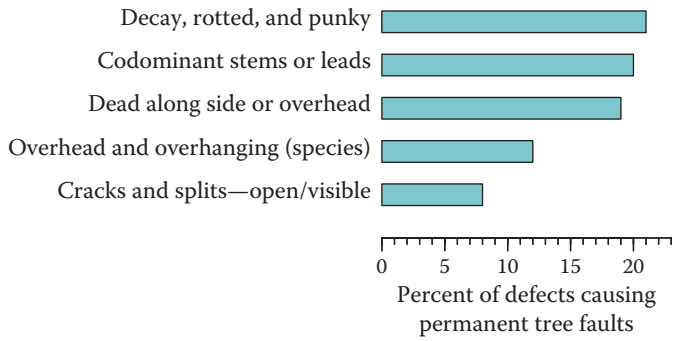

Figure 3.12 Defects causing tree failure for the Niagara Mohawk Power Corporation. (Data from Finch, K., *Understanding Tree Outages*, *EEI Vegetation Managers Meeting*, Palm Springs, CA, May 1, 2001.)

Targeting hazard trees is highly beneficial, but requires expertise to find many types of tree defects. Figure 3.12 shows some of the tree defects that led to tree faults in one study. In an examination of several cases where broken branches or trees damaged the system, Finch (2001) reported that 64% of the trees were living. Finch also advises examining trees from the backside, inside the tree line (defects on that side are more likely to fail the tree into the line). Finch describes several defects that help signal hazard trees. Dead trees or large splits are easy to spot. Cankers (a fungal disease) or codominant stems (two stems, neither of which dominates, where each stem at a branching point is approximately the same size) require more training and experience to detect.

For identifying hazard trees, it also helps to know the types of trees that are prone to interruptions—this varies by area and types of trees. Finch (2001) showed how Niagara Mohawk evaluated a sample set of tree outages in a study in 2000. Niagara Mohawk compared the tree species that caused faults to the tree species in New York state. They found that black locusts and aspens are particularly troublesome; large, old roadside maples also caused more than their share of damage (see Table 3.5). Finch also reported that much of the extra impact of aspens on outages was due to

TABLE 3.5 Comparison of Trees Causing Permanent Faults with the Tree Population

Species	Percent of Outages	Percent of New York State Population
Ash	8	7.9
Aspen	9	0.6
Black locust	11	0.3
Black walnut	5	N/A
Red maple	14	14.7
Silver maple	5	0.2
Sugar maple	20	12.0
White pine	6	3.3

Source: Data from Finch, K., *Understanding Tree Outages*, EEI Vegetation Managers Meeting, Palm Springs, CA, May 1, 2001.

hypoxilon canker, which their crews often overlooked as a defect. The sugar-maple faults were mainly from large, old roadside maples in serious decline.

In an informal survey of seven utilities, Guggenmoos (2003a) found that most utility hazard-tree programs removed about five trees per mile of circuit, with the most intense programs removing 10 to 15 trees per mile.

Note that while hazard-tree programs can improve distribution performance, they are not a panacea. Tree outages will still occur regularly. Many tree faults are from weather that causes tree failures of otherwise healthy trees. Hazard-tree programs must be ongoing programs. As Guggenmoos (2003a) shows in detail, with tree mortality rates on the order of 0.5 to 3% annually and the sheer number of trees within a striking distance of T&D circuits, a hazard-tree program cannot be a one-time expenditure.

While most hazard-tree programs are best directed by a professional forester, it is beneficial for anyone involved in distribution field investigations to have some background knowledge of the common tree defects. A number of resources are available for this, including USDA (1996, 2003), Fazio (1989), and EPRI 1012443 (2007).

3.1.5 Vegetation Program Performance

As with any program impacting reliability, efforts are best spent on the poorest-performing circuits that affect the most customers. To target, spend more on three-phase mains than on single-phase taps, as an example. Vegetation programs can be targeted by adjusting maintenance intervals, clearance requirements, use of herbicides or tree-growth retardants, and application of hazard-tree inspections and removals. These can be optimized based on the circuit or region or even system wide based on the needs and issues for the area. This type of reliability-centered maintenance can improve costs and performance (EPRI 1019417, 2009).

On the basis of outage reviews and testing on how trees were causing faults (Rees et al., 1994), Baltimore Gas and Electric switched to a more prioritized vegetation management program on its distribution system (mainly 13.2 kV). They focused less on pruning for natural growth and attempted to remove overhangs where possible. They implemented a 3-year maintenance cycle on the three-phase system, and delegated the one- and two-phase system to "trim only as necessary." Crews also removed hazard trees. On the 34.5-kV subtransmission system, they moved to a biannual inspection program with the goal of achieving reliability approaching that of their transmission lines.

Eastern Utilities, a small utility in Massachusetts (now a part of National Grid) implemented a hazard-tree mitigation project (Simpson, 1997; Simpson and Van Bossuyt, 1996). Three-phase primary circuits were targeted, dead or structurally unsound trees were removed, and overhanging limbs were cut back. Trees were "storm-proof" pruned, meaning that trees were pruned to remove less-severe structural defects. This was mostly crown thinning or reducing the height of a tree to reduce the sail effect. On circuits where this was implemented, customer outage

hours (SAIDI) due to tree faults were reduced by 20 to 30%. In addition, the program reduced tree-caused SAIDI by 62% per storm.

Eastern Utilities did not increase funding for their vegetation management program to fund their hazard-tree mitigation project. Instead, they funded the program by changes to their normal vegetation management program. They did less pruning of growth beneath the lines. They also embarked on a community communications effort to educate utility customers and win support for tree removal and more aggressive pruning. Also, they did not remove viable trees without the landowner's consent. In addition, they found significant overall savings from reduced hot spotting and an even more significant savings from reduced outage restoration costs.

Prior to implementing their program, Eastern Utilities surveyed random line sections to determine how extensive their program would need to be. They found that of the trees along those spans, 7% had excessive overhang, and another 6% were weak species or had a visible structural weakness.

After a study of tree-caused outages on their system, Niagara Mohawk Power Corporation (now National Grid) implemented a program called TORO (tree outage reduction operation), which had the following characteristics (EPRI 1008480, 2004; Finch, 2001, 2003a,b):

- Targeted work to the worst-performing circuits based on specific tree-caused indicators.
- Removed hazard trees located on targeted circuit segments.
- Specified greater clearances and removed overhanging limbs where possible on the backbone.
- Lengthened tree maintenance cycles on rural 5-kV systems from 6 years to 7 or 8 years. Urban and suburban systems kept to a 5-year cycle.
- Looked for opportunities to improve system protection. They also added inspections for the presence of single-phase tap fuses.

As of 2002, based on 250 feeders completed, on 92% of the feeders, tree SAIFI improved an average of 67%. More recent results show even more improvement.

Puget Sound Energy (PSE) implemented a hazard-tree program (Puget Sound Energy, 2003). Started in 1998, the focus was on removing dead, dying, and diseased trees from private property along PSE's distribution system. On the circuits where they implemented their program, the average number of tree-caused outages and average outage duration dropped measurably. They reduced the cost of tree maintenance per circuit mile by about 15%.

Finch (2003b) provides details on several targeted programs. Two utilities adjusted maintenance cycles to reduce cost and focus work on the most critical portions. On urban circuits, one utility used a 4-year cycle on the backbone with a 2-year inspection to catch cycle busters and used a 5-year cycle on laterals. On rural circuits, they used a 5-year cycle for all circuits. They also developed a hazard-tree removal program based on results from their outage database. Another utility extended the maintenance cycle from 4 years to between 5 and 6 years on rural single-phase circuits.

As noted earlier, clearances and vegetation specifications are tied with reliability performance, maintenance intervals required, and cost. Especially for feeder backbones and important lines, more clearance above and to the sides can reduce the number of branches and trees that can hit lines. Herbicides and tree-growth regulators are also options to consider for managing clearances and reducing the amount of cutting needed. Consider pruning performance as improper pruning can trigger exaggerated regrowth and excess wounds.

Acceptable tree pruning (that is also still effective) is a public relations battle. Some strategies that help along these lines include

- Talking to residents prior to/during tree pruning.
- Pruning trees during winter (or tree pruning done "under the radar")—the community will not notice tree trimming as much when the leaves are not on the trees.
- Pruning trees during storm cleanups. Right after outages, residents are more willing to accept their beloved trees being hacked up (this is a form of the often practiced "storm-induced maintenance"; fix it when it falls down).
- Cleaning up after trees are cut/removed.
- Offering free firewood.

Audits can help utilities manage vegetation maintenance and improve performance. Many utilities do quality-assurance audits after tree maintenance. Especially with contract crews, postwork inspections ensure that the work is being done to specifications. Even more so with hazard-tree programs and other targeted programs, audits can help educate tree crews at the same time that they ensure that the work is being done. Education comes from pointing out tree defects that were missed or tree cuts that should be made to reduce tree hazards or meet specified clearances.

There are limits to what vegetation management can realistically achieve for line performance. Just throwing money at vegetation management will not necessarily translate into improved reliability. A large portion of faults are caused by branches or trees from well outside normal maintenance zones. This effect is even more pronounced during major wind and ice storms, where much damage comes from trees falling from outside any realistic maintenance zone, many from healthy trees.

3.2 Covered Conductors

Utilities with heavy tree cover often use covered conductors, conductors with a thin insulation covering (Figure 3.13 shows an example). The covering is not rated for a full conductor line-to-ground voltage, but it is thick enough to reduce the chance of flashover when a tree branch falls between conductors. A covered conductor is also called tree wire or weatherproof wire. Tree wire also helps with animal faults and allows utilities to use armless or candlestick designs or other tight configurations. Tree wire is available with a variety of covering types. The insulation materials such as polyethylene, XLPE, and EPR are common. For modern-vintage material, insulation thicknesses typically range from 30 to 150 mils (1 mil = 0.001 in. = 0.00254 cm). From a design and operating viewpoint, covered conductors must be treated as bare

Figure 3.13 Example of a compact armless design using covered conductors. (Courtesy of Duke Energy.)

conductors according to the National Electrical Safety Code (NESC) (IEEE C2-2012), with the only difference that tighter conductor spacings are allowed. There are various grades of insulation used for the covering.

Spacer cable (Figure 3.14) and aerial cables are also alternatives that perform well in treed areas. Spacer cables are a bundled configuration using a messenger wire holding up three phase wires that use a covered wire. Aerial cables have fully rated insulation just like underground cables.

Other advantages of covered conductors include

- *Spacings*—The NESC allows tighter conductor spacings on structures with covered conductors. Tighter spacings have aesthetic advantages. Also, more conductors can be placed in proximity, making it easier to build multiple-circuit lines, including underbuilt distribution. Spacer cables and aerial cables allow even more flexibility in squeezing more circuits on a pole structure.

Figure 3.14 Spacer cable. (Courtesy of Hendrix Wire and Cable Inc.)

- *Animal-caused faults*—Covered conductors add another line of defense against squirrels and other animals. Covering jumpers and other conductors that are near grounded equipment is the application that is most effective at reducing animal-caused faults.
- *Fire reduction*—Covered conductors reduce the chances of fires starting from arcing between conductors and trees and other debris on the power line. Wildfire prevention is the main justification for using covered conductors in Australia (Barber, 1999).

Safety is sometimes cited as a reason for using tree wire, but covered conductor systems do not necessarily offer safety advantages, and in some ways, the covering is a disadvantage. Even though Landinger et al. (1997) found small leakage currents through covered wires, they correctly pointed out that it does not cover all scenarios: covered conductors *may* reduce the chance of death from contact in some cases, but they are in *no way* a reliable barrier for protection to line workers or the public. Covered conductor circuits are more likely than bare-wire circuits to lead to downed-wire scenarios with a live distribution conductor on the ground. And, if a covered wire does contact the ground, it is less likely to show visible signs that it is energized such as arcing or jumping that would help keep bystanders away.

Additionally, with the use of covered conductors and spacer cables for preventing tree faults, preventing a fault is not always a good thing! If the weight of a tree deeply sags a covered conductor down to within the reach of pedestrians, but because of its covering, a fault does not occur, then the covered conductor may remain energized posing a public safety issue. On the other hand, with bare conductors, if it is pulled down to this degree, then a fault is more likely and an upstream protective device is likely to interrupt the circuit and deenergize the conductor posing less hazard to the public. The covering may also make a high-impedance fault less likely to transition to a low-impedance fault. If a downed phase conductor comes in contact (either intermittent or sustained) with a metallic object, the covering may prevent flashover for some time.

Covered conductor systems have additional trade-offs to be aware of. They are more susceptible to damage from fault arcs, they may cause radio-frequency interference (RFI) if the correct insulator tie is not used, and conductor corrosion is more likely.

Good fault data is hard to find comparing fault rates of a bare wire with a covered wire. European experience with covered conductors suggests that covered-wire fault rates are about 75% less than bare-wire fault rates. In Finland, fault rates on bare lines are about 3 per 100 km/year on a bare wire and 1 per 100 km/year on a covered wire (Hart, 1994).

In South America, both covered wire and a form of aerial cable have been successfully used in treed areas (Bernis and de Minas Gerais, 2001). The Brazilian company CEMIG found that spacer cable faults were lower than bare-wire circuits by a 10:1 ratio (although the article did not specify if this included both temporary and permanent faults). The aerial cable faults were lower than a bare wire by a 20:1 ratio. The effect on interruption durations is shown in Table 3.6. Several spacer

TABLE 3.6 Comparison of the Reliability Index SAIDI

Construction	SAIDI (hours)
Bare wire	9.9
Spacer cable	4.7
Aerial cable	3.0

Source: Data from Bernis, R. A. O. and de Minas Gerais, C. E., *Transmission and Distribution World*, vol. 53, no. 3, pp. 56–61, March 2001.

Note: SAIDI = average hours of interruption per customer per year.

cables or aerial cables can be constructed on a pole. Spacer cables and aerial cables have some of the same burndown considerations as a covered wire. Spacer cable construction has a reputation for being hard to work with. Both spacer cable and aerial cable cost more than a bare wire. CEMIG estimated that the initial investment was returned by the reduction in tree maintenance. They did minimal pruning around an aerial cable (an estimated factor of 12 reduction in maintenance costs) and only minor pruning around the spacer cable (an estimated factor of 6 reduction in maintenance costs).

The utility data at the beginning of this chapter on the types of tree faults can give us some idea of the maximum benefit from covered conductors. Depending on the utility, from a low of about 23% (Baltimore Gas and Electric) to a high of over 70% (Duke Energy and BC Hydro) of tree faults were due to mechanical damage from large branches or entire trees falling on circuits. If we assume that the conductor covering will not affect mechanical damage from faults, then the best that a covered conductor will do is to reduce tree-caused faults by 30% (for utilities with a high percentage of mechanical damage) to 77% (for utilities with mainly growth or small limb contacts). This assumes application of covered conductors at the same spacings as bare conductors. If tighter spacings are used for covered conductors (often done), then the reduction in tree-caused faults may not be as great, but this is speculative as there is no industrial data or testing to allow us to estimate the differences. Tighter spacings may have other adverse effects such as reduced insulation levels and more animal contacts.

Duke Energy has found that the best use of covered conductors is in areas with high overhang, where the trees are far above the three-phase lines (Short and Taylor, 2006). Often, tree branches fall from the high canopy and land between two conductors. Covered conductors really help in this situation. Short of ground-to-sky clearance, no amount of tree pruning can eliminate the problem.

A conductor covering may slightly increase the likelihood of mechanical damage—the covering increases the wire's weight and mechanical load on the conductor, so it takes less force from a branch or tree to cause mechanical damage. Using the same reasoning, the extra ice loading on a covered conductor (due to increased surface area) could also increase the likelihood of damage from trees during ice storms.

On the other hand, spacer cable systems can be more immune to mechanical damage from tree limbs. The combination of the high-strength messenger cable along with the tightly bundled phase conductors is much stronger than single conductors. While spacer cables should perform better for tree growth issues and for small-to-medium branches, if entire trees fall into them, poles are more likely to break because of the strength of the messenger and attachment to poles.

Pole structures with covered conductors can generate RFI if the insulator wire tie is not compatible with the covering. Power-line noise can be generated by conducting insulator ties separated by insulation from the line conductor. These scenarios include the following combinations:

- Bare conductor tie on a covered line conductor that is not stripped at the insulator
- Insulated conductor tie on a bare or covered line conductor (see Figure 3.15)

A conducting insulator tie in close proximity to the phase conductors creates a prime arcing scenario that can cause power-line noise. A voltage can develop between the conducting insulator tie and the line conductor. The capacitance between the two is on the order of 30 to 50 pF, which is enough to charge the conducting tie relative to the line conductor (Vincent et al., 2007). The line covering may hold this voltage, but the covering may deteriorate or lightning may puncture it. Once the insulation has been bridged, repetitive arcing can occur across the air gap as the tie wire charges and then discharges into the line conductor. Arcing will further deteriorate the conductor insulation, possibly causing more arcing. Vincent et al. (2007) also document a second cause of RFI from incompatible insulator ties: if the insulation deteriorates enough so that the tie touches or nearly touches the line conductor, then an insulating oxide layer can build between the two, leading to microsparking noise from breakdowns across this small gap.

Figure 3.15 Example of a covered wire tie on a covered conductor. (From Vincent, W. R. et al., *The Mitigation of Radio Noise and Interference from External Sources*, 6th ed, United States Navy Naval Postgraduate School, 2007.)

The main problem with these partial discharges is that they cause radio interference. There has been speculation that these discharges could damage the conductor, but in tests by the Pennsylvania Power and Light Company (PP&L), Lee et al. (1980) reported that in tests of different wire tie and insulator combinations, no evidence of conductor damage was found.

To reduce radio interference with covered conductor systems, use insulator ties that are compatible with the insulator

- Either strip the conductor at each insulator and use bare metallic insulator ties or
- Leave the conductor covering on, and use nonconducting insulator ties

For covered conductors with conducting insulator ties, a retrofit is possible by stripping the insulation on one side and bonding the insulator tie to the conductor.

Some utilities argue that lines have better lightning protection if the covering is left on the conductor. While the improvement is marginal, there is some difference between different covering and insulator tie combinations. Tests at Clarkson University (Baker, 1984) of 15-kV class pin insulators in the 1980s found that keeping the cover on raises the critical flashover voltage from about 115 kV with a bare wire to about 145 kV with the cover on using a preformed plastic tie. With a semiconductive tie or a polyethylene-covered aluminum tie, the values were slightly less than this. For a direct strike, these differences should not matter, but for a weakly insulated line (with little wood or fiberglass), the extra insulation could help reduce induced-voltage flashovers, but for most North American designs, the difference in overall insulation is small. Direct strikes will still cause flashovers and possible damage; the most likely flashover point is where the insulation is the weakest: at the insulator where the tie comes in contact with the covering (Figure 3.16). The covering will not add significant insulation to a structure with an insulator and a foot (0.3 m) or more of wood or fiberglass.

Covered conductors are heavier, have a larger diameter, and have a lower-strength rating. Relative to the same size of a bare conductor, a 477-kcmil all-aluminum conductor with an 80-mil XLPE conductor covering weighs 20% more, has a 17% larger outside diameter, and has a 10% lower-strength rating.

The ice and wind loading of a covered conductor is also higher than a comparable bare conductor. Both increase with increasing diameter. In the example comparing a

Figure 3.16 Example of damage on a covered conductor from flashover at the insulator tie. (Courtesy of Duke Energy.)

477-kcmil all-aluminum conductor with an 80-mil XLPE covering, the loadings for the covered conductor versus a bare conductor increase as follows:

- *Vertical*—Loading due to ice and conductor weight increases by 14%
- *Horizontal*—Loading due to wind increases by 8%
- *Resultant*—Loading due to the vertical and horizontal component increases by 11%

Another issue with covered conductors is the integrity of the covering. The covering may be susceptible to degradation due to ultraviolet radiation, tracking and erosion, and abrasion from rubbing against trees or other objects. Early covering materials, including the widely used PVC, were especially susceptible to degradation from ultraviolet light, from tracking, and from abrasion. Modern EPR or XLPE coverings are much less susceptible to degradation and should be more reliable.

Covered conductors are more susceptible to corrosion, primarily from water. If water penetrates the covering, it settles at the low points and causes corrosion (the water cannot evaporate). On bare conductors, corrosion is rare—rain washes bare conductors periodically, and evaporation takes care of moisture. Australian experience has found that complete corrosion can occur with covered wires in 15 to 20 years of operation (Barber, 1999). Water enters the conductor at pinholes caused by lightning strikes, cover damage caused by abrasion or erosion, and at holes pierced by connectors. Temperature changes then cause water to be pumped into the conductor. Because of corrosion concerns, water-blocked conductors are better.

Covered conductors have ampacities that are close to bare-conductor ampacities for the same operating temperature (see the previous chapter). Covered conductors are darker, so they absorb more heat from the sun but radiate heat better. The most significant difference is that covered conductors have less ability to withstand higher temperatures—the insulation degrades at high temperatures. Polyethylene is especially prone to damage, so it should not be operated above 75°C. EPR and XLPE may be operated up to 90°C. A bare conductor may have a rating as high as 100°C.

3.3 Animal Protection

Animals cause many issues with distribution lines. For many utilities, they are the second or third cause of faults on overhead circuits. Many unknown faults are also likely to be animals. Fortunately, with proper construction practices that include animal protection, utilities can greatly reduce animal faults using relatively simple approaches.

A number of useful references for animal protection on distribution circuits include EPRI TE-114915 (1999), EPRI 1001883 (2001), EPRI 1012437 (2006), NRECA (1996), Frazier and Bonham (1996), Chow and Taylor (1995), and California Energy Commission (1999).

3.3.1 Animal-Fault Basics

Faults caused by animals are often the number two cause of interruptions for utilities (after trees). An animal that bridges the gap between an energized conductor and ground or another energized phase will create a highly ionized, low-impedance fault-current path. The fault will cause a voltage sag to nearby customers and an interruption to the portion of the circuit covered by the upstream protective device. An animal can cause a temporary fault or a permanent fault. If the animal remains or a charred arc path leaves a conducting path, the circuit will not be able to hold voltage, and the fault will be permanent. If the animal gets blown off or falls away, the circuit can be reenergized (a temporary fault). Animal-caused faults are normally phase to ground. A phase-to-phase flashover path is uncommon but can happen; a three-phase flashover is rare.

Squirrels cause the most faults on overhead distribution circuits. Squirrels thrive in suburbs and love trees; utilities have noted increases in squirrel faults following the development of wooded areas. Squirrels are creatures of habit and tend to repeatedly follow the same paths. Squirrels have a need to gnaw, which can be destructive to utility equipment; they will chew secondary wire coverings and aluminum connectors.

Different species of squirrels are of different lengths. From the longest to the shortest, the main species are (lengths are nose to tip-of-tail measurements (Jackson, 1994))

- Fox squirrels: 18 to 27 in. (46 to 69 cm)
- Eastern and Western gray squirrels and tassel-eared squirrels: 16 to 20 in. (41 to 51 cm)
- Red and Douglass pine squirrels: 10 to 15 in. (25 to 38 cm)
- Northern flying squirrels: 10 to 12 in. (25 to 30 cm)
- Southern flying squirrels: 8 to 10 in. (20 to 25 cm)

While we can see that the longest fox squirrels can stretch more than 2 ft, separations between energized conductors of 18 to 24 in. are normally enough to prevent most squirrel-caused outages. Spacings less than 10 in. are extremely prone to squirrels—for example, across an unprotected bushing. While squirrels are the most common cause of faults, several other climbing animals can cause faults on overhead circuits, including raccoons, rats, cats, and snakes. While some of these animals are longer than squirrels, the protective measures for squirrels also protect against most faults from other climbing animals.

Common birds (including starlings and blackbirds) rank second behind squirrels as far as the number of animal-caused interruptions caused on overhead distribution circuits (EPRI TE-114915, 1999; Frazier and Bonham, 1996). Birds normally cause faults in much the same way as squirrels—by bridging the gap across locations with tight spacings: for example, unprotected bushings or surge arresters Birds use utility equipment to perch on and for nests. Many of the same protective measures that protect against squirrel-caused faults will also protect against bird-caused faults. Other ways that birds can cause faults include bird-dropping contamination on insulators and woodpecker damage to poles. Large groups of flocking birds (such

as starlings or crows) can cause a conductor to swing into another conductor when the flock suddenly leaves the conductor. Many large birds, including eagles, hawks, owls, and herons are wide enough to span the normal phase-to-phase separations on overhead distribution circuits. Because of this, extra measures are needed to protect these birds from electrocution. As such, it is a matter of protecting endangered animals; in most cases, the frequency of large-raptor contacts is small relative to other animal contacts.

Most animal-caused faults occur in fair weather. Chow and Taylor (1995) found that over 85% of animal faults occurred during fair weather on the Duke Energy system. They also found that more than half of the animal faults occurred during the morning, and few occurred during the evening or late at night. Squirrels sleep at night and are most active in the morning as they are looking for food. Some utilities also experience seasonal variations in weather patterns, as animals are less active during winter.

Since animal-caused faults are normally during fair weather, the power-quality perception of these faults is heightened. Utility customers normally expect disturbances during poor weather—but not in good weather. When a customer loses a critical process due to a utility interruption or voltage sag, and it is not stormy, the customer is more likely to complain.

The types of animals causing faults vary considerably by region, and there is also a significant variation within a region. Animal faults also ebb and flow with animal populations. Animal population data can be used as one way to determine if "unknown" faults are really being caused by certain animals.

The patterns of animal-caused faults have been used to classify "unknown" faults. Chow et al. (1993) developed a classification routine to identify animal-caused faults based on the following outage inputs: circuit identity (ID), weather code, time of day, phases affected, and protective device that operated. Animal faults are more likely during fair weather, mornings, only one phase affected, and for a transformer or tap fuse. These same classification strategies can be used to estimate how many of the "unknown" faults are actually animals.

EPRI surveyed utilities on animal faults and animal protective measures (EPRI TE-114915, 1999). Out of 84 respondents, 77% had some sort of structured program to address animal-caused interruptions. 78% of animal-caused outages were attributed to overhead distribution with the remainder split almost evenly between underground distribution, substation, and transmission.

The EPRI survey also points out where most animal-caused outages occur—at equipment poles, where phase-to-ground spacings are tight. Figure 3.17 shows that most problem areas are at equipment poles. Transformers are by far the most widely found pole-mounted equipment on a distribution system. Unprotected transformer poles normally have many locations susceptible to animal faults: across the transformer bushing, across a surge arrester, and from a jumper to the transformer tank. Riser pole installations, regulators, reclosers, and capacitor banks all have susceptible flashover paths unless utilities employ protective measures. Poles without equipment are much less susceptible to animal faults (exceptions are poles with grounded guys or ground wires near phase conductors).

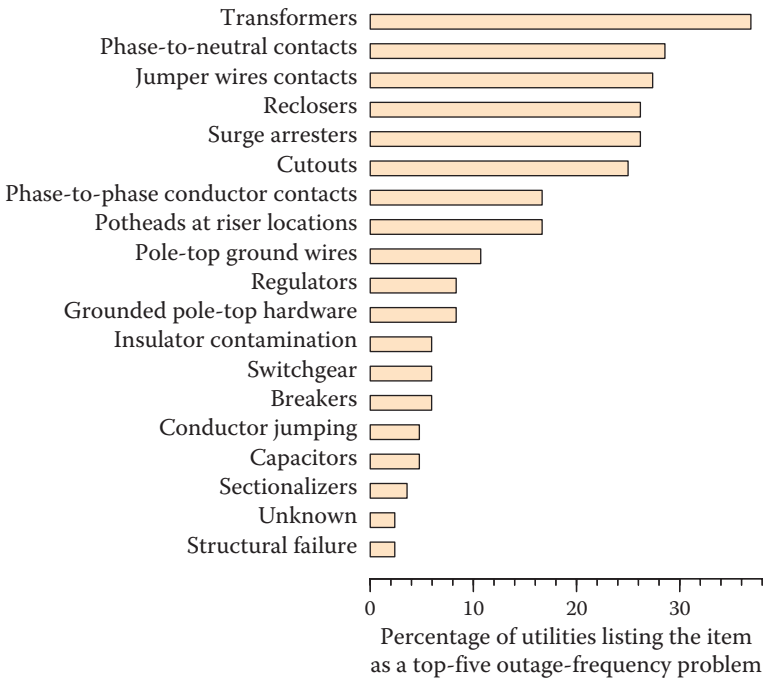

Figure 3.17 Overhead distribution points most susceptible to animal-caused faults. (From EPRI TE-114915, *Mitigation of Animal-Caused Outages for Distribution Lines and Substations*, Electric Power Research Institute, Palo Alto, CA, 1999; EPRI 1002188, *Power Quality Implications of Distribution Construction*. Copyright 2004. Reprinted with permission.)

3.3.2 Animal Guards, Wire Coverings, and Other Protective Equipment

Of the major causes of faults—animals, trees, lightning, and equipment failures—animal faults are the most easily prevented. The two main ways to protect equipment against animals (particularly squirrels and birds) are

- Bushing protectors
- Covered lead wires

Bushing protectors and covered lead wires are inexpensive if installed with equipment (but relatively expensive to retrofit). A variety of bushing guards are available. These can be used for bushings and surge arresters found on transformers, capacitors, regulators, reclosers, and sectionalizers. Of these locations, transformers are the most common. Properly applied bushing guards in conjunction with covered jumper wires can effectively prevent most animal-caused faults. For example, in one Duke Energy circuit, animal guard application on all distribution transformers on the circuit reduced animal faults from 12 per year to an average of 1.5 per year (Chow and Taylor, 1995). In Lincoln, Nebraska, the application of animal guards on all 13,000 transformers reduced the cost of animal-caused faults by 78% (Hamilton et al., 1989).

Animal guards and covered jumper wires prevent most animal flashovers at equipment poles by physically covering energized conductors. See Figure 3.18 for examples of installations. The insulation is not fully rated and provides no degree of safety for line workers (animal guards have no voltage rating, and covered jumper wire is normally 600-V class insulation). The insulation is normally enough to prevent a full flashover across an animal for a momentary contact. For retrofit situations, split-seam insulation covers for jumper wires are available.

Proper installation is important for bushing guards. The guard should be placed securely around the bushing and locked into place according to the manufacturer's directions. Height placement is also important (see Figure 3.19). For bushing protectors, have crews leave some room between the bottom of the bushing protector and the tank. Animal guards are not fully rated insulators—they can track and flashover, so we do not want the animal guard to fully bypass the insulator. Many manufacturers direct you to install the guard under the second shed from the top of the bushing. If you are more than half-way down the bushing, you are certainly incorrect.

The most common mistake is leaving some energized pathways exposed. Crews should cover every bushing and arrester and use insulated leads on all jumpers. In a survey of 253 poles that should have had animal protection, Pacific Gas & Electric (PG&E) found that 165 poles (65%) were found with incomplete or improperly installed devices (California Energy Commission, 1999). The most common problems were missing bushing covers or missing covers on jumpers (see Figure 3.20).

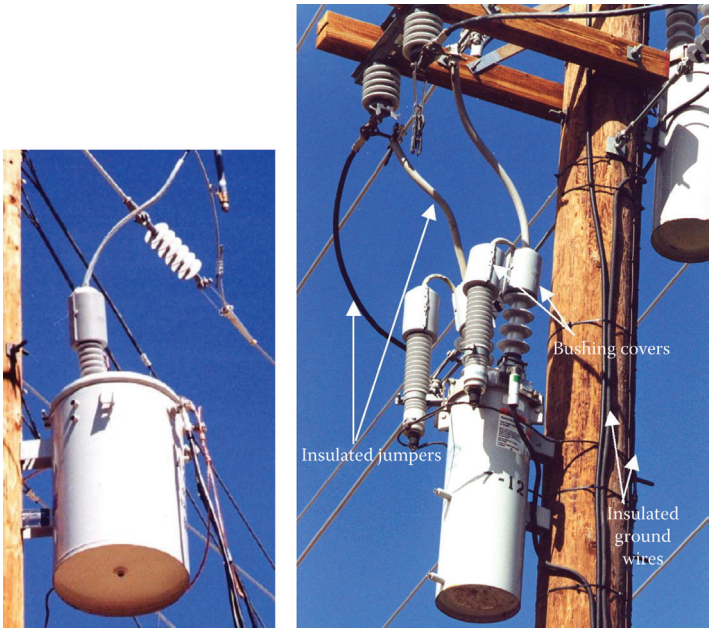

Figure 3.18 Examples of wildlife protection with animal guards and covered jumpers. (From EPRI 1001883, *Distribution Wildlife and Pest Control*, Electric Power Research Institute, Palo Alto, CA, 2001. Copyright 2001. Reprinted with permission.)

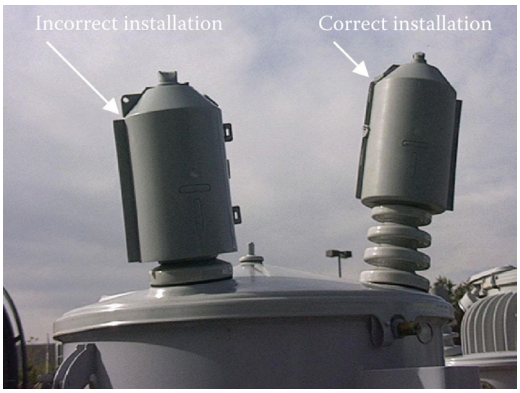

Figure 3.19 Animal guard installation. (From EPRI 1001883, *Distribution Wildlife and Pest Control*, Electric Power Research Institute, Palo Alto, CA, 2001. Copyright 2001. Reprinted with permission.)

Animal guards are relatively flimsy compared to most other distribution line hardware. When selecting animal guards, choose models that are large enough to sufficiently cover bushings and arresters. The small protectors that just cover the bushing cap can pop off, and determined animals can wedge between the caps and the bushing. Also, choose animal guards tested to withstand degradation from ultraviolet radiation. Crews should not use tape or nylon ties to secure guards. If the guard does not properly fit, then they should apply the one that does fit. Also, crews should be careful not to block the gap on air-gapped arresters. Some bushing guards come with knockouts that can be removed to maintain the gap.

In a survey (EPRI TE-114915, 1999), utilities reported some animal-mitigating measures caused new outage or maintenance problems. Several utilities reported bushing covers deteriorating and tracking. Figure 3.21 shows an example of a deteriorated animal guard. Exposure to ultraviolet radiation causes depolymerization in polymer

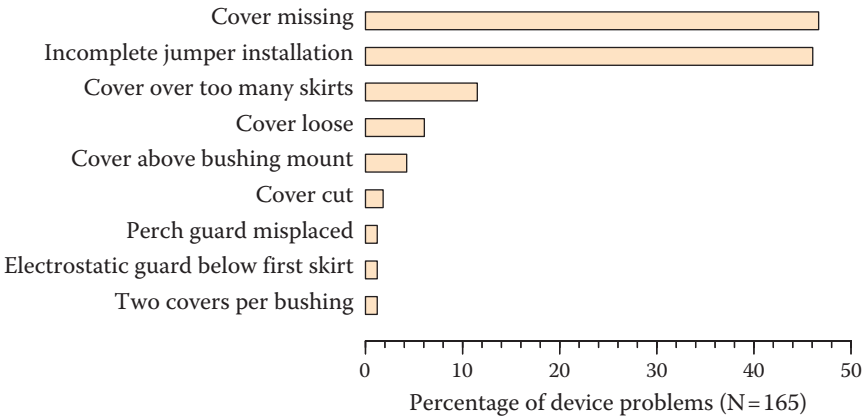

Figure 3.20 Problems with animal protective devices. (Data from California Energy Commission, *Reducing Wildlife Interactions with Electrical Distribution Facilities*, 1999.)

Figure 3.21 Example of a deteriorated animal guard compared to a new animal guard. (From EPRI TE-114915, *Mitigation of Animal-Caused Outages for Distribution Lines and Substations*, Electric Power Research Institute, Palo Alto, CA, 1999. Copyright 1999. Reprinted with permission.)

materials (the polymer bonds break down). The effect of the material depolymerization is a roughening of the material surface, which is often accompanied by cracking and pitting of the surface. The roughened surface may now be more susceptible to pollutant collection and thus more susceptible to dry-band arcing and further deterioration. Exposure to ultraviolet radiation is primarily achieved through exposure to sunlight (of which ultraviolet radiation is a component) although ultraviolet radiation is also present in corona discharge, which can create a localized rapid aging effect.

Of the 253 poles examined by PG&E, 80 poles (32%) were found with degraded devices (California Energy Commission, 1999). The type of degradation observed, ranked from least to most, was discoloration (e.g., ultraviolet light damage), black traces, tracking and/or erosion, tearing (caused by wear), and deformation. PG&E anticipated that those devices showing discoloration or black traces would have a greater likelihood of performing as they were designed, while those devices showing obvious tracking/erosion, tearing, or deformation would have lost some of their designed functionality. They grouped the results into classes A and B to represent these less severe (discoloration or black traces) and more severe (tracking/erosion, torn, or deformation) forms of degradation, respectively:

- *Class A*—Degradation that is of a lesser degree such as discoloration or black traces that will not likely affect performance.
- *Class B*—Degradation of a greater degree that will likely result in reduced performance such as tears, signs of tracking/erosion, or deformation.

This ranking of degradation severity is only based on what could be observed of the device's condition from the ground. A closer examination could reveal other clues

that would indicate greater or lesser degradation. For example, tracking could occur on the inside surface of a device that only appeared discolored on the outside surface.

Table 3.7 summarizes the extent of deterioration on the poles surveyed by PG&E. Of the 80 poles with degraded devices, 43% were exposed to heavy automobile exhaust, and all but one was fully exposed to sunlight (no environmental shielding). Also, 62% were in residential areas, and 14% were in agricultural areas.

PG&E reported that their tests in 1997 found that PVC products perform poorly compared to similar products made from other base materials, such as polypropylene copolymers, ethylene propylene diene methylene (EPDM), and silicone rubber (California Energy Commission, 1999).

Newer products are expected to resist degradation better than older units. The materials are more resistant to degradation from ultraviolet radiation.

When selecting animal guards, also consider their flammability. There have been incidents of reclosers and other significant equipment completely burning down because animal guards ignited and turned a temporary, low-damage event into major damage. Burning material can also drip from the guard and start secondary fires. From flammability tests of animal guards, some ignite faster than others, and some continue to burn while others self-extinguish when the heat source is removed (EPRI 1016043, 2008). Consider including a flammability test as part of purchasing specifications.

This section has concentrated on bushing guards and wire coverings—the most common and effective animal-control technologies. Some additional items that also help include

- Clear trees—Squirrels get to utility equipment via trees (pole climbing is less common). If trees are kept away from lines, utility equipment is less attractive.
- Good outage tracking—Many outages are repeated, so a good outage tracking system can pinpoint hot spots to identify where to target maintenance.
- Identify animal—If outages are tracked by an animal, it is easier to identify proper solutions.

Animal guards and wire coverings help with birds as well as with squirrels and other climbing animals. Additionally, some bird-specific practices include

- Getting rid of nests
- Installing perch guards (mainly in raptor areas)
- Tracking as a separate category
- Removing nearby roosting areas

TABLE 3.7 Deterioration of Animal-Protective Devices

Degradation	Number of Poles	Number of Degraded Devices
Class A	69 (27%)	91
Class B	28 (11%)	37

Source: Data from California Energy Commission, *Reducing Wildlife Interactions with Electrical Distribution Facilities*, 1999.

Note: Survey of 253 pole locations.

Unprotected transformer bushings and arresters are the main sources of animal problems. Other problems can occur where there are low clearances at cutouts or grounds and guys. Ground wires near phase conductors can create short phase-to-ground separations. Figure 3.22 shows an example that illustrates the problem. On this pole, a ground wire runs from the neutral to the top of the pole, leaving less than 6 in. (15 cm) between the phase and the neutral. This is the type of installation that could have repeated animal faults because of the short phase-to-ground separation. The best solution is to remove the ground wire. This type of ground wire is unnecessary in most cases. Insulated supports and standoffs can also help reduce animal issues.

Fusing can also change the impact of animal-caused faults for faults across a distribution transformer bushing or an arrester. Having an external fuse reduces the impacts of animal-caused faults. If the transformer is a completely self-protected transformer (CSP) with an internal fuse, then the tap fuse or upstream circuit breaker or recloser operates, leaving many more customers interrupted, with much more area for crews to patrol. CSPs on the mainline are especially problematic for reliability.

Line surge arresters are another common overhead line application that normally does not have a local fuse. Line arresters are arresters applied not to protect any particular piece of equipment, but to improve the performance of the line itself. On such installations, it is important to provide adequate animal protections.

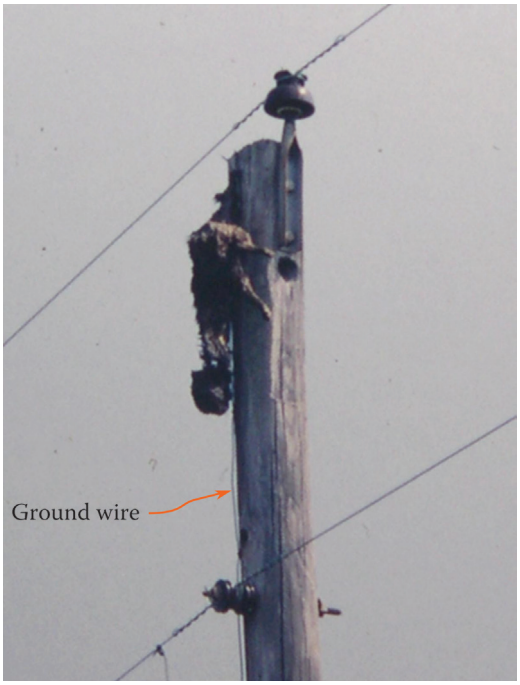

Figure 3.22 Electrocuted cat and the ground wire that made the pole susceptible to animal faults. (Courtesy of Duke Energy.)

3.4 Inspections and Maintenance

Historically, most distribution hardware was considered as "run to failure," and maintenance was minimal. Now, many utilities have programs for inspection and maintenance that covers much equipment.

Visual inspections can find many issues, including NESC violations, cracked or broken crossarms, cutout issues, severely deteriorated poles, and so on. Many regulatory bodies now require periodic inspections.

Voltage regulators and reclosers require inspection and maintenance. Inspection and maintenance of these are normally based either on a time interval or on operation counts. Manufacturers will normally provide operating duties for equipment that can form the basis for maintenance based on operation counts. Reclosers may be rated for 50 to several hundred operations. The actual duty is based on fault currents seen by the recloser. Modern recloser controls can provide a "wear monitor" that accounts for operations and fault currents.

Thermal or infrared imaging can help identify distribution problems, especially with connectors. Thermal inspections can be done in a drive-by inspection. Since hot-spot temperatures vary with current loading, inspections are most effective when performed with the circuit under heavier load. Some hot spots are not load dependent, such as arresters, tracking problems, and capacitor connections. The CEA reported that 27% of utilities did annual thermal inspections of overhead lines, 18% had inspection intervals between 2 and 5 years, 28% did not perform thermal inspections, and 20% had ad hoc or other inspection cycles (CEA 290 D 975, 1995).

Experience with finding problems with thermal imaging can vary based on utility equipment and design issues. Sullivan (2001) reported that 50% of problems identified on Mississippi Power feeders were hot arresters, 40% were connections and compression crimps, and 10% were fuse cutouts. Kregg (2001) found just over one anomaly for each 12-kV feeder for Commonwealth Edison. Connections were the largest portion of anomalies followed by transformers (see Figure 3.23). See Figure 3.24 for examples of issues.

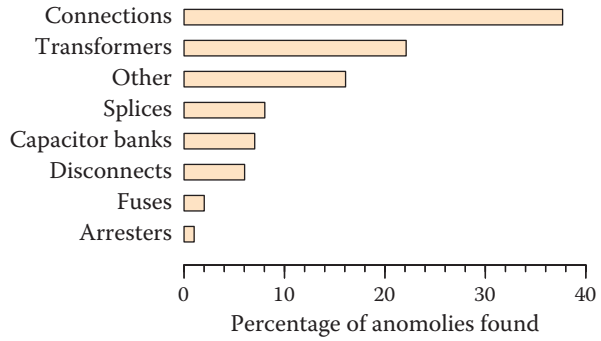

Figure 3.23 Portion of anomalies found from thermal inspections on 12-kV circuits. (Data from Kregg, M. A., Development of a utility feeder infrared thermography preventive maintenance program—With lessons learned, *InfraMation*, *The Thermographer's Conference*, 2001.)

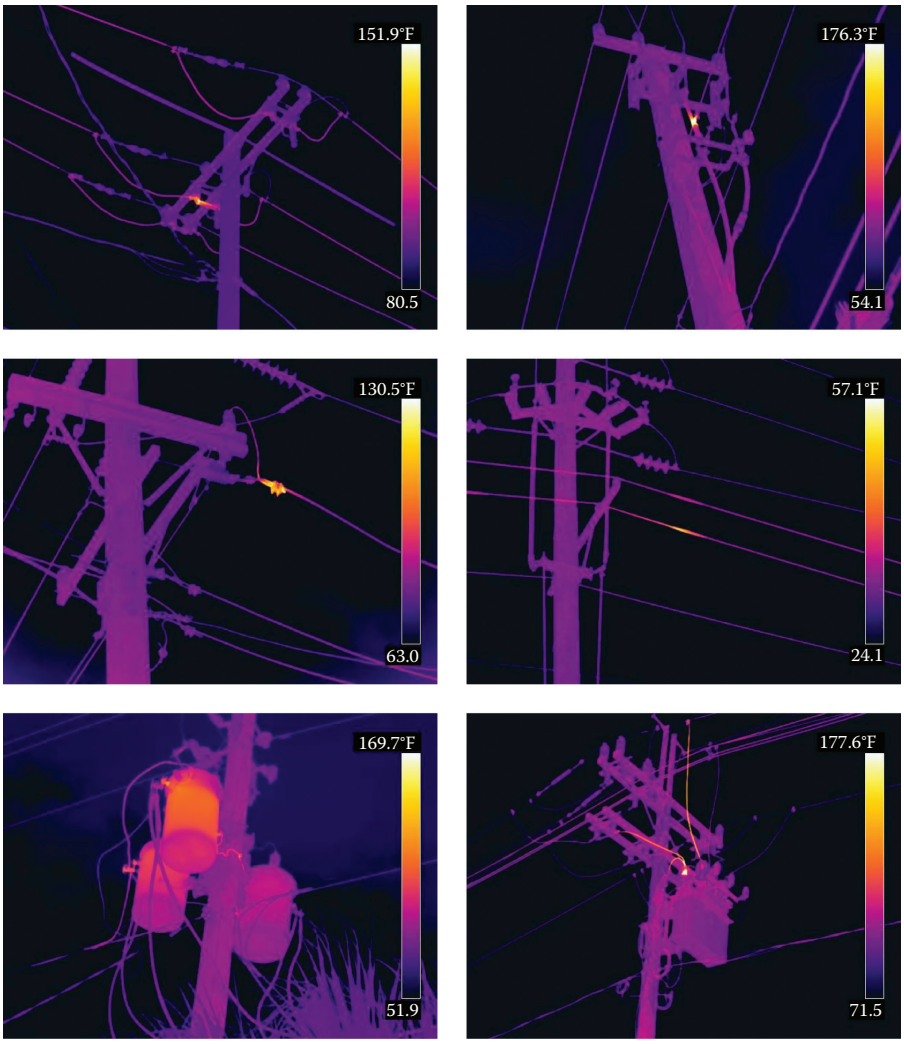

Figure 3.24 Examples of infrared issues. (Courtesy of Osmose Utilities Services, Inc.)

The criteria for identifying issues and assigning priorities are sometimes based on absolute temperature, but it is best to use a temperature rise relative to a comparable reference point. Table 3.8 shows one priority grading system. Table 3.9 shows prioritizations by Commonwealth Edison. These vary by equipment type; "nonline of sight items" have a tighter temperature criteria because in equipment such as transformers and pot heads, the heat source is internal and not directly observable.

Connector issues are commonly identified by thermal imaging. Sullivan (2001) reported that most of their connection issues were due to human error. For compression crimps, Sullivan found issues with using the wrong size crimp, the wrong die, an out-of-adjustment crimping tool, and improper crimping. Sullivan reported that bringing attention to issues and training has helped reduce this problem.

TABLE 3.8 Anomaly Priority Grading System

Priority	Temperature Rise	Repair Status
1	50°C or more	Repair immediately
2	21 to 49°C	Repair in 7 days
3	11 to 20°C	Repair in 3 months
4	10°C or less	Monitor regularly

Note: Used by Asplundh Infrared Services for thermal inspections of Orange and Rockland Utilities' infrastructure (EPRI 1000194, 2000).

TABLE 3.9 Thermal Inspection Priority System Used by Commonwealth Edison

Temperature Criteria	Priority
For *Line of Sight Items* Such as Bolted Connections, Splices, Disconnect Jaws, and So On	
>135°F	Critical—corrective action immediately
64 to 135°F	Serious—correction action as soon as possible
18 to 63°F	Intermediate—corrective action as scheduling permits
<18°F	Attention—no corrective action but monitor equipment
For *Non-Line of Sight Items* Such as Transformer and Capacitor Cans, Cable Up-Feed and Down-Feed Pot Heads, Arrester Bodies, and So On	
>36°F	Critical—corrective action immediately
18 to 36°F	Serious—correction action as soon as possible
1 to 17°F	Intermediate—corrective action as scheduling permits

Source: Adapted from Kregg, M. A., Development of a utility feeder infrared thermography preventive maintenance program—With lessons learned, *InfraMation*, *The Thermographer's Conference*, 2001.

Note: All temperatures are temperature rises above an appropriately selected reference point. The reference point is usually a similar component on another phase that is assumed to be under similar load.

Sullivan (2002) identified several issues with fuse cutouts at Mississippi Power. The most common issue they found was loose caps, but they also had issues with proper tightening of clamp nuts, and hinge problems. Bad connections were also a big portion of their problems. They also had issues with one cutout design where the mechanical stop was aligned wrong, so the fuse tube would not latch properly.

3.5 Pole Inspections and Maintenance

Most utilities use a pole inspection and maintenance program to manage their pole plant. Many utilities have relatively old pole populations, and an inspection and maintenance program can optimize replacements.

Pole decay is most common near the ground line. This decay is normally internal and cannot be seen externally. Fungi that feed on wood are the leading cause of pole decay. The initial chemical preservatives such as creosote, chromated copper arsenate (CCA), or pentachlorophenol (penta) delay decay. For ground-level decay, moisture and temperature are the primary variables affecting decay. Fungi grow with moisture content above 20%. Growth increases with temperature, peaking between 60°F and

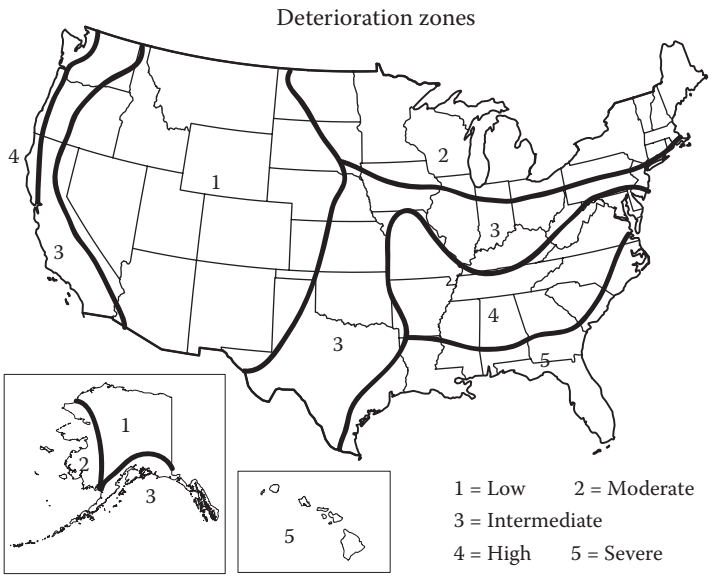

Figure 3.25 Wood pole deterioration zones from AWPA Standard U1 (2013). (Courtesy of the American Wood Protection Association.)

80°F (16 to 27°C). These factors are typically the worst near the ground line. Because of the dependency of decay on moisture and temperature, decay rates are different in different regions. See Figure 3.25 for a map with zones based on decay severity from the America Wood Protection Association (AWPA); a higher number of zones have more risk of pole decay.

Most decay occurs internally. Poles can look weathered but can still be good because the external damage is not deep. For mechanical strength, the outer shell is critical. Figure 3.26 shows theoretical bending strength as a function of the thickness

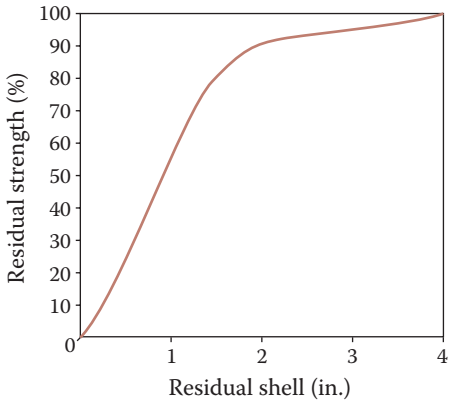

Figure 3.26 Theoretical strength remaining as a function of shell thickness. (Courtesy of Oregon State University; from Morrell, J. J., *Wood Pole Maintenance Manual: 2012 Edition*, Forest Research Laboratory of Oregon State University, 2012. With permission.)

of the sound outer shell. According to Morrell (2012), most utilities require a sound outer shell of 2 in. (5 cm).

Decay can also occur where the equipment is attached or near the top of the pole where the pole is more exposed and where preservatives may be lost due to gravity.

For more detailed information on pole decay and treatments, see Morrell (2012) and EPRI 1017703 (2009).

Pole inspections normally involve a visual inspection followed by a sounding test and boring:

- *Sounding or hammer test*—A hammer is used to test for dull-sounding points that might indicate decayed wood and indicate where boring might be needed.
- *Boring*—Poles are drilled at an angle to identify soft spots. Then shell thickness (the width of the sound wood) can be measured with a long steel bar with a hook on it.
- *Excavation and boring*—Since many instances of decay occur just below the ground line, boring tests can be made after excavating around the pole, typically 18 to 24 in. (0.4 to 0.6 m) deep.

Most inspections are combined with ground-line fumigant treatment to slow down further decay.

A number of pole-testing technologies have been tried, using different approaches, including ultrasound, resistivity measurements, mechanical movement, and back-scatter technology (EPRI 1010654, 2005; EPRI 1021996, 2011). Renforth and Taras (2002) reported on a technology that measures ground-line density and moisture content and found that the predictions from this technology correlated well with strengths measured in full-scale destructive tests.

Over 85% of utilities have a regular pole inspection program according to surveys (EPRI 1002093, 2004). In a 1997 survey with 261 responses, the average duration between pole inspections was 8.1 years (EPRI 1002093, 2004). The same report also reported an average duration between pole inspections of 11.4 years (though there were only eight responses to this survey). The U.S. Rural Utilities Service (RUS 1730B-121, 1996) recommends an initial inspection between 12 and 15 years for decay zone 1, 10 and 12 years for decay zones 2 and 3, and 8 and 10 years for decay zones 4 and 5. After the first inspection, the RUS recommends inspections every 12 years for zone 1, 10 years for zones 2 and 3, and 8 years for zones 4 and 5.

Pole inspection results can be used to generate information to understand the benefits of pole maintenance and possibly to tailor how often inspections and maintenance should be done. Translating pole inspection data into survivor curves or failure-rate curves is tricky. Figure 3.27 shows industry data from pole inspection programs. It includes two types of data: initial inspections and second inspections. Each provides different information.

- *Initial inspection*—These are the initial inspections. We know the age of the pole and whether or not it passed an inspection.
- *Second inspection*—These are the points labeled "recycle" in Figure 3.27. These are interval samples. We know the age of the pole, the age at which it was previously inspected, and whether or not it passed an inspection.

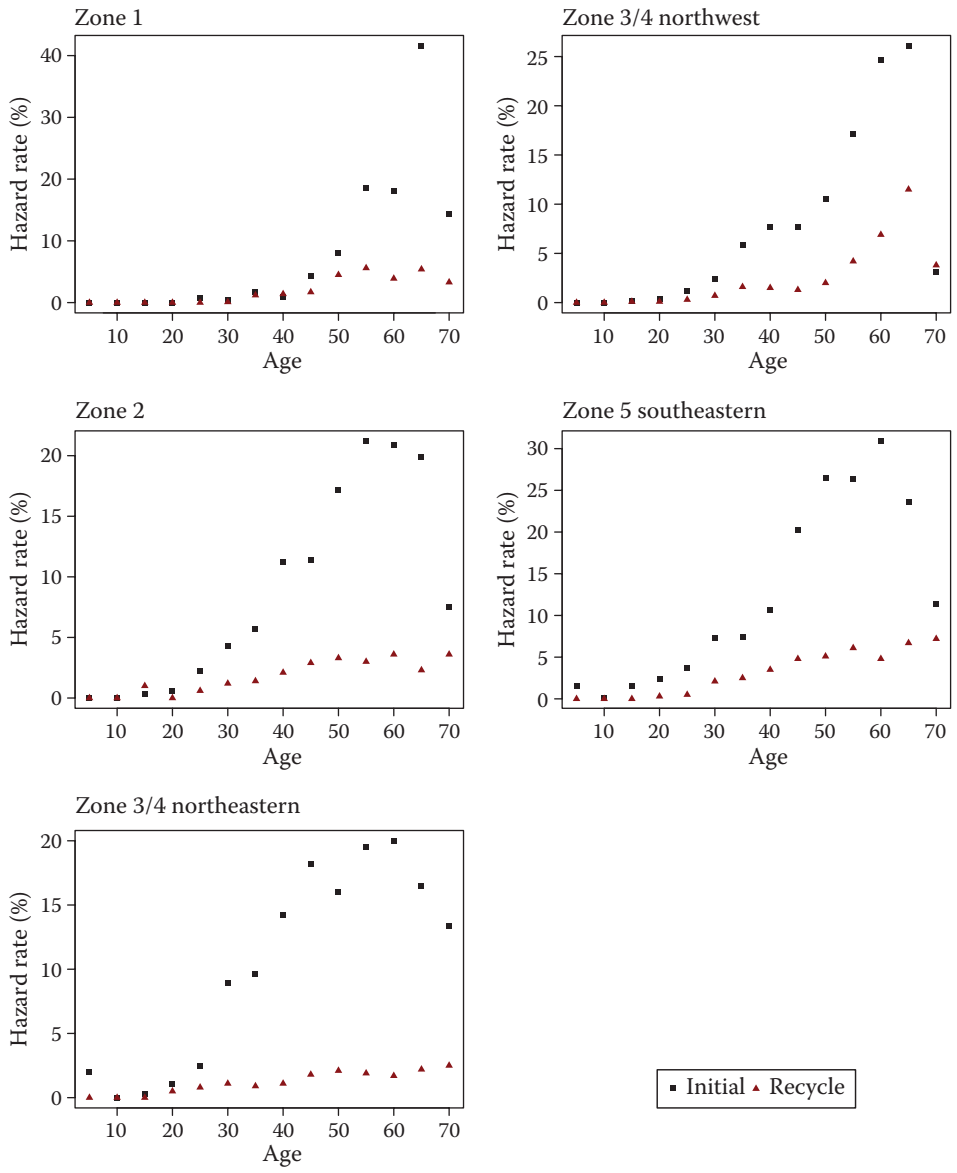

Figure 3.27 Pole inspection rejection rates as a function of pole age. (From EPRI 1012500, *Guidelines for Intelligent Asset Replacement: Volume 4: Wood Poles (Expanded Edition)*, Electric Power Research Institute, Palo Alto, CA, 2006. Copyright 2006. Reprinted with permission.)

From the inspection data, it is possible to estimate failure rates as a function of pole age and region. These failure rates or "hazard curves" are developed differently for different inspection types.

We also need to be careful about what type of failure rates we are looking for. Some possibilities are

- *Decayed*—The rate at which poles turn from the state of "good" to the state of "decayed." The states of "good" and "decayed" are determined by inspections.
- *Rejected*—The rate at which poles turn to the state of "rejected." Once rejected, the pole will normally be replaced or reinforced. One can actually have two hazard rates here: (1) the rate at which poles become rejected when either good or decayed or (2) the rate at which poles become rejected when decayed.
- *Failed*—The rate at which poles actually break or are otherwise removed from the system.

The normal progression is *decayed* → *rejected* → *failed*.

Figure 3.28 shows estimates of failure rates with age using the data in Figure 3.27. These are estimates with treatment and without treatment.

The "with treatment" estimates are based on initial pole inspections, which are censored survey data. Poles that pass an inspection are right censored, meaning that the pole will become "rejected" at some age after the inspection time. Poles that fail an inspection are left censored, meaning that they became "rejected" at some age before the inspection time. This is sometimes called doubly censored survey data. Both Meeker and Escobar (1988) and Nelson (1982) describe this problem well. A crude estimate of the survival curve for pole rejections is

$$S_i = 1 - r_i/n_i$$

where

r_i = number of rejections of poles within a given age range
n_i = number of poles within a given age range

This should be an ever-decreasing function. Hazard functions can be found from survival curves using

$$\lambda = -\frac{d}{dt}\log(S)$$

Nelson (1982) provides a more refined estimate of the cumulative hazard function by using maximum likelihoods.

The pole data in Figure 3.28 does not quite follow this. We should not expect the hazard function to decrease over time. What is missing is that rejection rates in the inspections are missing some data. Consider the set of poles inspected at age 50. The estimate of the survival rate is the number of poles that passed the inspection divided by all poles within that age group. This would be an appropriate estimate if the set of poles inspected included all poles of age 50. What is missing from the set is poles that were installed 50 years previously, became decayed, and failed or were otherwise removed because of decay. These are missing from the inspections because they are no longer in the field. The portion of poles removed would tend to become bigger with age, so this explains why the hazard rates level off or start to reduce with age. To account for this factor, use only the hazard curve up to the point

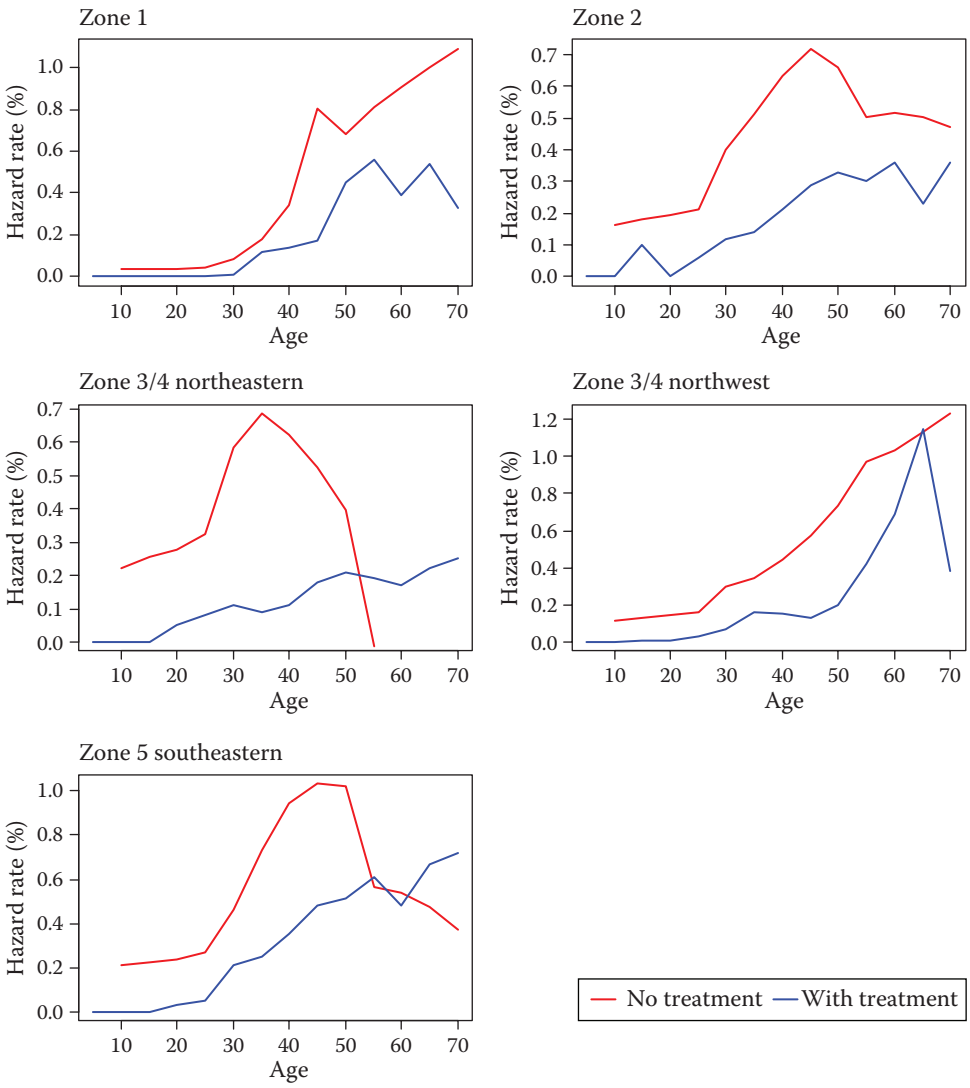

Figure 3.28 Estimates of pole failure rates. (From EPRI 1012500, *Guidelines for Intelligent Asset Replacement: Volume 4: Wood Poles (Expanded Edition)*, Electric Power Research Institute, Palo Alto, CA, 2006. Copyright 2006. Reprinted with permission.)

where it starts to level off or reduce. It is unknown what it really does beyond the point where failures become significant, but you could linearly extrapolate beyond that kneepoint.

The data also includes rejection rates on the second inspection. This is interval-censored inspection data. If we take poles that passed inspection at age 30 and were inspected again at age 40, those that passed at age 40 are right censored, and those that failed the inspection at age 40 are interval censored (they became "rejected" sometime between age 30 and age 40). With interval-censored data, we can directly

estimate the hazard function by breaking the data into groups by age and time between the first and second inspection:

$$\lambda = r_i/n_i/t$$

where

r_i = number of rejections of poles within a given age range and time between inspections
n_i = number of poles within a given age range
t = time between the first and second inspections

With the data in Figure 3.27, we do not know the time between inspections. The results in Figure 3.28 are based on a 10-year interval (it is probably between 10 and 15 years).

Having a better knowledge of pole performance can be used to try to optimize pole inspection and maintenance programs (EPRI 1012500, 2006).

3.6 Hardening and Resiliency

The impact of major storm events has increased focus on hardening distribution infrastructure and make it more "resilient" to major events. The options for utilities to improve resiliency include overhead improvements, undergrounding, more automation, and expanded vegetation management. For overhead improvements, options include stronger-class poles, concrete or steel poles, enhanced guying, more aggressive pole inspection and treatment, breakaway connectors on service drops, pole-top refurbishments, reconductoring with covered conductors, and design for NESC extreme wind conditions. Most programs implement changes based on new construction or are targeted at certain parts of the system, such as mainlines.

Hardening and resiliency sometimes require different focus than normal utility reliability programs. During major storm events, damage is more severe and repair costs increase. See Table 3.10 for storm damage from several different types of storm events in Connecticut (CT PURA, 2013). In larger storm events, both costs and damage increase. For example, in hurricane Sandy, one pole was replaced for every six outage events, but for typical thunderstorms, this ratio was one pole replaced for every 25 to 45 outage events. Overhead structure resiliency programs focus on reducing major damage such as pole breakage that is more common in larger events.

The industry has only a few examples of correlations between damage and overhead construction characteristics. For hurricane events, Brown (2008) found that the rates of pole failures increased exponentially with storm category for Florida Power and Light. Brown found little solid evidence for performance difference based on pole treatment type (creosote or CCA) during Wilma, an event that caused mainly wind-only damage. Mainline pole failure rates were more than twice that of poles on lateral taps, suggesting that mainlines are more vulnerable to wind events, possibly due to higher loading from conductors, pole-top equipment, and/or third-party

TABLE 3.10 Damage and Costs for Connecticut Light and Power for Several Storms

	June-2011 Storm	Storm Irene	October Nor'easter	September-2012 Storm	Storm Sandy
Storm date	6/8/2011	8/27/2011	10/29/2011	9/18/2012	10/29/2012
Storm type	Thunderstorm	Tropical storm	Nor'easter	Thunderstorm	Hurricane
Customer outages	209,045	1,024,032	1,438,797	80,575	856,184
Outage events	2603	16,101	25,475	1483	16,460
Transformers replaced	332	1748	1964	111	2198
Poles replaced	95	1297	1655	33	2763
Crossarms replaced	438	3204	5590	126	4745
Cost per customer outage	$52	$109	$122	$114	$182
Cost per outage event	$4187	$6906	$6873	$6204	$9478

Source: Data from CT PURA, *Petition of the Connecticut Light and Power Company for Approval to Recover Its 2011–2012 Major Storm Costs, Joint Testimony of William J. Quinlan and Kenneth B. Bowes*, State of Connecticut Public Utilities Regulatory Authority, 2013.

attachments. He also noted a surprisingly high failure rate for concrete poles, being only 30% lower than that for wood poles.

Trees causing mechanical damage make up a large portion of tree-caused outages, especially during major storms, and these are the faults that require the most time and expense be repaired. One approach to reducing the impact of damage from trees is to coordinate the mechanical design such that when tree and large limb failures occur, the equipment fails in a manner that is easier for crews to repair. When a tree falls on a line, crews will have an easier repair if it just breaks the conductors off of insulators rather than breaking poles and other supports. The fault still occurs, but crews are able to more quickly repair the damage and restore service. Figure 3.29 shows an example of a hard-to-repair failure; if the conductors or insulator ties had broken first, the poles may have been left standing, and crews would have been able to repair it more quickly.

The role of telecom attachments is also important to consider as these add extra wind loading and weight to the existing structures. They also provide an anchoring point at which poles tend to break as in the example in Figure 3.29.

Spacer cable systems are an example that can cause a mechanical "miscoordination." Spacer cable systems are quite strong, so they withstand some tree branch contact that an open-wire system would not. But, the spacer cable is strong enough that the conductors are less likely to be the weakest link. When a heavy tree does fall on the line, the spacer cable can break poles, leading to a much longer repair time.

Kaempffer and Wong (1996) describe an approach to overhead structure design that considers the order of failure of equipment. Yu et al. (1995) developed methodologies for calculating conductor tensions under the stress of a large concentrated

Figure 3.29 Example of a pole broken by a tree in a large wind storm.

load (the falling tree or branch). With the tension information, they use a probabilistic approach to determining failures of components. Each component's probability of failure is used to rank the likelihood of failure of each component. Then, once the weakest member is determined to fail, the stresses and probabilities are recalculated for the remaining components to determine what might fail next. This provides a sequence of failures for a given design. Kaempffer and Wong used this analytical approach to analyze several of BC Hydro's standard designs and found the following general results:

- Neither pole species, pole length, or pole classes affected results.
- Trees falling near midspan and those falling near a pole were similar.
- For tangent structures, with #2 ACSR, the phase and neutral failed first when a tree fell on either conductor. For 336.4-kcmil ACSR, the pole tended to fail first.
- For angle structures, the guy grip for the phase and the tie wire for the neutral usually failed first.
- For deadend structures, the guy grip tended to fail first.

Although this method of distribution design is not widely used, mechanical coordination should be given consideration in designing distribution structures to make them easier to repair during storms. The choice of conductor (AAC versus ACSR) also plays a role. In some applications, ACSR may be strong enough to move the weakest link to a harder-to-repair supporting structure.

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They quit respecting us when we got soft and started using bucket trucks and now anybody can become a lineman, it is sick.

In response to: Do linemen feel they are respected by management and coworkers for the jobs they are doing, do management and coworkers understand what you do?

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4

Underground Distribution

Contents

4.1 Applications 137
4.1.1 Underground Residential Distribution 138
4.1.2 Main Feeders 140
4.1.3 Urban Systems 141
4.1.4 Overhead versus Underground 141
4.2 Cables 144
4.2.1 Cable Insulation 145
4.2.2 Conductors 149
4.2.3 Neutral or Shield 149
4.2.4 Semiconducting Shields 151
4.2.5 Jacket 152
4.3 Installations and Configurations 153
4.4 Impedances 156
4.4.1 Resistance 156
4.4.2 Impedance Formulas 159
4.4.3 Impedance Tables 164
4.4.4 Capacitance 167
4.5 Ampacity 169
4.6 Fault Withstand Capability 180
4.7 Cable Reliability 182
4.7.1 Water Trees 182
4.7.2 Other Failure Modes 186
4.7.3 Failure Statistics 187
4.8 Cable Testing 191
4.9 Fault Location 193
References 197

Much of the new distribution is underground. Underground distribution is much more hidden from view than overhead circuits, and is more reliable. Cables, connectors, and installation equipment have advanced considerably in the last quarter of the twentieth century, making underground distribution installations faster and less expensive.

4.1 Applications

One of the main applications of underground circuits is for underground residential distribution (URD), underground branches or loops supplying residential neighborhoods. Utilities also use underground construction for substation exits

TABLE 4.1 Comparison of Costs of Different Underground Constructions at Different Utilities

Utility	Construction	$/ft[a]
TAU	Rural or urban, 1 phase, #2 Al, 25 kV, trenched, direct buried	6.7
	Rural, 3 phase, #2 Al, 25 kV, trenched, direct buried	13.4
	Urban commercial, 3 phase, #2 Al, 25 kV, trenched, direct buried	13.4
	Urban express, 3 phase, 500-kcmil Al, 25 kV, trenched, direct buried	23.5
WH	Urban, 1 phase, 1/0 Al, 12.5 kV, trenched, conduit	84.1
	Urban commercial, 3 phase, 1/0 Al, 12.5 kV, trenched, conduit	117.7
	Urban express, 3 phase, 500-kcmil Cu, 12.5 kV, trenched, conduit	277.4

Source: Data from CEA 274 D 723, *Underground versus Overhead Distribution Systems*, Canadian Electrical Association, 1992.

[a]Converted assuming that one 1991 Canadian dollar equals 1.1 U.S. dollars in 2000.

and drops to padmounted transformers serving industrial or commercial customers. Other uses are crossings: river crossings, highway crossings, or transmission line crossings. All-underground construction—widely used for decades in cities—now appears in more places.

Underground construction is expensive, and costs vary widely. Table 4.1 shows extracts from one survey of costs done by the CEA; the two utilities highlighted differ by a factor of 10. The main factors that influence underground costs are:

- *Degree of development*—Roads, driveways, sidewalks, and water pipes—these and other obstacles slow construction and increase costs.
- *Soil condition*—Rocks and frozen ground increase overtime pay for cable crews.
- *Urban, suburban, or rural*—Urban construction is more difficult not only because of concrete, but also because of traffic. Rural construction is generally the least expensive per length, but lengths are long.
- *Conduit*—Concrete-encased ducts cost more than direct-buried conduits, which cost more than preassembled flexible conduit, which cost more than directly buried cable with no conduits.
- *Cable size and materials*—The actual cable cost is relatively a smaller part of many underground applications. A 1/0 aluminum full-neutral 220-mil TR-XLPE cable costs just under $2 per ft; with a 500-kcmil conductor and a one-third neutral, the cable costs just under $4 per ft.
- *Installation equipment*—Bigger machines and machines more appropriate for the surface and soil conditions ease installations.

4.1.1 Underground Residential Distribution

A classic URD circuit is an underground circuit in a loop arrangement fed at each end from an overhead circuit (see Figure 4.1). The loop arrangement allows utilities to restore customers more quickly; after crews find the faulted section, they can reconfigure the loop and isolate any failed section of cable. This returns power to all customers. Crews can delay replacing or fixing the cable until a more convenient time

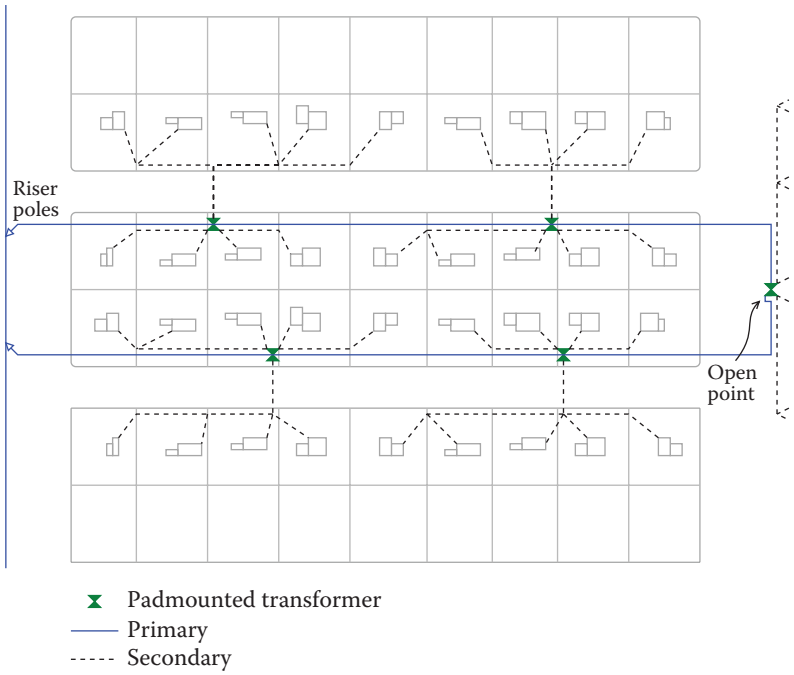

Figure 4.1 An example front-lot URD system.

or when suitable equipment arrives. Not all URD is configured in a loop. Utilities sometimes use purely radial circuits or circuits with radial taps or branches.

Padmounted transformers step voltage down for delivery to customers and provide a sectionalizing point. The elbow connectors on the cables (pistol grips) attach to bushings on the transformer to maintain a dead-front—no exposed, energized conductors. To open a section of cable, crews can simply pull an elbow off of the transformer bushing and place it on a parking stand, which is an elbow bushing meant for holding an energized elbow connector.

Elbows and other terminations are available with continuous-current ratings of 200 or 600 A (IEEE Std. 386-1995). Load-break elbows are designed to break load; these are only available in 200-A ratings. Without load-break capability, crews should of course only disconnect the elbow if the cable is deenergized. Elbows normally have a test point where crews can check if the cable is live. Elbows are also tested to withstand 10 cycles of fault current, with 200-A elbows tested at 10 kA and 600-A elbows tested at 25 kA (IEEE Std. 386-1995).

The interface between the overhead circuit and the URD circuit is the riser pole. At the riser pole (or a dip pole or simply a dip), cable terminations provide the interface between the insulated cable and the bare overhead conductors. These pothead terminations grade the insulation to prevent excessive electrical stress on the insulation. Potheads also keep water from entering the cable, which is critical for cable reliability. Also at the riser pole are expulsion fuses, normally in cutouts. Areas with high short-circuit current may also have current-limiting fuses. To keep lightning surges from

damaging the cable, the riser pole should have arresters right across the pothead with as little lead length as possible.

Underground designs for residential developments expanded dramatically in the 1970s. Political pressure coupled with technology improvements were the driving forces behind underground distribution. The main developments—direct-buried cables and padmounted transformers having load-break elbows—dramatically reduced the cost of underground distribution closer to that of overhead construction. In addition to improving the visual landscape, underground construction improves reliability. URD has had difficulties, especially high cable failure rates. In the late 1960s and early 1970s, given the durability of plastics, the polyethylene (PE) cables installed at that time were thought to have a life of at least 50 years. In practice, cables failed at a much higher rate than expected, enough so that many utilities had to replace large amounts of this cable.

According to Boucher (1991), 72% of utilities use front-lot designs for URD. With easier access and fewer trees and brush to clear, crews can more easily install cables along streets in the front of yards. Customers prefer rear-lot service, which hides padmounted transformers from view. Back-lot placement can ease siting issues and may be more economical if lots share rear property lines. But with rear-lot design, utility crews have more difficulty accessing cables and transformers for fault location, sectionalizing, and repair.

Of those utilities surveyed by Boucher (1991), 85% charge for underground residential service, ranging from $200 to $1200 per lot (1991 dollars). Some utilities charge by length, which ranges from $5.80 to $35.00 per ft.

4.1.2 Main Feeders

Whether urban, suburban, or even rural, all parts of a distribution circuit can be underground, including the main feeder. For reliability, utilities often configure an underground main feeder as a looped system with one or more tie points to other sources. Switching cabinets or junction boxes serve as tie points for tapping off lateral taps or branches to customers. These can be in handholes, padmounted enclosures, or pedestals above ground. Three-phase circuits can also be arranged much like URD with sections of cable run between three-phase padmounted transformers. As with URD, the padmounted transformers serve as switching stations.

Although short, many feeders have an important underground section—the substation exit. Underground substation exits make substations easier to design and improve the aesthetics of the substation. Because they are at the substation, the source of a radial circuit, substation exits are critical for reliability. In addition, the loading on the circuit is higher at the substation exit than anywhere else; the substation exit may limit the entire circuit's ampacity. Substation exits are not the place to cut corners. Some strategies to reduce the risks of failures or to speed recovery are: concrete-enclosed ducts to help protect cables, spare cables, overrated cables, and good surge protection.

While not as critical as substation exits, utilities use similar three-phase underground dips to cross large highways or rivers or other obstacles. These are designed in much the same way as substation exits.

4.1.3 Urban Systems

Underground distribution has reliably supplied urban systems since the early 1900s. Cables are normally installed in concrete-encased duct banks beneath streets, sidewalks, or alleys. A duct bank is a group of parallel ducts, usually with four to nine ducts but often many more. Ducts may be precast concrete sections or PVC encased in concrete. Duct banks carry both primary and secondary cables. Manholes every few hundred feet provide access to cables. Transformers are in vaults or in the basements of large buildings.

Paper-insulated lead-covered (PILC) cables dominated urban applications until the late twentieth century. Although a few utilities still install PILC, most use extruded cable for underground applications. In urban applications, copper is more widely used than in suburban applications. Whether feeding secondary networks or other distribution configurations, urban circuits may be subjected to heavy loads.

"Vertical" distribution systems are necessary in very tall buildings. Medium-voltage cable strung up many floors feed transformers within a building. Submarine cables are good for this application since their protective armor wire provides support when a cable is suspended for hundreds of feet.

4.1.4 Overhead versus Underground

Overhead or underground? The debate continues. Both designs have advantages (see Table 4.2). The major advantage of overhead circuits is cost; an underground circuit typically costs anywhere from 1 to 2.5 times the equivalent overhead circuit (see Table 4.3). But the cost differences vary wildly, and it's often difficult to define "equivalent" systems in terms of performance. Under the right conditions, some

TABLE 4.2 Overhead versus Underground: Advantages of Each

Overhead	Underground
Cost—Overhead's number one advantage. Significantly less cost, especially initial cost.	*Aesthetics*—Underground's number one advantage. Much less visual clutter.
Longer life—30 to 50 years vs. 20 to 40 for new underground works.	*Safety*—Less chance for public contact.
Reliability—Shorter outage durations because of faster fault finding and faster repair.	*Reliability*—Significantly fewer short- and long-duration interruptions.
Loading—Overhead circuits can more readily withstand overloads.	*O&M*—Notably lower maintenance costs (no tree trimming).
	Longer reach—Less voltage drop because reactance is lower.

TABLE 4.3 Comparison of Underground Construction Costs with Overhead Costs

Utility		Construction	$/ft[a]	Underground-to-Overhead Ratio
Single-Phase Lateral Comparisons				
NP	Overhead	1/0 AA, 12.5 kV, phase and neutral	8.4	
NP	Underground	1/0 AA, 12.5 kV, trenched, in conduit	10.9	1.3
APL	Overhead	Urban, #4 ACSR, 14.4 kV	2.8	
APL	Underground	Urban, #1 AA, 14.4 kV, trenched, direct buried	6.6	2.4
Three-Phase Mainline Comparisons				
NP	Overhead	Rural, 4/0 AA, 12.5 kV	10.3	
NP	Underground	Rural, 1/0 AA, 12.5 kV, trenched, in conduit	17.8	1.7
NP	Overhead	Urban, 4/0 AA, 12.5 kV	10.9	
NP	Underground	Urban, 4/0 AA, 12.5 kV, trenched, in conduit	17.8	1.6
APL	Overhead	Urban, 25 kV, 1/0 ACSR	8.5	
APL	Underground	Urban, 25 kV, #1 AA, trenched, direct buried	18.8	2.2
EP	Overhead	Urban, 336 ACSR, 13.8 kV	8.7	
EP	Underground	Urban residential, 350 AA, 13.8 kV, trenched, direct buried	53.2	6.1
EP	Underground	Urban commercial, 350 AA, 13.8 kV, trenched, direct buried	66.8	7.6

Source: Data from CEA 274 D 723, *Underground versus Overhead Distribution Systems*, Canadian Electrical Association, 1992.

[a]Converted assuming that one 1991 Canadian dollar equals 1.1 U.S. dollars in 2000.

estimates of cost report that cable installations can be less expensive than overhead lines. If the soil is easy to dig, if the soil has few rocks, if the ground has no other obstacles like water pipes or telephone wires, then crews may be able to plow in cable faster and for lesser cost than an overhead circuit. In urban areas, underground is almost the only choice; too many circuits are needed, and above-ground space is too expensive or just not available. But urban duct-bank construction is expensive on a per-length basis (fortunately, circuits are short in urban applications). On many rural applications, the cost of underground circuits is difficult to justify, especially on long, lightly loaded circuits, given the small number of customers that these circuits feed.

Aesthetics is the main driver toward underground circuits. Especially in residential areas, parks, wildlife areas, and scenic areas, visual impact is important. Undergrounding removes a significant amount of visual clutter. Overhead circuits are ugly. It is possible to make overhead circuits less ugly with tidy construction practices, fiberglass poles instead of wood, keeping poles straight, tight conductor configurations, joint use of poles to reduce the number of poles, and so on. Even the best though, are still ugly, and many older circuits look awful (weathered poles tipped at odd angles, crooked crossarms, rusted transformer tanks, etc.).

Underground circuits get rid of all that mess, with no visual impacts in the air. Trees replace wires, and trees don't have to be trimmed. At ground level, instead of poles every 150 ft (many having one or more guy wires) urban construction has no obstacles, and URD-style construction has just padmounted transformers spaced much less frequently. Of course, for maximum benefit, all utilities must be underground. There is little improvement to undergrounding electric circuits if phone and cable television are still strung on poles (i.e., if the telephone wires are overhead, you might as well have the electric lines there, too).

While underground circuits are certainly more appealing when finished, during installation construction is messier than overhead installation. Lawns, gardens, sidewalks, and driveways are dug up; construction lasts longer; and the installation "wounds" take time to heal. These factors don't matter much when installing circuits into land that is being developed, but it can be upsetting to customers in an existing, settled community.

Underground circuits are more reliable. Overhead circuits typically fault about 90 times/100 mi/year; underground circuits fail less than 10 times/100 mi/year. Because overhead circuits have more faults, they cause more voltage sags, more momentary interruptions, and more long-duration interruptions. Even accounting for the fact that most overhead faults are temporary, overhead circuits have more permanent faults that lead to long-duration circuit interruptions. The one disadvantage of underground circuits is that when they do fail, finding the failure is harder, and fixing the damage or replacing the equipment takes longer. This can partially be avoided by using loops capable of serving customers from two directions, by using conduits for faster replacement, and by using better fault location techniques. Underground circuits are much less prone to the elements. A major hurricane may drain an overhead utility's resources, crews are completely tied up, customer outages become very long, and cleanup costs are a major cost to utilities. However, underground circuits are not totally immune from the elements. In "heat storms," underground circuits are prone to rashes of failures. Underground circuits have less overload capability than overhead circuits; failures increase with operating temperature.

In addition to less storm cleanup, underground circuits require less periodic maintenance. Underground circuits don't require tree trimming, easily the largest fraction of most distribution operations and maintenance budgets. The CEA (1992) estimated that underground system maintenance averaged 2% of system plant investment whereas overhead systems averaged 3 to 4%, or as much as twice that of underground systems.

Underground circuits are safer to the public than overhead circuits. Overhead circuits are more exposed to the public. Kites, ladders, downed wires, truck booms—despite the best public awareness campaigns, these still expose the public to electrocution from overhead lines. Don't misunderstand; underground circuits still have dangers, but they're much lesser than on overhead circuits. For the public, dig-ins are the most likely source of contact. For utility crews, both overhead and underground circuits offer dangers that proper work practices must address to minimize risks.

We cannot assume that underground infrastructure will last as long as overhead circuits. Early URD systems failed at a much higher rate than expected. While most

experts believe that modern underground equipment is more reliable, it is still prudent to believe that an overhead circuit will last 40 years, while an underground circuit will only last 30 years.

Overhead versus underground is not an all or nothing proposition. Many systems are hybrids; some schemes are

- *Overhead mainline with underground taps*—The larger, high-current conductors are overhead. If the mains are routed along major roads, they have less visual impact. Lateral taps down side roads and into residential areas, parks, and shopping areas are underground. Larger primary equipment like regulators, reclosers, capacitor banks, and automated switches are installed where they are more economical—on the overhead mains. Because the mainline is a major contributor to reliability, this system is still less reliable than an all-underground system.
- *Overhead primary with underground secondary*—Underground secondary eliminates some of the clutter associated with overhead construction. Eliminating much of the street and yard crossings keeps the clutter to the pole-line corridor. Costs are reasonable because the primary-level equipment is still all overhead.

Converting from overhead to underground is costly, yet there are locations and situations where it is appropriate for utilities and their customers. Circuit extensions, circuit enhancements to carry more load, and road-rebuilding projects—all are opportunities for utilities and communities to upgrade to underground service.

4.2 Cables

At the center of a cable is the phase conductor, then comes a semiconducting conductor shield, the insulation, a semiconducting insulation shield, the neutral or shield, and finally a covering jacket. Most distribution cables are single conductors. Two main types of cable are available: concentric-neutral cable and power cable. Concentric-neutral cable normally has an aluminum conductor, an extruded insulation, and a concentric neutral (Figure 4.2 shows a typical construction). A concentric neutral is made from several copper wires wound concentrically around the insulation; the concentric neutral is a true neutral, meaning it can carry return current on a grounded system. URD normally has concentric-neutral cables; concentric-neutral cables are also used for three-phase mainline applications and three-phase power delivery to commercial and industrial customers. Because of their widespread use in URD, concentric-neutral cables are often called URD cables. Power cable has a copper or aluminum phase conductor, an extruded insulation, and normally a thin copper tape shield. On utility distribution circuits, power cables are typically used for mainline feeder applications, network feeders, and other high current, three-phase applications. Many other types of medium-voltage cable are available. These are sometimes appropriate for distribution circuit application: three-conductor power cables, armored cables, aerial cables, fire-resistant cables, extra flexible cables, and submarine cables.

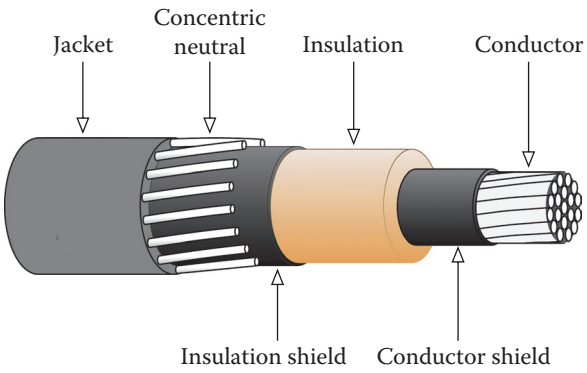

Figure 4.2 A concentric neutral cable, typically used for underground residential power delivery.

4.2.1 Cable Insulation

A cable's insulation holds back the electrons; the insulation allows cables with a small overall diameter to support a conductor at significant voltage. A 0.175-in. (4.5-mm) thick polymer cable is designed to support just over 8 kV continuously; that's an average stress of just under 50 kV per in. (20 kV/cm). In addition to handling significant voltage stress, insulation must withstand high temperatures during heavy loading and during short circuits and must be flexible enough to work with. For much of the twentieth century, paper insulation dominated underground application, particularly PILC cables. The last 30 years of the twentieth century saw the rise of polymer-insulated cables, PE-based insulations starting with high-molecular weight polyethylene (HMWPE), then cross-linked polyethylene (XLPE), then tree-retardant XLPE and also ethylene–propylene rubber (EPR) compounds.

Table 4.4 compares properties of TR-XLPE, EPR, and other insulation materials. Some of the key properties of cable insulation are

- *Dielectric constant* (ε, also called permittivity)—This determines the cable's capacitance: the dielectric constant is the ratio of the capacitance with the insulation material to the capacitance of the same configuration in free space. Cables with higher capacitance draw more charging current.
- *Volume resistivity*—Current leakage through the insulation is a function of the insulation's dc resistivity. Resistivity decreases as temperature increases. Modern insulation has such high resistivity that very little resistive current passes from the conductor through the insulation.
- *Dielectric losses*—Like a capacitor, a cable has dielectric losses. These losses are due to dipole movements within the polymer or by the movement of charge carriers within the insulation. Dielectric losses contribute to a cable's resistive leakage current. Dielectric losses increase with frequency and temperature and with operating voltage.

TABLE 4.4 Properties of Cable Insulations

	Dielectric Constant 20°C	Loss Angle Tan δ at 20°C	Volume Resistivity Ω-m	Annual Dielectric Loss[a] W/1000 ft	Unaged Impulse Strength V/mil	Water Absorption ppm
PILC	3.6	0.003	10^{11}	N/A	1000–2000	25
PE	2.3	0.0002	10^{14}	N/A		100
XLPE	2.3	0.0003	10^{14}	8	3300	350
TR-XLPE	2.4	0.001	10^{14}	10	3000	<300
EPR	2.7–3.3	0.005–0.008	10^{13}–10^{14}	28–599	1200–2000	1150–3200

Source: Adapted from EPRI 1001894, *EPRI Power Cable Materials Selection Guide*, EPRI, Palo Alto, CA, 2001. Copyright 2001. Reprinted with permission.

[a]For a typical 1/0 15-kV cable.

- *Dissipation factor* (also referred to as the loss angle, loss tangent, tan δ, and approximate power factor)—The dissipation factor is the ratio of the resistive current drawn by the cable to the capacitive current drawn (I_R/I_X). Because the leakage current is normally low, the dissipation factor is approximately the same as the power factor:

$$\text{pf} = I_R/|I| = I_R/\sqrt{I_R^2 + I_X^2} \approx I_R/I_X = \text{dissipation factor}$$

Paper-Insulated Lead-Covered Cables. Paper-insulated cables have provided reliable underground power delivery for decades. PILC cable has been the dominant cable configuration, used mainly in urban areas. PILC cables have kraft-paper tapes wound around the conductor that are dried and impregnated with insulating oil. A lead sheath is one of the best moisture blocks: it keeps the oil in and keeps water out. Paper cables are normally rated to 85°C with an emergency rating up to 105°C (EPRI TR-105502, 1995). PILC cables have held up astonishingly well; many 50-year-old cables are still in service with almost new insulation capability. While PILC has had very good reliability, some utilities are concerned about its present day failure, not because of bad design or application, but because the in-service stock is so old. Moisture ingress, loss of oil, and thermal stresses—these are the three main causes of PILC failure (EPRI 1000741, 2000). Water decreases the dielectric strength (especially when the cable is hot) and increases the dielectric losses (further heating the cable). Heat degrades the insulating capability of the paper, and if oil is lost, the paper's insulating capability declines. PILC use has declined but still not disappeared. Some utilities continue to use it, especially to supply urban networks. Utilities use less PILC because of its high cost, work difficulties, and environmental concerns. Splicing also requires significant skill, and working with the lead sheath requires environmental and health precautions.

Polyethylene. Most modern cables have polymer insulation extruded around the conductor—either PE derivatives or ethylene–propylene properties. PE is a tough, inexpensive polymer with good electrical properties. Most distribution cables made

since 1970 are based on some variation of PE. PE is an ethylene polymer, a long string or chain of connected molecules. In PE, some of the polymer chains align in crystalline regions, which give strength and moisture resistance to the material. Other regions have nonaligned polymer chains—these amorphous regions give the material flexibility but are permeable to gas and moisture and are where impurities are located. PE is a thermoplastic. When heated and softened, the polymer chains break apart (becoming completely amorphous); as it cools, the crystalline regions reform, and the material returns to its original state. PE naturally has high density and excellent electrical properties with a volume resistivity of greater than 10^{14} Ω-m and an impulse insulation strength of over 2700 V/mil.

High-Molecular Weight Polyethylene. HMWPE is PE that is stiffer, stronger, and more resistant to chemical attack than standard PE. Insulations with higher molecular weights (longer polymer chains) generally have better electrical properties. As with standard PE, HMWPE insulation is a thermoplastic rated to 75°C. PE softens considerably as temperature increases. Since plastics are stable and seem to last forever, when utilities first installed HMWPE in the late 1960s and early 1970s, utilities and manufacturers expected long life for PE cables. In practice, failure rates increased dramatically after as little as 5 years of service. The electrical insulating strength (the dielectric strength) of HMWPE was degraded by water treeing, an electrochemical degradation driven by the presence of water and voltage. PE also degrades quickly under partial discharges; once partial discharges start, they can quickly eat away the insulation. Because of high failure rates, HMWPE insulation is off the market now, but utilities still have many miles of this cable in the ground.

Cross-Linked Polyethylene. Cross-linking agents are added that form bonds between polymer chains. The cross-linking bonds interconnect the chains and make XLPE semi-crystalline and add stiffness. XLPE is a thermoset: the material is vulcanized (also called "cured"), irreversibly creating the cross-linking that sets when the insulation cools. XLPE has about the same insulation strengths as PE, is more rigid, and resists water treeing better than PE. Although not as bad as HMWPE, pre-1980s XLPE has proven susceptible to premature failures because of water treeing. XLPE has higher temperature ratings than HWMPE; cables are rated to 90°C under normal conditions and 130°C for emergency conditions.

Tree-Retardant Cross-Linked Polyethylene. This has adders to XLPE that slow the growth of water trees. Tree-retardant versions of XLPE have almost totally displaced XLPE in medium-voltage cables. Various compounds when added to XLPE reduce its tendency to grow water trees under voltage. These additives tend to slightly reduce XLPE's electrical properties, slightly increase dielectric losses, and slightly lower initial insulation strength (but much better insulation strength when aged). While there is no standard industry definition of TR-XLPE, different manufacturers offer XLPE compounds with various adders that reduce tree growth. The oldest and most widely used formulation was developed by Union Carbide (now Dow); their HFDA 4202 tree-retardant XLPE maintains its insulation strength better in accelerated aging tests (EPRI TR-108405-V1, 1997) and in field service (Katz and Walker, 1998) than standard XLPE.

Ethylene–Propylene Rubber. EPR compounds are polymers made from ethylene and propylene. Manufacturers offer different ethylene–propylene formulations,

which collectively are referred to as EPR. EPR compounds are thermoset, normally with a high-temperature steam curing process that sets cross-linking agents. EPR compounds have high concentrations of clay fillers that provide its stiffness. EPR is very flexible and rubbery. When new, EPR only has half of the insulation strength as XLPE, but as it ages, its insulation strength does not decrease nearly as much as that of XLPE. EPR is naturally quite resistant to water trees, and EPR has a proven reliable record in the field. EPR has very good high-temperature performance. Although soft, it deforms less at high temperature than XLPE and maintains its insulation strength well at high temperature (Brown, 1983). Most new EPR cables are rated to 105°C under normal conditions and to 140°C for emergency conditions, the MV-105 designation per UL Standard 1072. (Historically, both XLPE and EPR cables were rated to 90°C normal and 130°C emergency.) In addition to its use as cable insulation, most splices and joints are made of EPR compounds. EPR has higher dielectric losses than XLPE; depending on the particular formulation, EPR can have two to three times the losses of XLPE to over 10 times the losses of XLPE. These losses increase the cost of operation over its lifetime. While not as common or as widely used as XLPE in the utility market, EPR dominates for medium-voltage industrial applications.

TR-XLPE versus EPR: which to use? Of the largest investor-owned utilities 56% specify TR-XLPE cables, 24% specify EPR, and the remainder specify a mix (Dudas and Cochran, 1999). Trends are similar at rural cooperatives. In a survey of the co-ops with the largest installed base of underground cable, 42% specify TR-XLPE, 34% specify EPR, and the rest specify both (Dudas and Rodgers, 1999). When utilities specify both EPR and TR-XLPE, commonly EPR is used for 600-A three-phase circuits, and TR-XLPE is used for 200-A applications like URD. Each cable type has advocates. TR-XLPE is less expensive and has lower losses. EPR's main feature is its long history of reliability and water-tree resistance. EPR is also softer (easier to handle) and has a higher temperature rating (higher ampacity). Boggs and Xu (2001) show how EPR and TR-XLPE are becoming more similar: EPR compounds are being designed that have fewer losses; tree-retardant additives to XLPE make the cable more tree resistant at the expense of increasing its water absorption and slightly increasing losses.

Cables have a voltage rating based on the line-to-line voltage. Standard voltage ratings are 5, 8, 15, 25, and 35 kV. A single-phase circuit with a nominal voltage of 7.2 kV from line to ground must use a 15-kV cable, not an 8-kV cable (because the line-to-line voltage is 12.47 kV).

Within each voltage rating, more than one insulation thickness is available. Standards specify three levels of cable insulation based on how the cables are applied. The main factor is grounding and ability to clear line-to-ground faults in order to limit the overvoltage on the unfaulted phases. The standard levels are (AEIC CS5-94, 1994)

- *100% level*—Allowed where line-to-ground faults can be cleared quickly (at least within one minute); normally appropriate for grounded circuits
- *133% level*—Where line-to-ground faults can be cleared within one hour; normally can be used on ungrounded circuits

TABLE 4.5 Usual Insulation Thicknesses for XLPE or EPR Cables Based on Voltage and Insulation Level

	Insulation Thickness, mil (1 mil = 0.001 in. = 0.00254 cm)	
Voltage Rating, kV	100% Level	133% Level
8	115	140
15	175	220
25	260	320
35	345	420

Standards also define a 173% level for situations where faults cannot be cleared within one hour, but manufacturers typically offer the 100% and 133% levels as standard cables; higher insulation needs can be met by a custom order or going to a higher voltage rating. Table 4.5 shows standard insulation thicknesses for XLPE and EPR for each voltage level. In addition to protecting against temporary overvoltages, thicker insulations provide higher insulation to lightning and other overvoltages and reduce the chance of failure from water tree growth. For 15-kV class cables, Boucher (1991) reported that 59% of utilities surveyed in North America use 100% insulation (175-mil). At 25 and 35 kV, the surveyed utilities more universally use 100% insulation (88% and 99%, respectively). Dudas and Cochran (1999) report similar trends in a survey of practices of the 45 largest investor-owned utilities: at 15 kV, 69% of utilities specified 100% insulation; at 25 and 35 kV, over 99% of utilities specified 100% insulation.

4.2.2 Conductors

For URD applications, utilities normally use aluminum conductors; Boucher (1991) reported that 80% of utilities use aluminum (alloy 1350); the remainder, copper (annealed, soft). Copper is more prevalent in urban duct construction and in industrial applications. Copper has lower resistivity and higher ampacity for a given size; aluminum is less expensive and lighter. Cables are often stranded to increase their flexibility (solid conductor cables are available for less than 2/0). ASTM class B stranding is the standard stranding. Class C has more strands for applications requiring more flexibility. Each layer of strands is wound in an opposite direction. Table 4.6 shows diameters of available conductors.

4.2.3 Neutral or Shield

A cable's shield, the metallic barrier that surrounds the cable insulation, holds the outside of the cable at (or near) ground potential. It also provides a path for return

TABLE 4.6 Conductor Diameters

	Solid	Class B Stranding	
Size	Diameter, in.	Strands	Diameter, in.
24	0.0201	7	0.023
22	0.0253	7	0.029
20	0.032	7	0.036
19	0.035	7	0.041
18	0.0403	7	0.046
16	0.0508	7	0.058
14	0.0641	7	0.073
12	0.0808	7	0.092
10	0.1019	7	0.116
9	0.1144	7	0.13
8	0.1285	7	0.146
7	0.1443	7	0.164
6	0.162	7	0.184
5	0.1819	7	0.206
4	0.2043	7	0.232
3	0.2294	7	0.26
2	0.2576	7	0.292
1	0.2893	19	0.332
1/0	0.3249	19	0.373
2/0	0.3648	19	0.419
3/0	0.4096	19	0.47
4/0	0.46	19	0.528
250		37	0.575
300		37	0.63
350		37	0.681
400		37	0.728
500		37	0.813
600		61	0.893
750		61	0.998
1000		61	1.152
1250		91	1.289
1500		91	1.412
1750		127	1.526
2000		127	1.632
2500		127	1.824

current and for fault current. The shield also protects the cable from lightning strikes and from current from other fault sources. The metallic shield is also called the *sheath*.

A concentric neutral—a shield capable of carrying unbalanced current—has copper wires wound helically around the insulation shield. The concentric neutral is expected to carry much of the unbalanced load current, with the earth carrying the

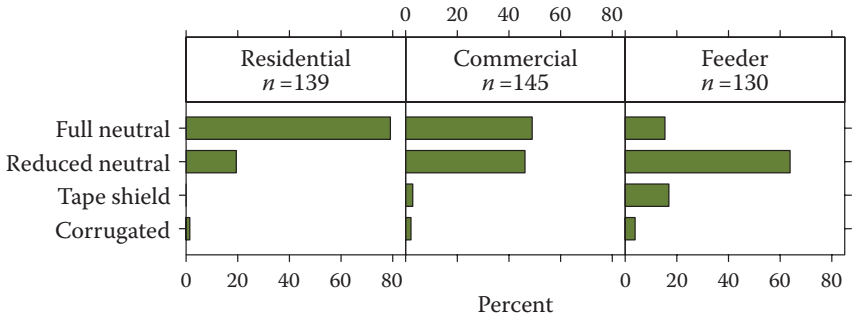

Figure 4.3 Surveyed utility use of cable neutral configurations for residential, commercial, and feeder applications. (Data from Boucher, R., A summary of the regional underground distribution practices for 1991, Regional Underground Distribution Practices, IEEE paper 91 TH0398-8-PWR, 1991.)

rest. For single-phase cables, utilities normally use a "full neutral," meaning that the resistance of the neutral equals that of the phase conductor. Also common is a "one-third neutral," which has a resistance that is three times that of the phase conductor. In a survey of underground distribution practices, Boucher (1991) reported that full neutrals dominated for residential application, and reduced neutrals are used more for commercial and feeder applications (see Figure 4.3).

Power cables commonly have 5-mil thick copper tape shields. These are wrapped helically around the cable with some overlap. In a tape-shield cable, the shield is not normally expected to carry unbalanced load current. As we will see, there is an advantage of having a higher resistance shield: the cable ampacity can be higher because there is less circulating current. Shields are also available that are helically wound wires (like a concentric neutral but with smaller wires).

Whether wires or tapes, cable shields and neutrals are copper. Aluminum corrodes too quickly to perform well in this function. Early unjacketed cables normally had a coating of lead–tin alloy to prevent corrosion. Cable neutrals still corroded. Dudas (1994) reports that in 1993, 84% of utilities specified a bare copper neutral rather than a coated neutral.

The longitudinally corrugated (LC) shield improves performance for fault currents and slows down water entry. The folds of a corrugated copper tape are overlapped over the cable core. The overlapping design allows movement and shifting while also slowing down water entry. The design performs better for faults because it is thicker than a tape shield, so it has less resistance, and it tends to distribute current throughout the shield rather than keeping it in a few strands.

4.2.4 Semiconducting Shields

In this application, semiconducting means "somewhat conducting": the material has some resistance (limited to a volume resistivity of 500 Ω-m [ANSI/ICEA S-94-649-2000, 2000; ANSI/ICEA S-97-682-2000, 2000]), more than the conductor and less than the

insulation. Semiconducting does not refer to nonlinear resistive materials like silicon or metal oxide; the resistance is fixed; it does not vary with voltage. Also called screens or semicons, these semiconducting shields are normally less than 80 mil. The resistive material evens out the electric field at the interface between the phase conductor and the insulation and between the insulation and the neutral or shield. Without the shields, the electric field gradient would concentrate at the closest interfaces between a wire and the insulation; the increased localized stress could break down the insulation. The shields are made by adding carbon to a normally insulating polymer like EPR or PE or XLPE. The conductor shield is normally about 20 to 40 mil thick; the insulation shield is normally about 40 to 80 mil thick. Thicker shields are used on larger diameter cables.

Semiconducting shields are important for smoothing out the electric field, but they also play a critical role in the formation of water trees. The most dangerous water trees are vented trees, those that start at the interface between the insulation and the semiconducting shield. Treeing starts at voids and impurities at this boundary. "Supersmooth" shield formulations have been developed to reduce vented trees (Burns, 1990). These mixtures use finer carbon particles to smooth out the interface. Under accelerated aging tests, cables with supersmooth semiconducting shields outperformed cables with standard semiconducting shields.

Modern manufacturing techniques can extrude the semiconducting conductor shield, the insulation, and the semiconducting insulation shield in one pass. Using this *triple* extrusion provides cleaner, smoother contact between layers than extruding each layer in a separate pass.

A note on terminology: a *shield* is the conductive layer surrounding another part of the cable. The conductor shield surrounds the conductor; the insulation shield surrounds the insulation. Used generically, shield refers to the metallic shield (the sheath). Commonly, the metallic shield is called the neutral, the shield, or the sheath. Sometimes, the sheath is used to mean the outer part of the cable, whether conducting or not conducting.

4.2.5 Jacket

Almost all new cables are jacketed, and the most common jacket is an encapsulating jacket (it is extruded between and over the neutral wires). The jacket provides some (but not complete) protection against water entry. It also provides mechanical protection for the neutral. Common LLDPE jackets are 50 to 80 mil thick.

Bare cable, used frequently in the 1970s, had a relatively high failure rate (Dedman and Bowles, 1990). Neutral corrosion was often cited as the main reason for the higher failure rate. At sections with a corroded neutral, the ground return current can heat spots missing neutral strands. Dielectric failure, not neutral corrosion, is still the dominant failure mode (Gurniak, 1996). Without the jacket, water enters easily and accelerates water treeing, which leads to premature dielectric failure.

Several materials are used for jackets. Polyvinyl chloride (PVC) was one of the earliest jacketing materials and is still common. The most common jacket material is

made from linear low-density polyethylene (LLDPE). PVC has good jacketing properties, but LLDPE is even better in most regards: mechanical properties, temperature limits, and water entry. Moisture passes through PVC jacketing more than 10 times faster than it passes through LLDPE. LLDPE starts to melt at 100°C; PVC is usually more limited, depending on composition. Low-density PE resists abrasion better and also has a lower coefficient of friction, which makes it easier to pull through conduit.

Semiconducting jackets are also available. Semiconducting jackets provide the grounding advantages of unjacketed cable, while also blocking moisture and physically protecting the cable. When direct buried, an exposed neutral provides an excellent grounding conductor. The neutral in contact with the soil helps improve equipment grounding and improves protection against surges. A semiconducting jacket has a resistivity equivalent to most soils (less than 100 Ω-m), so it transfers current to the ground the same as an unjacketed cable. NRECA (1993) recommends not using a semiconducting jacket for two reasons. First, semiconducting jackets let more water pass through than LLDPE jackets. Second, the semiconducting jacket could contribute to corrosion. The carbon in the jacket (which makes the jacket semiconducting) is galvanic to the neutral and other nearby metals; especially with water in the cable, the carbon accelerates neutral corrosion. Other nearby objects in the ground such as ground rods or pipes can also corrode more rapidly from the carbon in the jacket.

4.3 Installations and Configurations

Just as there are many different soil types and underground applications, utilities have many ways to install underground cable. Some common installation methods include [see NRECA RER Project 90-8 (1993) for more details]

- *Trenching*—This is the most common way to install cables, either direct-buried or cables in conduit. After a trench is dug, the cable is installed, backfill is added and tamped, and the surface is restored. A trenching machine with different cutting chains is available for use on different soils. Backhoes also help with trenching.
- *Plowing*—A cable plow blade breaks up and lifts the earth as it feeds a cable into the furrow. Plowing eliminates backfilling and disturbs the surface less than trenching. NRECA reports that plowing is 30 to 50% less expensive than trenching (NRECA RER Project 90-8, 1993). Plowed cables may have lower ampacity because of air pockets between the cable and the loose soil around the cable. Heat cannot transfer as effectively from the cable to the surrounding earth.
- *Boring*—A number of tunneling technologies are available to drill under roads or even over much longer distances with guided, fluid-assisted drill heads.

Utilities also have a number of installation options, each with tradeoffs:

- *Direct buried*—Cables are buried directly in the earth. This is the fastest and least expensive installation option. Its major disadvantage is that cable replacement or repair is difficult.

- *Conduit*—Using conduit allows for quicker replacement or repair. Rigid PVC conduit is the most common conduit material; steel and HDPE and fiberglass are also used. Cables in conduit have less ampacity than direct-buried cables.
- *Direct buried with a spare conduit*—Burying a cable with a spare conduit provides provisions for repair or upgrades. Crews can pull another cable through the spare conduit to increase capacity or, if the cable fails, run a replacement cable through the spare conduit and abandon the failed cable. Normally, when the cable is plowed in, the conduit is coilable PE.
- *Concrete-encased conduit*—Most often used in urban construction, conduit is encased in concrete. Concrete protects the conduit, resisting collapse due to shifting earth. The concrete also helps prevent dig-ins.
- *Preassembled cable in conduit*—Cable with flexible conduit can be purchased on reels, which crews can plow into the ground together. The flexible conduit is likely to be more difficult to pull the cable through, especially if the conduit is not straight. Flexible conduit is also not as strong as rigid conduit; the conduit can collapse due to rocks or other external forces.

Utilities are split between using direct-buried cable and conduits or ducts for underground residential applications. Conduits are used more for three-phase circuits, for commercial service, and for main feeder applications (see Figure 4.4). Conduit use is rising as shown by a more recent survey in Table 4.7. In a survey of the rural cooperatives with the most underground distribution, Dudas and Rodgers (1999) reported that 80% directly bury cable.

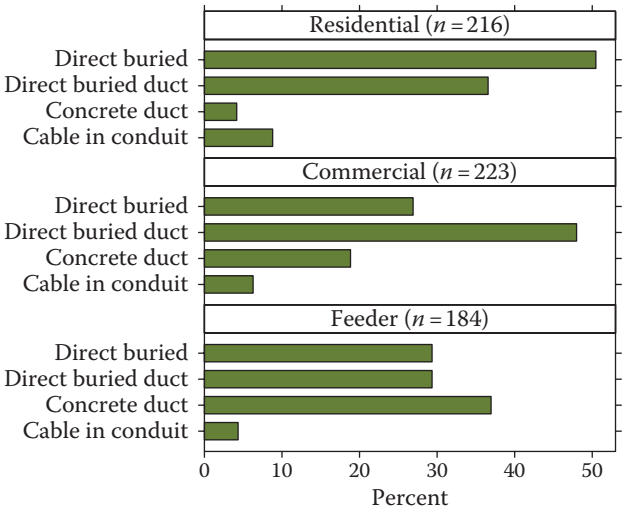

Figure 4.4 Surveyed utility cable installation configurations for residential, commercial, and feeder applications. (Data from Boucher, R., A summary of the regional underground distribution practices for 1991, Regional Underground Distribution Practices, IEEE paper 91 TH0398-8-PWR, 1991.)

TABLE 4.7 Surveyed Utility Use of Cable Duct Installations

	Percent of Cable Miles with Each Configuration	
	1998 Installed	Planned for the Future
Direct buried	64.6	46.9
Installed in conduit sections	25.5	37.9
Preassembled cable in conduit	7.1	11.7
Direct buried with a spare conduit	1.1	0.5
Continuous lengths of PE tubing	1.7	3.0

Source: Adapted from Tyner, J. T., *Transmission & Distribution World*, vol. 50, no. 7, pp. 44–56, July 1998.

With conduits, customers have less outage time because cables can be replaced or repaired more quickly. In addition, replacement causes much less trouble for customers. Replacement doesn't disturb driveways, streets, or lawns; crews can concentrate their work at padmounted gear, rather than spread out along entire cable runs; and crews are less likely to tie up traffic. Conduit costs more than direct buried cable initially, typically from 25% to 50% more for PVC conduit (but this ranges widely depend on soil conditions and obstacles in or on the ground). Cable in flexible conduit may be slightly less than cable in rigid conduit. While directly buried cable has lower initial costs, lifetime costs can be higher than conduit depending on economic assumptions and assumptions on how long cables will last or if they will need to be upgraded. Some utilities use a combination approach; most cables are directly buried, but ducts are used for road crossings and other obstacles.

The National Electrical Safety Code requires that direct-buried cable have at least 30 in. (0.75 m) of cover (IEEE C2-2012). Typically, trench depths are at least 36 in.

If communication cables are buried with primary power cables, extra rules apply. For direct-buried cable with an insulating jacket, the NESC requires that the neutral must have at least one half of the conductivity of the phase conductor (IEEE C2-2012) (it must be a one-half neutral or a full neutral).

Some urban applications are constrained by small ducts: 3, 3.5, or 4-in. diameters. These ducts were designed to hold three-conductor PILC cables, which have conductors squashed in a sector shape for a more compact arrangement. Insulation cannot be extruded over these shapes, so obtaining an equivalent replacement cable with extruded insulation is difficult. Manufacturers offer thinner cables to meet these applications. For triplex cable, the equivalent outside diameter is 2.155 times the diameter of an individual cable. So, to fit in a 3-in. duct, an individual cable must be less than 1.16 in. in diameter to leave a 1/2-in. space (see Table 4.8 for other duct sizes). Some cable offered as "thin-wall" cable has slightly reduced insulation. For 15-kV cable, the smallest insulation thicknesses range between 150 and 165 mil as compared to the standard 175 mil (EPRI 1001734, 2002) (the ICEA allows 100% 15-kV cable insulation to range from 165 to 205 mil (ANSI/ICEA S-97-682-2000, 2000)). One manufacturer has proposed reduced insulation thicknesses based on the fact

TABLE 4.8 Maximum Cable Diameters for Small Conduits Using PILC or Triplexed Cables That Leave 1/2-in. Pulling Room

Duct Size, in.	Largest Three-Conductor 15-kV PILC	Maximum Cable Diameter for Triplex Construction, in.	Largest Standard Construction Triplexed 15-kV Copper Cable
3.0	350 kcmil	1.16	3/0
3.5	750 kcmil	1.39	350 kcmil
4.0	1000 kcmil	1.62	500 kcmil

that larger conductors have lower peak voltage stress on the insulation than smaller conductors (Cinquemani et al., 1997), for example, 110-mil insulation at 15 kV for 4/0 through 750 kcmil. The maximum electric field (EPRI 1001734, 2002) is given by

$$E_{max} = \frac{2V}{d\ln(D/d)}$$

where

E_{max} = maximum electric field, V/mil (or other distance unit)
V = operating or rated voltage to neutral, V
d = inside diameter of the insulation, mil (or other distance unit)
D = outside diameter of the insulation in the same units as d

So, a 750-kcmil cable with 140-mil insulation has about the same maximum voltage stress as a 1/0 cable with 175-mil insulation at the same voltage. Nevertheless, most manufacturers are reluctant to trim the primary insulation too much, fearing premature failure due to water treeing. In addition to slightly reduced insulation, thin-wall cables are normally compressed copper and have thinner jackets and thinner semiconducting shields around the conductor and insulation. EPRI has also investigated other polymers for use in thin-wall cables (EPRI TR-111888, 2000). Their investigations found promising results with novel polymer blends that could achieve insulation strengths that are 30 to 40% higher than XLPE. These tests suggest promise, but more work must be done to improve the extrusion of these materials.

4.4 Impedances

4.4.1 Resistance

Cable conductor resistance is an important part of impedance that is used for fault studies and load flow studies. Resistance also greatly impacts a cable's ampacity. The major variable that affects resistance is the conductor's temperature; resistance rises with temperature. Magnetic fields from alternating currents also reduce a conductor's resistance relative to its dc resistance. At power frequencies, skin effect is only apparent for large conductors and proximity effect only occurs for conductors in very tight configurations. The starting point for resistance calculations is the dc resistance. From there, we can adjust for temperature and for frequency effects. Table 4.9 shows the dc resistances of several common conductors used for cables.

TABLE 4.9 DC Resistance at 25°C in Ω/1000 ft

	Aluminum		Uncoated Copper		Coated Copper	
Size	Solid	Class-B Stranded	Solid	Class-B Stranded	Solid	Class-B Stranded
24			26.2		27.3	
22			16.5		17.2	
20			10.3	10.5	10.7	11.2
19			8.21		8.53	
18			6.51	6.64	6.77	7.05
16			4.1	4.18	4.26	4.44
14	4.22		2.57	2.62	2.68	2.73
12	2.66	2.7	1.62	1.65	1.68	1.72
10	1.67	1.7	1.02	1.04	1.06	1.08
9	1.32	1.35	0.808	0.824	0.831	0.857
8	1.05	1.07	0.641	0.654	0.659	0.679
7	0.833	0.85	0.508	0.518	0.523	0.539
6	0.661	0.674	0.403	0.41	0.415	0.427
5	0.524	0.535	0.319	0.326	0.329	0.339
4	0.415	0.424	0.253	0.259	0.261	0.269
3	0.33	0.336	0.201	0.205	0.207	0.213
2	0.261	0.267	0.159	0.162	0.164	0.169
1	0.207	0.211	0.126	0.129	0.13	0.134
1/0	0.164	0.168	0.1	0.102	0.103	0.106
2/0	0.13	0.133	0.0795	0.0811	0.0814	0.0843
3/0	0.103	0.105	0.063	0.0642	0.0645	0.0668
4/0	0.082	0.0836	0.05	0.0509	0.0512	0.0525
250		0.0708		0.0431		0.0449
300		0.059		0.036		0.0374
350		0.0505		0.0308		0.032
400		0.0442		0.027		0.0278
500		0.0354		0.0216		0.0222
600		0.0295		0.018		0.0187
750		0.0236		0.0144		0.0148
1000		0.0177		0.0108		0.0111
1250		0.0142		0.00863		0.00888
1500		0.0118		0.00719		0.0074
1750		0.0101		0.00616		0.00634
2000		0.00885		0.00539		0.00555
2500		0.00715		0.00436		0.00448

Note: ×5.28 for Ω/mi or ×3.28 for Ω/km.

Resistance increases with temperature as

$$R_{t2} = R_{t1}\frac{M + t_2}{M + t_1}$$

where

R_{t2} = resistance at temperature t_2 given, °C
R_{t1} = resistance at temperature t_1 given, °C
M = a temperature coefficient for the given material
= 228.1 for aluminum
= 234.5 for soft-drawn copper

Both copper and aluminum change resistivity at about the same rate as shown in Figure 4.5.

The ac resistance of a conductor is the dc resistance increased by a skin effect factor and a proximity effect factor

$$R = R_{dc}\,(1 + Y_{cs} + Y_{cp})$$

where

R_{dc} = dc resistance at the desired operating temperature, Ω/1000 ft
Y_{cs} = skin-effect factor
Y_{cp} = proximity effect factor

The skin-effect factor is a complex function involving Bessel function solutions. The following polynomial approximates the skin-effect factor (Anders, 1998):

$$Y_{cs} = \frac{x_s^4}{192 + 0.8x_s^4} \qquad \text{for } x_s \le 2.8$$

$$Y_{cs} = -0.136 - 0.0177x_s + 0.0563x_s^2 \qquad \text{for } 2.8 < x_s \le 3.8$$

$$Y_{cs} = \frac{x_s}{2\sqrt{2}} - \frac{11}{15} \qquad \text{for } 3.8 < x_s$$

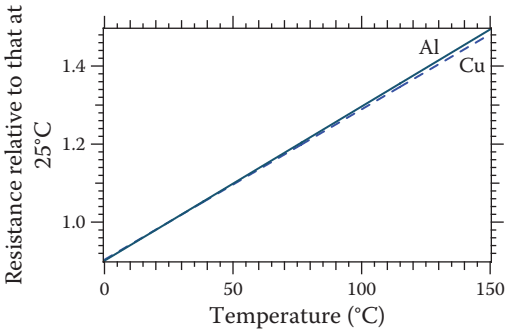

Figure 4.5 Resistance change with temperature.

where

$$x_s = 0.02768\sqrt{\frac{f \cdot k_s}{R_{dc}}}$$

f = frequency, Hz

k_s = skin effect constant = 1 for typical conductors in extruded cables, may be less than 1 for paper cables that are dried and impregnated and especially those with round segmental conductors [see Neher and McGrath (1957) or IEC (1982)].

R_{dc} = dc resistance at the desired operating temperature, Ω/1000 ft

For virtually all applications at power frequency, x_s is less than 2.8.

With a conductor in close proximity to another current-carrying conductor, the magnetic fields from the adjacent conductor force current to flow in the portions of the conductor most distant from the adjacent conductor (with both conductors carrying current in the same direction). This magnetic field effect increases the effective ac resistance. The proximity effect factor is approximately (Anders, 1998; IEC 287, 1982)

$$Y_{cp} = ay^2\left(0.312y^2 + \frac{1.18}{a + 0.27}\right)$$

where

$$a = \frac{x_p^4}{192 + 0.8x_p^4}, \quad y = \frac{d_c}{s}$$

$$x_p = 0.02768\sqrt{\frac{f \cdot k_p}{R_{dc}}}$$

d_c = conductor diameter

s = distance between conductor centers

k_p = proximity effect constant = 1 for typical conductors in extruded cables; may be < 1 for paper cables that are dried and impregnated and especially those with round segmental conductors [see Neher and McGrath (1957) or IEC (1982)].

At power frequencies, we can ignore proximity effect if the spacing exceeds 10 times the conductor diameter (the effect is less than 1%).

Tables 4.10 and 4.11 show characteristics of common cable conductors.

4.4.2 Impedance Formulas

Smith and Barger (1972) showed that we can treat a multi-wire concentric neutral as a uniform sheath; further work by Lewis and Allen (1978) and by Lewis et al. (1978) simplified the calculation of the representation of the concentric neutral. Following the procedure and nomenclature of Smith (1980) and Lewis and Allen (1978), we can

TABLE 4.10 Characteristics of Aluminum Cable Conductors

Conductor	Stranding	GMR, in.	ac/dc Resistance Ratio	Resistances, Ω/1000 ft		
				dc at 25°C	ac at 25°C	ac at 90°C
2	7	0.105	1	0.2660	0.2660	0.3328
1	19	0.124	1	0.2110	0.2110	0.2640
1/0	19	0.139	1	0.1680	0.1680	0.2102
2/0	19	0.156	1	0.1330	0.1330	0.1664
3/0	19	0.175	1	0.1050	0.1050	0.1314
4/0	19	0.197	1	0.0836	0.0836	0.1046
250	37	0.216	1.01	0.0707	0.0714	0.0893
350	37	0.256	1.01	0.0505	0.0510	0.0638
500	37	0.305	1.02	0.0354	0.0361	0.0452
750	61	0.377	1.05	0.0236	0.0248	0.0310
1000	61	0.435	1.09	0.0177	0.0193	0.0241

find a cable's sequence impedances from the self and mutual impedances of the cable phase and neutral conductors as

$$Z_{11} = Z_{aa} - Z_{ab} - \frac{(Z_{ax} - Z_{ab})^2}{Z_{xx} - Z_{ab}}$$

$$Z_{00} = Z_{aa} + 2Z_{ab} - \frac{(Z_{ax} + 2Z_{ab})^2}{Z_{xx} + 2Z_{ab}}$$

TABLE 4.11 Characteristics of Copper Cable Conductors

Conductor	Stranding	GMR, in.	ac/dc Resistance Ratio	Resistances, Ω/1000 ft		
				dc at 25°C	ac at 25°C	ac at 90°C
2	7	0.105	1	0.1620	0.1620	0.2027
1	19	0.124	1	0.1290	0.1290	0.1614
1/0	19	0.139	1	0.1020	0.1020	0.1276
2/0	19	0.156	1.01	0.0810	0.0818	0.1023
3/0	19	0.175	1.01	0.0642	0.0648	0.0811
4/0	19	0.197	1.01	0.0510	0.0515	0.0644
250	37	0.216	1.01	0.0431	0.0435	0.0545
350	37	0.256	1.03	0.0308	0.0317	0.0397
500	37	0.305	1.06	0.0216	0.0229	0.0286
750	61	0.377	1.13	0.0144	0.0163	0.0204
1000	61	0.435	1.22	0.0108	0.0132	0.0165

The self and mutual impedances in the sequence equations are found with

$$Z_{aa} = R_\phi + R_e + jk_1 \log_{10} \frac{D_e}{GMR_\phi}$$

$$Z_{ab} = R_e + jk_1 \log_{10} \frac{D_e}{GMD_\phi}$$

$$Z_{xx} = R_N + R_e + jk_1 \log_{10} \frac{D_e}{GMR_N}$$

$$Z_{ax} = R_e + jk_1 \log_{10} \frac{D_e}{DN2}$$

where the self and mutual impedances with earth return are

Z_{aa} = self-impedance of each phase conductor

Z_{ab} = the mutual impedance between two conductors (between two phases, between two neutral, or between a phase and a neutral)

Z_{ax} = the mutual impedance between a phase conductor and its concentric neutral (or sheath)

Z_{xx} = self-impedance of each concentric neutral (or shield)

and

R_ϕ = resistance of the phase conductor, Ω/distance

R_N = resistance of the neutral (or shield), Ω/distance

$k_1 = 0.2794f/60$ for outputs in Ω/mi

$= 0.0529f/60$ for outputs in Ω/1000 ft

f = frequency, Hz

GMR_ϕ = geometric mean radius of the phase conductor, in. (see Table 4.12)

GMD_ϕ = geometric mean distance between the phase conductors, in.

$= \sqrt[3]{d_{AB}d_{BC}d_{CA}}$

$= 1.26\, d_{AB}$ for a three-phase line with flat configuration, either horizontal or vertical, when $d_{AB} = d_{BC} = 0.5d_{CA}$

= the cable's outside diameter for triplex cables

= 1.15 times the cable's outside diameter for cables cradled in a duct

d_{ij} = distance between the center of conductor i and the center of conductor j, in. (see Figure 4.6)

R_e = resistance of the earth return path

$= 0.0954(f/60)$ Ω/mi

$= 0.01807(f/60)$ Ω/1000 ft

$D_e = 25920\sqrt{\rho/f}$ = equivalent depth of the earth return current, in.

ρ = earth resistivity, Ω-m

GMR_N = geometric mean radius of the sheath or neutral. For single-conductor cables with tape or lead sheaths, set GMR_N equal to the average radius of the sheath. For cables with a multi-wire concentric neutral, use $\text{GMR}_N = \sqrt[n]{0.7788nDN2^{(n-1)}r_n}$ where n is the number of neutrals and r_n is the radius of each neutral, in.

TABLE 4.12 Geometric Mean Radius of Class B Stranded Copper and Aluminum Conductors

		GMR, in.		
Size	Stranding	Round	Compressed	Compact
8	7	0.053		
6	7	0.067		
4	7	0.084		
2	7	0.106	0.105	
1	19	0.126	0.124	0.117
1/0	19	0.141	0.139	0.131
2/0	19	0.159	0.156	0.146
3/0	19	0.178	0.175	0.165
4/0	19	0.200	0.197	0.185
250	37	0.221	0.216	0.203
350	37	0.261	0.256	0.240
500	37	0.312	0.305	0.287
750	61	0.383	0.377	0.353
1000	61	0.442	0.435	0.413

Source: Data from Southwire Company, *Power Cable Manual*, 2nd ed., 1997.

$DN2$ = effective radius of the neutral = the distance from the center of the phase conductor to the center of a neutral strand, in.

Smith (1980) reported that assuming equal GMR_N and $DN2$ for cables from 1/0 to 1000 kcmil with one-third neutrals is accurate to 1%.

For single-phase circuits, the zero and positive-sequence impedances are the same:

$$Z_{11} = Z_{00} = Z_{aa} - \frac{Z_{ax}^2}{Z_{xx}}$$

This is the loop impedance, the impedance to current flow through the phase conductor that returns in the neutral and earth. The impedances of two-phase circuits are more difficult to calculate (see Smith, 1980).

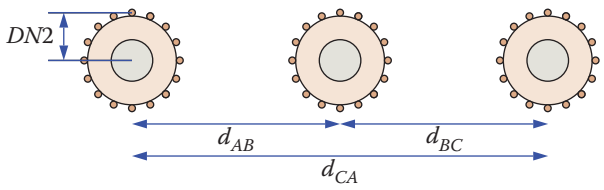

Figure 4.6 Cable dimensions for calculating impedances.

The sheath resistances depend on whether it is a concentric neutral, a tape shield, or some other configuration. For a concentric neutral, the resistance is approximately (ignoring the lay of the neutral)

$$R_{\text{neutral}} = \frac{R_{\text{strand}}}{n}$$

where

R_{strand} = resistance of one strand, in Ω/unit distance
n = number of strands

A tape shield's resistance (Southwire Company, 1997) is

$$R_{\text{shield}} = \frac{\rho_c}{A_s}$$

where

ρ_c = resistivity of the tape shield, Ω-cmil/ft = 10.575 for uncoated copper at 25°C
A_s = effective area of the shield in circular mil

$$A_s = 4b \cdot d_m \cdot \sqrt{\frac{50}{100 - L}}$$

b = thickness of the tape, mil
d_m = mean diameter outside of the metallic shield, mil
L = lap of the tape shield in percent (normally 10 to 25%)

Normally, we can use dc resistance as the ac resistance for tape shields or concentric neutrals. The skin effect is very small because the shield conductors are thin (skin effect just impacts larger conductors). We should adjust the sheath resistance for temperature; for copper conductors, the adjustment is

$$R_{t2} = R_{t1} \frac{234.5 + t_2}{234.5 + t_1}$$

where

R_{t2} = resistance at temperature t_2 given in °C
R_{t1} = resistance at temperature t_1 given in °C

These calculations are simplifications. More advanced models, normally requiring a computer, can accurately find each element in the full impedance matrix. For most load-flow calculations, this accuracy is not needed, though access to user-friendly computer models allows quicker results than calculating the equations shown here. For evaluating switching transients and some ampacity problems or configurations with several cables, we sometimes need more sophisticated models [see Ametani (1980) or Dommel (1986) for analytical details].

In a cable, the neutral tightly couples with the phase. Phase current induces neutral voltages that force circulating current in the neutrals. With balanced, positive-sequence current in the three phases and with symmetrical conductors, the neutral current (Lewis and Allen, 1978; Smith and Barger, 1972) is

$$I_{X1} = -\frac{Z_{ax} - Z_{ab}}{Z_{xx} - Z_{ab}} I_a$$

which is

$$I_{X1} = -\frac{j0.0529 \log_{10} \dfrac{d_{ab}}{DN2}}{R_N + j0.0529 \log_{10} \dfrac{d_{ab}}{GMR_N}} I_a$$

Since $DN2$ and GMR_N are almost equal, if R_N is near zero, the neutral (or shield) current (I_{X1}) almost equals the phase current (I_a). Higher neutral resistances actually reduce positive-sequence resistances.

Significant effects on positive and zero-sequence impedances include

- *Cable separation*—Larger separations increase Z_1; spacing does not affect Z_0. Triplex cables have the lowest positive-sequence impedance.
- *Conductor size*—Larger conductors have much less resistance; reactance drops somewhat with increasing size.
- *Neutral/shield resistance*—Increasing the neutral resistance increases the reactive portion of the positive and zero-sequence impedances. Beyond a certain point, increasing neutral resistances decreases the resistive portion of Z_1 and Z_0.
- *Other cables or ground wires*—Adding another grounded wire nearby has similar impacts to lowering sheath resistances. Zero-sequence resistance and reactance usually drop. Positive-sequence reactance is likely to decrease, but positive-sequence resistance may increase.

Figures 4.7 and 4.8 show the impact of the most significant variables on impedances for three-phase and single-phase circuits. None of the following significantly impacts either the positive or zero-sequence impedances: insulation thickness, insulation type, depth of burial, and earth resistivity.

4.4.3 Impedance Tables

This section contains tables of several common cable configurations found on distribution circuits (Tables 4.13 through 4.16). All values are for a multigrounded circuit. Many other cable configurations are possible, with widely varying impedances. For PILC cables, refer to impedances in the Westinghouse (1950) T&D book. For additional three-phase power cable configurations, refer to the IEEE Red Book (IEEE Std. 141-1993), St. Pierre (2001), or Southwire Company (1997).

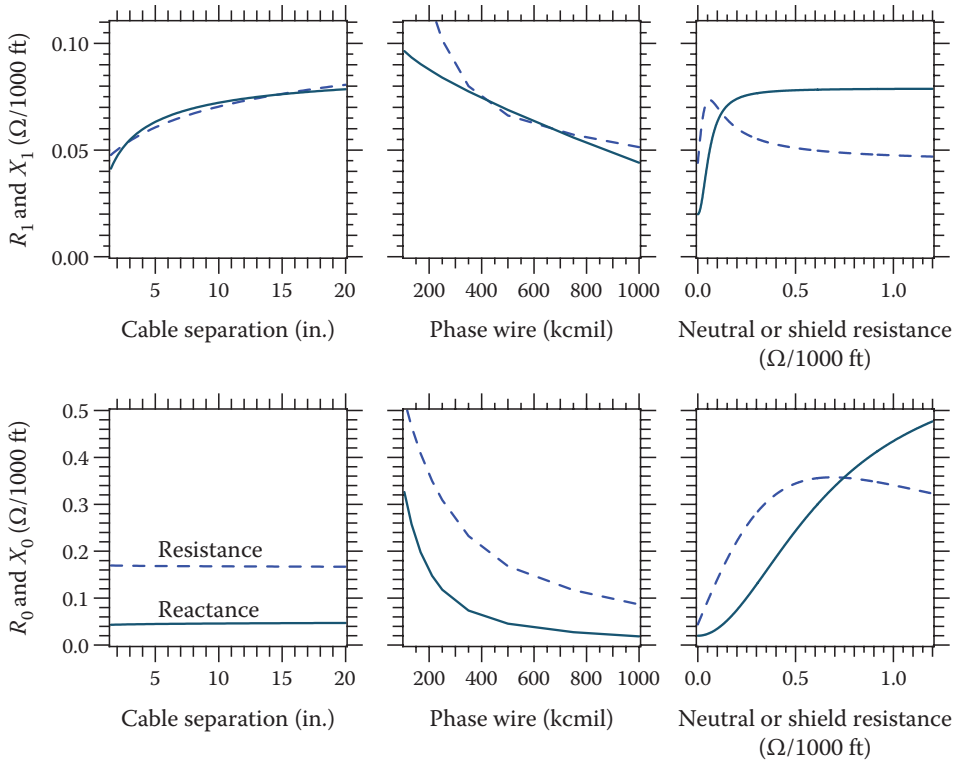

Figure 4.7 Effect of various parameters on the positive-sequence (top row) and zero-sequence impedances (bottom row) with a base case having 500-kcmil aluminum cables with 1/3 neutrals, 220-mil insulation, a horizontal configuration with 7.5 in. between cables, and ρ = 100 Ω-m.

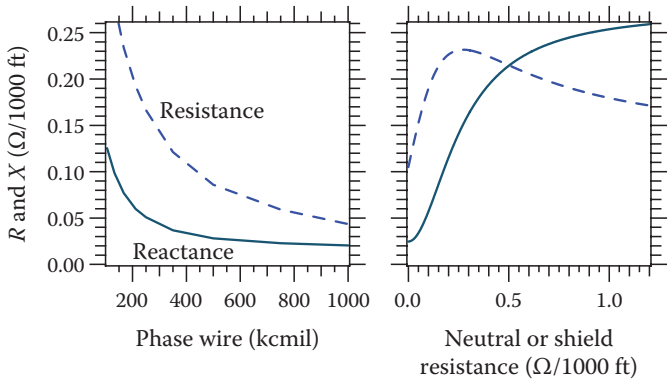

Figure 4.8 Resistance and reactance of a single-phase cable ($R = R_0 = R_1$ and $X = X_0 = X_1$) as the size of the cable and neutral varies with a base case having a 4/0 aluminum cable with a full neutral, 220-mil insulation, and ρ = 100 Ω-m.

TABLE 4.13 Loop Impedances of Single-Phase Concentric-Neutral Aluminum Cables

Conductor Size	Full Neutral			1/3 Neutral		
	Neutral	R	X	Neutral	R	X
2	10#14	0.4608	0.1857			
1	13#14	0.3932	0.1517			
1/0	16#14	0.3342	0.1259	6#14	0.3154	0.2295
2/0	13#12	0.2793	0.0974	7#14	0.2784	0.2148
3/0	16#12	0.2342	0.0779	9#14	0.2537	0.1884
4/0	13#10	0.1931	0.0613	11#14	0.2305	0.1645
250	16#10	0.1638	0.0493	13#14	0.2143	0.1444
350	20#10	0.1245	0.0387	18#14	0.1818	0.1092
500				16#12	0.1447	0.0726
750				15#10	0.1067	0.0462
1000				20#10	0.0831	0.0343

Note: Impedances, Ω/1000 ft (×5.28 for Ω/mi or ×3.28 for Ω/km). Conductor temperature = 90°C, neutral temperature = 80°C, 15-kV class, 220-mil insulation, ρ = 100 Ω-m. For the neutral, 10#14 means 10 strands of 14-gage wire.

TABLE 4.14 Impedances of Three-Phase Circuits Made of Three Single-Conductor Concentric-Neutral Aluminum Cables

Conductor Size	Neutral Size	R_1	X_1	R_0	X_0	R_S	X_S
Full Neutral							
2	10#14	0.3478	0.1005	0.5899	0.1642	0.4285	0.1217
1	13#14	0.2820	0.0950	0.4814	0.1166	0.3484	0.1022
1/0	16#14	0.2297	0.0906	0.3956	0.0895	0.2850	0.0902
2/0	13#12	0.1891	0.0848	0.3158	0.0660	0.2314	0.0785
3/0	16#12	0.1578	0.0789	0.2573	0.0523	0.1910	0.0701
4/0	13#10	0.1331	0.0720	0.2066	0.0423	0.1576	0.0621
250	16#10	0.1186	0.0651	0.1716	0.0356	0.1363	0.0553
350	20#10	0.0930	0.0560	0.1287	0.0294	0.1049	0.0471
1/3 Neutral							
1/0	6#14	0.2180	0.0959	0.5193	0.2854	0.3185	0.1591
2/0	7#14	0.1751	0.0930	0.4638	0.2415	0.2713	0.1425
3/0	9#14	0.1432	0.0896	0.4012	0.1787	0.2292	0.1193
4/0	11#14	0.1180	0.0861	0.3457	0.1375	0.1939	0.1032
250	13#14	0.1034	0.0833	0.3045	0.1103	0.1704	0.0923
350	18#14	0.0805	0.0774	0.2353	0.0740	0.1321	0.0762
500	16#12	0.0656	0.0693	0.1689	0.0468	0.1000	0.0618
750	15#10	0.0547	0.0584	0.1160	0.0312	0.0752	0.0494
1000	20#10	0.0478	0.0502	0.0876	0.0248	0.0611	0.0417

Note: Impedances, Ω/1000 ft (×5.28 for Ω/mi or ×3.28 for Ω/km). Resistances for a conductor temperature = 90°C and a neutral temperature = 80°C, 220-mil insulation (15 kV), ρ = 100 Ω-m. Flat spacing with a 7.5-in. separation between cables. For the neutral, 10#14 means 10 strands of 14-gage wire.

TABLE 4.15 Impedances of Single-Conductor Aluminum Power Cables with Copper Tape Shields

Conductor Size	R_1	X_1	R_0	X_0	R_S	X_S
Flat Spacing with a 7.5-in. Separation						
2	0.3399	0.1029	0.6484	0.4088	0.4427	0.2049
1	0.2710	0.0990	0.5808	0.3931	0.3743	0.1971
1/0	0.2161	0.0964	0.5268	0.3790	0.3196	0.1906
2/0	0.1721	0.0937	0.4833	0.3653	0.2759	0.1842
3/0	0.1382	0.0911	0.4494	0.3493	0.2419	0.1771
4/0	0.1113	0.0883	0.4217	0.3314	0.2148	0.1693
250	0.0955	0.0861	0.4037	0.3103	0.1982	0.1609
350	0.0696	0.0822	0.3734	0.2827	0.1709	0.1490
500	0.0508	0.0781	0.3483	0.2557	0.1499	0.1373
750	0.0369	0.0732	0.3220	0.2185	0.1319	0.1216
1000	0.0290	0.0698	0.3018	0.1915	0.1200	0.1104
Triplex						
2	0.3345	0.0531	0.7027	0.4244	0.4573	0.1769
1	0.2655	0.0501	0.6330	0.4060	0.3880	0.1687
1/0	0.2105	0.0483	0.5767	0.3893	0.3326	0.1620
2/0	0.1666	0.0465	0.5310	0.3734	0.2880	0.1554
3/0	0.1326	0.0448	0.4944	0.3550	0.2532	0.1482
4/0	0.1056	0.0432	0.4636	0.3346	0.2249	0.1403
250	0.0896	0.0424	0.4418	0.3109	0.2070	0.1319
350	0.0637	0.0403	0.4067	0.2807	0.1780	0.1204
500	0.0447	0.0381	0.3769	0.2518	0.1554	0.1093
750	0.0308	0.0359	0.3443	0.2129	0.1353	0.0949
1000	0.0228	0.0348	0.3197	0.1853	0.1218	0.0850

Note: Impedances, Ω/1000 ft (×5.28 for Ω/mi or ×3.28 for Ω/km). Resistances for a conductor temperature = 90°C and a shield temperature = 50°C, 220-mil insulation (15 kV), ρ = 100 Ω-m, 5-mil copper tape shield with a lap of 20%.

4.4.4 Capacitance

Cables have significant capacitance, much more than overhead lines. A single-conductor cable has a capacitance given by

$$C = \frac{0.00736\varepsilon}{\log_{10}\left(\frac{D}{d}\right)}$$

where

C = capacitance, μF/1000 ft
ε = dielectric constant (2.3 for XLPE, 3 for EPR, see Table 4.4 for others)

TABLE 4.16 Impedances of Single-Conductor Copper Power Cables

Conductor Size	R_1	X_1	R_0	X_0	R_S	X_S
Flat Spacing with a 7.5-in. Separation						
2	0.2083	0.1029	0.5108	0.4401	0.3092	0.2153
1	0.1671	0.0991	0.4718	0.4267	0.2687	0.2083
1/0	0.1334	0.0965	0.4405	0.4115	0.2358	0.2015
2/0	0.1082	0.0938	0.4171	0.3967	0.2112	0.1948
3/0	0.0871	0.0911	0.3975	0.3794	0.1906	0.1872
4/0	0.0705	0.0884	0.3816	0.3626	0.1742	0.1798
250	0.0607	0.0862	0.3719	0.3471	0.1644	0.1732
350	0.0461	0.0823	0.3558	0.3181	0.1493	0.1609
500	0.0352	0.0782	0.3411	0.2891	0.1372	0.1485
750	0.0272	0.0732	0.3241	0.2490	0.1261	0.1318
1000	0.0234	0.0699	0.3104	0.2196	0.1191	0.1198
Triplex						
2	0.2032	0.0508	0.5707	0.4642	0.3257	0.1886
1	0.1619	0.0477	0.5301	0.4480	0.2846	0.1811
1/0	0.1281	0.0460	0.4966	0.4295	0.2509	0.1738
2/0	0.1028	0.0442	0.4709	0.4116	0.2255	0.1667
3/0	0.0816	0.0426	0.4485	0.3910	0.2039	0.1587
4/0	0.0649	0.0409	0.4299	0.3713	0.1866	0.1510
250	0.0551	0.0398	0.4175	0.3532	0.1759	0.1442
350	0.0403	0.0377	0.3962	0.3202	0.1589	0.1319
500	0.0292	0.0355	0.3765	0.2882	0.1450	0.1197
750	0.0211	0.0333	0.3524	0.2450	0.1315	0.1039
1000	0.0173	0.0322	0.3336	0.2142	0.1227	0.0929

Note: Impedances, Ω/1000 ft (×5.28 for Ω/mi or ×3.28 for Ω/km). Resistances for a conductor temperature = 90°C and a shield temperature = 50°C, 220-mil insulation (15 kV), ρ = 100 Ω-m, 5-mil copper tape shield with a lap of 20%.

d = inside diameter of the insulation, mil (or other distance unit)
D = outside diameter of the insulation in the same units as d

The vars provided by cable are

$$Q_{\text{var}} = 2\pi \cdot f \cdot C \cdot V_{\text{LG,kV}}^2$$

where
Q_{var} = var/1000 ft/phase
f = frequency, Hz
C = capacitance, μF/1000 ft
$V_{\text{LG,kV}}$ = line-to-ground voltage, kV

TABLE 4.17 Cable Capacitance for Common Cable Sizes and Voltages

	Capacitance, μF/1000 ft				Reactive Power, kvar/1000 ft			
Size	175 mil	220 mil	260 mil	345 mil	12.5 kV 175 mil	12.5 kV 220 mil	25 kV 260 mil	34.5 kV 345 mil
2	0.0516	0.0441	0.0396	0.0333	1.01	0.862	3.09	4.98
1	0.0562	0.0479	0.0428	0.0358	1.1	0.936	3.35	5.35
1/0	0.0609	0.0516	0.046	0.0383	1.19	1.01	3.6	5.72
2/0	0.0655	0.0553	0.0492	0.0407	1.28	1.08	3.84	6.09
3/0	0.0712	0.0599	0.0531	0.0437	1.39	1.17	4.15	6.54
4/0	0.078	0.0654	0.0578	0.0473	1.52	1.28	4.52	7.08
250	0.0871	0.0727	0.064	0.0521	1.7	1.42	5.00	7.79
350	0.0995	0.0826	0.0725	0.0586	1.94	1.61	5.67	8.76
500	0.113	0.0934	0.0817	0.0656	2.21	1.83	6.38	9.81
750	0.135	0.111	0.0969	0.0772	2.65	2.18	7.57	11.5
1000	0.156	0.127	0.111	0.0875	3.04	2.49	8.64	13.1

Note: For XLPE cable with $\varepsilon = 2.3$.

Table 4.17 shows capacitance values and reactive power produced by cables for typical cables. The table results are for XLPE cable with a dielectric constant (ε) of 2.3. For other insulation, both the capacitance and the reactive power scale linearly. For example, for EPR with $\varepsilon = 3$, multiply the values in Table 4.17 by 1.3 (3/2.3 = 1.3).

4.5 Ampacity

A cable's ampacity is the maximum continuous current rating of the cable. We should realize that while we may derive one number, say 480 A, for ampacity during normal operations for a given conductor, there is nothing magic about 480 A. The cable will not burst into flames at 481 A; the 480 A is simply a design number. We don't want to exceed that current during normal operations.

The insulation temperature is normally the limiting factor. By operating below the ampacity of a given cable, we keep the cable insulation below its recommended maximum temperature. XLPE cables are rated for a maximum operating temperature of 90°C during normal operations. Operating cables above their ampacity increases the likelihood of premature failures: water trees may grow faster, thermal runaway failures are more likely, and insulation strength may decrease. In addition to absolute temperature, thermal cycling also ages cable more quickly.

Ampacity most often limits the loading on a cable; rarely, voltage drop or flicker limits loadings. Relative to overhead lines, cables of a given size have lower impedance and lower ampacities. So cable circuits are much less likely than overhead circuits to be voltage-drop limited. Only very long cable runs on circuits with low primary voltages are voltage-drop limited. Ampacity is not the only consideration for cable selection; losses and stocking considerations should also factor into cable selection. Choosing the smallest cable that meets ampacity requirements has the lowest initial

cost, but since the cable is running hotter, the cost over its life may not be optimal because of the losses. Also allow for load growth when selecting cables.

Ampacity calculations follow simple principles: the temperature at the conductor is a function of the heat generated in a cable (I^2R) and the amount of heat conducted away from the cable. We can model the thermal performance with a thermal circuit analogous to an electric circuit: heat is analogous to current; temperature to voltage; and thermal resistance to electrical resistance. Heat flow through a thermal resistance raises the temperature between the two sides of the thermal material. Higher resistance soils or insulations trap the heat and cause higher temperatures. Using the thermal equivalent of Ohm's law, the temperature difference is

$$\Delta T = T_C - T_A = R_{TH}H = R_{TH}(I^2R)$$

where

T_C = conductor temperature, °C
T_A = ambient earth temperature, °C
R_{TH} = total thermal resistance between the cable conductor and the air, thermal Ω-ft
H = heat generated in the cable, W (= I^2R)
I = electric current in the conductor, A
R = electric resistance of the conductor, Ω/ft

Most ampacity tables and computer calculation routines are based on the classic paper by Neher and McGrath (1957). The original paper is an excellent reference. Ander's book (1998) provides a detailed discussion of cable ampacity calculations, including the Neher–McGrath method along with IEC's method that is very similar (IEC 287, 1982). Hand calculations or spreadsheet calculations of the Neher–McGrath equations are possible, but tiresome; while straightforward in principle, the calculations are very detailed. A review of the Neher–McGrath procedure—the inputs, the techniques, the assumptions—provides a better understanding of ampacity calculations to better use computer ampacity calculations.

The Neher–McGrath procedure solves for the current in the equation above. Figure 4.9 shows a simplified model of the thermal circuit. The two main sources of heat within the cable are the I^2R losses in the phase conductor and the I^2R losses in the neutral or shield. The cable also has dielectric losses, but for distribution-class

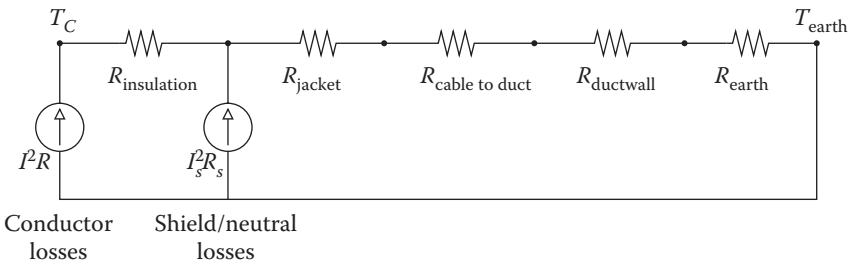

Figure 4.9 Thermal circuit model of a cable for ampacity calculations.

voltages, these are small enough that we can neglect them. The major thermal resistances are the insulation, the jacket, and the earth. If the cable system is in a duct, the air space within the duct and the duct walls adds thermal resistance. These thermal resistances are calculated from the thermal resistivities of the materials involved. For example, the thermal resistance of the insulation, jacket, and duct wall are all calculated with an equation of the following form:

$$R = 0.012\ \rho \log_{10}(D/d)$$

where

R = thermal resistance of the component, thermal Ω-ft
ρ = thermal resistivity of the component material, °C-cm/W
D = outside diameter of the component
d = inside diameter of the component

Thermal resistivity quantifies the insulating characteristics of a material. A material with ρ = 1°C-cm/W has a temperature rise of 1°C across two sides of a 1-cm^3 cube for a flow of 1 W of heat through the cube. As with electrical resistivity, the inverse of thermal resistivity is thermal conductivity. Table 4.18 shows resistivities commonly used for cable system components. The thermal resistance of a material quantifies the radial temperature rise from the center outward. One thermal Ω-ft has a radial temperature rise of 1°C for a heat flow of 1 W per ft of length (length along the conductor). Mixing of metric (SI) units with English units comes about for historical reasons.

TABLE 4.18 Thermal Resistivities of Common Components

Component	Thermal Resistivity, °C-cm/W
XLPE insulation	350
EPR insulation	500
Paper insulation	700
PE jackets	350
PVC jackets	500
Plastic ducts	480
Concrete	85
Thermal fill	60
Soil	90
Water	160
Air	4000

Data sources: IEC 287, *Calculation of the Continuous Current Rating of Cables (100% Load Factor)*, 2nd ed., International Electrical Commission (IEC), 1982; Neher, J. H. and McGrath, M. H., *AIEE Transactions*, vol. 76, pp. 752–64, October 1957.

The Neher–McGrath calculations also account for multiple cables, cables with cyclic daily load cycles, external heat sources, duct arrangements, and shield resistance and grounding variations.

Often, the easiest way to find ampacities for a given application is with ampacity tables. Tables 4.19 and 4.20 show ampacities for common distribution configurations. Of the many sources of ampacity tables, the IEEE publishes the most exhaustive set of tables (IEEE Std. 835-1994). The National Electrical Code (NFPA 70, 1999) and manufacturer's publications (Okonite, 1990; Southwire Company, 1997) are also useful. Ampacity tables provide a good starting point for determining the ampacity of a specific cable application. When using tables, be careful that the assumptions match your particular situation; if not, ampacity results can be much different than expected.

Conductor temperature limits, sheath resistance, thermal resistivity of the soil—these are some of the variables that most impact ampacity (see Figure 4.10). These and other effects are discussed in the next few paragraphs. See also CEA (1982), NRECA RER Project 90-8 (1993), and EPRI 1019937 (2010) for more discussions.

Sheath resistance—On a three-phase circuit, the resistance of the sheath (or shield or neutral) plays an important role in ampacity calculations. Because a cable's phase conductor and sheath couple so tightly, current through the phase induces a large voltage along the sheath. With the cable sheath grounded periodically, circulating current flows to counter the induced voltage. The circulating current is a function of the resistance of the sheath. This circulating current leads to something counterintuitive: sheaths with higher resistance have more ampacity. Higher resistance sheaths reduce the circulating current and reduce the I^2R losses in the sheath. This effect is most pronounced in larger conductors. Many ampacity tables assume that cable sheaths are open circuited, this eliminates the sheath losses and increases the ampacity. The open-circuit sheath values can be approximately corrected to account for circulating currents (Okonite, 1990) by

TABLE 4.19 Ampacities of Single-Phase Circuits of Full-Neutral Aluminum Conductor Cables

	Direct Buried Load Factor		In Conduit Load Factor	
Size	100%	75%	100%	75%
2	187	201	146	153
1	209	225	162	170
1/0	233	252	180	188
2/0	260	282	200	210
3/0	290	316	223	234
4/0	325	356	249	262
250	359	395	276	291
350	424	469	326	345

Note: 90°C conductor temperature, 25°C ambient earth temperature, ρ = 90°C-cm/W.

TABLE 4.20 Ampacities of Three-Phase Circuits Made of Single-Conductor, One-Third Neutral Aluminum Cables

	Direct Buried Load Factor		In Conduit Load Factor	
Size	100%	75%	100%	75%
Flat Spacing (7.5-in. Separation)				
1/0	216	244	183	199
2/0	244	277	207	226
3/0	274	312	233	255
4/0	308	352	262	287
250	336	386	285	315
350	392	455	334	370
500	448	525	382	426
750	508	601	435	489
1000	556	664	478	541
Triplex				
1/0	193	224	158	173
2/0	220	255	180	197
3/0	249	290	204	225
4/0	283	330	232	256
250	312	365	257	284
350	375	442	310	345
500	452	535	375	419
750	547	653	457	514
1000	630	756	529	598

Note: 90°C conductor temperature, 25°C ambient earth temperature, ρ = 90°C-cm/W.

$$k = \sqrt{\frac{I^2R}{I_S^2R_S + I^2R}}$$

where

k = ampacity multiplier to account for sheath losses, that is, $I_{\text{grounded sheath}} = k \cdot I_{\text{open sheath}}$
I = phase conductor current, A
I_S = sheath current, A
I^2R = phase conductor losses, W/unit of length
$I_S^2R_S$ = sheath losses, W/unit of length

The sheath losses are a function of the resistance of the sheath and the mutual inductance between the sheath and other conductors. For a triangular configuration like triplex, the shield losses are

$$I_S^2R_S = I^2R_S\frac{X_M^2}{R_S^2 + X_M^2}$$

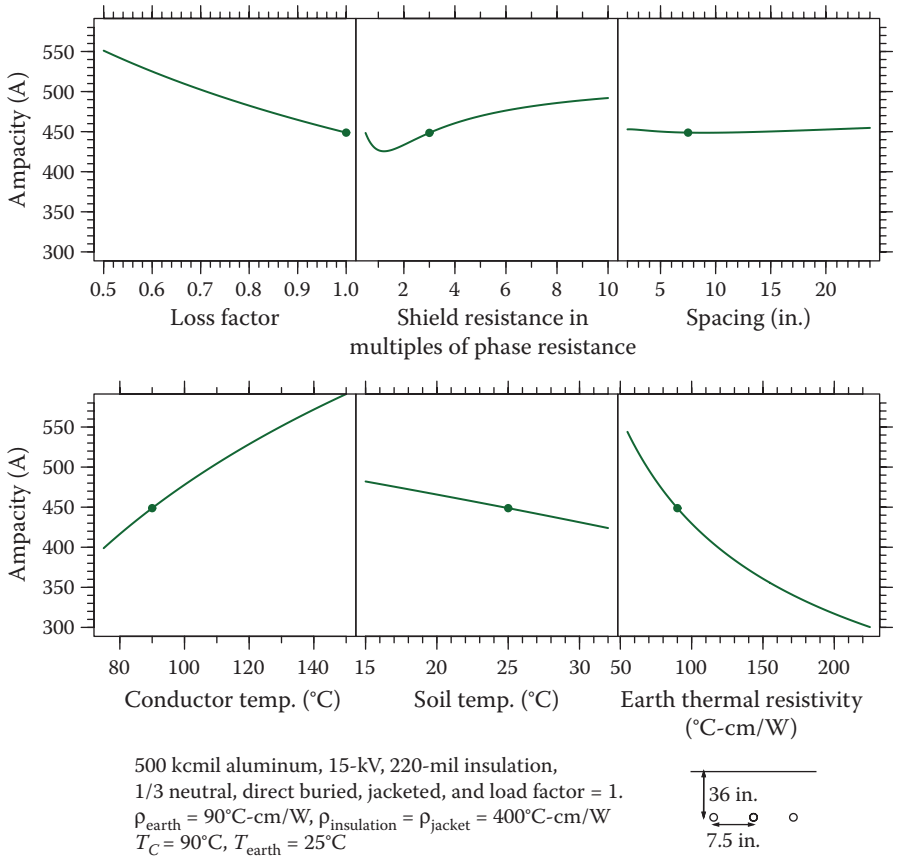

Figure 4.10 Effect of variables on ampacity for an example cable.

where

$X_M = 2\pi f(0.1404)\log_{10}(2S/d_S)$

and

X_M = mutual inductance of the sheath and another conductor, mΩ/1000 ft
R_S = resistance of the sheath, mΩ/1000 ft
f = frequency, Hz
S = spacing between the phase conductors, in.
d_S = mean diameter of the sheath, in.

For configurations other than triplex, see Southwire Company (1997) or Okonite (1990). Figure 4.11 shows how sheath losses vary with conductor size and with spacing. Spacing has a pronounced effect. Steel ducts can significantly increase heating from circulating currents. In fact, even nearby steel pipes can significantly reduce ampacity.

Spacings—Separating cables separates the heat sources. But at larger spacings, circulating currents are higher. Optimal spacings involve balancing these effects. For

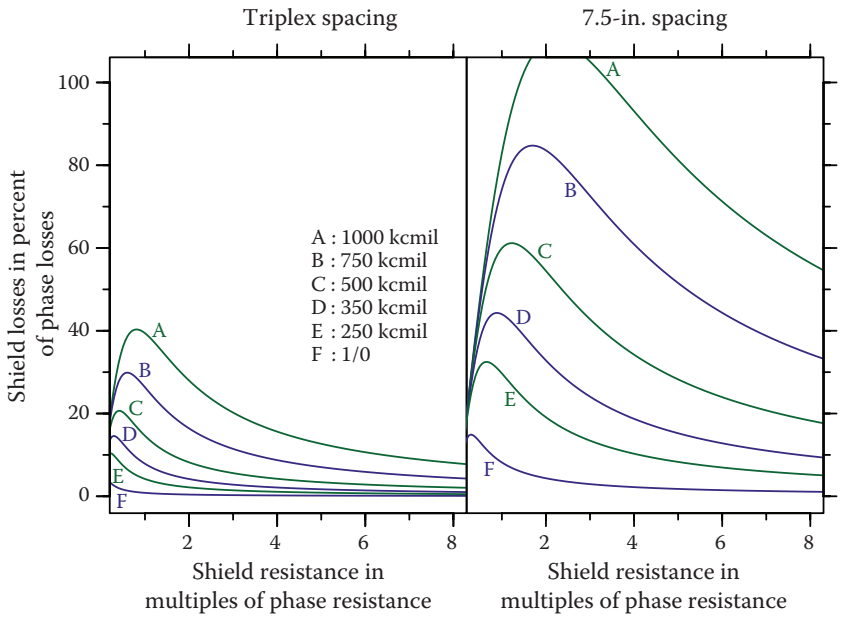

Figure 4.11 Shield losses as a function of shield resistance for aluminum cables (triplex configuration).

smaller cables, separating cables provides the best ampacity. For larger cables (with larger circulating currents), triplex or other tight spacing improves ampacity. For one-third neutral, aluminum cables, NRECA (1993) shows that a flat spacing with 7.5 in between cables has better ampacity than triplex for conductors 500 kcmil and smaller. For copper cables, the threshold is lower: conductors larger than 4/0 have better ampacity with a triplex configuration.

Conductor temperature—If we allow a higher conductor temperature, we can operate a cable at higher current. If we know the ampacity for a given conductor temperature, at a different conductor temperature we can find the ampacity with the following approximation:

$$I' = I\sqrt{\frac{T_C' - T_A'}{T_C - T_A}\frac{228.1 + T_C}{228.1 + T_C'}} \quad \text{(Aluminum conductor)}$$

$$I' = I\sqrt{\frac{T_C' - T_A'}{T_C - T_A}\frac{234.5 + T_C}{234.5 + T_C'}} \quad \text{(Copper conductor)}$$

where

I' = ampacity at a conductor temperature of T_C' and an ambient earth temperature T_A'

I = ampacity at a conductor temperature of T_C and an ambient earth temperature T_A (all temperatures are in °C)

We can use these equations to find emergency ampacity ratings of cables. In an emergency, XLPE can be operated to 130°C. Some EPR cables can be operated to 140°C (MV-105 cables). ICEA standards allow emergency overload for 100 hours per year with five such periods over the life of the cable. PE cables, including HMWPE, have little overload capability. Their maximum recommended emergency temperature is 95°C. Table 4.21 shows common ampacity multipliers; these are valid for both copper and aluminum conductors within the accuracy shown. We can also use the appropriate temperature-adjustment equation to adjust for different ambient earth temperatures.

Loss factor—The earth has a high thermal storage capability; it takes considerable time to heat (or cool) the soil surrounding the cable. Close to the cable, the peak heat generated in the cable determines the temperature drop; farther out, the average heat generated in the cable determines the temperature drop. As discussed in Chapter 6, we normally account for losses using the loss factor, which is the average losses divided by the peak losses. Since this number is not normally available, we find the loss factor from the load factor (the load factor is the average load divided by the peak load). Assuming a 100% load factor (continuous current) is most conservative but can lead to a cable that is larger than necessary. We should try to err on the high side when estimating the load factor. A 75% load factor is commonly used.

Conduits—The air space in conduits or ducts significantly reduces ampacity. The air insulation barrier traps more heat in the cable. Direct-buried cables may have 10 to 25% higher ampacities. Although, the less air the better, there is little practical difference in the thermal performance between the sizes of ducts commonly used. Concrete duct banks have roughly the same thermal performance as direct-buried conduits (concrete is more consistent and less prone to moisture fluctuations).

Soil thermal resistivity and temperature—Soils with lower thermal resistivity more readily conduct heat away from cables. Moisture is an important component, moist soil has lower thermal resistivity (see Figure 4.12). Dense soil normally has better conductivity. More so than any other single factor, soil resistivity impacts the conductor's temperature and the cable's ampacity. A resistivity of 90°C-cm/W is often assumed for ampacity calculations. This number is conservative enough for many areas, but if soil resistivities are higher, cable temperatures can be much higher than expected. For common soils, Table 4.22 shows typical ranges of thermal resistivities. At typical installation depths, resistivity varies significantly with season as moisture content changes. Unfortunately in many locations, just when we need ampacity the most—during peak load in the summer—the soil is close to its hottest and driest. Seasonal

TABLE 4.21 Common Ampacity Rating Conversions (with T_A = 25°C)

Original Temperature, °C	New Temperature, °C	Ampacity Multiplier
75	95	1.15
90	75	0.90
90	105	1.08
90	130	1.20
105	140	1.14

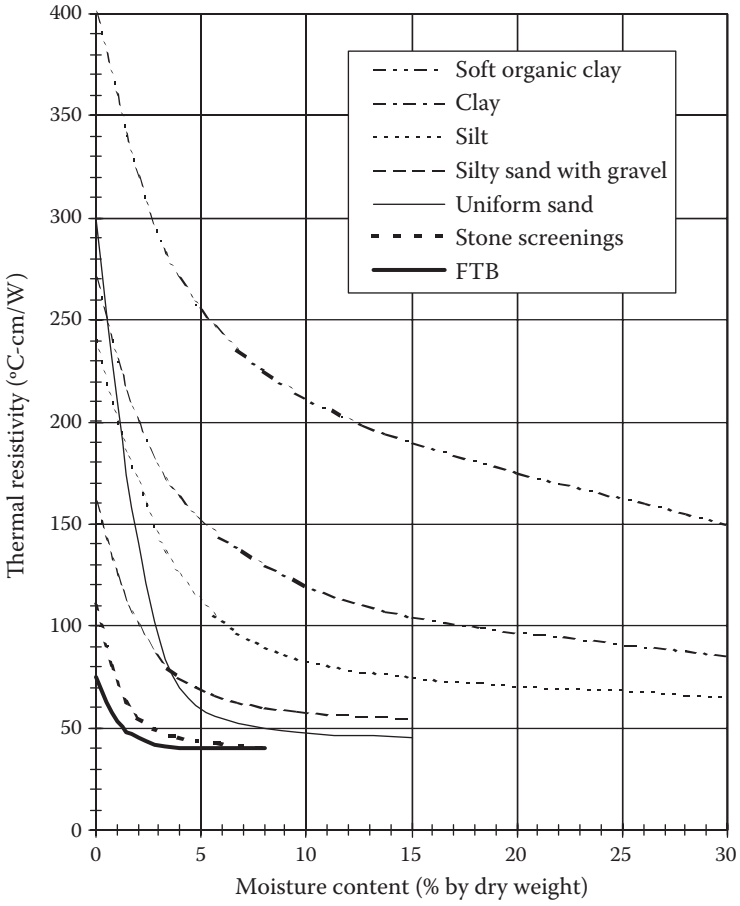

Figure 4.12 Effect of moisture on the thermal resistivity of various soils. (From EPRI TR-108919, *Soil Thermal Properties Manual for Underground Power Transmission*, Electric Power Research Institute, Palo Alto, CA, 1997. Copyright 1997. Reprinted with permission.)

changes can be significant, but daily changes are not; soil temperature changes lag air temperature changes by 2 to 4 weeks.

The depth of burial can affect ampacity. With a constant resistivity and soil temperature, deeper burial decreases ampacity. But deeper, the soil tends to have lower temperature, more moisture, and soil is more stable seasonally. To go deep enough to take advantage of this is not cost effective though.

For areas with poor soil (high clay content in a dry area, for example), one of several thermal backfills can give good performance, with stable resistivities below 60°C-cm/W even when moisture content drops below 1%.

Earth interface temperature—Because soil conductivity depends on moisture, the temperature at the interface between the cable or duct and the soil is important. Unfortunately, heat tends to push moisture away. High interface temperatures can dry out the surrounding soil, which further increases the soil's thermal resistivity. Soil drying can lead to a runaway situation; hotter cable temperatures dry the soil

TABLE 4.22 Typical Thermal Resistivities of Common Soils

USCS	Soil	Dry Density (g/cm^3)	Range of Moisture Contents (%) Above Water Table	Saturated Moisture Content (%)	Thermal Resistivity (°C-cm/W) Wet–Dry
GW	Well-graded gravel	2.1	3–8	10	40–120
GP	Poor-graded gravel	1.9	2–6	15	45–190
GM	Silty gravel	2.0	4–9	12	50–140
GC	Clayey gravel	1.9	5–12	15	55–150
SW	Well-graded sand	1.8	4–12	18	40–130
SP	Uniform sand	1.6	2–8	25	45–300
SM	Silty sand	1.7	6–16	20	55–170
SC	Clayey sand	1.6	8–18	25	60–180
ML	Silt	1.5	8–24	30	65–240
CL	Silty clay	1.6	10–22	25	70–210
OL	Organic silt	1.2	15–35	45	90–350
MH	Micaceous silt	1.3	12–30	40	75–300
CH	Clay	1.3	20–35	40	85–270
OH	Soft organic clay	0.9	30–70	75	110–400
Pt	Silty peat	0.4			150–600+

Source: From EPRI TR-108919, *Soil Thermal Properties Manual for Underground Power Transmission*, Electric Power Research Institute, Palo Alto, CA, 1997. Copyright 1997. Reprinted with permission.

more, raising the cable temperature more and so on. Some soils, especially clay, shrink significantly as it dries; the soil can pull away from the cable, leaving an insulating air layer. Thermal runaway can lead to immediate failure. Direct-buried cables are the most susceptible; ducts provide enough of a barrier that temperature is reduced by the time it reaches the soil.

Depending on the soil drying characteristics in an area, we may decide to limit earth interface temperatures. Limiting earth interface temperatures to 50 to 60°C reduces the risk of thermal runaway. But doing this also significantly decreases the ampacity of direct-buried cable to about that of cables in conduit. In fact, using the conduit ampacity values is a good approximation for the limits needed to keep interface temperatures in the 50 to 60°C range.

Current unbalance—Almost every ampacity table (including those in this section) assumes balanced, three-phase currents. On multigrounded distribution systems, this assumption is rarely true. An ampacity of 100 A means a limit of 100 A on each conductor. Unbalance restricts the power a three-phase cable circuit can carry ($I_A = I_B = I_C = 100$ A carries more power than $I_A = 100$ A, $I_B = I_C = 70$ A). In addition, the unbalanced return current may increase the heating in the cable carrying the highest current. It may or it may not; it depends on phase relationships and the phase angle of the unbalanced current. If the unbalances are just right, the unbalanced return current can significantly increase the neutral current on the most heavily loaded phases. Unbalance also depends on the placement of the cables. In a flat configuration, the middle cable is the most limiting because the outer two cables heat the middle cable.

Just as higher sheath resistances reduce circulating currents, higher sheath resistances reduce unbalanced currents in the sheath. Higher sheath resistances force more of the unbalanced current to return to the earth. The heat generated in the sheath from unbalanced current also decreases with increasing sheath resistance (except for very low sheath resistances, where the sheath has lesser resistance than the phase conductor).

System voltage and insulation thickness—Neither significantly impacts the ampacity of distribution cables. Ampacity stays constant with voltage; 5-kV cables have roughly the same ampacity as 35-kV cables. At higher voltages, insulation is thicker, but this rise in the thermal resistance of the insulation reduces the ampacity just slightly. Higher operating voltages also cause higher dielectric losses, but again, the effect is small (it is more noticeable with EPR cable).

Number of cables—Cables in parallel heat each other, which restricts ampacity. Figure 4.13 shows an example for triplex power cables in duct banks.

Cable crossings and other hotspots—Tests have found that cable crossings can produce significant hotspots (Koch, 2001). Other hotspots can occur in locations where cables are paralleled for a short distance like taps to padmounted transformers or other gear. Differences in surface covering (such as asphalt roads) can also produce hot spots. Anders and Brakelmann (1999a,b) provide an extension to the Neher–McGrath model that includes the effects of cable crossings at different angles. They conclude: "the derating of 3 to 5% used by some utilities may be insufficient, especially for cables with smaller conductors."

Riser poles—Cables on a riser pole require special attention. The protective vertical conduit traps air, and the sun adds external heating. Hartlein and Black (1983) tested a specific riser configuration and developed an analytical model. They concluded that the size of the riser and the amount of venting were important. Large diameter risers vented at both ends are the best. With three cables in one riser, they found that the riser portion of the circuit limits the ampacity. This is especially important in substation exit cables and their riser poles. In a riser pole application, ampacity does not increase for lower load factors; a cable heats up much faster in the air than when buried in the ground (the air has little thermal storage). NRECA (1993) concluded

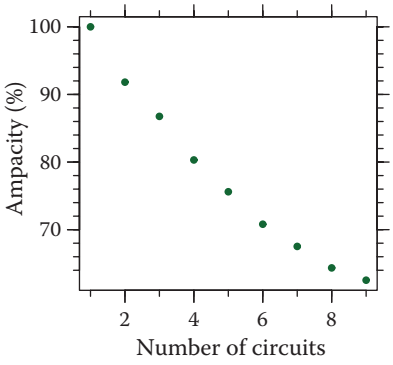

Figure 4.13 Ampacity reduction with multiple cable circuits in a duct bank (15 kV, aluminum, 500 kcmil, tape shield power cables, triplex configuration).

that properly vented risers do not need to be derated, given that venting can increase ampacity between 10% and 25%. If risers are not vented, then the riser becomes the limiting factor. Additional work in this area has been done by Cress and Motlis (1991) (tests and modeling for submarine cables in riser poles) and Anders (1996) (an updated analytical model).

4.6 Fault Withstand Capability

Short-circuit currents through a conductor's resistance generates tremendous heat. All cables between the source and the fault is subjected to the same phase current. For cables, the weakest link is the insulation; both XLPE and EPR have a short-duration upper temperature limit of 250°C. The short-circuit current injects energy as a function of the fault duration multiplied by the square of the current.

For aluminum conductors and XLPE or EPR insulation, the maximum allowable time–current characteristic is given by

$$I^2t = (48.4\text{A})^2$$

where

I = fault current, A
t = fault duration, sec
A = cross-sectional area of the conductor, kcmil

This assumes an upper temperature limit of 250°C and a 90°C starting temperature. For copper, the upper limit is defined by

$$I^2t = (72.2\text{A})^2$$

We can plot these curves along with the time–current characteristics of the protecting relay, fuse, or recloser to ensure that the protective devices protect our cables.

Damage to the shield or the neutral is more likely than damage to the phase conductor. During a ground fault, the sheath may conduct almost as much current as the phase conductor, and the sheath is normally smaller. With a one-third neutral, the cable neutral's I^2t withstand is approximately 2.5 times less than the values for the phase conductor indicated in Figure 4.14 (this assumes a 65°C starting temperature). Having more resistance, a tape shield is even more vulnerable. A tape shield has a limiting time–current characteristic of

$$I^2t = (z \cdot A)^2$$

where z is 79.1 for sheaths of copper, 58.2 for bronze, 39.2 for zinc, 23.7 for copper-nickel, and 15 for lead (with a 65°C starting temperature and an upper limit of 250°C; using data from Kerite Company). Figure 4.15 shows withstand characteristics for a 5-mil copper tape shield. The characteristic changes with cable size because larger

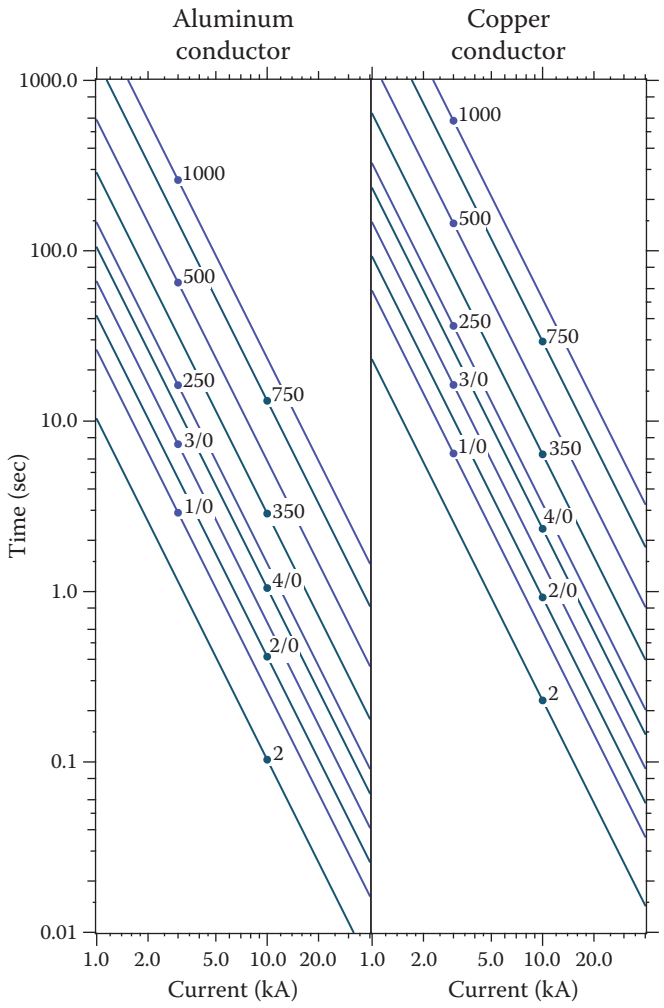

Figure 4.14 Short-circuit limit of cables with EPR or XLPE insulation.

diameter cables have a shield with a larger circumference and more cross-sectional area. If a given fault current lasts longer than five times the insulation withstand characteristic (at 250°C), the shield reaches its melting point.

In the vicinity of the fault, the fault current can cause considerably more damage to the shield or neutral. With a concentric neutral, the fault current may only flow on a few strands of the conductor until the cable has a grounding point where the strands are tied together. Excessive temperatures can damage the insulation shield, the insulation, and the jacket. In addition, the temperature may reach levels that melt the neutral strands. A tape shield can suffer similar effects: where tape layers overlap, oxidation can build up between tape layers, which insulate the layers from each other. This can restrict the fault current to a smaller portion of the shield. Additionally, where the fault arc attaches, the arc injects considerable heat into the shield or neutral, causing further damage at the failure point. Some additional damage at the fault

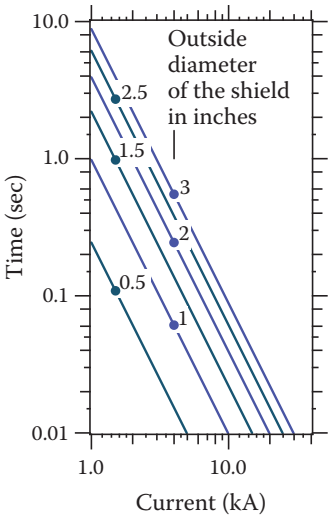

Figure 4.15 Short-circuit insulation limit of copper tape shields based on outside diameter (starting temperature is 65°C, final temperature is 250°C, 20% lap on the shield).

location must be tolerated, but the arc can burn one or more neutral strands several feet back toward the source.

Martin et al. (1974) reported that longitudinally corrugated sheaths perform better than wire or tape shields for high fault currents. They also reported that a semiconducting jacket helped spread the fault current to the sheaths of other cables (the semiconducting material breaks down).

Pay special attention to substation exit cables in areas with high fault currents (especially since exit cables are critical for circuit reliability). During a close fault, where currents are high, a reduced neutral or tape shield is most prone to damage.

4.7 Cable Reliability

4.7.1 Water Trees

The most common failure cause of solid-dielectric cables has been *water treeing*. Water trees develop over a period of many years and accelerate the failure of solid dielectric cables. Excessive treeing has led to the premature failure of many PE cables. Cable insulation can tree two ways:

- *Electrical trees*—These hollow tubes develop from high electrical stress; this stress creates partial discharges that eat away at the insulation. Once initiated, electrical trees can grow fast, failing cable within hours or days.
- *Water trees*—Water trees are small discrete voids separated by insulation. Water trees develop slowly, growing over a period of months or years. Much less electrical stress is needed to cause water trees. Water trees actually look more like fans, blooms, or bushes whereas electrical trees look more like jagged branched trees. As

its name indicates, water trees need moisture to grow; water that enters the dielectric accumulates in specific areas (noncrystalline regions) and causes localized degradation. Voids, contaminants, temperature, and voltage stress—all influence the rate of growth.

The formation of water trees does not necessarily mean the cable will fail. A water tree can even bridge the entire dielectric without immediate failure. Failure occurs when a water tree converts into an electrical tree. One explanation of the initiation of electrical trees is from charges trapped in the cable insulation. In Thue's words (1999), "they can literally bore a tunnel from one void or contaminant to the next." Impulses and dc voltage (in a hi-pot test) can trigger electrical treeing in a cable that is heavily water treed.

The growth rate of water trees tends to reduce with time; as trees fan out, the electrical stress on the tree reduces. Trees that grow from contaminants near the boundary of the conductor shield are most likely to keep growing. These are "vented" trees. Bow-tie trees (those that originate inside the cable) tend to grow to a critical length and then stop growing.

The electrical breakdown strength of aged cable has variation, a variation that has a skewed probability distribution. Weibull or lognormal distributions are often used to characterize this probability and predict future failure probabilities.

PE insulation systems have been plagued by early failures caused by water trees. Early XLPE and especially HMWPE had increasing failure rates that have led utilities to replace large quantities of cable. By most accounts, PE-based insulation systems have become much more resistant to water treeing and more reliable for many reasons (Dudas, 1994; EPRI 1001894, 2001; Thue, 1999):

- *Extruded semiconducting shields*—Rather than taped conductor and insulation shields, manufacturers extrude both semiconducting shields as they are extruding the insulation. This one-pass extrusion provides a continuous, smooth interface. The most dangerous water trees are those that initiate from imperfections at the interface between the insulation and the semiconducting shield. Reducing these imperfections reduces treeing.
- *Cleaner insulation*—AEIC specifications for the allowable number and size of contaminants and protrusions have steadily improved. Both XLPE compound manufacturers and cable manufacturers have reduced contaminants by improving their production and handling processes.
- *Fewer voids*—Dry curing reduces the number and size of voids in the cable. Steam-cured cables pass through a long vulcanizing tube filled with 205°C steam pressurized at 20 atm. Cables cured with steam have sizeable voids in the insulation. Instead of steam, dry curing uses nitrogen gas pressurized to 10 atm; an electrically heated tube radiates infrared energy that heats the cable. Dry curing has voids, but these voids have volumes 10 to 100 times less than with steam curing.
- *Tree-retardant formulations*—Tree-retardant formulations of XLPE perform much better in accelerated aging tests, tests of field-aged cables, and also in field experience.

EPR insulation has proven to be naturally water tree resistant; EPR cables have performed well in service since the 1970s. EPR insulation can and does have water

trees, but they tend to be smaller. EPR cable systems have also improved by having cleaner insulation compounds, jackets, and extruded semiconductor shields.

Several accelerated aging tests have been devised to predict the performance of insulation systems. The tests use one of two main methods to quantify performance: (1) loss of insulation strength or (2) time to failure. In accelerated aging, testers normally submerge cables in water, operate the cables at a continuous overvoltage, and possibly subject the cables to thermal cycling. The accelerated water treeing test (AWTT) is a protocol that measures the loss of insulation strength of a set of samples during one year of testing (ANSI/ICEA S-94-649-2000, 2000). The wet aging as part of this test includes application of three times rated voltage and current sufficient to heat the water to 60°C. In another common test protocol, the accelerated cable life test (ACLT), cables are submerged in water, water is injected into the conductor strands, cables are operated to (commonly) four times nominal voltage, and cables are brought to 90°C for eight hours each day. The cables are operated to failure. Brown (1991) reported that under such a test, XLPE and TR-XLPE cables had geometric mean failure times of 53 and 161 days, respectively. Two EPR constructions did not fail after 597 days of testing. Because EPR and XLPE age differently depending on the type of stress, EPR can come out better or worse than TR-XLPE, depending on the test conditions. There is no consensus on the best accelerated-aging test. Normally such tests are used to compare two types of cable constructions. Bernstein concludes, "… there is still no acceptable means of relating service and laboratory aging to 'remaining life'" (EPRI 1000273, 2000).

Even without voltage, XLPE cable left outdoors can age. EPRI found that XLPE cables left in the Texas sun for 10 years lost over 25% of their ac insulation strength (EPRI 1001389, 2002). These researchers speculate that heating from the sun led to a loss of peroxide decomposition by-products, which is known to result in loss of insulation strength.

Since water promotes water treeing, a few utilities use different forms of water blocking (Powers, 1993). Water trees grow faster when water enters the insulation from both sides: into the conductor strands and through the cable sheath. The most common water-protection method is a filled strand conductor; moisture movement or migration is minimized by the filling, which can be a semiconducting or an insulating filler. Another variation uses water-absorbing powders; as the powder absorbs water it turns to a gel that blocks further water movement. An industry standard water blocking test is provided (ICEA Publication T-31-610, 1994; ICEA Publication T-34-664, 1996). In addition to reducing the growth and initiation of water trees, a strand-blocked conductor reduces corrosion of aluminum phase conductors. We can also use solid conductors to achieve the same effect (on smaller cables).

Another approach to dealing with water entry and treeing in existing cable is to use a silicone injection treatment (Nannery et al., 1989). After injection into the stranded conductor, the silicone diffuses out through the conductor shield and into the insulation. The silicone fills water-tree voids and reacts with water such that it dries the cable. This increases the dielectric strength and helps prevent further treeing and loss of life. Northeast Utilities has data covering 10 years of injection (EPRI 1019937, 2010). Their annual failure rate of injected cable was 1.2 failures/100 mi compared

with 29 failures/100 mi for similar uninjected cable (though they point out that the numbers are not directly comparable). They found that in 18% of cases, the cable could not be injected.

Another way to increase the reliability is to increase the insulation thickness. As an example, the maximum electrical stress in a cable with an insulation thickness of 220 mil (1 mil = 0.001 in. = 0.00254 cm) is 14% lower than a 175-mil cable (Mackevich, 1988).

Utilities and manufacturers have taken steps to reduce the likelihood of cable degradation. Table 4.23 shows trends in cable specifications for underground residential cable. Tree-retardant insulation and smooth semiconductor shields, jackets and filled conductors, and dry curing and triple extrusion are features specified by utilities to improve reliability.

Good lightning protection also reduces cable faults. This requires surge arresters at the riser pole and possibly arresters at the cable open point (depending on the voltage). Keep arrester lead lengths as short as possible. Surges are a known cause of dielectric failures. Surges that do not fail the insulation may cause aging. Accelerated aging tests have found that 15-kV XLPE cables tested with periodic surges applied with magnitudes of 40, 70, and 120 kV failed more often and earlier than samples that were not surged (EPRI EL-6902, 1990; EPRI TR-108405-V1, 1997; Hartlein et al., 1989, 1994). Very few of the failures occurred during the application of a surge; this follows industrial observations that cables often fail after a thunderstorm, not during the storm.

Rather than continue patching, many utilities regularly replace cable. Program policies are done based on the number of failures (the most common approach), cable inspection, customer complaints, or cable testing. HMWPE and older XLPE are the most likely candidates for replacement. Most commonly, utilities replace cable after two or three electrical failures within a given time period (see Table 4.24).

TABLE 4.23 Trends in URD Cable Specifications

Characteristic	1983	1988	1993	1998
XLPE insulation	84	52	20	0
TR-XLPE insulation		36	52	68
EPR insulation	12	12	28	32
Protective jacket	64	80	92	93[a]
Filled strand conductor	4	32	60	68
Dry cure for XLPE and TR-XLPE		24	56	52
Triple extrusion		44	64	67[a]
Supersmooth semicon shields		0	44	56
Bare copper neutrals		72	84	

Data sources: Dudas, J. H., *IEEE Electrical Insulation Magazine*, 10(2), 7–16, March/April 1994; Dudas, J. H. and Rodgers, J. R., *IEEE Transactions on Industry Applications*, vol. 35, no. 2, pp. 324–31, March/April 1999.

Note: Percentage of the 25 largest investor-owned utilities in the United States that specify the given characteristic.

[a]Somewhat different data set: percentages from the top 45 largest investor-owned utilities.

TABLE 4.24 Typical Cable Replacement Criteria

Replacement Criteria	Responses ($n = 51$)
One failure	2%
Two failures	31%
Three failures	41%
Four failures	4%
Five failures	6%
Based on evaluation procedures	16%

Data source: Tyner, J. T., *Transmission & Distribution World*, vol. 50, no. 7, pp. 44–56, July 1998.

4.7.2 Other Failure Modes

Cable faults can be caused by several events including:

- Dig-ins
- Cable failures
- Cable equipment failures—splices, elbows, terminations

Better public communications reduces dig-ins into cables. The most common way is with one phone number that can be used to coordinate marking of underground facilities before digging is done. Physical methods of reducing dig-ins include marker tape, surface markings, or concrete covers. Marker tape identifies cable. A few utilities use surface marking to permanently identify the location of underground facilities. Concrete covers above underground facilities physically block dig-ins.

Temporary faults are unusual in underground facilities. Faults are normally bolted, permanent short circuits. Reclosing will just do additional damage to the cable. Occasionally, animals or water will temporarily fault a piece of live-front equipment. Recurring temporary faults like these can be very difficult to find.

Another type of temporary, self-clearing fault can occur on a cable splice (Stringer and Kojovic, 2001). Figure 4.16 shows a typical waveform of an impending splice failure. This type of fault has some distinguishing characteristics: it self-clears in 1/4 cycle, the frequency of occurrence increases with time, and faults occur near the peak of the voltage. The author has observed this type of fault during monitoring (but never identified the culprit). This type of fault can occur in a cable splice following penetration of water into the splice. The water breaks down the insulation, then the arc energy melts the water and creates vapor at high pressure. Finally, the high-pressure vapor extinguishes the arc. The process can repeat when enough water accumulates again until the failure is permanent. This type of self-clearing fault can go unnoticed until it finally fails. The downside is that it causes a short-duration voltage sag that may affect sensitive equipment. Another problem, the fault may have enough current to blow a fuse; but since the fault self-clears, it can be much harder to find. Crews may just replace the fuse (successfully) and leave without replacing the damaged equipment.

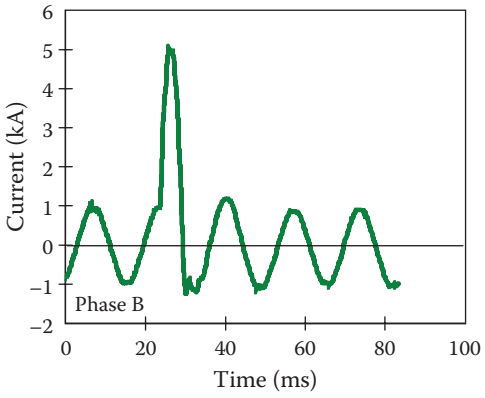

Figure 4.16 Self-clearing fault signature on an incipient cable-splice failure. (From Stringer, N. T. and Kojovic, L. A., *IEEE Trans. Industry App.* vol. 37, no. 1, pp. 230–239, Jan./Feb. 2001. © 2001 IEEE.)

4.7.3 Failure Statistics

The annual failure of cables is on the order of 6 to 7 failures per 100 mi per year (3.7 to 4.3 failures per 100 km/year) according to survey data from the Association of Edison Illuminating Companies from 1965 through 1991 (Thue, 1999). Figure 4.17 shows cable failure data from a variety of sources; experience varies widely. Application, age, and type of cable markedly change the results. Utilities have experienced high failures of HMWPE, especially those that were installed in the early 1970s. An EPRI database of 15 utilities showed a marked increase in failure rates for HMWPE cables with time (Stember et al., 1985). XLPE also shows a rise in failure rates with time, but not as dramatic (see Figure 4.18). The EPRI data showed failure rates increased faster with a higher voltage gradient on the dielectric for both HMWPE and XLPE.

Much of the failure data in Figure 4.17 is dominated by earlier PE-based cable insulation technologies. Not as much data is available on the most commonly used insulation materials: TR-XLPE and EPR. The AEIC survey reported results in 1991—both had fewer than 0.5 failures per 100 cable mi during that year. TR-XLPE results were better (0.2 versus 0.4 failures/100 mi/year for EPR), but the installed base of TR-XLPE would have been newer than EPR at that time. Jacketed cable has had fewer failures than unjacketed cable as shown in Table 4.25.

Con Edison in New York City has a large database of cable and accessory failures from 1998 to 2007. Figure 4.19 summarizes cable failures by cause (Campbell, 2008). Campbell also reported the following annual failure rates covering 1999 through 2007:

- PILC: 0.22 failures per 100 sections with a flat trend line
- XLPE: 0.14 failures per 100 sections with an increasing trend line (from 0.12 in 1998 to 0.15 in 2007)
- EPR: 0.07 failures per 100 sections with a decreasing trend line (from 0.093 in 1998 to 0.054 in 2007)

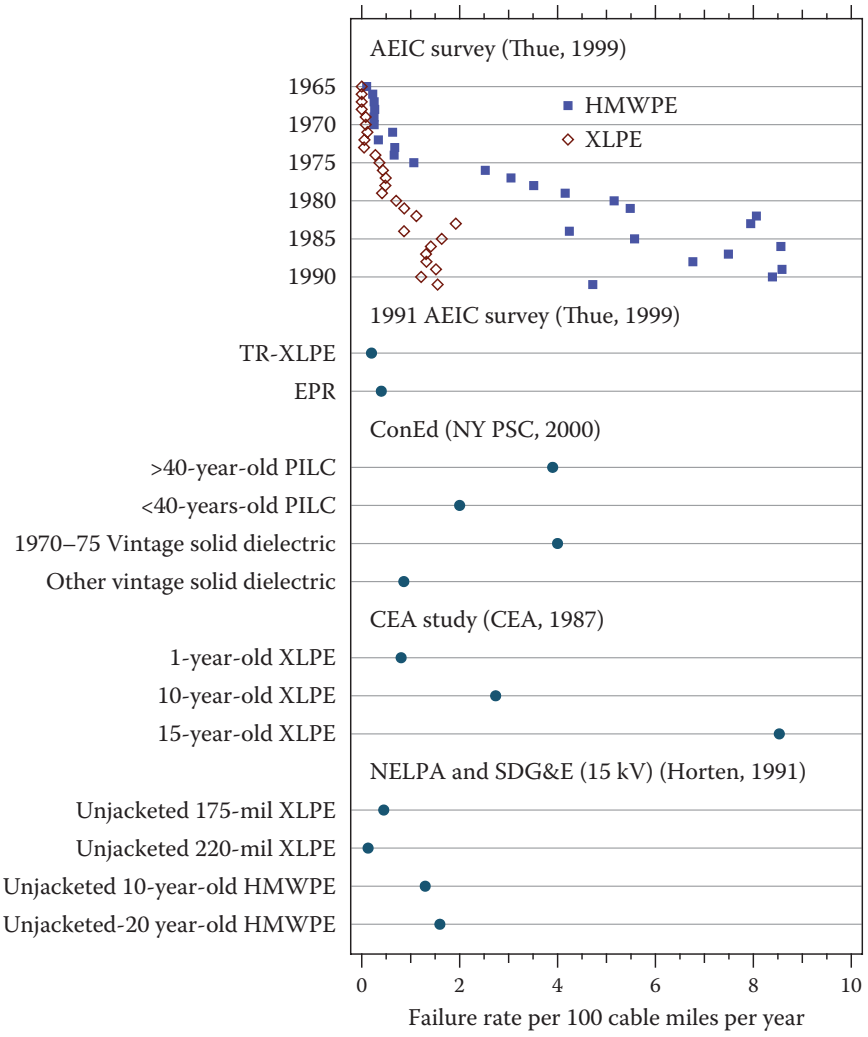

Figure 4.17 Cable failure rates found in different studies and surveys (in cable miles, not circuit miles). (Data from CEA 117 D 295, *Survey of Experience with Polymer Insulated Power Cable in Underground Service*, Canadian Electrical Association, 1987; Horton, W. F. and Golberg, S., Determination of failure rates of underground distribution system components from historical data, *IEEE/PES Transmission and Distribution Conference*, 1991; State of New York Department of Public Service, A report on consolidated Edison's July 1999 system outages, March 2000; Thue, 1999.)

Another consideration for underground circuits is the performance of connectors and other cable accessories. 200-A elbows have failed at high rates (and they tend to fail when switching under load) (Champion, 1986). One important factor is that the type of splice should be correctly matched with the type of cable (Mackevich, 1988). Table 4.26 shows annual failure rates for some common underground components that were developed based on data from the Northwest

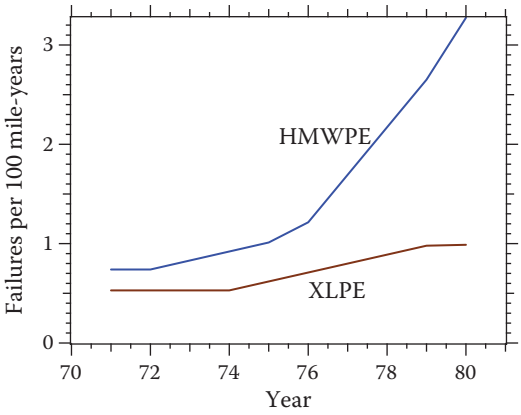

Figure 4.18 Cumulative service-time failure rates for HMWPE and XLPE cable. (From Stember, L. H. et al., *IEEE Trans. Power Apparatus Sy*stems, vol. PAS-104, no. 8, pp. 1979–85, August 1985. © 1985 IEEE.)

TABLE 4.25 Comparison of the Median of the Average Yearly Failure Rates of XLPE Found by AEIC from 1983 to 1991

Configuration	Failures per 100 Cable miles/year
No jacket	3.1
Jacketed	0.2
Direct buried	2.6
Duct	0.2

Source: Data from Thue, W. A., *Electrical Power Cable Engineering*, Marcel Dekker, New York, 1999.

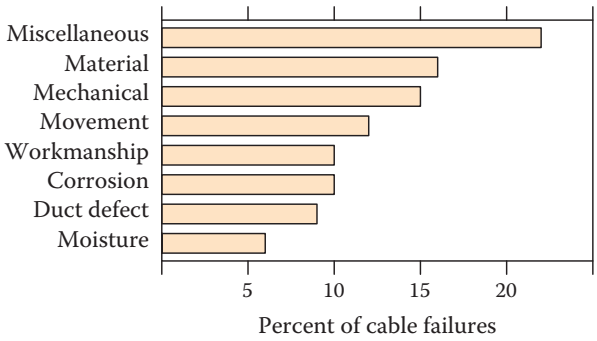

Figure 4.19 Causes of failures of Con Edison cables. (Data from Campbell, T., Three decades of cable failure data, *IEEE Insulated Conductors Committee meeting*, St. Petersburg Beach, FL, March 10, 2008.)

TABLE 4.26 Annual Underground-Component Failure Rates

Component	Annual Failure Rate, %
Load-break elbows	0.009*t*
15-kV molded rubber splices	0.31
25-kV molded rubber splices	0.18
35-kV molded rubber splices	0.25
Single-phase padmounted transformers	0.3

Data sources: Horton, W. F. and Golberg, S., The failure rates of underground distribution system components, *Proceedings of the Twenty-Second Annual North American Power Symposium*, 1990; Horton, W. F. and Golberg, S., Determination of failure rates of underground distribution system components from historical data, *IEEE/PES Transmission and Distribution Conference*, 1991.

Note: t is the age of the elbow in years.

Underground Distribution Committee of the Northwest Electric Light and Power Association (Horton and Golberg, 1990; 1991). Table 4.27 shows failure rates of splices for New York City.

An EPRI review of separable connector reliability found mixed results (EPRI 1001732, 2002). Most utilities do not track these failures. One utility that did keep records found that failure rates of separable connectors ranged from 0.1% to 0.4% annually. Of these failures, an estimated 3 to 20% is from overheating. They also suggested that thermal monitoring is a good practice, but effectiveness is limited because the monitoring is often done when the loadings and temperatures are well below their peak.

Hartlein (2012) reported that in a 2008 NEETRAC survey, cable joints and terminations had a high infant mortality rate, and in addition, almost half of accessory failures were poor workmanship (see Figure 4.20). Hartlein also described a number of important workmanship issues and ways to avoid them, including:

- Correct blade depth adjustment prior to making cutbacks, so cable insulation is not damaged
- Proper cleaning of insulation
- Keeping the cable clean
- Wire brushing
- Applying appropriate compression to the connector

TABLE 4.27 Underground Network Component Failure Rates in New York City (Con Edison)

Component	Annual Failure Rate, %
Splices connecting paper to solid cables (stop joints)	1.20
Splices connecting similar cables (straight joints)	0.51
Network transformers	0.58

Data source: State of New York Department of Public Service, A Report on Consolidated Edison's July 1999 System Outages, March 2000.

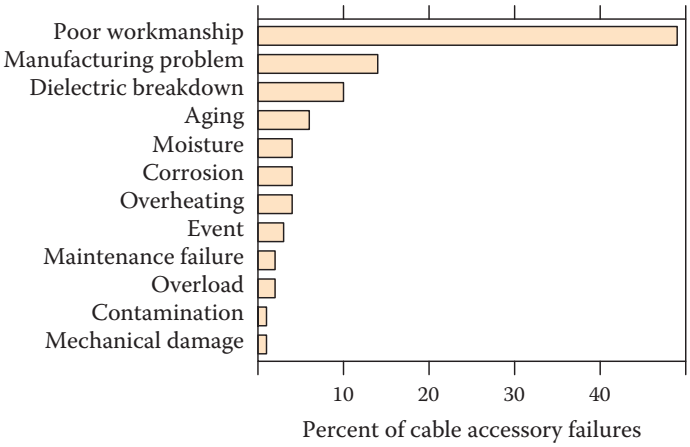

Figure 4.20 Causes of cable joint and termination failures based on a NEETRAC survey. (Data source: Hartlein, R. A., Secrets of underground distribution installation & condition assessment (birth to death), TechAdvantage, Nashville, TN, National Rural Electric Cooperative Association (NRECA), 2012.)

4.8 Cable Testing

A common approach to test cable and determine insulation integrity is to use a hi-pot (withstand) test. In a hi-pot test, a dc voltage is applied for 5 to 15 min. IEEE-400 specifies that the hi-pot voltage for a 15-kV class cable is 56 kV for an acceptance test and 46 kV for a maintenance test (ANSI/IEEE Std. 400-2012). Other industry standard tests are given in (AEIC CS5-94, 1994; AEIC CS6-96, 1996; ICEA S-66-524, 1988). High-pot testing is a brute-force test; imminent failures are detected, but the amount of deterioration due to aging is not quantified (it is a go/no–go test).

The dc test is controversial—some evidence has shown that hi-pot testing may damage XLPE cable (Mercier and Ticker, 1998). EPRI work has shown that dc testing accelerates treeing (EPRI TR-101245, 1993; EPRI TR-101245-V2, 1995). For hi-pot testing of 15-kV, 100% insulation (175-mil, 4.445-mm) XLPE cable, EPRI recommended:

- Do not test at 40 kV (228 V/mil) on cables that are aged (especially those that failed once in service and then spliced). Above 300 V/mil, deterioration was predominant.
- New cable can be tested at the factory at 70 kV. No effect on cable life was observed for testing of new cable.
- New cable can be tested at 55 kV in the field prior to energization if aged cable has not been spliced in.
- Testing at lower dc voltages (such as 200 V/mil) will not pick out bad sections of cable.

Another option for testing cable integrity, ac testing, does not degrade solid dielectric insulation (or at least degrades it more slowly). The use of very low-frequency ac

(at about 0.1 Hz) to withstand testing may cause less damage to aged cable than dc testing (Eager et al., 1997). The low frequency has the advantage that the equipment is much smaller than 60-Hz ac testing equipment.

A number of technologies are available to help diagnose cable health, including dielectric response tests like tan delta and various partial discharge detection approaches. The cable diagnostic focused initiative (CDFI) has evaluated several cable diagnostic tests based on many diagnostic tests followed by failure monitoring (NEETRAC, 2010).

The tan delta (δ) or dissipation factor test is a type of dielectric response test that tests the insulation system of the section under test as a whole. Tan delta is a measurement of the resistive portion of the insulation to the capacitive portion of the insulation:

$$\tan\delta = \frac{I_R}{I_C}$$

where

I_R = resistive (loss) component of the current
I_C = capacitive (charging) component of the current

Stable cable systems should have stable tan δ, independent of voltage and time. Tan δ can be applied to all major insulation systems, although each has its own set of typical tan δ characteristics. Cable systems with increasing tan δ over time or increasing tan δ with increasing voltage indicates deteriorated insulation. Tan δ can be measured with different source voltages with very low-frequency ac typically used. The CDFI developed criteria for assessment of cables based on three criteria: tan δ at operating phase-to-ground voltage (1.0 per unit), the "tip up" or change in tan δ between 0.5 and 1.5 per unit voltage, and the standard deviation of tan δ at 1.0 per unit voltage (NEETRAC, 2010). Then, thresholds were developed for each of these to classify based on "no action," "further study," and "action required" for each major type of cable insulation. The "action required" threshold was developed to match the 95th percentile point in the utility measurement dataset, and NEETRAC found that this corresponded to a 32% probability of failure within 2 years.

Partial discharge measurements can also provide diagnostics. Partial discharges are small arcs discharging across gas-filled voids in cables or accessories. Partial discharges can be picked up between frequency ranges of 100 kHz to 100 MHz. Partial discharge detection can be used with various sources, including online measurements with the power-frequency source and offline measurements using 60-Hz ac, damped ac, or very low-frequency ac. Partial discharges can detect deterioration in all major cable insulation types. Thresholds for risk or for action are normally provided by equipment manufacturers.

A monitored withstand test combines a withstand test with a diagnostic measure like tan δ or partial discharge. By adding a diagnostic, the test result is more than just a go/no-go test, and the diagnostics can be used to adjust test parameters. Fletcher

et al. (2011) describe a monitored withstand test based on very low-frequency ac withstand in combination with tan δ measurements. They describe a voltage step-up phase covering 5 min where the voltage is stepped from 0.5 per unit to 1.5 per unit. Tan δ measurements from this step-up phase are used to adjust the overall length of the test; if the tan δ measurements are questionable, the withstand test is run longer (one hour in their case). Likewise, if the tan δ measurements suggest good cable properties, the test time is reduced to 15 min; this case happens 80% of the time. Fletcher et al. also offered criteria for test adjustment based on tan δ criteria for different insulation types. Results provide a qualitative estimate as well as a go/no-go result.

4.9 Fault Location

Utilities use a variety of tools and techniques to locate underground faults. Several are described in the next few paragraphs [see also EPRI TR-105502 (1995) and EPRI 1019937 (2010)].

Divide and conquer—On a radial tap where the fuse has blown, crews narrow down the faulted section by opening the cable at locations. Crews start by opening the cable near the center, then they replace the fuse. If the fuse blows, the fault is upstream; if it doesn't blow, the fault is downstream. Crews then open the cable near the center of the remaining portion and continue bisecting the circuit at appropriate sectionalizing points (usually padmounted transformers). Of course, each time the cable faults, more damage is done at the fault location, and the rest of the system has the stress of carrying the fault currents. Using current-limiting fuses reduces the fault-current stress but increases the cost.

Fault indicators—Faulted circuit indicators (FCIs) are small devices clamped around a cable that measure current and signal the passage of fault current. Normally, these are applied at padmounted transformers. Faulted circuit indicators do not pinpoint the fault; they identify the fault to a cable section. After identifying the failed section, crews must use another method such as the thumper to precisely identify the fault. If the entire section is in conduit, crews don't need to pinpoint the location; they can just pull the cable and replace it (or repair it if the faulted portion is visible from the outside). Cables in conduit require less precise fault location; a crew only needs to identify the fault to a given conduit section.

Utilities' main justification for faulted circuit indicators is reducing the length of customer interruptions. Faulted circuit indicators can significantly decrease the fault-finding stage relative to the divide-and-conquer method. Models that make an audible noise or have an external indicator decrease the time needed to open cabinets.

Utilities use most fault indicators on URD loops. With one fault indicator per transformer (see Figure 4.21), a crew can identify the failed section and immediately reconfigure the loop to restore power to all customers. The crew can then proceed to pinpoint the fault and repair it (or even delay the repair for a more convenient time). For larger residential subdivisions or for circuits through commercial areas, location is more complicated. In addition to transformers, fault indicators should be placed at each sectionalizing or junction box. On three-phase circuits, either a three-phase

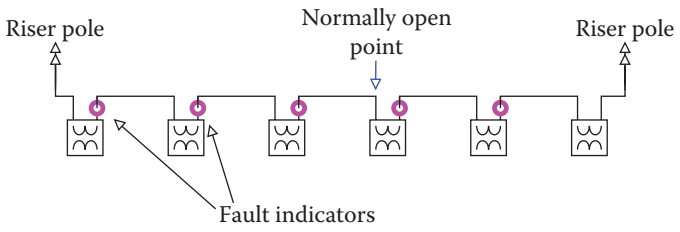

Figure 4.21 Typical URD fault indicator application.

fault indicator or three single-phase indicators are available; single-phase indicators identify the faulted phase (a significant advantage). Other useful locations for fault indicators are on either end of cable sections of overhead circuits, which are common at river crossings or under major highways. These sections are not fused, but fault indicators will show patrolling crews whether the cable section has failed.

Fault indicators may be reset in a variety of ways. On manual reset units, crews must reset the devices once they trip. These units are less likely to reliably indicate faults. Self-resetting devices are more likely to be accurate as they automatically reset based on current, voltage, or time. Current-reset is most common; after tripping, if the unit senses current above a threshold, it resets [standard values are 3, 1.5, and 0.1 A (NRECA RER Project 90-8, 1993)]. With current reset, the minimum circuit load at that point must be above the threshold, or the unit will never reset. On URD loops, when applying current-reset indicators, consider that the open point might change. This changes the current that the fault indicator sees. Again, make sure the circuit load is enough to reset the fault indicator. Voltage reset models provide a voltage sensor; when the voltage exceeds some value (the voltage sensor senses at secondary voltage or at an elbow's capacitive test point). Time-reset units simply reset after a given length of time.

Fault indicators should only operate for faults—not for load, not for inrush, not for lightning, and not for backfeed currents. False readings can send crews on wild chases looking for faults. Reclose operations also cause loads and transformers to draw inrush, which can falsely trip a fault indicator. An inrush restraint feature disables tripping for up to one second following energization. On single-phase taps, inrush restraint is really only needed for manually reset fault indicators (the faulted phase with the blown fuse will not have inrush that affects downstream fault indicators). Faults in adjacent cables can also falsely trip indicators; the magnetic fields couple into the pickup coil. Shielding can help prevent this. Several scenarios cause backfeed that can trip fault indicators. Downstream of a fault, the stored charge in the cable will rush into the fault, possibly tripping fault indicators. McNulty (1994) reported that 2000 ft of 15-kV cable created an oscillatory current transient that peaked at 100 A and decayed in 0.15 ms. Nearby capacitor banks on the overhead system can make outrush worse. Motors and other rotating equipment can also backfeed faults. To avoid false trips, use a high set point. Equipment with filtering that reduces the indicator's sensitivity to transient currents also helps, but too much filtering may leave the faulted-circuit indicator unable to detect faults cleared rapidly by current-limiting fuses.

Self-resetting fault indicators can also falsely reset. Backfeed currents and voltages can reset fault indicators. On a three-phase circuit with one phase tripped, the faulted phase can backfeed through three-phase transformer connections (see Chapter 5), providing enough current or enough voltage to reset faulted-circuit indicators. On single-phase circuits, these are not a problem. In general, single-phase application is much easier; we do not have backfeed problems or problems with indicators tripping from faults on nearby cables. For single-phase application guidelines, see IEEE Std 1216-2000.

Fault indicators may have a threshold-type trip characteristic like an instantaneous relay (any current above the set point trips the flag), or they may have a time-overcurrent characteristic which trips faster for higher currents. Those units with time–overcurrent characteristics should be coordinated with minimum clearing curves of current-limiting fuses to ensure that they operate. Another type of fault indicator uses an adaptive setting that trips based on a sudden increase in current followed by a loss of current.

Set the trip level on fault indicators to less than 50% of the available fault current or 500 A, whichever is less (IEEE 1610–2007). This trip threshold should be at least two to three times the load on the circuit to minimize false indications. These two conditions will almost never conflict, only at the end of a very long feeder (low fault currents) on a cable that is heavily loaded.

Normally, fault indicators are fixed equipment, but they can be used for targeted fault location. When crews arrive at a faulted and isolated section, they first apply fault indicators between sections (normally at padmounted transformers). Crews re-energize the failed portion and then check the fault indicators to identify the faulted section. Only one extra fault is applied to the circuit, not multiple faults as with the divide and conquer method.

Section testing—Crews isolate a section of cable and apply a dc hi-pot voltage. If the cable holds the hi-pot voltage, crews proceed to the next section and repeat until finding a cable that cannot hold the hi-pot voltage. Because the voltage is dc, the cable must be isolated from the transformer. In a faster variation of this, high-voltage sticks are available that use the ac line voltage to apply a dc voltage to the isolated cable section.

Thumper—The thumper applies a pulsed dc voltage to the cable. As its name implies, at the fault the thumper discharges sound like a thumping noise as the gap at the failure point repeatedly sparks over. The thumper charges a capacitor and uses a triggered gap to discharge the capacitor's charge into the cable. Crews can find the fault by listening for the thumping noise. Acoustic enhancement devices can help crews locate weak thumping noises; antennas that pick up the radio-frequency interference from the arc discharge also help pinpoint the fault. Thumpers are good for finding the exact fault location so that crews can start digging. On a 15-kV class system, utilities typically thump with voltages from 10 to 15 kV, but utilities sometimes use voltages to 25 kV.

While pulsed discharges are thought to be less damaging to cable than a steady dc voltage, utilities have concern that thumping can damage the unfailed sections of cable. When a thumper pulse breaks down the cable, the incoming surge shoots past

the fault. When it reaches the open point, the voltage doubles, then the voltage pulse bounces back and forth between the open point and the fault, switching from +2 to –2*E* (where *E* is the thumper pulse voltage). In tests, EPRI research found that thumping can reduce the life of aged cable (EPRI EL-6902, 1990; EPRI TR-108405-V1, 1997; Hartlein et al., 1989, 1994). The thumping discharges at the failure point can also increase the damage at the fault point. Most utilities try to limit the voltage or discharge energy, and a few don't use a thumper for fear of additional damage to cables and components (Tyner, 1998). A few utilities also disconnect transformers from the system during thumping to protect the transformer and prevent surges from propagating through the transformer (these surges should be small). If the fault has no gap, and if the fault is a solid short circuit, then no arc forms, and the thumper will not create its characteristic thump (fortunately, solid short circuits are rare in cable faults). Some crews keep thumping in an effort to burn the short circuit apart enough to start arcing. With cable in conduit, the thumping may be louder near the conduit ends than at the fault location. Generally, crews should start with low voltage and increase it as needed. A dc hi-pot voltage can help determine how much voltage the thumper needs.

Radar—Also called time-domain reflectometry (TDR), a radar set injects a very short-duration current pulse into the cable. At discontinuities, a portion of the pulse will reflect back to the set; knowing the velocity of wave propagation along cable gives us an estimate of the distance to the fault. Depending on the test set and settings, radar pulses can be from 5 ns to 5 μs wide. Narrower pulses give higher resolution, so users can better differentiate between faults and reflections from splices and other discontinuities (Banker et al., 1994).

Radar does not give pinpoint accuracy; its main use is to narrow the fault to a certain section. Then, crews can use a thumper or other pinpoint technique to find the failure. Taking a radar pulse from either end of a cable and averaging the results can lead to an improved estimate of the location. Radar location on circuits with taps can be complicated, especially those with multiple taps; the pulse will reflect off the taps, and the reflection from the actual fault will be less than it otherwise would be. Technology has been developed to use above-ground antennas to sense and pinpoint faults based on the radar signals.

Radar and thumper—After a fuse or other circuit interrupter clears a fault in a cable, the area around the fault point recovers some insulation strength. Checking the cable with an ohm meter would show an open circuit. Likewise, the radar pulse passes right by the fault, so the radar set alone cannot detect the fault. Using radar with a thumper solves this problem. A thumper pulse breaks down the gap, and the radar superimposes a pulse that reflects off the fault arc. The risetime of the thumper waveshape is on the order of a few microseconds; the radar pulse total width may be less than 0.05 μs. Another less attractive approach is to use a thumper to continually burn the cable until the fault resistance becomes low enough to get a reading on a radar set (this is less attractive because it subjects the cable to many more thumps, especially if crews use high voltages).

Boucher (1991) reported that fault indicators were the most popular fault locating approach, but most utilities use a variety of techniques (see Figure 4.22). Depending

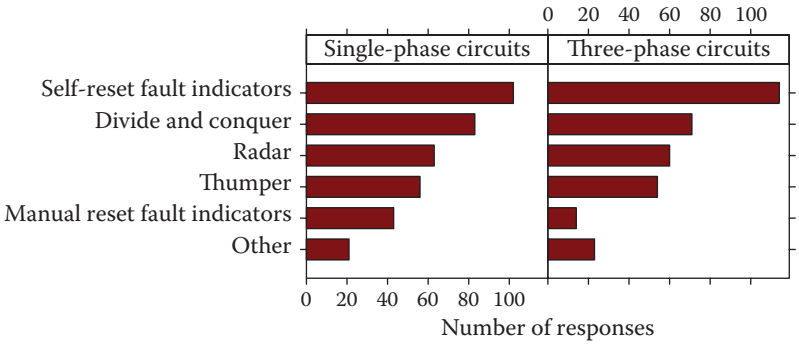

Figure 4.22 Utility use of fault-locating techniques (204 utilities surveyed, multiple responses allowed). (Data from Boucher, R., A summary of the regional underground distribution practices for 1991, Regional Underground Distribution Practices, IEEE paper 91 TH0398-8-PWR, 1991.)

on the type of circuit, the circuit layout, and the equipment available, different approaches are sometimes better.

When applying test voltages to cables, crews must be mindful that cables can hold significant charge. Cables have significant capacitance, and cables can maintain charge for days.

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I was down in the hole and pulled on one of the splices thinking that I might find the faulted one by pulling it apart, well you can only guess what happens next! KA-BOOOM, I was really pissed off at that point and still am. BUT YOU KNOW SOMETHING, ITS MY FAULT FOR TAKING SOME OTHER HALF ASS LINEMAN'S WORD FOR IT BEING DEAD AND NOT CHECKING IT OUT FOR MY SELF!

Anonymous poster, about beginning work after another lineman told him that the cables were disconnected at the source end.

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5

Transformers

Contents

5.1 Basics 204
5.2 Distribution Transformers 208
5.3 Single-Phase Transformers 210
5.4 Three-Phase Transformers 217
5.4.1 Grounded Wye–Grounded Wye 221
5.4.2 Delta–Grounded Wye 224
5.4.3 Floating Wye–Delta 225
5.4.4 Other Common Connections 226
5.4.1.1 Delta–Delta 226
5.4.1.2 Open Wye–Open Delta 227
5.4.1.3 Other Suitable Connections 230
5.4.5 Neutral Stability with a Floating Wye 230
5.4.6 Sequence Connections of Three-Phase Transformers 232
5.5 Loadings 232
5.6 Losses 238
5.7 Network Transformers 242
5.8 Substation Transformers 244
5.9 Special Transformers 247
5.9.1 Autotransformers 247
5.9.2 Grounding Transformers 248
5.10 Special Problems 251
5.10.1 Paralleling 251
5.10.2 Ferroresonance 252
5.10.3 Switching Floating Wye–Delta Banks 260
5.10.4 Backfeeds 262
5.10.5 Inrush 265
References 268

Alternating current (ac) transformers are one of the keys to allowing widespread distribution of electric power as we see it today. Transformers efficiently convert electricity to higher voltage for long-distance transmission and back down to low voltages suitable for customer usage. The distribution transformer normally serves as the final transition to the customer and often provides a local grounding reference. Most distribution circuits have hundreds of distribution transformers. Distribution feeders may also have other transformers: voltage regulators, feeder step banks to interface circuits of different voltages, and grounding banks.

5.1 Basics

A transformer efficiently converts electric power from one voltage level into another. A transformer is two sets of coils coupled together through a magnetic field. The magnetic field transfers all the energy (except in an autotransformer). In an ideal transformer, the voltages on the input and the output are related by the turns ratio of the transformer:

$$V_1 = \frac{N_1}{N_2} V_2$$

where N_1 and N_2 are the number of turns and V_1 and V_2 are the voltages on windings 1 and 2.

In a real transformer, not all of the flux couples between windings. This *leakage* flux creates a voltage drop between windings, so the voltage is more accurately described by

$$V_1 = \frac{N_1}{N_2} V_2 - X_L I_1$$

where X_L is the leakage reactance in ohms as seen from winding 1, and I_1 is the current out of winding 1.

The current also transforms by the turns ratio, opposite of the voltage as

$$I_1 = \frac{N_2}{N_1} I_2 \quad \text{or} \quad N_1 I_1 = N_2 I_2$$

The "ampere-turns" stay constant at $N_1\ I_1 = N_2\ I_2$; this fundamental relationship holds well for power and distribution transformers.

A transformer has a magnetic core that can carry large magnetic fields. The cold-rolled, grain-oriented steels used in cores have permeabilities of over 1000 times that of air. The steel provides a very low-reluctance path for magnetic fields created by current through the windings.

Consider voltage applied to the *primary* side (source side, high-voltage side) with no load on the *secondary* side (load side, low-voltage side). The winding draws *exciting* current from the system that sets up a sinusoidal magnetic field in the core. The flux in turn creates a back emf in the coil that limits the current drawn into the transformer. A transformer with no load on the secondary draws very little current, just the exciting current, which is normally less than 0.5% of the transformer's full-load current. On the unloaded secondary, the sinusoidal flux creates an open-circuit voltage equal to the primary-side voltage times the turns ratio.

When we add load to the secondary of the transformer, the load pulls current through the secondary winding. The magnetic coupling of the secondary current pulls current through the primary winding, keeping constant ampere-turns. Normally in an inductive circuit, higher current creates more flux, but not in a transformer (except

for the leakage flux). The increasing force from current in one winding is countered by the decreasing force from current through the other winding (see Figure 5.1). The flux in the core on a loaded transformer is the same as that on an unloaded transformer, even though the current is much higher.

The voltage on the primary winding determines the flux in the transformer (the flux is proportional to the time integral of voltage). The flux in the core determines the voltage on the output side of the transformer (the voltage is proportional to the time derivative of the flux).

Figure 5.2 shows models with the significant impedances in a transformer. The detailed model shows the series impedances, the resistances, and the reactances.

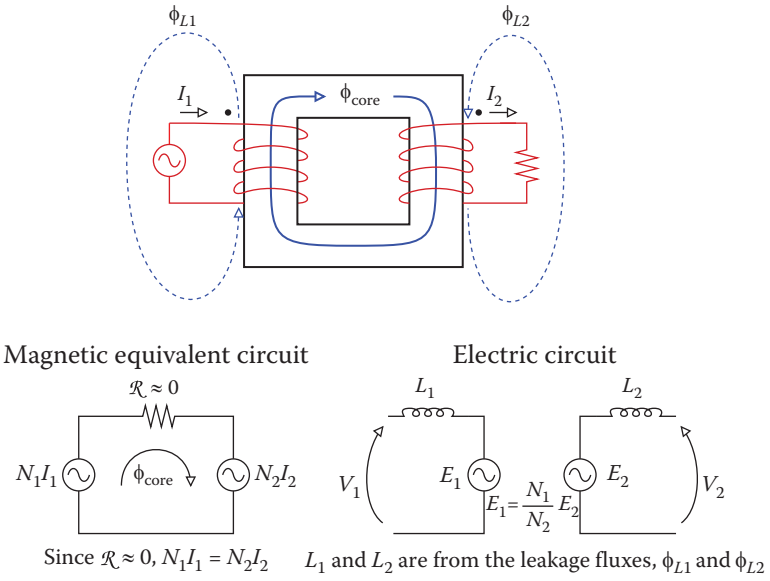


Figure 5.1 Transformer basic function.

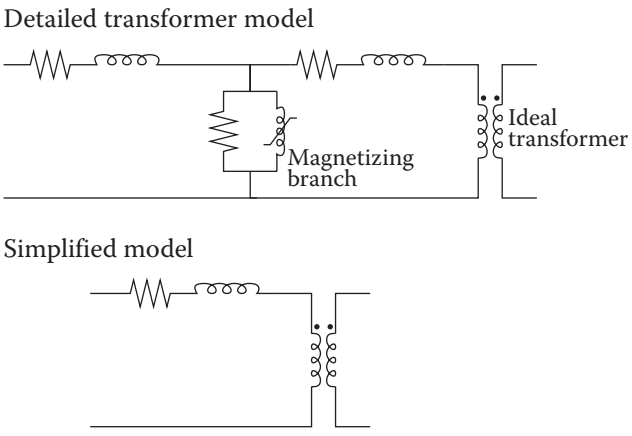


Figure 5.2 Transformer models.

The series resistance is mainly the resistance of the wires in each winding. The series reactance is the leakage impedance. The shunt branch is the magnetizing branch, current that flows to magnetize the core. Most of the magnetizing current is reactive power, but it includes a real power component. Power is lost in the core through

- *Hysteresis*—As the magnetic dipoles change direction, the core heats up from the friction of the molecules.
- *Eddy currents*—Eddy currents in the core material cause resistive losses. The core flux induces the eddy currents tending to oppose the change in flux density.

The magnetizing branch impedance is normally above 5000% on a transformer's base, so we can neglect it in many cases. The core losses are often referred to as iron losses or no-load losses. The load losses are frequently called the wire losses or copper losses. The various parameters of transformers scale with sizes differently as summarized in Table 5.1.

The simplified transformer model in Figure 5.2 with series resistance and reactance is sufficient for most calculations, including load flows, short-circuit calculations, motor starting, or unbalance. Small distribution transformers have low leakage reactances, some less than 1% on the transformer rating, and X/R ratios of 0.5 to 5. Larger power transformers used in distribution substations have higher impedances, usually on the order of 7 to 10% with X/R ratios between 10 and 40.

TABLE 5.1 Common Scaling Ratios in Transformers

Quantity	Relative to kVA	Relative to a Reference Dimension, l
Rating	kVA	l^4
Weight	K $kVA^{3/4}$	K l^3
Cost	K $kVA^{3/4}$	K $(\%\ \text{total loss})^{-3}$
Length	K $kVA^{1/4}$	K l
Width	K $kVA^{1/4}$	K l
Height	K $kVA^{1/4}$	K l
Total losses	K $kVA^{3/4}$	K l^3
No-load losses	K $kVA^{3/4}$	K l^3
Exciting current	K $kVA^{3/4}$	K l^3
% Total loss	K $kVA^{-1/4}$	K l^{-1}
% No-load loss	K $kVA^{-1/4}$	K l^{-1}
% Exciting current	K $kVA^{-1/4}$	K l^{-1}
% R	K $kVA^{-1/4}$	K l^{-1}
% X	K $kVA^{1/4}$	K l
Volts/turn	K $kVA^{1/2}$	K l^2

Source: Adapted from Arthur D. Little, Distribution transformer rulemaking engineering analysis update, *Report to U.S. Department of Energy Office of Building Technology*, State, and Community Programs. Draft. December 17, 2001.

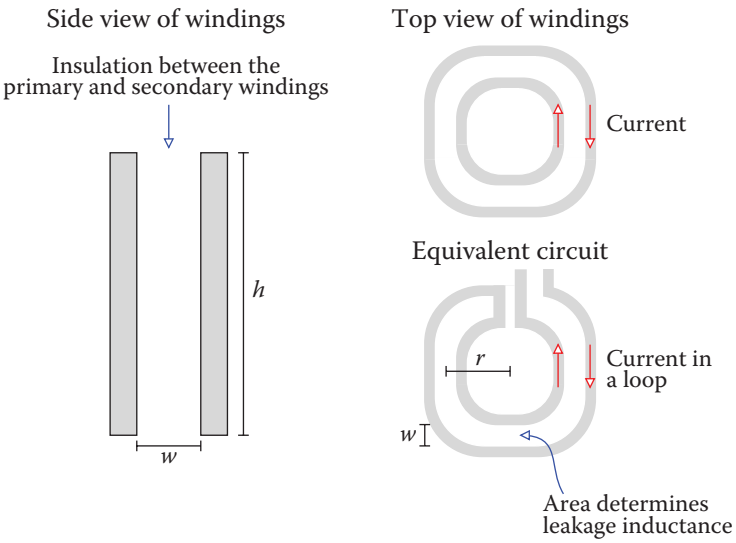


Figure 5.3 Leakage reactance.

The leakage reactance causes voltage drop on a loaded transformer. The voltage is from flux that does not couple from the primary to the secondary winding. Blume et al. (1951) describes leakage reactance well. In a real transformer, the windings are wound around a core; the high- and low-voltage windings are adjacent to each other. Figure 5.3 shows a configuration; each winding contains a number of turns of wire. The sum of the current in each wire of the high-voltage winding equals the sum of the currents in the low-voltage winding ($N_1I_1 = N_2I_2$), so each winding is equivalent to a busbar. Each busbar carries equal current, but in opposite directions. The opposing currents create flux in the gap between the windings (this is called *leakage flux*). Now, looking at the two windings from the top, we see that the windings are equivalent to current flowing in a loop encompassing a given area. This area determines the leakage inductance.

The leakage reactance in percent is based on the coil parameters and separations (Blume et al., 1951) as follows:

$$X_{\%} = \frac{126 f (NI)^2 rw}{10^{11} h S_{\text{kVA}}}$$

where

f = system frequency, Hz
N = number of turns on one winding
I = full load current on the winding, A
r = radius of the windings, in.
w = width between windings, in.
h = height of the windings, in.
S_{kVA} = transformer rating, kVA

In general, leakage impedance increases with

- Higher primary voltage (thicker insulation between windings)
- kVA rating
- Larger core (larger diameter leads to more area enclosed)

Leakage impedances are under control of the designer, and companies will make transformers for utilities with customized impedances. Large distribution substation transformers often need high leakage impedance to control fault currents, some as high as 30% on the base rating.

Mineral oil fills most distribution and substation transformers. The oil provides two critical functions: conducting heat and insulation. Because the oil is a good heat conductor, an oil-filled transformer has more load-carrying capability than a dry-type transformer. Since it provides good electrical insulation, clearances in an oil-filled transformer are smaller than a dry-type transformer. The oil conducts heat away from the coils into the larger thermal mass of the surrounding oil and to the transformer tank to be dissipated into the surrounding environment. Oil can operate continuously at high temperatures, with a normal operating temperature of 105°C. It is flammable; the flash point is 150°C, and the fire point is 180°C. Oil has high dielectric strength, 220 kV/in. (86.6 kV/cm), and evens out voltage stresses since the dielectric constant of oil is about 2.2, which is close to that of the insulation. The oil also coats and protects the coils and cores and other metal surfaces from corrosion.

5.2 Distribution Transformers

From a few kVA to a few MVA, distribution transformers convert primary voltage to low voltage that customers can use. In North America, 40 million distribution transformers are in service, and another 1 million are installed each year (Alexander Publications, 2001). The transformer connection determines the customer's voltages and grounding configuration.

Distribution transformers are available in several standardized sizes as shown in Table 5.2. Most installations are single phase. The most common overhead transformer is the 25-kVA unit; padmounted transformers tend to be slightly larger where the 50-kVA unit is the most common.

Distribution transformer impedances are rather low. Units under 50 kVA have impedances less than 2%. Three-phase underground transformers in the range of 750 to 2500 kVA normally have a 5.75% impedance as specified in ANSI/IEEE C57.12.24-1988. Lower impedance transformers provide better voltage regulation

TABLE 5.2 Standard Distribution Transformer Sizes

	Distribution Transformer Standard Ratings, kVA
Single phase	5, 10, 15, 25, 37.5, 50, 75, 100, 167, 250, 333, 500
Three phase	30, 45, 75, 112.5, 150, 225, 300, 500

TABLE 5.3 Insulation Levels for Distribution Transformers

Low-Frequency Test Level, kV rms	Basic Lightning Impulse Insulation Level, kV Crest	Chopped-Wave Impulse Levels	
		Minimum Voltage, kV Crest	Minimum Time to Flashover, μs
10	30	36	1.0
15	45	54	1.5
19	60	69	1.5
26	75	88	1.6
34	95	110	1.8
40	125	145	2.25
50	150	175	3.0
70	200	230	3.0
95	250	290	3.0
140	350	400	3.0

Source: Adapted from IEEE C57.12.00-2000, *IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers*. Copyright 2000 IEEE.

and less voltage flicker for motor starting or other fluctuating loads. But lower impedance transformers increase fault currents on the secondary, and secondary faults impact the primary side more (deeper voltage sags and more fault current on the primary).

Standards specify the insulation capabilities of distribution transformer windings (see Table 5.3). The low-frequency test is a power-frequency (60 Hz) test applied for one minute. The basic lightning impulse insulation level (BIL) is a fast impulse transient. The front-of-wave impulse levels are even shorter-duration impulses.

The through-fault capability of distribution transformers is also given in IEEE C57.12.00-2000 (see Table 5.4). The duration in seconds of the short-circuit capability is

$$t = \frac{1250}{I^2}$$

where I is the symmetrical current in multiples of the normal base current from Table 5.4.

Overhead and padmounted transformer tanks are normally made of mild carbon steel. Corrosion is one of the main concerns, especially for anything on the ground

TABLE 5.4 Through-Fault Capability of Distribution Transformers

Single-Phase Rating, kVA	Three-Phase Rating, kVA	Withstand Capability in per Unit of Base Current (Symmetrical)
5–25	15–75	40
37.5–110	112.5–300	35
167–500	500	25

Source: Adapted from IEEE Std. C57.12.00-2000, *IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers.*

or in the ground. Padmounted transformers tend to corrode near the base (where moisture and dirt and other debris may collect). Submersible units, being highly susceptible to corrosion, are often stainless steel.

Distribution transformers are "self cooled"; they do not have extra cooling capability like power transformers. They only have one kVA rating. Because they are small and because customer peak loadings are relatively short duration, overhead and padmounted distribution transformers have significant overload capability. Utilities regularly size them to have peak loads exceeding 150% of the nameplate rating.

Transformers in underground vaults are often used in cities, especially for network transformers (feeding secondary grid networks). In this application, heat can be effectively dissipated (but not as well as with an overhead or padmounted transformer).

Subsurface transformers are installed in an enclosure just big enough to house the transformer with a grate covering the top. A "submersible" transformer is normally used, one which can be submerged in water for an extended period (ANSI/IEEE C57.12.80-1978). Heat is dissipated through the grate at the top. Dirt and debris in the enclosure can accelerate corrosion. Debris blocking the grates or vents can overheat the transformer.

Direct-buried transformers have been attempted over the years. The main problems have been overheating and corrosion. In soils with high electrical and thermal resistivity, overheating is the main concern. In soils with low electrical and thermal resistivity, overheating is not as much of a concern, but corrosion becomes a problem. Thermal conductivity in a direct-buried transformer depends on the thermal conductivity of the soil. The buried transformer generates enough heat to dry out the surrounding soil; the dried soil shrinks and creates air gaps. These air gaps act as insulating layers that further trap heat in the transformer.

5.3 Single-Phase Transformers

Single-phase transformers supply single-phase service; we can use two or three single-phase units in a variety of configurations to supply three-phase service. A transformer's nameplate gives the kVA ratings, the voltage ratings, percent impedance, polarity, weight, connection diagram, and cooling class. Figure 5.4 shows a cutaway view of a single-phase transformer.

For a single-phase transformer supplying single-phase service, the load-full current in amperes is

$$I = \frac{S_{\text{kVA}}}{V_{\text{kV}}}$$

where

S_{kVA} = transformer kVA rating
V_{kV} = line-to-ground voltage rating in kV

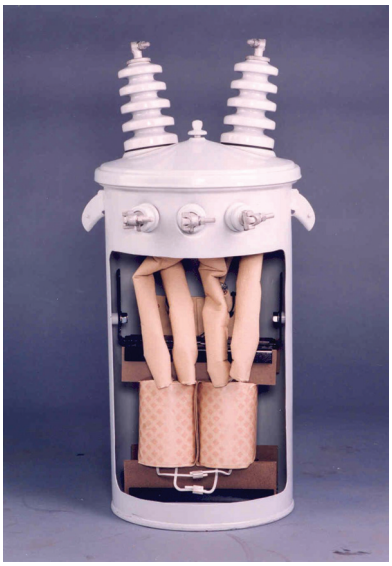


Figure 5.4 Single-phase distribution transformer. (Photo courtesy of ABB. With permission.)

So, a single-phase 50-kVA transformer with a high-voltage winding of 12470GrdY/7200 V has a full-load current of 6.94 A on the primary. On a 240/120-V secondary, the full-load current across the 240-V winding is 208.3 A.

Tables 5.5 and 5.6 show the standard single-phase winding connections for primary and secondary windings. High-voltage bushings are labeled H*, starting with H1 and then H2 and so forth. Similarly, the low-voltage bushings are labeled X1, X2, X3, and so on.

The standard North American single-phase transformer connection is shown in Figure 5.5. The standard secondary load service is a 120/240-V three-wire service. This configuration has two secondary windings in series with the midpoint grounded. The secondary terminals are labeled X1, X2, and X3 where the voltage X1–X2 and X2–X3 are each 120 V. X1–X3 is 240 V.

Power and distribution transformers are assigned polarity dots according to the terminal markings. Current entering H1 results in current leaving X1. The voltage from H1 to H2 is in phase with the voltage from X1 to X3.

On overhead distribution transformers, the high-voltage terminal H1 is always on the left (when looking into the low-voltage terminals; the terminals are not marked). On the low-voltage side, the terminal locations are different, depending on size. If X1 is on the right, it is referred to as *additive polarity* (if X3 is on the right, it is *subtractive polarity*). Polarity is additive if the voltages add when the two windings are connected in series around the transformer (see Figure 5.6). Industry standards specify the polarity of a transformer, which depends on the size and the high-voltage winding. Single-phase transformers have additive polarity if (IEEE C57.12.00-2000)

$$\text{kVA} \leq 200 \quad \text{and} \quad \text{V} \leq 8660$$

TABLE 5.5 Winding Designations for Single-Phase Primary and Secondary Transformer Windings with One Winding

Nomenclature	Examples	Description
E	13800	E shall indicate a winding of E volts that is suitable for Δ connection on an E volt system.
E/E_1Y	2400/4160Y	E/E_1Y shall indicate a winding of E volts that is suitable for Δ connection on an E volt system or for Y connection on an E_1 volt system.
E/E_1GrdY	7200/12470GrdY	E/E_1GrdY shall indicate a winding of E volts having reduced insulation that is suitable for Δ connection on an E volt system or Y connection on an E_1 volt system, transformer, neutral effectively grounded.
E_1GrdY/E	12470GrdY/7200 480GrdY/277	E_1GrdY/E shall indicate a winding of E volts with reduced insulation at the neutral end. The neutral end may be connected directly to the tank for Y or for single-phase operation on an E_1 volt system, provided the neutral end of the winding is effectively grounded.

$E_1 = \sqrt{3}E$

Source: Adapted from IEEE C57.12.00-2000, *IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers*. Copyright 2000 IEEE. All rights reserved.

Note: E is line-to-neutral voltage of a Y winding, or line-to-line voltage of a Δ winding.

TABLE 5.6 Two-Winding Transformer Designations for Single-Phase Primaries and Secondaries

Nomenclature	Examples	Description
E/2E	120/240 240/280	E/2E shall indicate a winding, the sections of which can be connected in parallel for operation at E volts, or which can be connected in series for operation at 2E volts, or connected in series with a center terminal for three-wire operation at 2E volts between the extreme terminals and E volts between the center terminal and each of the extreme terminals.
2E/E	240/120	2E/E shall indicate a winding for 2E volts, two-wire full kilovoltamperes between extreme terminals, or for 2E/E volts three-wire service with 1/2 kVA available only, from midpoint to each extreme terminal.
E × 2E	240 × 480	E × 2E shall indicate a winding for parallel or series operation only but not suitable for three-wire service.

Source: Adapted from IEEE C57.12.00-2000, *IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers*. Copyright 2000 IEEE.

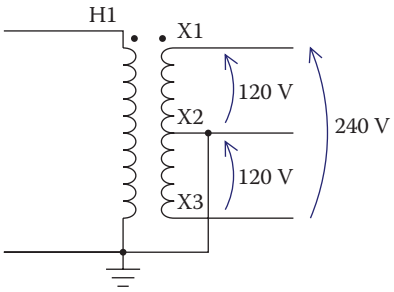


Figure 5.5 Single-phase distribution transformer diagram.

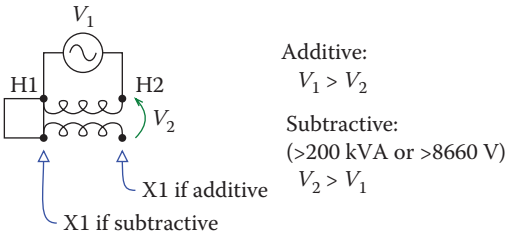


Figure 5.6 Additive and subtractive polarity.

All other distribution transformers have subtractive polarity. The reason for the division is that originally all distribution transformers had additive polarity and all power transformers had subtractive polarity. Increasing sizes of distribution transformers caused overlap between "distribution" and "power" transformers, so larger distribution transformers were made with subtractive polarity for consistency. Polarity is important when connecting single-phase units in three-phase banks and for paralleling units.

Manufacturers make single-phase transformers as either shell form or core form (see Figure 5.7). Core-form designs prevailed prior to the 1960s; now, both shell- and core-form designs are available. Single-phase core-form transformers must have *interlaced* secondary windings (the low–high–low design). Every secondary leg has two coils, one wrapped around each leg of the core. The balanced configuration of the interlaced design allows unbalanced loadings on each secondary leg. Without interlacing, unbalanced secondary loads excessively heat the tank. An unbalanced secondary load creates an unbalanced flux in the iron core. The core-form construction does not have a return path for the unbalanced flux, so the flux returns outside of the iron core (in contrast, the shell-form construction has a return path for such flux). Some of the stray flux loops through the transformer tank and heats the tank.

The shell-form design does not need to have interlaced windings, so the *noninterlaced* configuration is normally used on shell-form transformers since it is simpler. The noninterlaced secondary has two to four times the reactance: the secondary windings

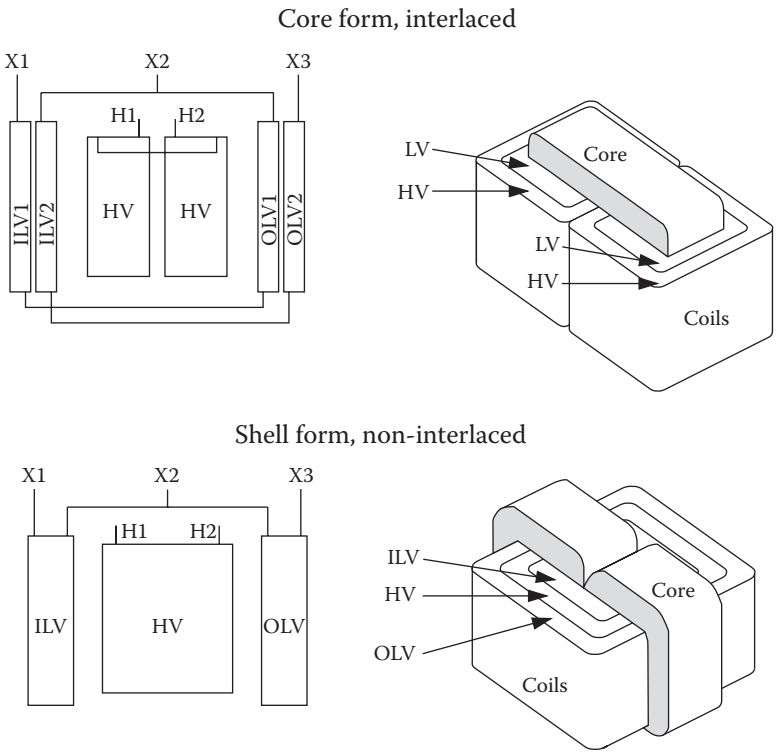


Figure 5.7 Core-form and shell-form single-phase distribution transformers. (IEEE Task Force Report, Secondary (low-side) surges in distribution transformers, *IEEE Transactions on Power Delivery*, 7(2), 746–56, April 1992. Copyright 1992 IEEE.)

are separated by the high-voltage winding and the insulation between them. Interlacing reduces the reactance since the low-voltage windings are right next to each other.

Using a transformer's impedance magnitude and load losses, we can find the real and reactive impedance in percent as

$$R = \frac{W_{CU}}{10S_{kVA}}$$

$$X = \sqrt{Z^2 - R^2}$$

where

S_{kVA} = transformer rating, kVA
$W_{CU} = W_{TOT} - W_{NL}$ = load loss at rated load, W
W_{TOT} = total losses at rated load, W
W_{NL} = no-load losses, W
Z = nameplate impedance magnitude, %

The nameplate impedance of a single-phase transformer is the *full-winding* impedance, the impedance seen from the primary when the full secondary winding is shorted from X1 to X3. Other impedances are also important; we need the two *half-winding* impedances for secondary short-circuit calculations and for unbalanced calculations on the secondary. One impedance is the impedance seen from the primary for a short circuit from X1 to X2. Another is from X2 to X3. The half-winding impedances are not provided on the nameplate; we can measure them or use the following approximations. Figure 5.8 shows a model of a secondary winding for use in calculations.

The half-winding impedance of a transformer depends on the construction. In the model in Figure 5.8, one of the half-winding impedances in percent equals $Z_A + Z_1$; the other equals $Z_A + Z_2$. A core- or shell-form transformer with an interlaced secondary winding has an impedance in percent of approximately

$$Z_{\text{HX1–2}} = Z_{\text{HX2–3}} = 1.5R + j1.2X$$

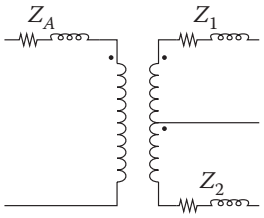
where R and X are the real and reactive components of the full-winding impedance (H1 to H2 and X1 to X3) in percent. A noninterlaced shell-form transformer has an impedance in percent of approximately

$$Z_{\text{HX1–2}} = Z_{\text{HX2–3}} = 1.75R + j2.5X$$

In a noninterlaced transformer, the two half-winding impedances are not identical; the impedance to the inner low-voltage winding is less than the impedance to the outer winding (the radius to the gap between the outer secondary winding and the primary winding is larger, so the gap between windings has more area).

A secondary fault across one 120-V winding at the terminals of a noninterlaced transformer has current equal to about the current for a fault across the 240-V winding. On an interlaced transformer, the lower relative impedance causes higher currents for the 120-V fault.

Consider a 50-kVA transformer with $Z = 2\%$, 655 W of total losses, no-load losses of 106 W, and a noninterlaced 120/240-V secondary winding. This translates into a



Full-winding impedance = $R + jX$
Interlaced secondary winding
$Z_A = 0.5R + j0.8X$
$Z_1 = Z_2 = R + j0.4X$
Noninterlaced secondary winding
$Z_A = 0.25R - j0.6X$
$Z_1 = 1.5R + j3.3X$
$Z_2 = 1.5R + j3.1X$ (inner winding)

Figure 5.8 Model of a 120/240-V secondary winding with all impedances in percent. (Impedance data from Hopkinson, F. H., Approximate distribution transformer impedances, *General Electric Internal Memorandum*, 1976. As cited by Kersting, W. H. and Phillips, W. H., Modeling and analysis of unsymmetrical transformer banks serving unbalanced loads, *Rural Electric Power Conference*, 1995.)

full-winding percent impedance of 1.1 + *j*1.67. For a fault across the 240-V winding, the current is found as

$$Z_{\Omega,240\text{V}} = (R + jX)\frac{10(0.24\text{kV})^2}{S_{\text{kVA}}} = (1.1 + j1.67)\frac{10(0.24\text{kV})^2}{50\text{kVA}} = 0.013 + j0.019\,\Omega$$

$$I_{240\text{V}} = \left|\frac{0.24\text{kV}}{Z_{\Omega,240\text{V}}}\right| = 10.4\text{kA}$$

For a fault across the 120-V winding on this noninterlaced transformer, the current is found as

$$Z_{\Omega,120\text{V}} = (1.75R + j2.5X)\frac{10(0.12\text{kV})^2}{S_{\text{kVA}}} = (1.93 + j4.18)\frac{10(0.12\text{kV})^2}{50\text{kVA}}$$

$$= 0.0055 + j0.0120\,\Omega$$

$$I_{120\text{V}} = \left|\frac{0.12\text{kV}}{Z_{\Omega,120\text{V}}}\right| = 9.06\text{kA}$$

Consider the same transformer characteristics on a transformer with an interlaced secondary and $Z = 1.4\%$. The 240-V and 120-V short-circuit currents are found as

$$Z_{\Omega,240\text{V}} = (R + jX)\frac{10(0.24\text{kV})^2}{S_{\text{kVA}}} = (1.1 + j0.87)\frac{10(0.24\text{kV})^2}{50\text{kVA}} = 0.013 + j0.01\,\Omega$$

$$I_{240\text{V}} = \left|\frac{0.24\text{kV}}{Z_{\Omega,240\text{V}}}\right| = 14.9\text{kA}$$

$$Z_{\Omega,120\text{V}} = (1.5R + j1.2X)\frac{10(0.12\text{kV})^2}{S_{kVA}} = (1.65 + j1.04)\frac{10(0.12\text{kV})^2}{50\text{kVA}}$$

$$= 0.0048 + j0.003\Omega$$

$$I_{120\text{V}} = \left|\frac{0.12\text{kV}}{Z_{\Omega,120\text{V}}}\right| = 21.4\text{kA}$$

The fault current for a 120-V fault is significantly higher than the 240-V current.

Completely self-protected transformers (CSPs) are a widely used single-phase distribution transformer with several built-in features (see Figure 5.9):

- Tank-mounted arrester
- Internal "weak-link" fuse
- Secondary breaker

CSPs do not need a primary-side cutout with a fuse. The internal primary fuse protects against an internal failure in the transformer. The weak link has less fault-clearing

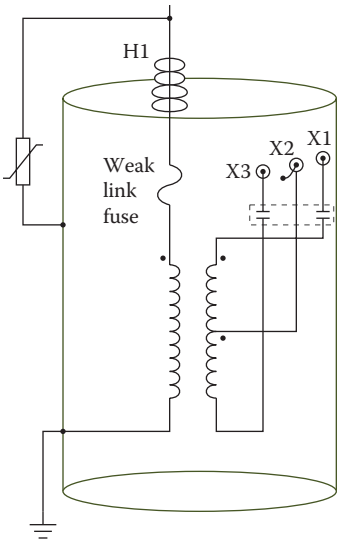


FIGURE 5.9 Completely self-protected transformer.

capability than a fuse in a cutout, so they need external current-limiting fuses where fault currents are high.

Secondary breakers provide protection against overloads and secondary faults. The breaker responds to current and oil temperature. Tripping is controlled by deflection of bimetallic elements in series. The oil temperature and current through the bimetallic strips heat the bimetal. Past a critical temperature, the bimetallic strips deflect enough to operate the breaker. Figure 5.10 shows trip characteristics for secondary breakers inside two size transformers. The secondary breaker has an emergency position to allow extra overload without tripping (to allow crews time to replace the unit). Crews can also use the breaker to drop the secondary load.

Some CSPs have overload-indicating lights that signal an overload. The indicator light does not go off until line crews reset the breaker. The indicator lights are not ordered as often (and crews often disable them in the field) because they generate a fair number of nuisance phone calls from curious/helpful customers.

5.4 Three-Phase Transformers

Three-phase overhead transformer services are normally constructed from three single-phase units. Three-phase transformers for underground service (either pad-mounted, direct buried, or in a vault or building or manhole) are normally single units, usually on a three- or five-legged core. Three-phase distribution transformers are usually core construction (see Figure 5.11), with either a three-, four-, or five-legged core construction (shell-type construction is rarely used). The five-legged wound core transformer is very common. Another option is *triplex* construction, where the three transformer legs are made from single individual core/coil assemblies (just like having three separate transformers).

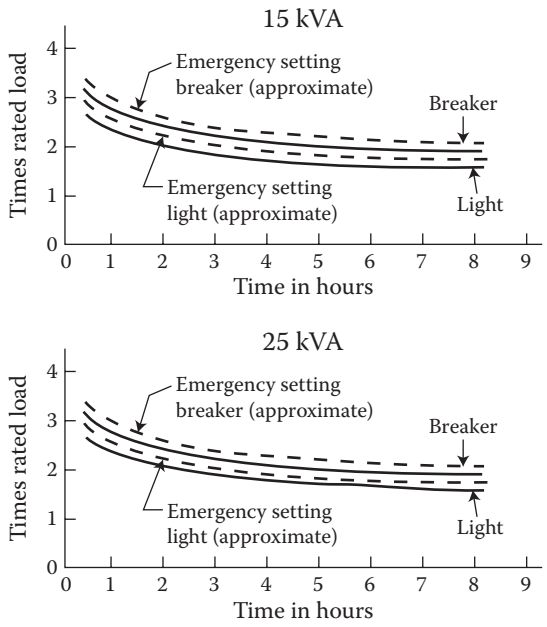


Figure 5.10 Clearing characteristics of a secondary breaker. (From ERMCO, Inc. With permission.)

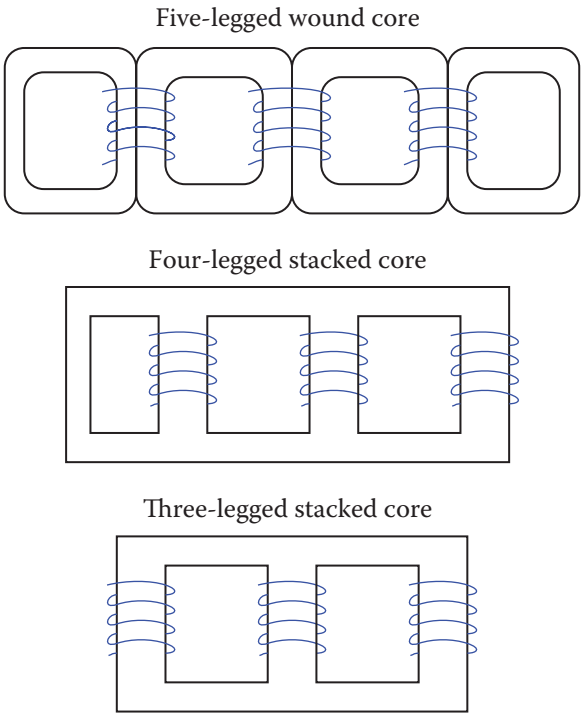


Figure 5.11 Three-phase core constructions.

The kVA rating for a three-phase bank is the total of all three phases. The full-load current in amps in each phase of a three-phase unit or bank is

$$I = \frac{S_{\text{kVA}}}{3V_{\text{LG,kV}}} = \frac{S_{\text{kVA}}}{\sqrt{3}V_{\text{LL,kV}}}$$

where

S_{kVA} = transformer three-phase kVA rating
$V_{\text{LG,kV}}$ = line-to-ground voltage rating, kV
$V_{\text{LL,kV}}$ = line-to-line voltage rating, kV

A three-phase, 150-kVA transformer with a high-voltage winding of 12470GrdY/7200 V has a full-load current of 6.94 A on the primary (the same current as one 50-kVA single-phase transformer).

There are many types of three-phase connections used to serve three-phase load on distribution systems (ANSI/IEEE C57.105-1978; Long, 1984; Rusch and Good, 1989). Both the primary and secondary windings may be connected in different ways: delta, floating wye, or grounded wye. This notation describes the connection of the transformer windings, not the configuration of the supply system. A "wye" primary winding may be applied on a "delta" distribution system. On the primary side of three-phase distribution transformers, utilities have a choice between grounded and ungrounded winding connections. The tradeoffs are

- *Ungrounded primary*—The delta and floating-wye primary connections are suitable for ungrounded and grounded distribution systems. Ferroresonance is more likely with ungrounded primary connections. Ungrounded primary connections do not supply ground fault current to the primary distribution system.
- *Grounded primary*—The grounded-wye primary connection is only suitable on four-wire grounded systems (either multigrounded or unigrounded). It is not for use on ungrounded systems. Grounded-wye primaries may provide an unwanted source for ground fault current.

Customer needs play a role in the selection of the secondary configuration. The delta configuration and the grounded-wye configuration are the two most common secondary configurations. Each has advantages and disadvantages:

- *Grounded-wye secondary*—Figure 5.12 shows the most commonly used transformers with a grounded-wye secondary winding: grounded wye–grounded wye and the delta–grounded wye. The standard secondary voltages are 480Y/277-V and 208Y/120-V. The 480Y/277-V connection is suitable for driving larger motors; lighting and other 120-V loads are normally supplied by dry-type transformers. A grounded-wye secondary adeptly handles single-phase loads on any of the three phases with less concerns about unbalances.
- *Delta secondary*—An ungrounded secondary system like the delta can supply three-wire ungrounded service. Some industrial facilities prefer an ungrounded system, so they can continue to operate with line-to-ground faults. With one leg of the delta grounded at the midpoint of the winding, the utility can supply 240/120-V service.

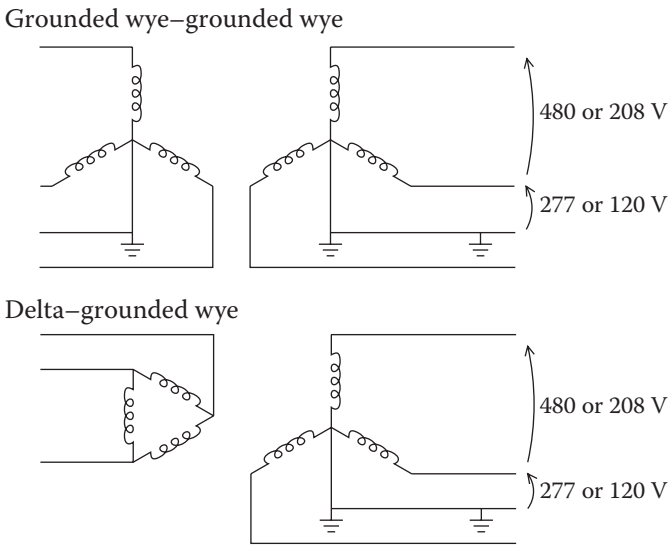


Figure 5.12 Three-phase distribution transformer connections with a grounded-wye secondary.

End-users can use more standard 230-V motors (without worrying about reduced performance when run at 208 V) and still run lighting and other single-phase loads. This tapped leg is often called the *lighting* leg (the other two legs are the *power* legs). Figure 5.13 shows the most commonly used connections with delta secondary windings. This is commonly supplied with overhead transformers.

Many utilities offer a variety of three-phase service options and, of course, most have a variety of existing transformer connections. Some utilities restrict choices in an effort to increase consistency and reduce inventory. A restrictive utility may only offer three choices: 480Y/277-V and 208Y/120-V four-wire, three-phase services, and 120/240-V three-wire single-phase service.

For supplying customers requiring an ungrounded secondary voltage, either a three-wire service or a four-wire service with 120 and 240 V, the following provides the best connection:

- Floating wye–delta

For customers with a four-wire service, either of the following are normally used:

- Grounded wye–grounded-wye
- Delta–grounded wye

Choice of preferred connection is often based on past practices and equipment availability.

A wye–delta transformer connection shifts the phase-to-phase voltages by 30° with the direction dependent on how the connection is wired. The phase angle difference between the high-side and low-side voltage on delta–wye and wye–delta transformers

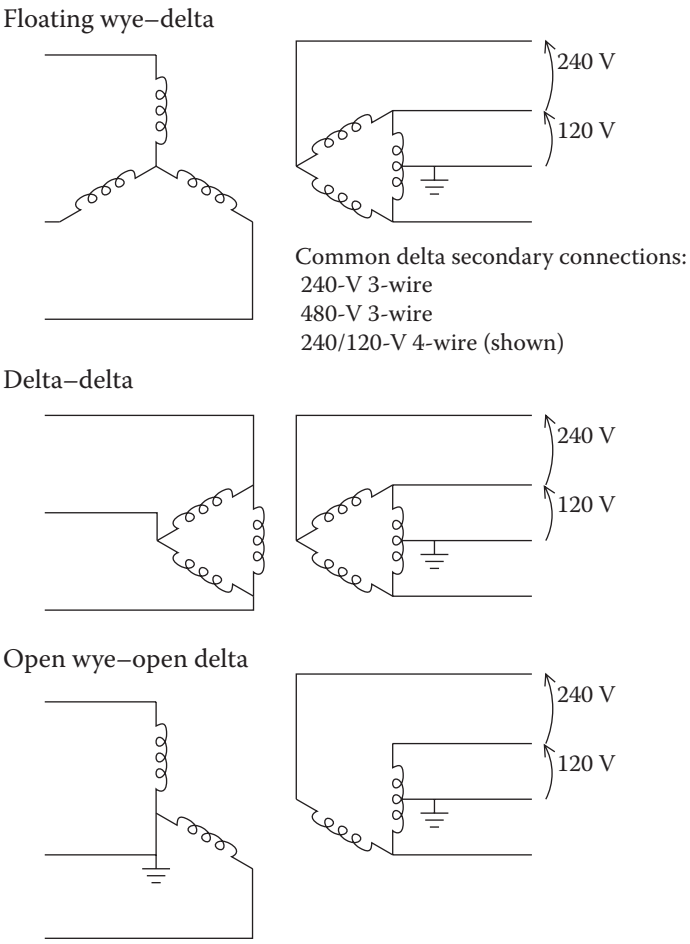


Figure 5.13 Common three-phase distribution transformer connections with a delta-connected secondary.

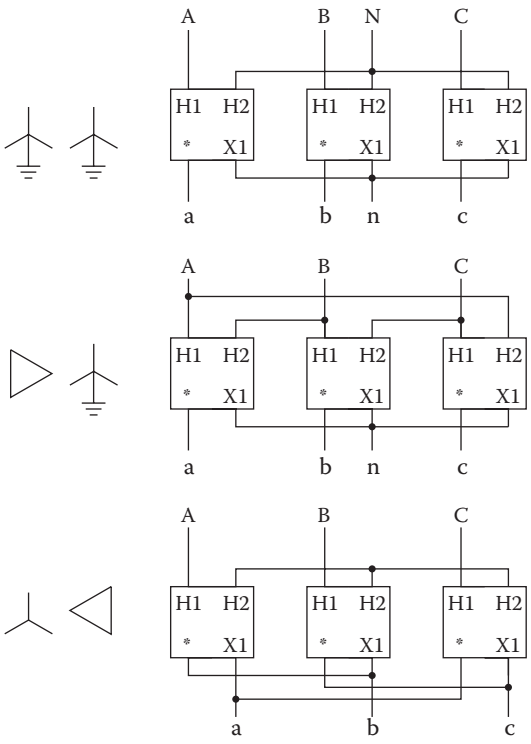
is 30°; by industry definition, the low voltage lags the high voltage (IEEE C57.12.00-2000). Figure 5.14 shows wiring diagrams to ensure proper phase connections of popular three-phase connections.

Table 5.7 shows the standard winding designations shown on the nameplate of three-phase units.

5.4.1 Grounded Wye–Grounded Wye

The most common three-phase transformer supply connection is the grounded-wye–grounded-wye connection. Its main characteristics are

- *Supply*—Must be a grounded four-wire system
- *Service*



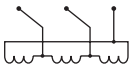
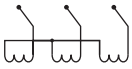
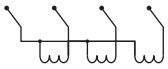
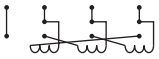
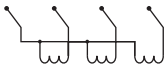
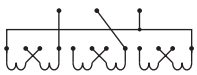
* is the opposite winding to X1, either X2, X3, or X4 depending on the transformer

Figure 5.14 Wiring diagrams for common transformer connections with additive units. Subtractive units have the same secondary connections, but the physical positions of X1 and * are reversed on the transformer.

  - Supplies grounded-wye service, normally either 480Y/277 V or 208Y/120 V.
  - Cannot supply 120 and 240 V.
  - Does not supply ungrounded service. (But a grounded-wye–floating-wye connection can.)
- *Tank heating*—Probable with three-legged core construction; less likely, but possible under severe unbalance with five-legged core construction. Impossible if made from three single-phase units.
- *Zero sequence*—All zero-sequence currents—harmonics, unbalance, and ground faults—transfer to the primary. It also acts as a high-impedance ground source to the primary.
- *Ferroresonance*—No chance of ferroresonance with a bank of single-phase units or triplex construction; some chance with a four- or five-legged core construction.
- *Coordination*—Because ground faults pass through to the primary, larger transformer services and local protective devices should be coordinated with utility ground relays.

The grounded-wye–grounded-wye connection has become the most common three-phase transformer connection. Reduced ferroresonance is the main reason for the shift from the delta–grounded wye to the grounded wye–grounded wye.

TABLE 5.7 Three-Phase Transformer Designations

Nomenclature	Examples	Description
E	2400 	E shall indicate a winding that is permanently Δ connected for operation on an E volt system.
E_1Y	4160Y 	E_1Y shall indicate a winding that is permanently Y connected without a neutral brought out (isolated) for operation on an E_1 volt system.
E_1Y/E	4160Y/2400 	E_1Y/E shall indicate a winding that is permanently Y connected with a fully insulated neutral brought out for operation on an E_1 volt system, with E volts available from line to neutral.
E/E_1Y	2400/4160Y	E/E_1Y shall indicate a winding that may be Δ connected for operation on an E volt system, or may be Y connected without a neutral brought out (isolated) for operation on an E_1 volt system.
$E/E_1Y/E$	2400/4160Y/2400 	$E/E_1Y/E$ shall indicate a winding that may be Δ connected for operation on an E volt system or may be Y connected with a fully insulated neutral brought out for operation on an E_1 volt system with E volts available from line to neutral.
E_1GrdY/E	12470GrdY/7200 	E_1GrdY/E shall indicate a winding with reduced insulation and permanently Y connected, with a neutral brought out and effectively grounded for operation on an E_1 volt system with E volts available from line to neutral.
$E/E_1GrdY/E$	7200/12470GrdY/7200	$E/E_1GrdY/E$ shall indicate a winding, having reduced insulation, which may be Δ connected for operation on an E volt system or may be connected Y with a neutral brought out and effectively grounded for operation on an E_1 volt system with E volts available from line to neutral.
$V \times V_1$	7200 × 14400 	$V \times V_1$ shall indicate a winding, the sections of which may be connected in parallel to obtain one of the voltage ratings (as defined in a–g) of V, or may be connected in series to obtain one of the voltage ratings (as defined in a–g) of V_1. Windings are permanently Δ or Y connected.

Source: Adapted from IEEE C57.12.00-2000, *IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers*. Copyright 2000 IEEE.

A grounded-wye–grounded-wye transformer with three-legged core construction is not suitable for supplying four-wire service. Unbalanced secondary loading and voltage unbalance on the primary system, these unbalances heat the transformer tank. In a three-legged core design, zero-sequence flux has no iron-core return path, so it must return via a high-reluctance path through the air gap and partially through the transformer tank (see Figure 5.15). The zero-sequence flux induces eddy currents in the tank that heat the tank.

A four- or five-legged core transformer greatly reduces the problem of tank heating with a grounded-wye–grounded-wye connection. The extra leg(s) provide an iron path for zero-sequence flux, so none travels into the tank. Although much less of a

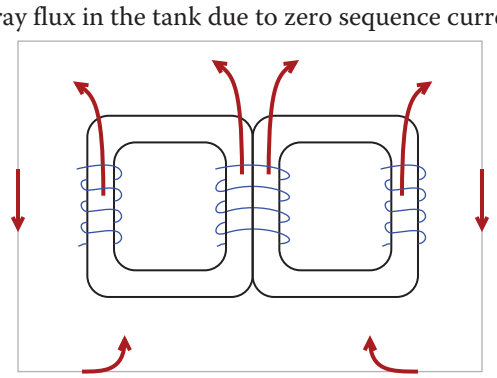


Figure 5.15 Zero-sequence flux caused by unbalanced voltages or unbalanced loads.

problem, tank heating can occur on four- and five-legged core transformers under certain conditions; very large voltage unbalances may heat the tank. The outer leg cores normally do not have full capacity for zero-sequence flux (they are smaller than the inner leg cores), so under very high voltage unbalance, the outer legs may saturate. Once the legs saturate, some of the zero-sequence flux flows in the tank causing heating. The outer legs may saturate for a zero-sequence voltage of about 50 to 60% of the rated voltage. If a fuse or single-phase recloser or single-pole switch opens upstream of the transformer, the unbalance may be high enough to heat the tank, depending on the loading on the transformer and whether faults still exist. The worst conditions are when a single-phase interrupter clears a line-to-line or line-to-line-to-line fault (but not to ground) and the transformer is energized through one or two phases.

To completely eliminate the chance of tank heating, do not use a core-form transformer. Use a bank made of three single-phase transformers, or use triplex construction.

A wye–wye transformer with the primary and secondary neutrals tied together internally causes high line-to-ground secondary voltages if the neutral is not grounded. This connection cannot supply three-wire ungrounded service. Three-phase padmounted transformers with an H0X0 bushing have the neutrals bonded internally. If the H0X0 bushing is floated, high voltages can occur from phase to ground on the secondary.

To supply ungrounded secondary service with a grounded-wye primary, use a grounded-wye–floating-wye connection: the secondary should be floating-wye with no connection between the primary and secondary neutral points.

5.4.2 Delta–Grounded Wye

The delta–grounded-wye connection has several interesting features, many related to its delta winding, which establishes a local grounding reference and blocks zero-sequence currents from entering the primary.

- *Supply*—three-wire or four-wire system.
- *Service*

  - Supplies grounded-wye service, normally either 480Y/277 V or 208Y/120 V.
  - Cannot supply both 120 and 240 V.
  - Does not supply ungrounded service.
- *Ground faults*—This connection blocks zero sequence, so upstream ground relays are isolated from line-to-ground faults on the secondary of the customer transformer.
- *Harmonics*—The delta winding isolates the primary from zero-sequence harmonics created on the secondary. Third harmonics and other zero-sequence harmonics cannot get through to the primary (they circulate in the delta winding).
- *No primary ground source*—For line-to-ground faults on the primary, the delta–grounded wye connection cannot act as a grounding source.
- *Secondary ground source*—Provides a grounding source for the secondary, independent of the primary-side grounding configuration.
- *No tank heating*—The delta connection ensures that zero-sequence flux will not flow in the transformer's core. We can safely use a three-legged core transformer.
- *Ferroresonance*—Highly susceptible.

5.4.3 Floating Wye–Delta

The floating-wye–delta connection is popular for supplying ungrounded service and 120/240-V service. This type of connection may be used from either a grounded or ungrounded distribution primary. The main characteristics of this supply are

- *Supply*—three-wire or four-wire system.
- *Service*
  - Can supply ungrounded service.
  - Can supply four-wire service with 240/120-V on one leg with a midtapped ground.
  - Cannot supply grounded-wye four-wire service.
- *Unit failure*—Can continue to operate if one unit fails if it is rewired as an open wye–open delta.
- *Voltage unbalance*—Secondary-side unbalances are more likely than with a wye secondary connection.
- *Ferroresonance*—Highly susceptible.

Do not use single-phase transformers with secondary breakers (CSPs) in this connection. If one secondary breaker opens, it breaks the delta on the secondary. Now, the primary neutral can shift wildly. The transformer may be severely overloaded by load unbalance or single phasing on the primary.

Facilities should ensure that single-phase loads only connect to the lighting leg; any miswired loads have overvoltages. The phase-to-neutral connection from the neutral to the opposite phase (where both power legs come together) is 208 V on a 240/120-V system.

The floating wye–delta is best used when supplying mainly three-phase load with a smaller amount of single-phase load. If the single-phase load is large, the three transformers making up the connection are not used as efficiently, and voltage unbalances can be high on the secondary.

In a conservative loading guideline, size the lighting transformer to supply all of the single-phase load plus 1/3 of the three-phase load (ANSI/IEEE C57.105-1978). Size each power leg to carry 1/3 of the three-phase load plus 1/3 of the single-phase load. ABB (1995) describes more accurate loading equations:

Lighting leg loading in kVA:

$$kVA_{bc} = \frac{1}{3}\sqrt{k_3^2 + 4k_1^2 + 4k_3k_1\cos\alpha}$$

Lagging power leg loading in kVA:

$$kVA_{ca} = \frac{1}{3}\sqrt{k_3^2 + k_1^2 - 2k_3k_1\cos(120° + \alpha)}$$

Leading power leg loading in kVA:

$$kVA_{ab} = \frac{1}{3}\sqrt{k_3^2 + k_1^2 - 2k_3k_1\cos(120° - \alpha)}$$

where

k_1 = single-phase load, kVA
k_3 = balanced three-phase load, kVA
$\alpha = \theta_3 - \theta_1$
θ_3 = phase angle in degrees for the three-phase load
θ_1 = phase angle in degrees for the single-phase load

For wye–delta connections, the wye on the primary is normally intentionally ungrounded. If it is grounded, it creates a grounding bank. This is normally undesirable because it may disrupt the feeder protection schemes and cause excessive circulating current in the delta winding. Utilities sometimes use this connection as a grounding source or for other unusual reasons.

Delta secondary windings are more prone to voltage unbalance problems than a wye secondary winding (Smith et al., 1988). A balanced three-phase load can cause voltage unbalance if the impedances of each leg are different. With the normal practice of using a larger lighting leg, the lighting leg has a lower impedance. Voltage unbalance is worse with longer secondaries and higher impedance transformers. High levels of single-phase load also aggravate unbalances.

5.4.4 Other Common Connections

5.4.1.1 Delta–Delta

The main features and drawbacks of the delta–delta supply are

- *Supply*—three-wire or four-wire system.
- *Service*

  - Can supply ungrounded service.
  - Can supply four-wire service with 240/120-V on one leg with a midtapped ground.
  - Cannot supply grounded-wye four-wire service.
- *Ferroresonance*—Highly susceptible.
- *Unit failure*—Can continue to operate if one unit fails (as an open delta—open delta).
- *Circulating current*—Has high circulating current if the turns ratios of each unit are not equal.

A delta–delta transformer may have high circulating current if any of the three legs has unbalance in the voltage ratio. A delta winding forms a series loop. Two windings are enough to fix the three phase-to-phase voltage vectors. If the third winding does not have the same voltage as that created by the series sum of the other two windings, large circulating currents flow to offset the voltage imbalance. ANSI/IEEE C57.105-1978 provides an example where the three phase-to-phase voltages summed to 1.5% of nominal as measured at the open corner of the delta winding (this voltage should be zero for no circulating current). With a 5% transformer impedance, a current equal to 10% of the transformer rating circulates in the delta when the open corner is connected. The voltage sees an impedance equal to the three winding impedances in series, resulting in a circulating current of $100\% \times 1.5\%/(3 \times 5\%) = 10\%$. This circulating current directly adds to one of the three windings, possibly overloading the transformer.

Single-phase units with secondary breakers (CSPs) should not be used for the lighting leg. If the secondary breaker on the lighting leg opens, the load loses its neutral reference, but the phase-to-phase voltages are maintained by the other two legs (like an open delta–open delta connection). As with the loss of the neutral connection to a single-phase 120/240-V customer, unbalanced single-phase loads shift the neutral and create low voltages on one leg and high voltages on the lightly loaded leg.

5.4.1.2 Open Wye–Open Delta

The main advantage of the open-wye–open-delta transformer configuration is that it can supply three-phase load from a two-phase supply (but the supply must have a neutral).

The main features and drawbacks of the open-wye–delta supply are

- *Supply*—2 phases and the neutral of a four-wire grounded system.
- *Service*
  - Can supply ungrounded service.
  - Can supply four-wire service with 240/120-V on one leg with a midtapped ground.
  - Cannot supply grounded-wye four-wire service.
- *Ferroresonance*—Immune.
- *Voltage unbalance*—May have high secondary voltage unbalance.
- *Primary ground current*—Creates high primary-side current unbalance. Even with balanced loading, high currents are forced into the primary neutral.

Open-wye–open-delta connections are most efficiently applied when the load is predominantly single phase with some three-phase load, using one large lighting-leg transformer and another smaller unit. This connection is easily upgraded if the customer's three-phase load grows by adding a second power-leg transformer.

For sizing each bank, size the power leg for $1/\sqrt{3} = 0.577$ times the balanced three-phase load, and size the lighting leg for all of the single-phase load plus 0.577 times the three-phase load (ANSI/IEEE C57.105–1978). The following equations more accurately describe the split in loading on the two transformers (ABB, 1995). The load on the lighting leg in kVA is

$$kVA_L = \frac{k_3^2}{3} + k_1^2 + \frac{2k_3k_1}{\sqrt{3}}\cos(\alpha + 30°) \quad \text{for a leading lighting leg}$$

$$kVA_L = \frac{k_3^2}{3} + k_1^2 + \frac{2k_3k_1}{\sqrt{3}}\cos(\alpha - 30°) \quad \text{for a lagging lighting leg}$$

The power leg loading in kVA is

$$kVA_L = \frac{k_3}{\sqrt{3}}$$

where

k_1 = single-phase load, kVA
k_3 = balanced three-phase load, kVA
$\alpha = \theta_3 - \theta_1$
θ_3 = phase angle in degrees for the three-phase load
θ_1 = phase angle in degrees for the single-phase load

The lighting leg may be on the leading or lagging leg. In the open-wye–open-delta connection shown in Figure 5.13, the single-phase load is on the leading leg. For a lagging connection, switch the lighting and the power leg. Having the lighting connection on the leading leg reduces the loading on the lighting leg. Normally, the power factor of the three-phase load is less than that of the single-phase load, so α is positive, which reduces the loading on the lighting leg.

On the primary side, it is important that the two high-voltage primary connections are not made to the same primary phase. If this is accidentally done, the phase-to-phase voltage across the open secondary is two times the normal phase-to-phase voltage.

The open-wye–open-delta connection injects significant current into the neutral on the four-wire primary. Even with a balanced three-phase load, significant current is forced into the ground as shown in Figure 5.16. The extra unbalanced current can cause primary-side voltage unbalance and may trigger ground relays.

Open-delta secondary windings are very prone to voltage unbalance, which can cause excessive heating in end-use motors (Smith et al., 1988). Even balanced

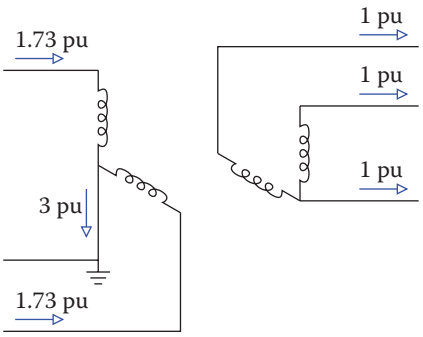


Figure 5.16 Current flow in an open wye–open delta transformer with balanced three-phase load.

three-phase loads significantly unbalance the voltages. Voltage unbalance is less with lower-impedance transformers. Voltage unbalance reduces significantly if the connection is upgraded to a floating-wye–closed-delta connection. In addition, the component of the negative-sequence voltage on the primary (which is what really causes motor heating) can add to that caused by the transformer configuration to sometimes cause a negative-sequence voltage above 5% (which is a level that significantly increases heating in a three-phase induction motor).

While an unusual connection, it is possible to supply a balanced, grounded four-wire service from an open-wye primary. This connection (open wye–partial zig-zag) can be used to supply 208Y/120-V service from a two-phase line. One of the 120/240-V transformers must have four bushings; X2 and X3 are not tied together but connected as shown in Figure 5.17. Each of the transformers must be sized to supply 2/3 of the balanced three-phase load. If four-bushing transformers are not available, this connection can be made with three single-phase transformers. Instead of the four-bushing transformer, two single-phase transformers are placed in parallel on the primary, and the secondary terminals of each are configured to give the arrangement in Figure 5.17.

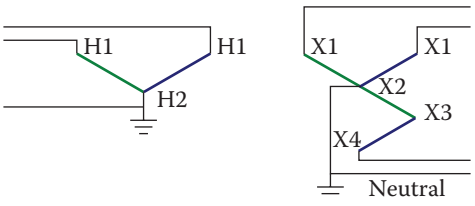


Figure 5.17 Quasiphasor diagram of an open-wye primary connection supplying a wye four-wire neutral service such as 208Y/120 V. (ANSI/IEEE C57.105-1978, *IEEE Guide for Application of Transformer Connections in Three-Phase Distribution Systems*. © 1978 IEEE.)

5.4.1.3 Other Suitable Connections

While not as common, several other three-phase connections are used at times:

- *Open delta–Open delta*—Can supply a three-wire ungrounded service or a four-wire 120/240-V service with a midtapped ground on one leg of the transformer. The ungrounded high-side connection is susceptible to ferroresonance. Only two transformers are needed, but it requires all three primary phases. This connection is less efficient for supplying balanced three-phase loads; the two units must total 115% of the connected load. This connection is most efficiently applied when the load is predominantly single phase with some three-phase load, using one large lighting-leg transformer and another smaller unit.
- *Delta–Floating wye*—Suitable for supplying a three-wire ungrounded service. The ungrounded high-side connection is susceptible to ferroresonance.
- *Grounded wye–Floating wye*—Suitable for supplying a three-wire ungrounded service from a multigrounded primary system. The grounded primary-side connection reduces the possibility of ferroresonance.

5.4.5 Neutral Stability with a Floating Wye

Some connections with a floating-wye winding have an unstable neutral, which we should avoid. Unbalanced single-phase loads on the secondary, unequal magnetizing currents, and suppression of third harmonics—all can shift the neutral.

Consider a *floating-wye–grounded-wye* connection. In a wye–wye transformer, the primary and secondary voltages have the same vector relationships. The problem is that the neutral point does not have a grounding source; it is free to float. Unbalanced loads or magnetizing currents can shift the neutral and create high neutral-to-earth voltages and overvoltages on the phases with less loading. The reverse connection with a grounded-wye–floating-wye works because the primary-side neutral is connected to the system neutral, which has a grounding source. The grounding source fixes the neutral voltage.

In a floating wye, current in one branch is dependent on the currents in the other two branches. What flows in one branch must flow out in the other two branches. This creates conditions that shift the neutral (Blume et al., 1951):

- *Unbalanced loads*—Unequal single-phase loads shift the neutral point. Zero-sequence current has no path to flow (again, the ground source is missing). Loading one phase drops the voltage on that phase and raises the voltage on the other two phases. Even a small unbalance significantly shifts the neutral.
- *Unequal magnetizing currents*—Just like unequal loads, differences in the amount of magnetizing current each leg needs can shift the floating neutral. In a four- or five-legged core, the asymmetry of the core causes unequal magnetizing requirements on each phase.
- *Suppression of third harmonics*—Magnetizing currents contain significant third harmonics that are zero sequence. But, the floating-wye connection has no ground source to absorb the zero-sequence currents, so they are suppressed. The suppression of the zero-sequence currents generates a significant third-harmonic voltage in

each winding, about 50% of the phase voltage on each leg according to Blume et al. (1951). With the neutral grounded in the floating wye–grounded wye, a significant third-harmonic voltage adds to each phase-to-ground load. If the neutral is floating (on the wye–wye transformer with the neutrals tied together), the third-harmonic voltage appears between the neutral and ground.

In addition to the floating wye–grounded wye, avoid these problem connections that have an unstable neutral:

- *Grounded wye–grounded wye on a three-wire system*—The grounded-wye on the primary does not have an effective grounding source, so it acts the same as a floating wye–grounded wye.
- *A wye–wye transformer with the primary and secondary neutrals tied together internally (the H0X0 bushing) but with the neutral left floating*—Again, the neutral point can float. Unbalanced loading is not a problem, but magnetizing currents and suppression of third harmonics are. These can generate large voltages between the neutral point and ground (and between the phase wires and ground). If the secondary neutral is isolated from the primary neutral, each neutral settles to a different value. But when the secondary neutral is locked into the primary neutral, the secondary neutral follows the neutral shift of the primary and shifts the secondary phases relative to ground.

If a grounded-wye–grounded-wye transformer loses a connection to ground on the primary side or from the internal neutral to the H0X0 bushing, instability can occur. See Figure 5.18 for an example of voltage measured on one phase. In this case, the line-to-neutral voltages were extremely unbalanced, and the line-to-neutral voltages contained 20 to 25% third-harmonic content.

Another poor connection is the floating wye–floating wye. Although not as bad as the floating-wye–grounded-wye connection, the neutral can shift if the connection is made of three units of different magnetizing characteristics. The neutral shift can lead to an overvoltage across one of the windings. Also, high harmonic voltage appears on the primary-side neutral (which is okay if the neutral is properly insulated from the tank).

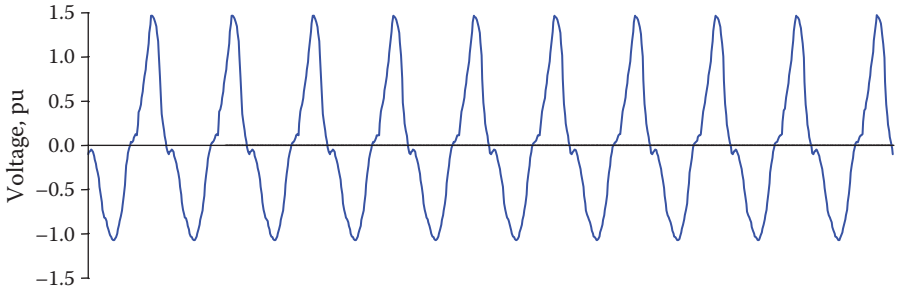


Figure 5.18 Line-to-neutral voltages on a grounded-wye–grounded-wye transformer with a bad ground.

Three-legged core transformers avoid some of the problems with a floating wye. The phantom tertiary acts as a mini ground source, stabilizes the neutral, and even allows some unbalance of single-phase loads. But as it stabilizes the neutral, the unbalances heat the tank. Given that, it is best to avoid these transformer connections. They provide no features or advantages over other transformer connections.

5.4.6 Sequence Connections of Three-Phase Transformers

The connection determines the effect on zero sequence, which impacts unbalances and response to line-to-ground faults and zero-sequence harmonics. Figure 5.19 shows how to derive sequence connections along with common examples. In general, three-phase transformers may affect the zero-sequence circuit as follows:

- *Isolation*—A floating-wye–delta connection isolates the primary from the secondary in the zero sequence.
- *Pass through*—The grounding of the grounded-wye–grounded-wye connection is determined by the grounding upstream of the transformer.
- *Ground source*—A delta–grounded-wye connection provides a ground source on the secondary. (And, the delta–grounded-wye connection also isolates the primary from the secondary.)

5.5 Loadings

Distribution transformers are *output rated*; they can deliver their rated kVA without exceeding temperature rise limits when the following conditions apply:

- The secondary voltage and the voltage/frequency do not exceed 105% of rating. So, a transformer is a constant kVA device for a voltage from 100% to 105% (the standards are unclear below that, so treat them as constant current devices).
- The load power factor ≥80%.
- Frequency ≥95% of rating.

The transformer loading and sizing guidelines of many utilities are based on ANSI/IEEE C57.91-1981.

Modern distribution transformers are 65°C rise units, meaning they have normal life expectancy when operated with an average winding temperature rise above ambient of not more than 65°C and a hottest spot winding temperature rise of not more than 80°C. Some older units are 55°C rise units, which have less overloading capability.

At an ambient temperature of 30°C, the 80°C hottest-spot rise for 65°C rise units gives a hottest-spot winding temperature of 110°C. The hot-spot temperature on the winding is critical; that's where insulation degrades. The insulation's life exponentially relates to hot-spot winding temperature as shown in Figure 5.20. At 110°C, the normal life expectancy is 20 years. Because of daily and seasonal load cycles, most of

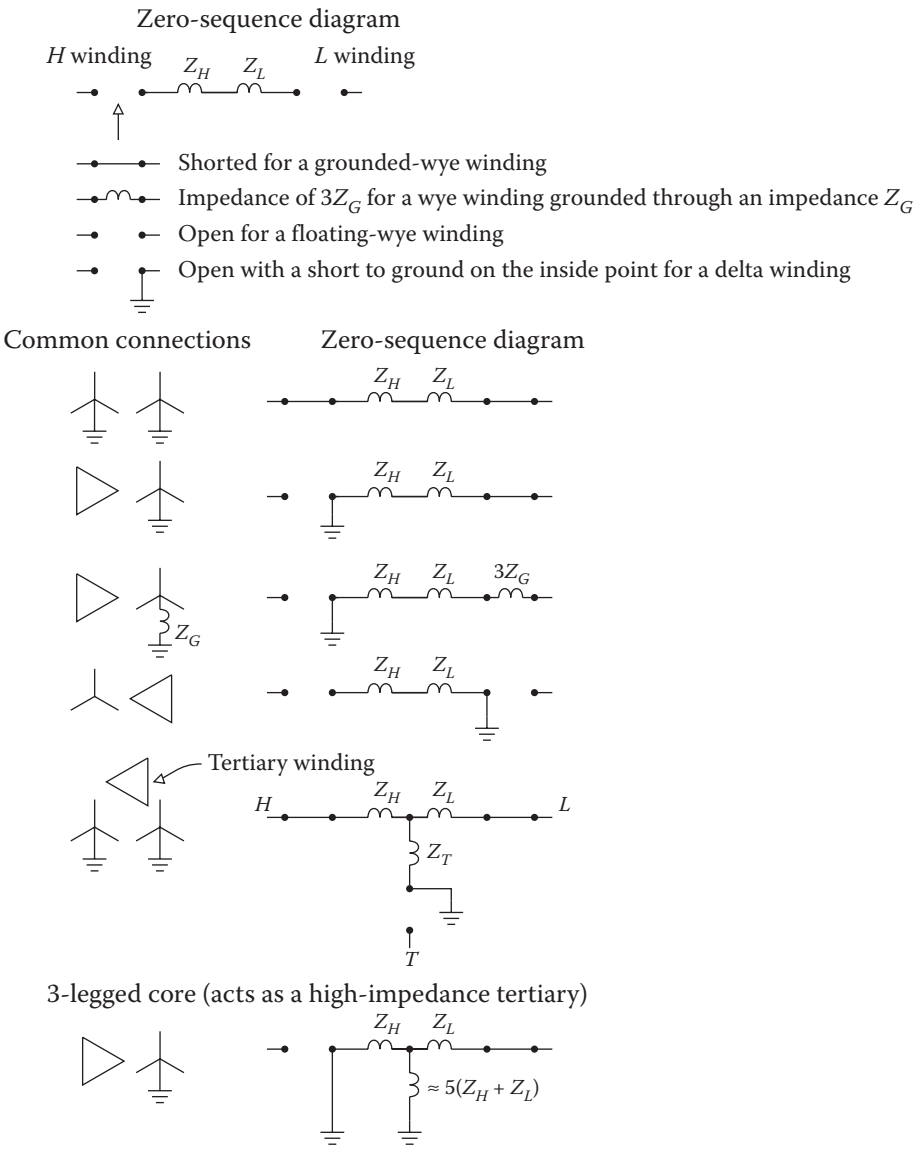


Figure 5.19 Zero-sequence connections of various three-phase transformer connections.

the time temperatures are nowhere near these values. Most of the time, temperatures are low enough not to do any significant insulation degradation. We can even run at temperatures above 110°C for short periods. For the most economic operation of distribution transformers, they are normally sized to operate at significant overloads for short periods of the year.

We can load distribution transformers much more heavily when it is cold. Locations with winter-peaking loads can have smaller transformers for a given loading level. The transformer's kVA rating is based on an ambient temperature of 30°C.

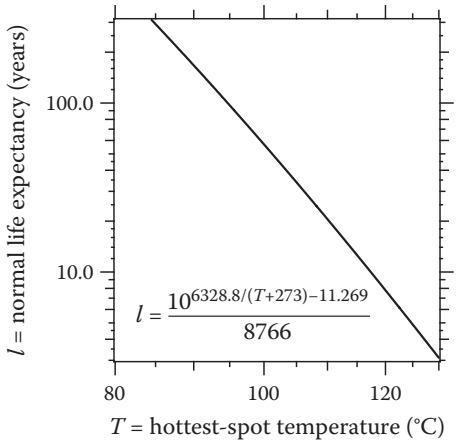


Figure 5.20 Transformer life as a function of the hottest-spot winding temperature.

For other temperatures, ANSI/IEEE C57.91-1981 suggests the following adjustments to loading capability:

- >30°C: decrease loading capability by 1.5% of rated kVA for each °C above 30°C.
- <30°C: increase loading capability by 1% of rated kVA for each °C below 30°C.

Ambient temperature estimates for a given region can be found using historical weather data. For loads with normal life expectancy, ANSI/IEEE C57.91-1981 recommends the following estimate of ambient temperature:

- *Average daily temperature for the month involved*—As an approximation, the average can be approximated as the average of the daily highs and the daily lows.

For short-time loads where we are designing for a moderate sacrifice of life, use

- *Maximum daily temperature*

In either case, the values should be averaged over several years for the month involved. C57.91-1981 also suggests adding 5°C to be conservative. These values are for outdoor overhead or padmounted units. Transformers installed in vaults or other cases with limited air flow may require some adjustments.

Transformers should also be derated for altitudes above 3300 ft (1000 m). At higher altitudes, the decreased air density reduces the heat conducted away from the transformer. ANSI/IEEE C57.91-1981 recommends derating by 0.4% for each 330 ft (100 m) that the altitude is above 3300 ft (1000 m).

Load cycles play an important role in determining loading. ANSI/IEEE C57.91-1981 derives an equivalent load cycle with two levels: the peak load and the initial load. The equivalent two-step load cycle may be derived from a more detailed load cycle. The guide finds a continuous load and a short-duration peak load. Both are found using the equivalent load value from a more complicated load cycle:

$$L = \sqrt{\frac{L_1^2 t_1 + L_2^2 t_2 + L_3^2 t_3 + \cdots + L_n^2 t_n}{t_1 + t_2 + t_3 + \cdots + t_n}}$$

where

L = equivalent load in percent, per unit, or actual kVA
$L_1, L_2, \ldots$ = the load steps in percent, per unit, or actual kVA
$t_1, t_2, \ldots$ = the corresponding load durations

The continuous load is the equivalent load found using the equation above for 12 h preceding and 12 h following the peak and choosing the higher of these two values. The guide suggests using 1-h time blocks. The peak is the equivalent load from the equation above where the irregular peak exists.

The C57.91 guide has loading guidelines based on the peak duration and continuous load prior to the peak. Table 5.8 shows that significant overloads are allowed depending on the preload and the duration of the peak.

Because a region's temperature and loading patterns vary significantly, there is no universal transformer application guideline. Coming up with standardized tables for initial loading is based on a prediction of peak load, which for residential service normally factors in the number of houses, average size (square footage), central air conditioner size, and whether electric heat is used. Once the peak load is estimated, it is common to pick a transformer with a kVA rating equal to or greater than the peak load kVA estimate. With this arrangement, some transformers may operate significantly above their ratings for short periods of the year. Load growth can push the peak load above the peak kVA estimate, and inaccuracy of the load prediction will mean that some units are going to be loaded more than expected. The load factor (the ratio of average demand to peak demand) for most distribution transformers is 40–60%. Most distribution transformers are relatively lightly loaded most of the time, but some have peak loads well above their rating. In analysis of data from three utilities, the Oak Ridge National Laboratory found that distribution transformers have an average load of 15–40% of their rating, with 30% being most typical (ORNL-6925, 1997).

The heat input into the transformer is from no-load losses and from load losses. The economics of transformer application and purchasing involve consideration of the thermal limitations as well as the operating costs of the losses. Transformer stocking considerations also play a role. For residential customers, a utility may limit inventory to 15, 25, and 50-kVA units (5, 10, 15, 25, 37.5, 50-kVA units are standard sizes).

Some utilities use transformer load management programs to more precisely load transformers to get the most economic use of each transformer's life. These programs take billing data for the loads from each transformer to estimate that transformer's loading. These programs allow the utility to more aggressively load transformers because those needing changeout can be targeted more precisely. Load management programs require data setup and maintenance. Most important, each meter must be tied to a given transformer (many utilities have this information infrastructure, but some do not).

TABLE 5.8 Transformer Loading Guidelines

Peak Load Duration, Hours	Extra Loss of Life[a], %	Equivalent Peak Loading in Per Unit of Rated kVA with the Percent Preload and Ambient Temperatures Given Below										
		50% Preload				75% Preload				90% Preload		
		Ambient Temp., °C				Ambient Temp., °C				Ambient Temp., °C		
		20	30	40	50	20	30	40	50	20	30	40
1	Normal	2.26	2.12	1.96	1.79	2.12	1.96	1.77	1.49	2.02	1.82	1.43
	0.05	2.51	2.38	2.25	2.11	2.40	2.27	2.12	1.95	2.31	2.16	1.97
	0.10	2.61	2.49	2.36	2.23	2.50	2.37	2.22	2.07	2.41	2.27	2.11
	0.50	2.88	2.76	2.64	2.51	2.77	2.65	2.52	2.39	2.70	2.57	2.43
2	Normal	1.91	1.79	1.65	1.50	1.82	1.68	1.52	1.26	1.74	1.57	1.26
	0.05	2.13	2.02	1.89	1.77	2.05	1.93	1.80	1.65	1.98	1.85	1.70
	0.10	2.22	2.10	1.99	1.87	2.14	2.02	1.90	1.75	2.07	1.95	1.81
	0.50	2.44	2.34	2.23	—	2.37	2.26	2.15	—	2.31	2.20	2.08
4	Normal	1.61	2.50	1.38	1.25	1.56	1.44	1.30	1.09	1.50	1.36	1.13
	0.05	1.80	1.70	1.60	1.48	1.76	1.65	1.54	1.40	1.71	1.60	1.47
	0.10	1.87	1.77	1.67	—	1.83	1.72	1.62	1.50	1.79	1.68	1.56
	0.50	2.06	1.97	—	—	2.02	1.93	—	—	1.99	1.89	—
8	Normal	1.39	1.28	1.18	1.05	1.36	1.25	1.13	0.96	1.33	1.21	1.02
	0.05	1.55	1.46	1.36	1.25	1.53	1.43	1.33	1.21	1.51	1.41	1.29
	0.10	1.61	1.53	1.43	1.33	1.59	1.50	1.41	1.30	1.57	1.47	1.38
	0.50	1.78	1.69	1.61	—	1.76	1.67	1.58	—	1.74	1.65	1.56
24	Normal	1.18	1.08	0.97	0.86	1.17	1.07	0.97	0.84	1.16	1.07	0.95
	0.05	1.33	1.24	1.15	1.04	1.33	1.24	1.13	1.04	1.32	1.23	1.13
	0.10	1.39	1.30	1.21	1.11	1.38	1.29	1.20	1.10	1.38	1.29	1.20
	0.50	1.54	1.45	1.37	1.28	1.53	1.45	1.37	1.28	1.53	1.45	1.36

Source: Adapted from ANSI/IEEE C57.91-1981, *IEEE Guide for Loading Mineral-Oil-Immersed Overhead and Pad-Mounted Distribution Transformers Rated 500 kVA and Less with 65 Degrees C or 55 Degrees C Average Winding Rise*.

[a]Extra loss of life in addition to 0.0137% per day loss of life for normal life expectancy.

Transformer loadings vary considerably. Figure 5.21 shows the distribution of average loadings on two sizes of transformers at one typical utility. Most transformers are not heavily loaded: in this case, 85% of units have average loadings less than the nameplate. Many units are very lightly loaded, and 10% are quite heavily loaded. Smaller units have more spread in their loading.

Seevers (1995) demonstrates a simple approach to determining transformer loading. Their customers (in the southern US) had 1 kW of demand for every 400 kWh's, regardless of whether the loads peaked in the winter or summer. Seevers derived the ratio by comparing substation demand with kWh totals for all customers fed from the substation (after removing primary-metered customers and other large loads). To estimate the load on a given transformer, sum the kWh for the month of highest usage for all customers connected to the transformer and convert into peak demand, in this case by dividing by 400 kWh per kW-demand. While simple, this method

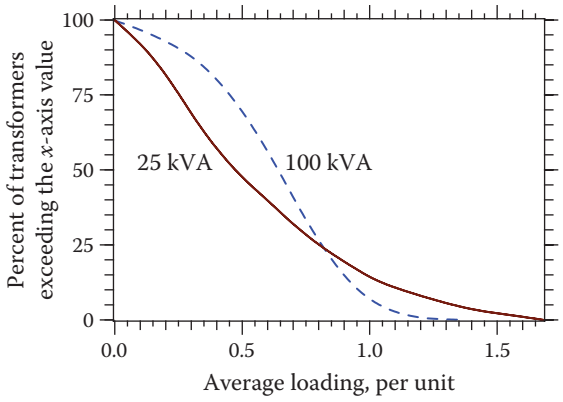


Figure 5.21 Distributions of average loadings of two transformer sizes at one utility. (From ORNL-6927, *Economic Analysis of Efficient Distribution Transformer Trends*, Oak Ridge National Laboratory, U.S. Department of Energy, 1998.)

identifies grossly undersized or oversized transformers. Table 5.9 shows guidelines for replacement of underloaded transformers.

Transformers with an internal secondary breaker (CSPs) are a poor-man's form of transformer load management. If the breaker trips from overload, replace the transformer (unless there are extraordinary weather and loading conditions that are unlikely to be repeated).

Automated metering infrastructure (AMI) offers high precision for managing transformer loading and improving planning criteria for sizing transformers. Figure 5.22 shows distributions of transformer loading as a function of rating. This example is for a utility in the US Midwest with an AMI pilot covering suburban/rural territory. The loading is given as the 99.9% kVA rating; approximately 9 h per year are above this loading. Most of these transformers are relatively lightly loaded. This example is based on kVA measurements. Most AMI meters only measure kilowatt hours, so some approximations are needed to convert into kVA. To use AMI for evaluating transformer loading, the customer meter-to-transformer mapping is needed to sum

TABLE 5.9 One Approach to a Transformer Replacement Program

Existing Transformer kVA	Loading Estimate in kVA	Recommended Size in kVA
25	10 or less	10
37.5	15 or less	10
50	20 or less	15
75	37.5 or less	37.5
100	50 or less	50
167	100 or less	100
	75 or less	75 or 50

Data Source: Seevers, O. C., *Management of Transmission and Distribution Systems*, Penn Well Publishing Company, Tulsa, OK, 1995.

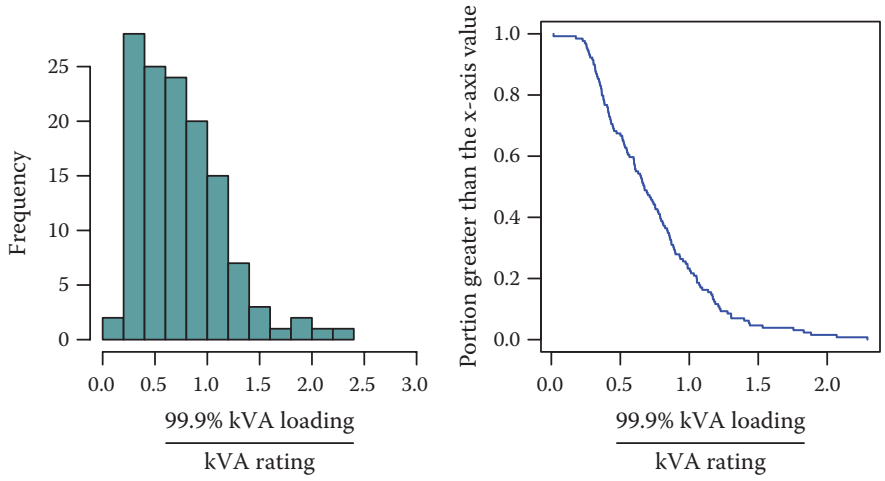


Figure 5.22 Probability distributions of loading for a pilot set of transformers with AMI.

the load on the transformer. Research shows promising approaches to automate this customer-to-transformer connectivity using AMI data (Short, 2013).

Especially in high-lightning areas, consider the implications of reduction of insulation capability. At hottest-spot temperatures above 140°C, the solid insulation and the oil may release gases. While not permanently reducing insulation, the short-term loss of insulation strength can make the transformer susceptible to damage from lightning-caused voltage surges. The thermal time constant of the winding is very short, 5 to 15 min. On this time scale, loads on distribution transformers are quite erratic with large, short-duration overloads (well above the 20- or 30-min demand loadings). These loads can push the winding hottest-spot temperature above 140°C.

Padmounted transformers have a special concern related to loading: case temperatures. Under heavy loading on a hot day, case temperatures can become hot. ABB measured absolute case temperatures of 185 to 200°F (85 to 95°C) and case temperature rises above ambient of 50 to 60°C on 25 and 37.5-kVA transformers at 180% loadings and on a 50-kVA transformer at 150% continuous load (NRECA RER Project 90-8, 1993). The hottest temperatures were on the sides of the case where the oil was in contact with the case (the top of the case was significantly cooler). While these temperatures sound quite high, a person's pain-withdrawal reflexes will normally protect against burns for normal loadings that would be encountered. Reflexes will protect against blistering and burning for case temperatures below 300°F (149°C). Skin contacts must be quite long before blistering occurs. For a case temperature of 239°F (115°C), NRECA reported that the skin-contact time to blister is 6.5 sec (which is more than enough time to pull away). At 190°F (88°C), the contact time to blister is 19 sec.

5.6 Losses

Transformer losses are important purchase criteria and make up an appreciable portion of a utility's overall losses. The Oak Ridge National Laboratory estimates that

distribution transformers account for 26% of transmission and distribution losses and 41% of distribution and subtransmission losses (ORNL-6804/R1, 1995). At one utility, Grainger and Kendrew (1989) estimated that distribution transformers were 55% of distribution losses and 2.14% of electricity sales; of the two main contributors to losses, 86% were no-load losses, and 14% were load losses.

Load losses are also called copper or wire or winding losses. Load losses are from current through the transformer's windings generating heat through the winding resistance as I^2R.

No-load losses are the continuous losses of a transformer, regardless of load. No-load losses for modern silicon-steel-core transformers average about 0.2% of the transformer rating (a typical 50-kVA transformer has no-load losses of 100 W), but designs vary from 0.15% to 0.4% depending on the needs of the utility. No-load losses are also called iron or core losses because they are mainly a function of the core materials. The two main components of no-load losses are eddy currents and hysteresis. Hysteresis describes the memory of a magnetic material. More force is necessary to demagnetize magnetic material than it takes to magnetize it; the magnetic domains in the material resist realignment. Eddy current losses are small circulating currents in the core material. The steel core is a conductor that carries an alternating magnetic field, which induces circulating currents in the core. These currents through the resistive conductor generate heat and losses. Cores are typically made from cold-rolled, grain-oriented silicon steel laminations. Manufacturers limit eddy currents by laminating the steel core in 9- to 14-mil thick layers, each insulated from the other. Core losses increase with steady-state voltage.

Utility losses from transformers will vary by purchasing history and loss criteria, transformer rating populations, and transformer age populations. Table 5.10 shows average loss statistics by size for one utility in the Southwest US purchased between 1986 and 2006. Transformer losses have decreased significantly in the past 50 years. Table 5.11 shows typical losses based on Westinghouse (1965).

TABLE 5.10 15-kV Class Transformer Losses (1986–2006 Vintage)

1-Phase			3-Phase		
kVA	NLL (%)	LL (%)	kVA	NLL (%)	LL (%)
10	0.318	1.153	225	0.157	0.668
15	0.280	1.090	300	0.139	0.664
25	0.230	1.008	500	0.128	0.607
38	0.219	0.831	750	0.109	0.629
50	0.184	0.811	1000	0.097	0.594
75	0.171	0.749	1500	0.111	0.537
100	0.173	0.715	2000	0.096	0.536
167	0.156	0.633	2500	0.079	0.528

Source: EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright 2011. Reprinted with permission.

Note: NLL = no-load losses, LL = load losses.

TABLE 5.11 Transformer Losses for Older Transformers

1 Phase			3 Phase		
kVA	NLL (%)	LL (%)	kVA	NLL (%)	LL (%)
5	0.86	2.14	9	1.00	2.47
10	0.67	1.83	15	0.96	2.18
15	0.6	1.70	30	0.75	1.90
25	0.52	1.52	75	0.59	1.55
50	0.43	1.33	150	0.52	1.34
100	0.37	1.15	300	0.46	1.31
333	0.34	1.02	500	0.44	1.13
500	0.29	0.96			

Source: Data from Westinghouse Electric Corporation, *Distribution Systems*, Vol. 3, 1965.

Note: NLL = no-load losses, LL = load losses.

Hysteresis losses are a function of the volume of the core, the frequency, and the maximum flux density (Sankaran, 2000):

$$P_h \propto V_e \, f \, B^{1.6}$$

where

V_e = volume of the core
f = frequency
B = maximum flux density

The eddy-current losses are a function of core volume, frequency, flux density, lamination thicknesses, and resistivity of the core material (Sankaran, 2000):

$$P_e \propto V_e B^2 f^{\,2} t^2 / r$$

where

t = thickness of the laminations
r = resistivity of the core material

Amorphous core metals significantly reduce core losses—as low as one-quarter of the losses of silicon-steel cores—on the order of 0.005 to 0.01% of the transformer rating. Amorphous cores do not have a crystalline structure like silicon-steel cores; their iron atoms are randomly distributed. Amorphous materials are made by rapidly cooling a molten alloy, so crystals do not have a chance to form. Such core materials have low hysteresis loss. Eddy current losses are very low because of the high resistivity of the material and very thin laminations (1-mil thick). Amorphous-core transformers are larger for the same kVA rating and have higher initial costs.

TABLE 5.12 Loss Reduction Alternatives

	No-Load Losses	Load Losses	Cost
To Decrease No-Load Losses			
Use lower-loss core materials	Lower	No change[a]	Higher
Decrease flux density by:			
1. Increasing core CSA[b]	Lower	Higher	Higher
2. Decreasing volts/turn	Lower	Higher	Higher
Decrease flux path length by decreasing conductor CSA	Lower	Higher	Lower
To Decrease Load Losses			
Use lower-loss conductor materials	No change	Lower	Higher
Decrease current density by increasing conductor CSA	Higher	Lower	Higher
Decrease current path length by:			
1. Decreasing core CSA	Higher	Lower	Lower
2. Increasing volts/turn	Higher	Lower	Higher

Source: Adapted from ORNL-6847, *Determination Analysis of Energy Conservation Standards for Distribution Transformers*, Oak Ridge National Laboratory, U.S. Department of Energy, 1996.
[a]Amorphous core materials would result in higher load losses.
[b]CSA = cross-sectional area.

Load losses, no-load losses, and purchase price are all interrelated. Approaches to reduce load losses tend to increase no-load losses and vice versa. For example, a larger core cross-sectional area decreases no-load losses (the flux density core is less), but this requires longer winding conductors and more I^2R load losses. Table 5.12 shows some of the main tradeoffs.

Information from transformer load management programs can help with transformer loss analysis. Table 5.13 shows typical transformer loading data from one utility. The average load on most transformers is relatively low (25 to 30% of transformer rating), which highlights the importance of no-load losses. The total equivalent losses on a transformer are

$$L_{\text{total}} = P^2 F_{\text{ls}} L_{\text{load}} + L_{\text{no-load}}$$

where

L_{total} = average losses, kW (multiply this by 8760 to find the annual kilowatt-hours)
P = peak transformer load, per unit
F_{ls} = loss factor, per unit
$L_{\text{no-load}}$ =rated no-load losses, kW
L_{load} = rated load losses, kW

Many utilities evaluate the total life-cycle cost of distribution transformers, accounting for the initial purchase price and the cost of losses over the life of the

TABLE 5.13 Summary of the Loading of One Utility's Single-Phase Pole-Mounted Distribution Transformers

Size (kVA)	No. of Installed Transformers	MWh/ Transformer	Annual PU Avg. Load	Annual PU Load Factor	Calculated Loss Factor
10	59,793	21	0.267	0.405	0.200
15	106,476	34	0.292	0.430	0.221
25	118,584	60	0.309	0.444	0.234
37	77,076	96	0.329	0.445	0.235
50	50,580	121	0.308	0.430	0.222
75	24,682	166	0.281	0.434	0.225
100	8,457	220	0.280	0.463	0.252
167	3,820	372	0.283	0.516	0.304
250	592	631	0.320	0.568	0.360
333	284	869	0.331	0.609	0.407
500	231	1,200	0.304	0.598	0.394
667	9	1,666	0.317	0.476	0.264
833	51	2,187	0.333	0.629	0.431

Source: Adapted from ORNL-6925, *Supplement to the Determination Analysis (ORNL-6847) and Analysis of the NEMA Efficiency Standard for Distribution Transformers*, Oak Ridge National Laboratory, U.S. Department of Energy, 1997.

Note: PU = per unit.

transformer (the total owning cost or TOC). The classic work done by Gangel and Propst (1965) on transformer loads and loss evaluation provides the foundation for much of the later work. Many utilities follow the Edison Electric Association's economic evaluation guidelines (EEI, 1981). To evaluate the total owning cost, the utility's cost of losses are evaluated using transformer loading assumptions, including load factor, coincident factor, and responsibility factor. Utilities typically assign an equivalent present value for the costs of no-load losses and another for the cost of load losses. Loss values typically range from $2 to $4/W of no-load losses and $0.50 to $1.50/W of load losses (ORNL-6847, 1996). Utilities that evaluate the life costs of transformers purchase lower-loss transformers. For example, a 50-kVA single-phase, non-loss-evaluated transformer would have approximately 150 W of no-load losses and 675 W of load losses; the same loss-evaluated transformer would have approximately 100 W of no-load losses and 540 W of load losses (ORNL-6925, 1997). Nickel (1981) describes an economic approach in detail and compares it to the EEI method. The IEEE is developing a guide (IEEE PC57.12.33, 2009).

5.7 Network Transformers

Network transformers, the distribution transformers that serve grid and spot networks, are large three-phase units. Network units are normally vault-types or subway types, which are defined as (ANSI C57.12.40-1982)

- *Vault-type transformers*—Suitable for occasional submerged operation
- *Subway-type transformers*—Suitable for frequent or continuous submerged operation

Network transformers are often housed in vaults. Vaults are underground rooms accessed through manholes that house transformers and other equipment. Vaults may have sump pumps to remove water, air venting systems, and even forced-air circulation systems. Network transformers are also used in buildings, usually in the basement. In these, vault-type transformers may be used (as long as the room is properly built and secured for such use). Utilities may also use dry-type units and units with less flammable insulating oils.

A network transformer has a three-phase, primary-side switch that can open, close, or short the primary-side connection to ground. The standard secondary voltages are 216Y/125 V and 480Y/277 V. Table 5.14 shows standard sizes. Transformers up to 1000 kVA have a 5% impedance; above 1000 kVA, 7% is standard. *X/R* ratios are generally between 3 and 12. Lower impedance transformers (say 4%) have lower voltage drop and higher secondary fault currents. (Higher secondary fault currents help on a network to burn clear faults.) Lower impedance has a price though—higher circulating currents and less load balance between transformers. Network transformers may also be made out of standard single-phase distribution transformers, but caution is warranted if the units have very low leakage impedances (which could cause very high circulating currents and secondary fault levels higher than network protector ratings).

Most network transformers are connected delta–grounded wye. By blocking zero sequence, this connection keeps ground currents low on the primary cables. Then, we can use a very sensitive ground-fault relay on the substation breaker. Blocking zero sequence also reduces the current on cable neutrals and cable sheaths, including zero-sequence harmonics, mainly the third harmonic. One disadvantage of this connection is with combination feeders—those that feed network loads as well as radial loads. For a primary line-to-ground fault, the feeder breaker opens, but the network transformers will continue to backfeed the fault until all of the network protectors operate (and some may stick). Now, the network transformers backfeed the primary feeder as an ungrounded circuit. An ungrounded circuit with a single line-to-ground fault on one phase causes a neutral shift that raises the line-to-neutral voltage on the unfaulted phases to line-to-line voltage. The non-network load connected phase-to-neutral is subjected to this overvoltage.

Some networks use grounded-wye–grounded-wye connections. This connection fits better for combination feeders. For a primary line-to-ground fault, the feeder breaker opens. Backfeeds to the primary through the network still have a grounding reference with the wye–wye connection, so chances of overvoltages are limited. The grounded-wye–grounded-wye connection also reduces the change of ferroresonance in cases where a transformer has single-pole switching.

TABLE 5.14 Standard Network Transformer Sizes

	Standard Ratings, kVA
216Y/125 V	300, 500, 750, 1000
480Y/277 V	500, 750, 1000, 1500, 2000, 2500

Most network transformers are core type, either a three- or five-legged core. The three-legged core, either with a stacked or wound core, is suitable for a delta–grounded-wye connection (but not a grounded-wye–grounded-wye connection because of tank heating). A five-legged core transformer is suitable for either connection type.

5.8 Substation Transformers

In a distribution substation, power-class transformers provide the conversion from subtransmission circuits to the distribution primary. Most are connected delta–grounded wye to provide a ground source for the distribution neutral and to isolate the distribution ground system from the subtransmission system.

Station transformers can range from 5 MVA in smaller rural substations to over 80 MVA at urban stations (base ratings). Stations with two banks, each about 20 MVA, are common. Such a station can serve about six to eight feeders.

Power transformers have multiple ratings, depending on cooling methods. The base rating is the self-cooled rating, just due to the natural flow to the surrounding air through radiators. The transformer can supply more load with extra cooling turned on. Normally, fans blow air across the radiators and/or oil circulating pumps. Station transformers are commonly supplied with OA/FA/FOA ratings. The OA is open air, FA is forced air cooling, and FOA is forced air cooling plus oil circulating pumps.

The ANSI ratings were revised in the year 2000 to make them more consistent with IEC designations. This system has a four-letter code that indicates the cooling (IEEE C57.12.00-2000):

- *First letter*—Internal cooling medium in contact with the windings:
  - **O** mineral oil or synthetic insulating liquid with fire point = 300°C
  - **K** insulating liquid with fire point >300°C
  - **L** insulating liquid with no measurable fire point
- *Second letter*—Circulation mechanism for internal cooling medium:
  - **N** natural convection flow through cooling equipment and in windings
  - **F** forced circulation through cooling equipment (i.e., coolant pumps); natural convection flow in windings (also called nondirected flow)
  - **D** forced circulation through cooling equipment, directed from the cooling equipment into at least the main windings
- *Third letter*—External cooling medium:
  - **A** air
  - **W** water
- *Fourth letter*—Circulation mechanism for external cooling medium:
  - **N** natural convection
  - **F** forced circulation: fans (air cooling), pumps (water cooling)

So, OA/FA/FOA is equivalent to ONAN/ONAF/OFAF. Each cooling level typically provides an extra one-third capability: 21/28/35 MVA. Table 5.15 shows equivalent cooling classes in the old and new naming schemes.

TABLE 5.15 Equivalent Cooling Classes

Year 2000 Designations	Designations Prior to Year 2000
ONAN	OA
ONAF	FA
ONAN/ONAF/ONAF	OA/FA/FA
ONAN/ONAF/OFAF	OA/FA/FOA
OFAF	FOA
OFWF	FOW

Source: Adapted from IEEE C57.12.00-2000, *IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers*. Copyright 2000 IEEE. All rights reserved.

Utilities do not overload substation transformers as much as distribution transformers, but they do run them hot at times. As with distribution transformers, the tradeoff is loss of life versus the immediate replacement cost of the transformer. Ambient conditions also affect loading. Summer peaks are much worse than winter peaks. IEEE Std. C57.91-1995 provides detailed loading guidelines and also suggests an approximate adjustment of 1% of the maximum nameplate rating for every degree C above or below 30°C. The hottest-spot conductor temperature is the critical point where insulation degrades. Above a hot-spot conductor temperature of 110°C, life expectancy decreases exponentially. The life halves for every 8°C increase in operating temperature. Most of the time, the hottest temperatures are nowhere near this. Tillman (2001) provides the loading guide for station transformers shown in Table 5.16.

The impedance of station transformers is normally about 7 to 10%. This is the impedance on the base rating, the self-cooled rating (OA or ONAN). The impedance is normally higher for voltages on the high side of the transformer that are higher (like 230 kV). Transformer impedance can be specified when ordering. Large stations with 50 plus MVA transformers are normally provided with extra impedance to control fault currents, some as high as 30% on the transformer's base rating.

The positive and zero-sequence impedances are the same for a shell-type transformer, so the bolted fault currents on the secondary of the transformer are the same for a three-phase fault and for a line-to-ground fault (provided that both are fed from an infinite bus). In a three-legged core-type transformer, the zero-sequence impedance is lower than the positive-sequence impedance (typically $Z_0 = 0.85Z_1$), so ground faults can cause higher currents. With a three-legged core transformer design, there is no path for zero-sequence flux. Therefore, zero-sequence current will meet a lower-impedance branch. This makes the core-type transformer act as if it had a delta-connected tertiary winding. This is the magnetizing branch (from line to ground), and this effectively reduces the zero-sequence impedance. In a shell-type transformer, there is a path through the iron for flux to flow, so the excitation impedance to zero sequence is high.

Because most distribution circuits are radial, the substation transformer is a critical component. Power transformers normally have a failure rate between 1% and

TABLE 5.16 Example Substation Transformer Loading Guide

	FA (ONAF)	NDFOA (OFAF)		
Type of Load	Max Top Oil Temp (°C)	Max Top Oil Temp (°C)	Max Winding Temp (°C)	Max % Load
Normal summer load	105	95	135	130
Normal winter load	80	70	115	140
Emergency summer load	115	105	150	140
Emergency winter load	90	80	130	150
Noncyclical load	95	85	115	110

Alarm settings	FA 65°C Rise	NDFOA 65°C Rise
Top oil	105°C	95°C
Hot spot	135°C	135°C
Load amps	130%	130%

Source: Adapted from Tillman, R. F., Jr, in *The Electric Power Engineering Handbook*, L. L. Grigsby, ed. CRC Press, Boca Raton, FL, 2001.

Note: (1) The normal summer loading accounts for periods when temperatures are abnormally high. These might occur every 3 to 5 years. For every degree C that the normal ambient temperature during the hottest month of the year exceeds 30°C, de-rate the transformer 1% (i.e., 129% loading for 31°C average ambient). (2) The % load is given on the basis of the current rating. For MVA loading, multiply by the per unit output voltage. If the output voltage is 0.92 per unit, the recommended normal summer MVA loading is 120%. (3) Exercise caution if the load power factor is less than 0.95 lagging. If the power factor is less than 0.92 lagging, then lower the recommended loading by 10% (i.e., 130 to 120%). (4) Verify that cooling fans and pumps are in good working order and oil levels are correct. (5) Verify that the soil condition is good: moisture is less than 1.5% (1.0% preferred) by dry weight, oxygen is less than 2%, acidity is less than 0.5, and CO gas increases after heavy load seasons are not excessive. (6) Verify that the gauges are reading correctly when transformer loads are heavy. If correct field measurements differ from manufacturer's test report data, then investigate further before loading past nameplate criteria. (7) Verify with infrared camera or RTD during heavy load periods that the LTC top oil temperature relative to the main tank top oil temperature is correct. For normal LTC operation, the LTC top oil is cooler than the main tank top oil. A significant deviation from this indicates LTC abnormalities. (8) If the load current exceeds the bushing rating, do not exceed 110°C top oil temperature (IEEE, 1995). If bushing size is not known, perform an infrared scan of the bushing terminal during heavy load periods. Investigate further if the temperature of the top terminal cap is excessive. (9) Use winding power factor tests as a measure to confirm the integrity of a transformer's insulation system. This gives an indication of moisture and other contaminants in the system. High BIL transformers require low winding power factors (<0.5%), while low BIL transformers can tolerate higher winding power factors (<1.5%). (10) If the transformer is extremely dry (<0.5% by dry weight) and the load power factor is extremely good (0.99 lag to 0.99 lead), then add 10% to the above recommendations.

2% annually (CEA 485 T 1049, 1996; CIGRE working group 12.05, 1983; IEEE Std. 493-1997). Many distribution stations are originally designed with two transformers, where each is able to serve all of the substation's feeders if one of the transformers fails. Load growth in some areas has severely reduced the ability of one transformer to supply the whole station. To ensure transformer reliability, use good lightning protection and thermal management. Do not use reduced-BIL designs (BIL is the basic

lightning impulse insulation level). Also, reclosing and relaying practices should ensure that excessive through faults do not damage transformers.

5.9 Special Transformers

5.9.1 Autotransformers

An autotransformer is a winding on a core with a tap off the winding that provides voltage boost or buck. This is equivalent to a transformer with one winding in series with another (see Figure 5.23).

For small voltage changes, autotransformers are smaller and less costly than standard transformers. An autotransformer transfers much of the power directly through a wire connection. Most of the current passes through the lower-voltage series winding at the top, and considerably less current flows through the shunt winding.

Autotransformers have two main applications on distribution systems:

- *Voltage regulators*—A regulator is an autotransformer with adjustable taps that is normally capable of adjusting the voltage by ±10%.
- *Step banks*—Autotransformers are often used instead of traditional transformers on step banks and even substation transformers where the relative voltage change is moderate. This is normally voltage changes of less than a factor of three such as a 24.94Y/14.4 kV–12.47Y/7.2 kV bank.

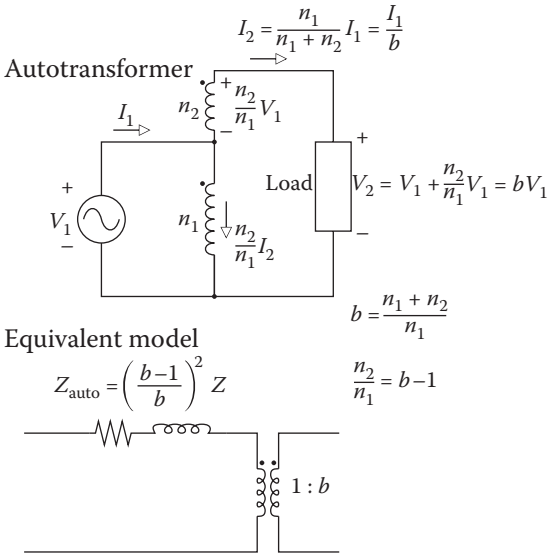


Figure 5.23 Autotransformer with an equivalent circuit.

The required rating of an autotransformer depends on the voltage change between the primary and secondary. The rating of each winding as a percentage of the load is

$$S = \frac{b-1}{b}$$

where

b = voltage change ratio, per unit

To obtain a 10% voltage change ($b = 1.1$), an autotransformer only has to be rated at 9% of the load kVA. For a 2:1 voltage change ($b = 2$), an autotransformer has to be rated at 50% of the load kVA. By comparison, a standard transformer must have a kVA rating equal to the load kVA.

The series impedance of autotransformers is less than an equivalent standard transformer. The equivalent series impedance of the autotransformer is

$$Z_{\text{auto}} = \left(\frac{b-1}{b}\right)^2 Z$$

where Z is the impedance across the entire winding. A 5%, 100-kVA conventional transformer has an impedance of 25.9 Ω at 7.2 kV line to ground. A 2:1 autotransformer ($b = 2$) with a load-carrying capability of 100 kVA and a winding rating of 50 kVA and also a 5% winding impedance has an impedance of 6.5 Ω, one-fourth that of a conventional transformer.

For three-phase applications on grounded systems, autotransformers are often connected in a grounded wye. Other possibilities are delta (each winding is phase to phase), open delta (same as a delta, but without one leg), and open wye. Because of the direct connection, it is not possible to provide ground isolation between the high- and low-voltage windings.

5.9.2 Grounding Transformers

Grounding transformers are sometimes used on distribution systems. A grounding transformer provides a source for zero-sequence current. Grounding transformers are sometimes used to convert a three-wire, ungrounded circuit into a four-wire, grounded circuit. Figure 5.24 shows the two most common grounding transformers. The zig-zag connection is the most widely used grounding transformer. Figure 5.25 shows how a grounding bank supplies current to a ground fault. Grounding transformers used as the only ground source to a distribution circuit should be in service whenever the three-phase power source is in service. If the grounding transformer is lost, a line-to-ground fault causes high phase-to-neutral voltages on the unfaulted phases, and load unbalances can also cause neutral shifts and overvoltages.

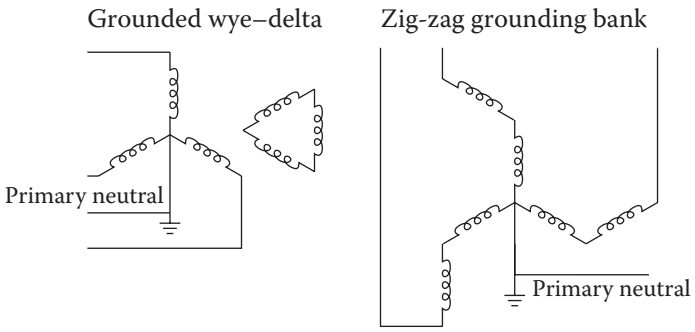


Figure 5.24 Grounding transformer connections.

A grounding transformer must handle the unbalanced load on the circuit as well as the duty during line-to-ground faults. If the circuit has minimal unbalance, then we can drastically reduce the rating of the transformer. It only has to be rated to carry short-duration (but high-magnitude) faults, normally a 10-sec or 1-min rating is used. We can also select the impedance of the grounding transformer to limit ground-fault currents.

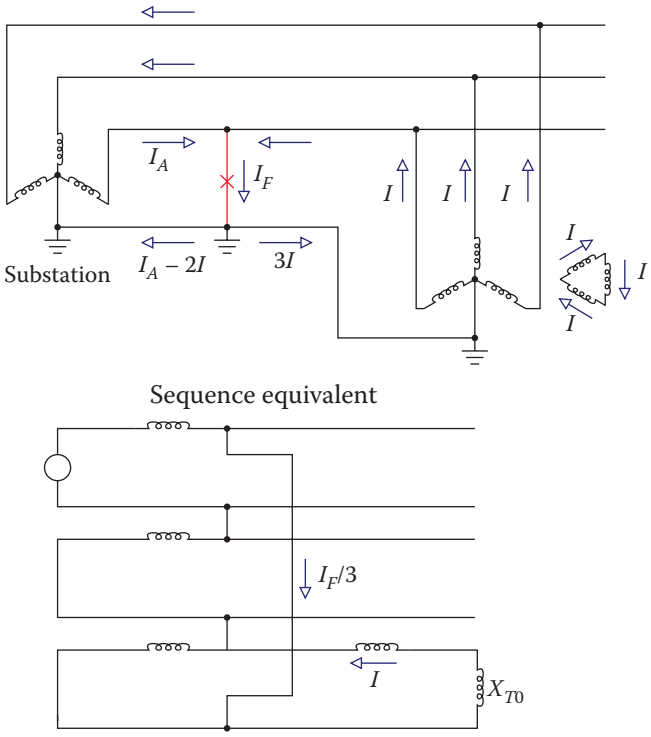


Figure 5.25 A grounding transformer feeding a ground fault.

Each leg of a grounding transformer carries one-third of the neutral current and has line-to-neutral voltage. So in a grounded-wye–delta transformer, the total power rating including all three phases is the neutral current times the line-to-ground voltage:

$$S = V_{\mathrm{LG}}\, I_N$$

A zig-zag transformer is more efficient than a grounded-wye–delta transformer. In a zig-zag, each winding has less than the line-to-ground voltage, by a factor of $\sqrt{3}$, so the bank may be rated lower:

$$S = V_{\mathrm{LG}} I_N / \sqrt{3}$$

ANSI/IEEE Std. 32-1972 requires a continuous rating of 3% for a 10-sec rated unit (which means the short-time rating is 33 times the continuous rating). A 1-min rated bank has a continuous current rating of 7%. On a 12.47-kV system supplying a ground-fault current of 6000 A, a zig-zag would need a 24.9-MVA rating. We will size the bank to handle the 24.9 MVA for 10 sec, which is equivalent to a 0.75-MVA continuous rating, so this bank could handle 180 A of neutral current continuously.

For both the zig-zag and the grounded wye–delta, the zero-sequence impedance equals the impedance between one transformer primary and its secondary.

Another application of grounding transformers is in cases of telephone interference due to current flow in the neutral/ground. By placing a grounding bank closer to the source of the neutral current, the grounding bank shifts some of the current from the neutral to the phase conductors to lower the neutral current that interferes with the telecommunication wires.

Grounding transformers are also used where utilities need a ground source during abnormal conditions. One such application is for a combination feeder that feeds secondary network loads and other non-network line-to-ground connected loads. If the network transformers are delta–grounded-wye connected, the network will backfeed the circuit during a line-to-ground fault. If that happens while the main feeder breaker is open, the single-phase load on the unfaulted phases will see an overvoltage because the circuit is being back fed through the network loads as an ungrounded system. A grounding bank installed on the feeder prevents the overvoltage during backfeed conditions. Another similar application is found when applying distributed generators. A grounded-wye–delta transformer is often specified as the interconnection transformer to prevent overvoltages if the generator drives an island that is separated from the utility source.

Even if a grounding bank is not the only ground source, it must be sized to carry the voltage unbalance. The zero-sequence current drawn by a bank is the zero-sequence voltage divided by the zero-sequence impedance:

$$I_0 = V_0 / Z_0$$

Severe voltage unbalance can result when one phase voltage is opened upstream (usually from a blown fuse or a tripped single-phase recloser). In this case, the zero-sequence voltage equals the line-to-neutral voltage. The grounding bank will try to hold up the voltage on the opened phase and supply all the load on that phase, which could severely overload the transformer.

5.10 Special Problems

5.10.1 Paralleling

Occasionally, crews must install distribution transformers, either at a changeover or for extra capacity. If a larger bank is being installed to replace an existing unit, paralleling the banks during the changeover eliminates the customer interruption. In order to parallel transformer banks, several criteria should be met:

- *Phasing*—The high and low-voltage connections must have the same phasing relationship. On three-phase units, banks of different connection types can be paralleled as long as they have compatible outputs: a delta–grounded wye may be paralleled with a grounded wye–grounded wye.
- *Polarity*—If the units have different polarity, they should be wired accordingly. (Flip one of the secondary connections.)
- *Voltage*—The phase-to-phase and phase-to-ground voltages on the outputs should be equal. Differences in turns ratios between the transformers will cause circulating current to flow through the transformers (continuously, even with zero load).

Before connecting the second transformer, crews should ensure that the secondary voltages are all zero or very close to zero (phase A to phase A, B to B, C to C, and the neutral to neutral).

If the percent impedances of the transformers are unequal, the load will not split in the same proportion between the two units. Note that this is the percent impedance, not the impedance in ohms. The unit with the lower percent impedance takes more of the current relative to its rating. For unequal impedances, the total bank must be derated (ABB, 1995) as

$$d = \frac{\frac{Z_2}{Z_1}K_1 + K_2}{K_1 + K_2}$$

where

K_1 = capacity of the unit or bank with the *larger* percent impedance
K_2 = capacity of the unit or bank with the *smaller* percent impedance
Z_1 = percent impedance of unit or bank 1
Z_2 = percent impedance of unit or bank 2

5.10.2 Ferroresonance

Ferroresonance is a special form of series resonance between the magnetizing reactance of a transformer and the system capacitance. A common form of ferroresonance occurs during single phasing of three-phase distribution transformers (Hopkinson, 1967). This most commonly happens on cable-fed transformers because of the high capacitance of the cables. The transformer connection is also critical for ferroresonance. An ungrounded primary connection (see Figure 5.26) leads to the highest magnitude ferroresonance. During single phasing (usually when line crews energize or de-energize the transformer with single-phase cutouts at the cable riser pole), a ferroresonant circuit between the cable capacitance and the transformer's magnetizing reactance drives voltages to as high as five per unit on the open legs of the transformer. The voltage waveform is normally distorted and often chaotic (see Figures 5.27 and 5.28).

Ferroresonance drove utilities to use three-phase transformer connections with a grounded-wye primary, especially on underground systems.

The chance of ferroresonance is determined by the capacitance (cable length) and by the core losses and other resistive load on the transformer (Walling et al., 1993). The core losses are an important part of the ferroresonant circuit.

Walling (1994) breaks down ferroresonance in a way that highlights several important aspects of this complicated phenomenon. Consider the simplified ferroresonant circuit in Figure 5.29. The transformer magnetizing branch has the core-loss resistance in parallel with a switched inductor. When the transformer is unsaturated, the switched inductance is open, and the only connection between the capacitance and the system is through the core-loss resistance. When the core saturates, the capacitive charge dumps into the system (the switch in Figure 5.29 closes). The voltage overshoots; and, as the core comes out of saturation, charge is again trapped on the capacitor (but of opposite polarity). This happens every half cycle (see Figure 5.30 for waveforms). If the core loss is large enough (or the resistive load on the transformer is large enough), the charge on the capacitor drains off before the next half cycle, and ferroresonance does not occur. The transformer core does not stay saturated long during each half cycle, just long enough to release the trapped charge on the capacitor. If the cable susceptance or even just the transformer susceptance is greater than the transformer core loss conductance, then ferroresonant overvoltages may occur.

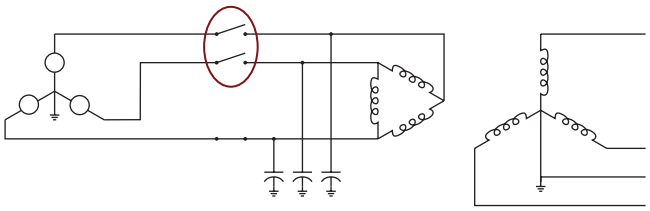


Figure 5.26 Ferroresonant circuit with a cable-fed transformer with an ungrounded high-side connection.

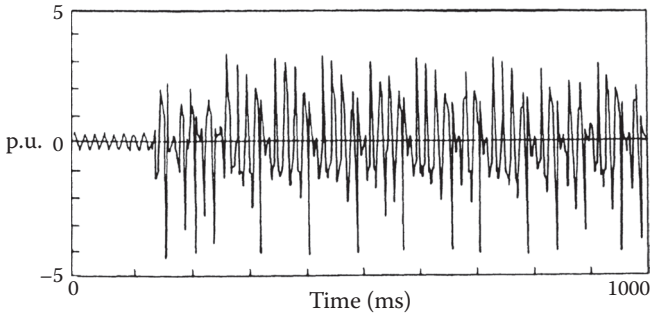


Figure 5.27 Example of ferroresonance. (From Walling, R. A., Hartana, R. K., and Ros, W. J., *IEEE Transactions on Power Delivery*, 10(1), pp. 526–33, January 1995. Copyright 1995 IEEE. With permission.)

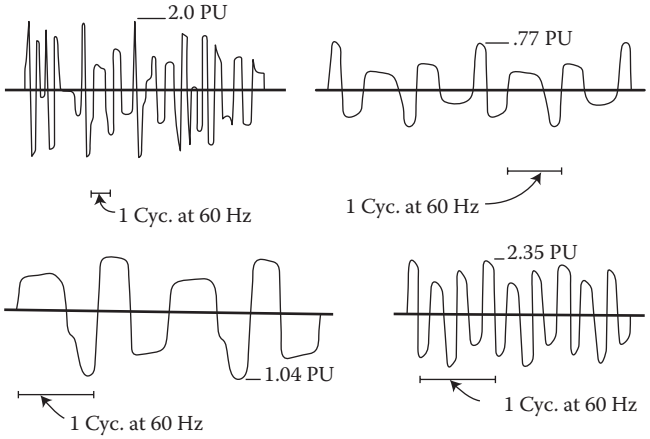


Figure 5.28 Example of ferroresonance. (From Smith, D. R., Swanson, S. R., and Borst, J. D., *IEEE Transactions on Power Apparatus and Systems*, PAS-94(5), 1843–53, 1975. Copyright 1975 IEEE. With permission.)

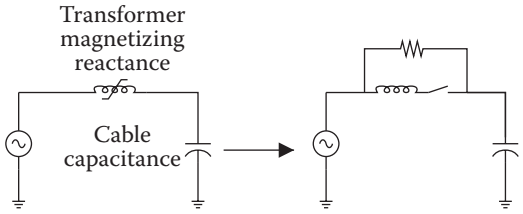


Figure 5.29 Simplified equivalent circuit of ferroresonance on a transformer with an ungrounded high-side connection.

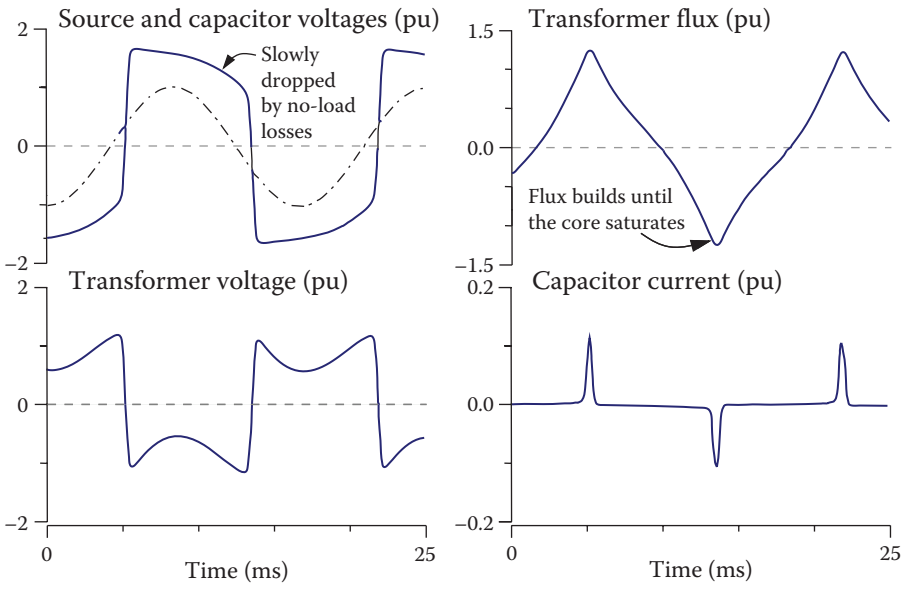


Figure 5.30 Voltages, currents and transformer flux during ferroresonance. (Adapted from Walling, R. A., *IEEE/PES Transmission and Distribution Conference*, 1994. With permission of the General Electric Company.)

In modern silicon-steel distribution transformers, the flux density at rated voltage is typically between 1.3 and 1.6 T. These operating flux densities slightly saturate the core (magnetic steel fully saturates at about 2 T). Because the core is operated near saturation, a small transient (such as switching) is enough to saturate the core. Once started, the ferroresonance self-sustains. The resonance repeatedly saturates the transformer every half cycle.

Table 5.17 shows what types of transformer connections are susceptible to ferroresonance. To avoid ferroresonance on floating-wye–delta transformers, some utilities temporarily ground the wye on the primary side of floating-wye–delta connections during switching operations.

Ferroresonance can occur on transformers with a grounded primary connection if the windings are on a common core such as the five-legged core transformer [the magnetic coupling between phases completes the ferroresonant circuit (Smith et al., 1975)]. The five-legged core transformer connected as a grounded wye–grounded

TABLE 5.17 Transformer Primary Connections Susceptible to Ferroresonance

Susceptible Connections	Not Susceptible
Floating wye	Grounded wye made of three individual units or units of triplex construction
Delta	Open wye–open delta
Grounded wye with 3, 4, or 5-legged core construction	Line-to-ground connected single-phase units
Line-to-line connected single-phase units	

wye is the most common underground transformer configuration. Ferroresonant overvoltages involving five-legged core transformers normally do not exceed two per unit.

Ferroresonance is a function of the cable capacitance and the transformer no-load losses. The lower the losses relative to the capacitance, the higher the ferroresonant overvoltage can be. For transformer configurations that are susceptible to ferroresonance, ferroresonance can occur approximately when

$$B_C \geq P_{NL}$$

where

B_C = capacitive reactive power per phase, vars
P_{NL} = core loss per phase, W

The capacitive reactive power on one phase in vars depends on the voltage and the capacitance as

$$B_C = \frac{V_{kV}^2}{3} 2\pi f C$$

where

V_{kV} = rated line-to-line voltage, kV
f = frequency, Hz
C = capacitance from one phase to ground, μF

Normally, ferroresonance occurs without equipment failure if the crew finishes the switching operation in a timely manner. The loud banging, rumbling, and rattling of the transformer during ferroresonance may alarm line crews. Occasionally, ferroresonance is severe enough to fail a transformer. The overvoltage stresses the transformer insulation, and the repeated saturation may cause tank heating as flux leaves the core (although many modes of ferroresonance barely saturate the transformer and do not cause significant tank heating). Surge arresters are the most likely equipment casualty. In attempting to limit the ferroresonant overvoltage, an arrester may absorb more current than it can handle and thermally run away. Gapped silicon-carbide arresters were particularly prone to failure, as the gap could not reseal the repeated sparkovers from a long-duration overvoltage. Gapless metal-oxide arresters are much more resistant to failure from ferroresonance and help hold down the overvoltages. Ferroresonant overvoltages may also fail customer's equipment from high secondary voltages. Small end-use arresters are particularly susceptible to damage.

Ferroresonance is more likely with

- *Unloaded transformers*—Ferroresonance disappears with load as little as a few percent of the transformer rating.
- *Higher primary voltages*—Shorter cable lengths are required for ferroresonance. Resonance is more likely even without cables, just due to the internal capacitance of

the transformer. With higher voltages, the capacitances do not change significantly (cable capacitance increases just slightly because of thicker insulation), but vars are much higher for the same capacitance.
- *Smaller transformers*—Smaller no-load losses.
- *Low-loss transformers*—Smaller no-load losses.

Severe ferroresonance with voltages reaching peaks of 4 or 5 per unit occurs on three-phase transformers with an ungrounded high-voltage winding during single-pole switching. If the transformer is fed by underground cables and crews switch the transformer remotely, ferroresonance is likely.

On overhead circuits, ferroresonance is common with ungrounded primary connections on 25- and 35-kV distribution systems. At these voltages, the internal capacitance of most transformers is enough to ferroresonate. The use of low-loss transformers has caused ferroresonance to appear on overhead 15-kV distribution systems as well. Amorphous core and low-loss silicon-steel core transformers have much lower core losses than previous designs. With less core losses, ferroresonance happens with lower amounts of capacitance. Tests by the Southern California Edison Company on three-phase transformers with ungrounded primary connections found that ferroresonance occurred when the capacitive power per phase exceeded the transformer's no-load losses per phase by the following relationship (Jufer, 1994):

$$B_C \geq 1.27\ P_{\mathrm{NL}}$$

The phase-to-ground capacitance of overhead transformers is primarily due to the capacitance between the primary and secondary windings (the secondary windings are almost at zero potential). A typical 25-kVA transformer has a phase-to-ground capacitance of about 2 nF (Walling et al., 1995). For a 7.2-kV line-to-ground voltage, 0.002 μF is 39 vars. So, if the no-load losses are less than 39 vars/1.27 = 30.7 W per phase, the transformer may ferroresonate under single-pole switching.

Normally, ferroresonance occurs on three-phase transformers, but ferroresonance can occur on single-phase transformers if they are connected phase to phase, and one of the phases is opened either remotely or at the transformer. Jufer (1994) found that small single-phase padmounted transformers connected phase to phase ferroresonate when remotely switched with relatively short cable lengths. Their tests of silicon-steel core transformers found that a 25-kVA transformer resonated with 50 ft (15 m) of 1/0 XLPE cable at 12 kV. A 50-kVA transformer resonated with 100 ft of cable, and a 75-kVA unit resonated with 150 ft of the cable. Peak primary voltages reached 3 to 4 per unit. Secondary-side peaks were all under 2 per unit. Longer cables produced slightly higher voltages during ferroresonance. Jufer found that ferroresonance did not occur if the resistive load in watts per phase (including the transformer's no-load losses and the resistive load on the secondary) exceeded 1.15 times the capacitive vars per phase ($P_{\mathrm{NL}} + P_L > 1.15B_C$). Bohmann et al. (1991) describes a feeder where single-phase loads were switched to a phase-to-phase configuration, and the reconfiguration caused a higher-than-normal arrester failure rate that was attributed to ferroresonant conditions on the circuit.

It is widely believed that a grounded-wye primary connection eliminates ferroresonance. This is not true if the three-phase transformer has windings on a common core. The most common underground three-phase distribution transformer has a five-legged wound core. The common core couples the phases. With the center phase energized and the outer phases open, the coupling induces 50% voltage in the outer phases. Any load on the outer two phases is effectively in series with the voltage induced on the center phase. Because the coupling is indirect and the open phase capacitance is in parallel with a transformer winding to ground, this type of ferroresonance is not as severe as ferroresonance on configurations with an ungrounded primary winding. Overvoltages rarely exceed 2.5 per unit.

Five-legged core ferroresonance also depends on the core losses of the transformer and the phase-to-ground capacitance. If the capacitive vars exceed the resistive load in watts, ferroresonance may occur. Higher capacitances—longer cable lengths—generally cause higher voltages (see Figure 5.31). To limit peak voltages to below 1.25 per unit, the capacitive power must be limited such that [equivalent to that proposed by Walling (1992)]

$$B_C \leq 1.86 P_{\text{NL}}$$

with B_C in vars and P_{NL} in watts; both are per phase.

Ferroresonance can occur with five-legged core transformers, even when switching at the transformer terminals, due to the transformer's internal line-to-ground capacitance. On 34.5-kV systems, transformers smaller than 500 kVA may ferroresonate if single-pole switched right at the transformer terminals. Even on 15-kV class systems where crews can safely switch all but the smallest 5-legged core transformers

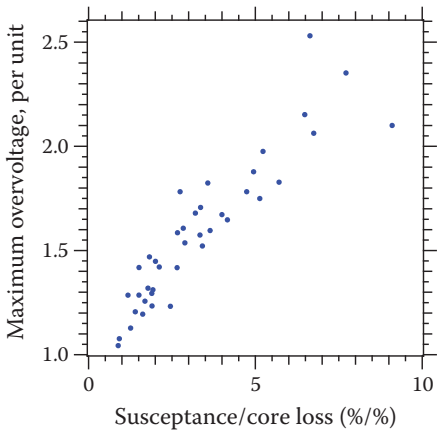


Figure 5.31 Five-legged core ferroresonance as a function of no-load losses and line-to-ground capacitance. (Adapted from Walling, R. A., in *Final Report to the Distribution Systems Testing, Application, and Research (DSTAR) Consortium*. General Electric, Industrial and Power Systems, Power Systems Engineering Department, 1992. As cited in NRECA RER Project 90–8, 1993. Copyright 1993 IEEE. With permission.)

at the terminals, we should include the transformer's capacitance in any cable length calculation; the transformer's capacitance is equivalent to several feet (meters) of cable. The capacitance from line-to-ground is mainly due to the capacitance between the small paper-filled layers of the high-voltage winding. This capacitance is very difficult to measure since it is in parallel with the coil. Walling (1992) derived an empirical equation to estimate the line-to-ground transformer capacitance per phase in μF:

$$C = \frac{0.000469 S_{\text{kVA}}^{0.4}}{V_{\text{kV}}^{0.25}}$$

where

S_{kVA} = transformer three-phase kVA rating
V_{kV} = rated line-to-line voltage in kV

In vars, this is

$$B_C = 0.000982 f V_{\text{kV}}^{1.75} S_{\text{kVA}}^{0.4}$$

where f is the system frequency, Hz.

To determine whether the transformer no-load losses exceed the capacitive power, the transformer's datasheet data is most accurate. For coming up with generalized guidelines, using such data is not realistic since so many different transformer makes and models are ordered. Walling (1992) offered the following approximation between the three-phase transformer rating and the no-load losses in watts per phase:

$$P_{\text{NL}} = S_{\text{kVA}} (4.54 - 1.13 \log_{10} (S_{\text{kVA}}))/3$$

Walling (1992) used his approximations of transformer no-load losses and transformer capacitance to find cable length criteria for remote single-pole switching. Consider a 75-kVA 3-phase 5-legged core transformer at 12.47 kV. Using these approximations, the no-load losses are 60.5 W per phase, and the transformer's capacitance is 27.4 vars per phase. To keep the voltage under 1.25 per unit, the total vars allowed per phase is 1.86(60.5 W) = 112.5 vars. So, the cable can add another 85.1 vars before we exceed the limit. At 12.47 kV, a 4/0 175-mil XLPE cable has a capacitance of 0.412 μF/mi, which is 1.52 vars per foot. For this cable, 56 ft is the maximum length that we should switch remotely. Beyond that, we may have ferroresonance above 1.25 per unit. Table 5.18 shows similar criteria for several three-phase transformers and voltages. The table shows critical lengths for 4/0 cables; smaller cables have less capacitance, so somewhat longer lengths are permissible. At 34.5 kV, crews should only remotely switch larger banks.

Another situation that can cause ferroresonance is when a secondary has ungrounded power factor correction capacitors. Resonance can even occur on a grounded-wye–grounded-wye connection with three separate transformers. With one phase open on the utility side, the ungrounded capacitor bank forms a series resonance with the magnetizing reactance of the open leg of the grounded-wye transformer.

TABLE 5.18 Cable Length Limits in Feet for Remote Single-Pole Switching to Limit Ferroresonant Overvoltages to Less than 1.25 per Unit

	Critical Cable Lengths, ft		
	12.47 kV 4/0 XLPE 175 mil	24.94 kV 4/0 XLPE 260 mil	34.5 kV 4/0 XLPE 345 mil
Transformer Rating kVA	0.412 μF/mi 1.52 vars/ft	0.305 μF/mi 4.52 vars/ft	0.250 μF/mi 7.08 vars/ft
75	56	5	0
112.5	81	10	0
150	103	16	0
225	144	26	1
300	181	36	6
500	265	59	16
750	349	82	27
1000	417	100	36
1500	520	128	49
2000	592	146	56

Ferroresonance most commonly happens when switching an unloaded transformer. It also usually happens with manual switching; ferroresonance can occur because a fault clears a single-phase protective device, but this is much less common. The main reason that ferroresonance is unlikely for most situations using a single-phase protective device is that either the fault or the existing load on the transformer prevents ferroresonance.

If the fuse is a tap fuse and several customers are on a section, the transformers will have somewhat different characteristics, which lowers the probability of ferroresonance (and ferroresonance is less likely with larger transformers).

Solutions to ferroresonance include

- Using a higher-loss transformer
- Using a three-phase switching device instead of a single-phase device
- Switching right at the transformer rather than at the riser pole
- Using a transformer connection not susceptible to ferroresonance
- Limiting remote switching of transformers to cases where the capacitive vars of the cable are less than the transformer's no load losses

Arrester application on transformer connections susceptible to ferroresonance brings up several interesting points. Ferroresonance can slowly heat arresters until failure. Ferroresonance is a weak source; even though the per-unit magnitudes are high, the voltage collapses when the arrester starts to conduct (we cannot use the arresters time-overvoltage curve [TOV] to predict failure). Normally, extended ferroresonance of several minutes can occur before arresters are heated enough to enter thermal runaway. The most vulnerable arresters are those that are tightly applied relative to the voltage rating. Tests by the DSTAR group for ferroresonance on 5-legged

core transformers in a grounded-wye–grounded-wye connection (Lunsford, 1994; Walling et al., 1994) found

- Arrester currents were always less than 2 A.
- Under-oil arresters, which have superior thermal characteristics, reached thermal stability and did not fail.
- Porcelain-housed arresters showed slow heating—sometimes enough to fail, sometimes not, depending on the transformer type, cable lengths, and arrester type. Elbow arresters showed slow heating—slower than the riser-pole arresters. Failure times for either type were typically longer than 30 min.

With normal switching times of less than one minute, arresters do not have enough time to heat and fail. Crews should be able to safely switch transformers under most circumstances. Load—even 5% of the transformer rating—prevents ferroresonance in most cases. The most danger lies with unloaded transformers. If an arrester fails, the failure may not operate the disconnect, which can lead to a dangerous scenario. When a line worker recloses the switch, the stiff power–frequency source will fail the arrester. The disconnect should operate and draw an arc. On occasion, the arrester may violently shatter.

One option to limit the exposure of the arresters is to put the arresters upstream of the switch. At a cable riser pole this is very difficult to do without seriously compromising the lead length of the arrester.

5.10.3 Switching Floating Wye–Delta Banks

Floating-wye–delta banks present special concerns. As well as being prone to ferroresonance, single-pole switching can cause overvoltages due to a neutral shift. On a floating wye–delta, the secondary delta connection fixes the transformer's primary neutral close to ground potential. After one phase of the primary wye is opened, the neutral can float far from ground. This causes overvoltages, both on the secondary side and the primary side. The severity depends on the balance of the load.

When crews open one of the power-leg phases, if there is no three-phase load and only the single-phase load on the lighting leg of the transformer, the open primary voltage V_{open} reaches 2.65 times normal as shown in Figure 5.32. The voltage across the open switch also sees high voltage. The voltage from B to B′ in Figure 5.32 can reach over 2.75 per unit. Secondary line-to-line voltages on the power legs can reach 1.73 per unit. The secondary delta forces the sum of the three primary line-to-neutral voltages to be equal. With single-phase load on phase C and no other load, the neutral shifts to the C-phase voltage. The delta winding forces $V_{B'N}$ to be equal to $-V_{AN}$, which significantly shifts the potential of point B′.

The line-to-ground voltage on the primary side of the transformer on the open phase is a function of the load unbalance on the secondary. Given the ratio of the single-phase load to the three-phase load, this voltage is [assuming passive loads and that the power factor of the three-phase load equals that of the single-phase load (Walling et al., 1995)]

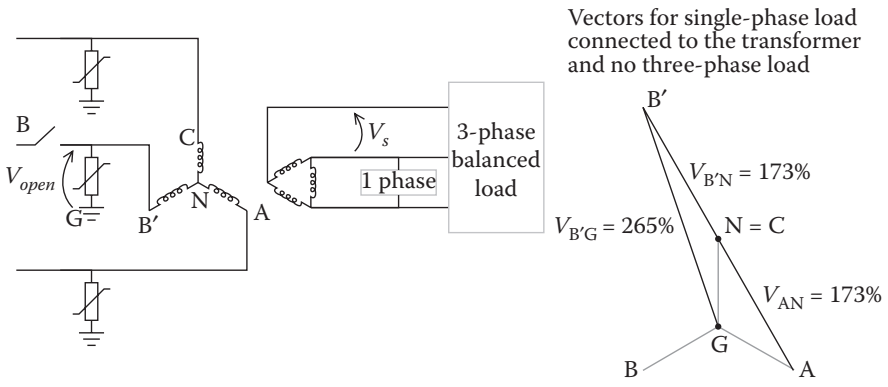


Figure 5.32 Neutral-shift overvoltages on a floating-wye–delta transformer during single-pole switching.

$$V_{\text{open}} = \frac{\sqrt{7K^2 + K + 1}}{K + 2}$$

where

$$K = \frac{\text{Single-phase load}}{\text{Balanced three-phase load}}$$

On the secondary side, the worst of the two line-to-line voltages across the power legs have the following overvoltages depending on loading balance (PTI, 1999):

$$V_s = \sqrt{3}\frac{K + 1}{K + 2}$$

Figure 5.33 shows these voltages as a function of the ratio *K*.

Contrary to a widespread belief, transformer saturation does not significantly reduce the overvoltage. Walling et al.'s (1995) EMTP simulations showed that saturation did not significantly reduce the peak voltage magnitude. Saturation does distort the waveforms significantly and reduces the energy into a primary arrester.

Some ways to avoid these problems are

- *Use another connection*—The best way to avoid problems with this connection is to use some other connection. Some utilities do not offer an open-wye–delta connection and instead move customers to grounded-wye connections.
- *Neutral grounding*—Ground the primary-wye neutral during switching operations, either with a temporary grounding jumper or install a cutout. This prevents the neutral-shift and ferroresonant overvoltage. The ground–source effects during the short-time switching are not a problem. The line crew must remove the neutral jumper after switching. Extended operation as a grounding bank can overheat the transformer and interfere with a circuit's ground-fault protection schemes.

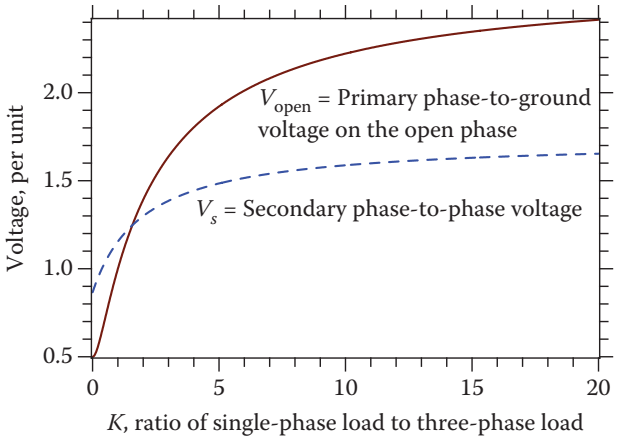


Figure 5.33 Neutral-shift overvoltages as a function of the load unbalance.

- *Switching order*—Neutral shifts (but not ferroresonance) are eliminated by always switching in the lighting leg last and taking it out first.

Arrester placement is a sticky situation. If the arrester is upstream of the switch, it does not see the neutral-shift/ferroresonant overvoltage. But the transformer is not protected against the overvoltages. Arresters downstream of the switch protect the transformer but may fail. One would rather have an arrester failure than a transformer failure, unless the failure is near a line crew (since an arrester is smaller, it is more likely than a transformer to explode violently—especially porcelain-housed arresters). Another concern was reported by Walling (2000): during switching operations, 10-per-unit overvoltage bursts for 1/4 cycle ringing at about 2 kHz when closing in the second phase. These were found in measurements during full-scale tests and also in simulations. This transient repeats every cycle with a declining peak magnitude for more than one second. If arresters are downstream from the switches, they can easily control the overvoltage. But if they are upstream of the switches, this high voltage stresses the transformer insulation.

Overall, grounding the transformer's primary neutral is the safest approach.

5.10.4 Backfeeds

During a line-to-ground fault where a single-phase device opens, current may backfeed through a three-phase load (see Figure 5.34). It is a common misconception that this type of backfeed can only happen with an ungrounded transformer connection. Backfeed can also occur with a grounded three-phase connection. This creates hazards to the public in downed wire situations. Even though it is a weak source, the backfed voltage is just as dangerous. Lineworkers also have to be careful. A few have been killed after touching wires downstream of open cutouts that they thought were de-energized.

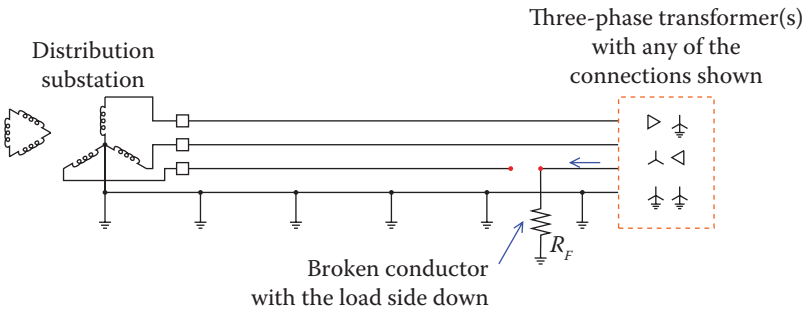


Figure 5.34 Backfeed to a downed conductor.

The general equations for the backfeed voltage and current based on the sequence impedances of the load (Smith, 1994) are

$$I_F = \frac{(A - 3Z_0Z_2)V}{3Z_0Z_1Z_2 + R_FA}$$

$$V_F = R_F I_F$$

where

$A = Z_0Z_1 + Z_1Z_2 + Z_0Z_2$
Z_1 = positive-sequence impedance of the load, Ω
Z_2 = negative-sequence impedance of the load, Ω
Z_0 = zero-sequence impedance of the load, Ω
R_F = fault resistance, Ω
V = line-to-neutral voltage, V

The line and source impedances are left out of the equations because they are small relative to the load impedances. Under an open circuit with no fault ($R_F = \infty$), the backfeed voltage is

$$V_F = \frac{(A - 3Z_0Z_2)V}{A}$$

For an ungrounded transformer connection ($Z_0 = \infty$), the backfeed current is

$$I_F = \frac{(Z_1 - 2Z_2)V}{3Z_1Z_2 + R_F(Z_1 + Z_2)}$$

The backfeed differs depending on the transformer connection and the load:

- Grounded-wye–grounded-wye transformer connection
  - Will not backfeed the fault when the transformer is unloaded or has balanced line-to-ground loads (no motors). It will backfeed the fault with line-to-line connected load (especially motors).

- Ungrounded primary transformer
  - Will backfeed the fault under no load. It may not be able to provide much current with no load, but there can be significant voltage on the conductor. Motor load will increase the backfeed current available.

Whether it is a grounded or ungrounded transformer, the available backfeed current depends primarily on the connected motor load. Motors dominate since they have much lower negative-sequence impedance; typically it is equal to the locked-rotor impedance or about 15 to 20%. With no fault impedance ($R_F = 0$), the backfeed current is approximately:

$$I_F = \frac{M_{\text{kVA}}}{9V_{\text{LG,kV}} \cdot Z_{2,\text{pu}}}$$

where M_{kVA} is the three-phase motor power rating in kVA (and we can make the common assumption that 1 hp = 1 kVA), $V_{\text{LG,kV}}$ is the line-to-ground voltage in kV, and $Z_{2,\text{pu}}$ is the per-unit negative-sequence (or locked-rotor) impedance of the motor(s). Figure 5.35 shows the variation in backfeed current versus motor kVA on the transformer for a 12.47-kV system (assuming $Z_{2,\text{pu}} = 0.15$).

The voltage on the open phases depends on the type of transformer connection and the portion of the load that is motors. Figure 5.36 shows the backfeed voltage for an open circuit and for a typical high-impedance fault ($R_F = 200\ \Omega$).

As discussed in Chapter 8, the maximum sustainable arc length in inches is roughly $l = \sqrt{I} \cdot V$ where I is the rms current in amperes, and V is the voltage in kV. For a line-to-ground fault on a 12.47-kV circuit, if the backfeed voltage is 4 kV with 50 A available (typical values from Figures 5.35 and 5.36), the maximum arc length is 28 in. (0.7 m). Even though the backfeed source is weak relative to a traditional fault source, it is still strong enough to maintain a significant arc during backfeeds.

In summary, the backfeed voltage is enough to be a safety hazard to workers or the public (e.g., in a wire down situation). The available backfeed is a stiff enough source to maintain an arc of significant length. The arc can continue to cause damage at the

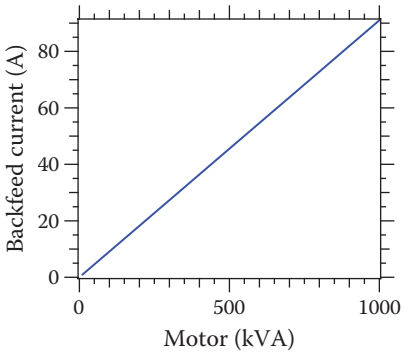


Figure 5.35 Available backfeed current on a 12.47-kV circuit (grounded wye–grounded wye or an ungrounded connection, $R_F = 0$).

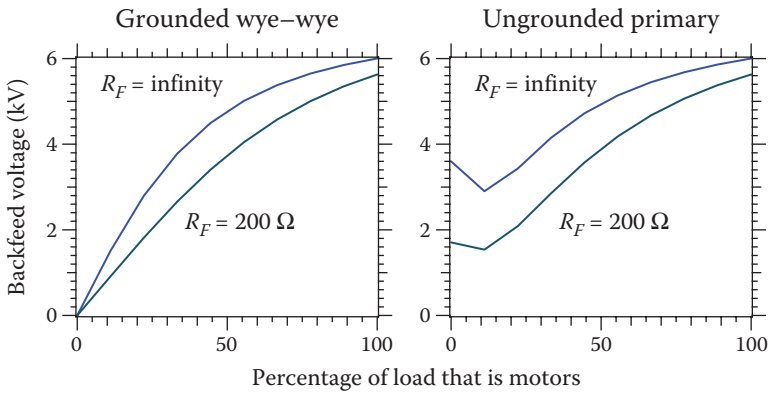


Figure 5.36 Available backfeed voltage on a 12.47-kV circuit.

fault location during a backfeed condition. It may also spark and sputter at a low level. Options to reduce the chances of backfeed problems include

- Make sure crews follow safety procedures (if it is not grounded, it is not dead).
- Follow standard practices regarding downed conductors including proper line designs and maintenance, public education, and worker training.

Another option is to avoid single-pole protective devices (switches, fuses, or single-phase reclosers) upstream of three-phase transformer banks. Most utilities have found that backfeeding problems are not severe enough to warrant not using single-pole protective devices.

To analyze more complicated arrangements, use a steady-state circuit analysis program (EMTP has this capability). Most distribution fault analysis programs cannot handle this type of complex arrangement.

5.10.5 Inrush

When a transformer is first energized or re-energized after a short interruption, the transformer may draw *inrush* current from the system due to the core magnetization being out of sync with the voltage. The inrush current may approach short-circuit levels, as much as 40 times the transformer's full-load current. Inrush may cause fuses, reclosers, or relays to falsely operate. It may also falsely operate faulted-circuit indicators or cause sectionalizers to misoperate.

When the transformer is switched in, if the system voltage and the transformer core magnetization are not in sync, a magnetic transient occurs. The transient drives the core into saturation and draws a large amount of current into the transformer.

The worst inrush occurs with residual flux left on the transformer core. Consider Figures 5.37 and 5.38, which shows the worst-case scenario. A transformer is de-energized near the peak core flux density (B_{max}), when the voltage is near zero. The flux decays to about 70% of the maximum and holds there (the residual flux, B_r).

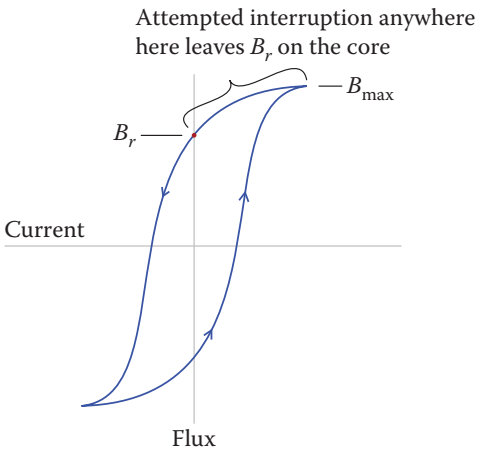


Figure 5.37 Hysteresis curve showing the residual flux during a circuit interruption.

Sometime later, the transformer is re-energized at a point in time when the flux would have been at its negative peak; the system voltage is crossing through zero and rising positively. The positive voltage creates positive flux that adds to the residual flux already on the transformer core (remember, flux is the time integral of the voltage). This quickly saturates the core; the effective magnetizing branch drops to the air-core impedance of the transformer.

The air-core impedance is roughly the same magnitude as the transformer's leakage impedance. Flux controls the effective impedance, so when the core saturates, the

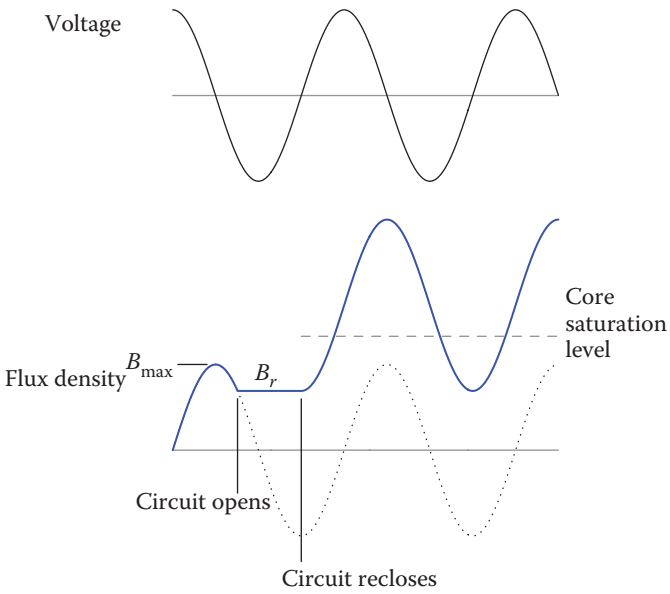


Figure 5.38 Voltage and flux during worst-case inrush.

small impedance pulls high-magnitude current from the system. The core saturates in one direction, so the transformer draws pulses of inrush every other half cycle with a heavy dc component. The dc offset introduced by the switching decays away relatively quickly. Figure 5.39 shows an example of inrush following a reclose operation measured at the distribution substation breaker.

Several factors significantly impact inrush:

- *Closing point*—The point where the circuit closes back determines how close the core flux can get to its theoretical maximum. The worst case is when the flux is near its peak. Fortunately, this is also when the voltage is near zero, and switches tend to engage closer to a voltage peak (an arc tends to jump the gap).
- *Design flux*—A transformer that is designed to operate lower on the saturation curve draws less inrush. Because there is more margin between the saturation point and the normal operating region, the extra flux during switching is less likely to push the core into saturation.
- *Transformer size*—Larger transformers draw more inrush. Their saturated impedances are smaller. But, on a per-unit basis relative to their full-load capability, smaller transformers draw more inrush. The inrush into smaller transformers dies out more quickly.
- *Source impedance*—Higher source impedance relative to the transformer size limits the current that the transformer can pull from the system. The peak inrush with significant source impedance (Westinghouse Electric Corporation, 1950) is

$$i_{\text{peak}} = \frac{i_0}{1 + i_0 X}$$

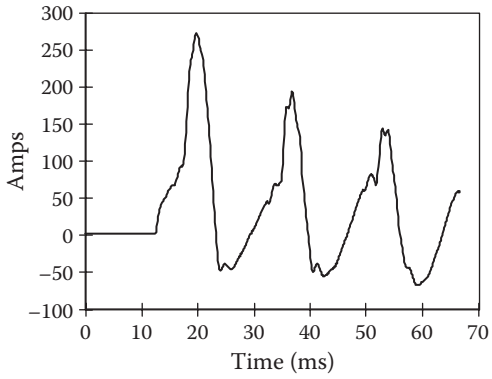


Figure 5.39 Example inrush current measured at a substation (many distribution transformers together). (From EPRI TR-106294-V3, *An Assessment of Distribution System Power Quality: Volume 3: Library of Distribution System Power Quality Monitoring Case Studies*, Electric Power Research Institute, Palo Alto, CA, 1996. Copyright 1996. Reprinted with permission.)

where

i_0 = peak inrush without source impedance in per unit of the transformer rated current

X = source impedance in per unit on the transformer kVA base

Other factors have less significance. The load on the transformer does not significantly change the inrush. For most typical loading conditions, the current into the transformer will interrupt at points that still leave about 70% of the peak flux on the core.

While interruptions generally cause the most severe inrush, other voltage disturbances may cause inrush into a transformer. Voltage transients and especially voltage with a dc component can saturate the transformer and cause inrush. Some examples are

- *Voltage sags*—Upon recovery from a voltage sag from a nearby fault, the sudden rise in voltage can drive a transformer into saturation.
- *Sympathetic inrush*—Energizing a transformer can cause a nearby transformer to draw inrush. The inrush into the switched transformer has a significant dc component that causes a dc voltage drop. The dc voltage can push the other transformer into saturation and draw inrush.
- *Lightning*—A flash to the line near the transformer can push the transformer into saturation.

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All hell broke loose, we had a ball of fire that went phase to phase shooting fire out the xfmer vents like a flame thrower showering slag on the linemen and sent the monster galloping down the line doing the Jacobs ladder effect for 2 spans before it broke ...

The next time you're closing in on that new shiny xfmer out of the shop, think about the night we got a lemon

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6

Voltage Regulation

Contents

6.1 Voltage Standards 272
6.2 Voltage Drop 275
6.3 Regulation Techniques 276
6.3.1 Voltage Drop Allocation and Primary Voltage Limits 276
6.3.2 Load Flow Models 278
6.3.3 Voltage Problems 279
6.4 Regulators 281
6.4.1 Line-Drop Compensation 284
6.4.1.1 Load-Center Compensation 285
6.4.1.2 Voltage-Spread Compensation 288
6.4.1.3 Effects of Regulator Connections 292
6.4.2 Voltage Override 292
6.4.3 Regulator Placement 293
6.4.4 Other Regulator Issues 294
6.5 Station Regulation 295
6.5.1 Parallel Operation 295
6.5.2 Bus Regulation Settings 296
6.6 Line Loss and Voltage Drop Relationships 297
6.7 Voltage Optimization 299
6.7.1 Field Results from Voltage Reduction 301
6.7.2 Equipment Response to Voltage 310
6.7.3 Approaches to Voltage Optimization 313
References 316

One of a utility's core responsibilities is to deliver voltage to customers within a suitable range, so utilities must regulate the voltage. On distribution circuits, voltage drops due to current flowing through the line impedances. Primary and secondary voltage drop can be allocated as necessary along the circuit to provide end users with suitable voltage. Voltage regulators—in the substation or on feeders—can adjust primary voltage. This chapter discusses voltage regulators and regulation standards and techniques.

6.1 Voltage Standards

Most regulatory bodies and most utilities in America follow the ANSI voltage standards (ANSI C84.1-1995). This standard specifies acceptable operational ranges at two locations on electric power systems:

- *Service voltage*—The service voltage is the point where the electrical systems of the supplier and the user are interconnected. This is normally at the meter. Maintaining acceptable voltage at the service entrance is the *utility's* responsibility.
- *Utilization voltage*—This is the voltage at the line terminals of utilization equipment. This voltage is the *facility's* responsibility. Equipment manufacturers should design equipment that operates satisfactorily within the given limits.

The standard allows for some voltage drop within a facility, so service voltage requirements are tighter than utilization requirements.

The standard also defines two ranges of voltage:

- *Range A*—Most service voltages are within these limits, and utilities should design electric systems to provide service voltages within these limits. As the standard says, voltage excursions "should be infrequent."
- *Range B*—These requirements are more relaxed than Range A limits. According to the standard: "Although such conditions are a part of practical operations, they shall be limited in extent, frequency, and duration. When they occur, corrective measures shall be undertaken within a reasonable time to improve voltages to meet Range A requirements." Utilization equipment should give acceptable performance when operating within the Range B utilization limits, "insofar as practical" according to the standard.

These limits only apply to sustained voltage levels and not to momentary excursions, sags, switching surges, or short-duration interruptions.

Table 6.1 shows the most important limits, the limits on low-voltage systems. The table is given on a 120-V base; it applies at 120 V but also to any low-voltage system up to and including 600 V. The main target for utilities is the Range A service voltage, 114 to 126 V.

ANSI C84.1 defines three voltage classes: low voltage (1 kV or less), medium voltage (greater than 1 kV and less than 100 kV), and high voltage (greater than or equal to 100 kV). Within these classes, ANSI provides standard nominal system voltages along with the voltage ranges. A more detailed summary of the ANSI voltages is shown in Tables 6.2 and 6.3.

TABLE 6.1 ANSI C84.1 Voltage Ranges for 120 V

	Service Voltage		Utilization Voltage	
	Minimum	Maximum	Minimum	Maximum
Range A	114 (−5%)	126 (+5%)	110 (−8.3%)	125 (+4.2%)
Range B	110 (−8.3%)	127 (+5.8%)	106 (−11.7%)	127 (+5.8%)

TABLE 6.2 ANSI Standard Nominal System Voltages and Voltage Ranges for Low-Voltage Systems

		Range A			Range B		
		Maximum	Minimum		Maximum	Minimum	
Nominal System Voltage	Nominal Utilization Voltage	Utilization and Service Voltage[a]	Service Voltage	Utilization Voltage	Utilization and Service Voltage	Service Voltage	Utilization Voltage
Two Wire, Single Phase							
120	115	126	114	110	127	110	106
Three Wire, Single Phase							
120/240	**115/230**	**126/252**	**114/228**	**110/220**	**127/254**	**110/220**	**106/212**
Four Wire, Three Phase							
208Y/120	**200**	**218/126**	**197/114**	**191/110**	**220/127**	**191/110**	**184/106**
240/120	**230/115**	**252/126**	**228/114**	**220/110**	**254/127**	**220/110**	**212/106**
480Y/277	**460**	**504/291**	**456/263**	**440/254**	**508/293**	**440/254**	**424/245**
Three Wire, Three Phase							
240	230	252	228	220	254	220	212
480	**460**	**504**	**456**	**440**	**508**	**440**	**424**
600	575	630	570	550	635	550	530

Note: Bold entries show preferred system voltages.

[a]The maximum utilization voltage for Range A is 125 V or the equivalent (+4.2%) for other nominal voltages through 600 V.

For low-voltage classes, two nominal voltages are given—one for the electric system and the other, somewhat lower, nominal for the utilization equipment (for low-voltage motors and controls; other utilization equipment may have different nominal voltages). In addition, the standard gives common nameplate voltage ratings of equipment as well as information on what nominal system voltages the equipment is applicable to. As the standard points out, there are many inconsistencies between equipment voltage ratings and system nominal voltages.

For medium-voltage systems, ANSI C84.1 gives tighter limits for Ranges A and B. Range A is –2.5% to +5%, and Range B is –5% to +5.8%. However, most utilities do not follow these as limits for their primary distribution systems (utilities use the ANSI service voltage guidelines and set their primary voltage limits to meet the service voltage guidelines based on their practices). The three-wire voltages of 4160, 6900, and 13,800 V are mainly suited for industrial customers with large motors. Industrial facilities use motors on these systems with ratings of 4000, 6600, and 13,200 V, respectively.

Improper voltage regulation can cause many problems for end users. Sustained overvoltages or undervoltages can cause the following end-use impacts:

- *Improper or less-efficient equipment operation*—For example, lights may give incorrect illumination or a machine may run fast or slow.

TABLE 6.3 ANSI Standard Nominal System Voltages and Voltage Ranges for Medium-Voltage Systems

	Range A			Range B		
	Maximum	Minimum		Maximum	Minimum	
Nominal System Voltage	Utilization and Service Voltage	Service Voltage	Utilization Voltage	Utilization and Service Voltage	Service Voltage	Utilization Voltage
Four Wire, Three Phase						
4160Y/2400	4370/2520	4050/2340	3740/2160	4400/2540	3950/2280	3600/2080
8320Y/4800	8730/5040	8110/4680		8800/5080	7900/4560	
12000Y/6930	12600/7270	11700/6760		12700/7330	11400/6580	
12470Y/7200	**13090/7560**	**12160/7020**		**13200/7620**	**11850/6840**	
13200Y/7620	**13860/8000**	**12870/7430**		**13970/8070**	**12504/7240**	
13800Y/7970	14490/8370	13460/7770		14520/8380	13110/7570	
20780Y/12000	21820/12600	20260/11700		22000/12700	19740/11400	
22860Y/13200	24000/13860	22290/12870		24200/13970	21720/12540	
24940Y/14400	**26190/15120**	**24320/14040**		**26400/15240**	**23690/13680**	
34500Y/19920	**36230/20920**	**33640/19420**		**36510/21080**	**32780/18930**	
Three Wire, Three Phase						
2400	2520	2340	2160	2540	2280	2080
4160	**4370**	**4050**	**3740**	**4400**	**3950**	**3600**
4800	5040	4680	4320	5080	4560	4160
6900	7240	6730	6210	7260	6560	5940
13800	**14490**	**13460**	**12420**	**14520**	**13110**	**11880**
23000	24150	22430		24340	21850	
34500	36230	33640		36510	32780	

Notes: Bold entries show preferred system voltages. Some utilization voltages are blank because utilization equipment normally does not operate directly at these voltages.

- *Tripping of sensitive loads*—For example, an uninterruptible power supply (UPS) may revert to battery storage during high or low voltage. This may drain the UPS batteries and cause an outage to critical equipment.

In addition, undervoltages can cause

- *Overheating of induction motors*—For lower voltage, an induction motor draws higher current. Operating at 90% of nominal, the full-load current is 10 to 50% higher, and the temperature rises by 10 to 15%. With less voltage, the motor has reduced motor starting torque.

Also, overvoltages can cause

- *Equipment damage or failure*—Equipment can suffer insulation damage. Incandescent light bulbs wear out much faster at higher voltages.
- *Higher no-load losses in transformers*—Magnetizing currents are higher at higher voltages.

6.2 Voltage Drop

We can approximate the voltage drop along a circuit as

$$V_{\text{drop}} = |V_s| - |V_r| \approx I_R \cdot R + I_X \cdot X$$

where

V_{drop} = voltage drop along the feeder, V
R = line resistance, Ω
X = line reactance, Ω
I_R = line current due to real power flow (in phase with the voltage), A
I_X = line current due to reactive power flow (90° out of phase with the voltage), A

In terms of the load power factor, *pf*, the real and reactive line currents are

$$I_R = I \cdot pf = I\cos\theta$$
$$I_X = I \cdot qf = I\sin\theta = I\sin(\cos^{-1}(pf))$$

where

I = magnitude of the line current, A
pf = load power factor
qf = load reactive power factor = $\sin(\cos^{-1}(pf))$
θ = angle between the voltage and the current

While just an approximation, Brice (1982) showed that $I_R \cdot R + I_X \cdot X$ is quite accurate for most distribution situations. The largest error occurs under heavy current and leading power factor. The approximation has an error less than 1% for an angle between the sending and receiving end voltages up to 8° (which is unlikely on a distribution circuit). Most distribution programs use the full complex phasor calculations, so the error is mainly a consideration for hand calculations.

This approximation highlights two important aspects about voltage drop:

- *Resistive load*—At high power factors, the voltage drop strongly depends on the resistance of the conductors. At a power factor of 0.95, the reactive power factor (*qf*) is 0.31; so even though the resistance is normally smaller than the reactance, the resistance plays a major role.
- *Reactive load*—At moderate to low power factors, the voltage drop depends mainly on the reactance of the conductors. At a power factor of 0.8, the reactive power factor is 0.6, and because the reactance is usually larger than the resistance, the reactive load causes most of the voltage drop. Poor power factor significantly increases voltage drop.

Voltage drop is higher with lower voltage distribution systems, poor power factor, single-phase circuits, and unbalanced circuits. The main ways to reduce voltage drop are to

- Increase power factor (add capacitors)
- Reconductor with a larger size

- Balance circuits
- Convert single-phase sections to three-phase sections
- Reduce load
- Reduce length

In many cases, we can live with significant voltage drop as long as we have enough voltage regulation equipment to adjust for the voltage drop on the circuit.

6.3 Regulation Techniques

Distribution utilities have several ways to control steady-state voltage. The most popular regulation methods include

- Substation load tap-changing transformers (LTCs)
- Substation feeder or bus voltage regulators
- Line voltage regulators
- Fixed and switched capacitors

Most utilities use LTCs to regulate the substation bus and supplementary feeder regulators and/or switched capacitor banks where needed.

Taps on distribution transformers are another tool to provide proper voltage to customers. Distribution transformers are available with and without no-load taps (meaning the taps are to be changed without load) with standard taps of ±2.5% and ±5%. Utilities can use this feature to provide a fixed boost for customers on a circuit with low primary voltage. This also allows the primary voltage to go lower than most utilities would normally allow. Remember, the service entrance voltage is most important. Most distribution transformers are sold without taps, so this practice is not widespread. It also requires consistency; an area of low primary voltage may have several transformers to adjust—if one is left out, the customers fed by that transformer could receive low voltage.

6.3.1 Voltage Drop Allocation and Primary Voltage Limits

Most utilities use the ANSI C84.1 ranges for the service entrance, 114 to 126 V. How they control voltage and allocate voltage drop varies. Consider the voltage profile along the circuit in Figure 6.1. The substation LTC or bus regulator controls the voltage at the source. Voltage drops along the primary line, the distribution transformer, and the secondary. We must consider the customers at the start and end of the circuit:

- *End—Heavily loaded*—Low voltages are a concern, so we consider a heavily loaded transformer and secondary. The allocation across the secondary depends on the utility's design practices as far as allowable secondary lengths and conductor sizes are concerned.
- *Source—Lightly loaded*—Near the source, we can operate the primary above 126 V, but we must ensure that the first customer does not have overvoltages when that

customer is lightly loaded. Commonly, utilities assume that the secondary and transformer drop to this lightly loaded customer is 1 V. With that, the upper primary voltage limit is 127 V.

In the voltage drop along the primary, we must consider the regulator bandwidth (and bandwidths for capacitors if they are switched based on voltage). Voltage regulators allow the voltage to deviate by half the bandwidth in either direction. So, if we have a 2-V bandwidth and a desired range of 7 V of primary drop, subtracting the 2-V bandwidth only leaves 5 V of actual drop (see Figure 6.1). Likewise, if we choose 127 V as our upper limit on the primary, our maximum set voltage is 126 V with a 2-V regulator bandwidth.

Normally, utilities use standardized practices to allocate voltage drop. Deviations from the standard are possible but often not worth the effort.

If we have an express feeder at the start of a circuit, we can regulate the voltage much higher than 126 V as long as the voltage drops enough by the time the circuit reaches the first customer.

Primary voltage allocation affects secondary allocation and vice versa. A rural utility may have to allow a wide primary voltage range to run long circuits, which leaves little voltage drop left for the transformer and secondary. Since rural loads are typically each fed by their own transformer, rural utilities can run the primary almost right to the service entrance. Using low-impedance distribution transformers and larger-than-usual transformers also helps reduce the voltage drop beyond the primary. For the secondary conductors, triplex instead of open wire and larger size conductors help reduce secondary drop. Utilities that allow less primary voltage drop can run longer secondaries.

Utility practices on voltage limits on the primary range widely, as shown in Table 6.4. The upper range is more consistent—most are from 125 to 127 V—unless the utility uses voltage reduction (for energy conservation or peak shaving). The lower range is more variable, anywhere from 112 to 123 V. Obviously, the utility that uses a 112-V lower limit is not required to abide by the ANSI C84.1 limits. In the EPRI

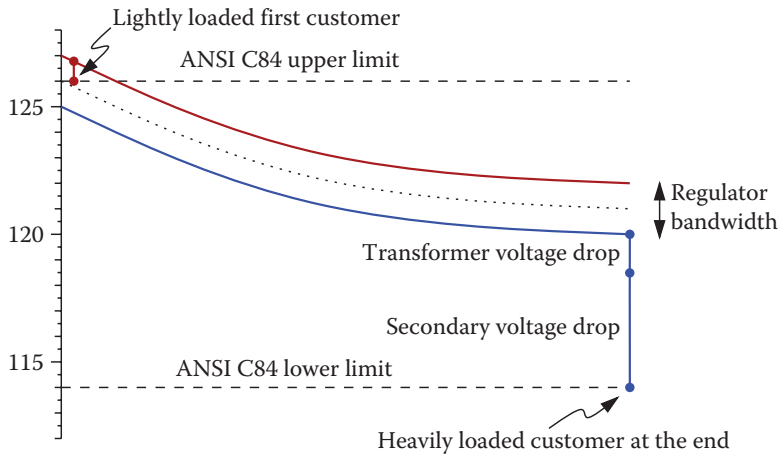

Figure 6.1 Voltage drop along a radial circuit with no capacitors or line regulators.

TABLE 6.4 Primary Voltage Ranges at Several Utilities

Service Area Type	Minimum	Maximum	Percent Range
Dense urban area	120	127	5.4
Dense urban area	117	126	7.5
Urban/suburban	114	126	10.0
Urban/suburban	115	125	8.3
Urban/suburban			
No conservation reduction	119	126	5.8
With conservation reduction	119	123	3.3
Multistate area	117	126	7.5
Multistate area			
Urban standard	123	127	3.3
Rural standard	119	127	6.6
Suburban and rural	113	125	10.0
Suburban and rural			
Urban standard	116	125	7.5
Rural standard	112	125	10.8
Urban and rural	115	127	10.0
Rural, mountainous	116	126	8.3
Rural, mountainous	113	127	11.7

Source: Adapted from Willis, H. L., *Power Distribution Planning Reference Book*, Marcel Dekker, New York, 2004. With additional utilities added.

Green Circuits project (EPRI 1023518, 2011), the lower design limit by participating utilities for the primary ranged from 116 to 119 V with an average of 117.5 V and with a relatively uniform distribution across that range.

6.3.2 Load Flow Models

Load flows provide voltage profiles that help when planning new distribution circuits, adding customers, and tracking down and fixing voltage problems. Most distribution load flow programs offer a function to plot the voltage as a function of distance from the source.

We can model a distribution circuit at many levels of detail. Many utilities are modeling more of their systems in more detail. For most load flows, utilities normally just model the primary. Modeling the secondary is occasionally useful for modeling specific problems at a customer. We can still have very good models with simplifications. Modeling long laterals or branches is normally a good idea, but we can lump most laterals together as a load where they tie into the main line. Modeling each transformer as a load is rarely worth the effort; we can combine loads together and maintain accuracy with some common sense. Most mainline circuits can be accurately modeled if broken into 10 to 20 sections with load lumped with each section. Of course, accurate models of capacitors and line regulators are a good idea.

Correctly modeling load phasing provides a better voltage profile on each phase. Unbalanced loads cause more voltage drop because of

- *Higher loop impedance*—The impedance seen by unbalanced loads, the loop impedance including the zero-sequence impedance, is higher than the positive-sequence impedance seen by balanced loads.
- *Higher current on the loaded phases*—If the current splits unevenly by phases, the more heavily loaded phases see more voltage drop.

Utilities often do not keep accurate phasing information, but it helps improve load flow results. We do not need the phasing on every transformer, but we will have better accuracy if we know the phasing of large single-phase taps.

Of the data entered into the load flow model, the load allocation is the trickiest. Most commonly, loads are entered in proportion to the transformer kVA. If a circuit has a peak load equal to the sum of the kVA of all of the connected transformers divided by 2.5, then each load is modeled as the given transformer size in kVA divided by 2.5. Incorporating metering data is another more sophisticated way to allocate load. If a utility has a transformer load management system or other system that ties metered kilowatt-hour usage to a transformer to estimate loadings, feeding this data to the load flow can yield a more precise result. In most cases, all of the loads are given the same power factor, usually what is measured at the substation. Additional measurements could be used to fine-tune the allocation of power factor. Some utilities also assign power factor by customer class.

Most distribution load flow programs offer several load types, normally constant power, constant current, and constant impedance:

- *Constant power load*—The real and reactive power stays constant as the voltage changes. As voltage decreases, this load draws more current, which increases the voltage drop. A constant power model is good for induction motors.
- *Constant current load*—The current stays constant as the voltage changes, and the power increases with voltage. As voltage decreases, the current draw stays the same, so the voltage drop does not change.
- *Constant impedance load*—The impedance is constant as the voltage changes, and the power increases as the square of the voltage. As voltage decreases, the current draw drops off linearly, so the voltage drop decreases. The constant impedance model is good for incandescent lights and other resistive loads.

Normally, we can model most circuits as something like 40 to 60% constant power and 40 to 60% constant impedance (see Table 6.5 for one set of recommendations). Modeling all loads as constant current is a good approximation for many circuits. Modeling all loads as constant power is conservative for voltage drop.

6.3.3 Voltage Problems

Voltage complaints (normally undervoltages) are regular trouble calls for utilities. Some are easy to fix; others are not. First, check the secondary. Before tackling the

TABLE 6.5 Load Modeling Approximations Recommended by Willis (1997)

Feeder Type	Percent Constant Power	Percent Constant Impedance
Residential and commercial, summer peaking	67	33
Residential and commercial, winter peaking	40	60
Urban	50	50
Industrial	100	0
Developing countries	25	75

Source: Data from Willis, H. L., in *Electrical Transmission and Distribution Reference Book*. ABB Power T&D Company, Raleigh, NC, 1997.

primary, confirm that the voltage problem is not isolated to the customers on the secondary. If secondary voltage drop is occurring, check loadings, make sure the transformer is not overloaded, and check for a loose secondary neutral.

If the problem is on the primary, some things to look for include

- *Excessive unbalance*—Balancing currents helps reduce voltage drop.
- *Capacitors*—Look for blown fuses, incorrect time clock settings, other incorrect control settings, or switch malfunctions.
- *Regulators*—Check settings. See if more aggressive settings can improve the voltage profile enough: a higher set voltage, more line-drop compensation, and/or a tighter bandwidth.

These problems are relatively easy to fix. If it is not these, and if there is too much load for the given amount of impedance, we will have to add equipment to fix the problem. Measure the primary voltage (and if possible the loadings) at several points along the circuit. An easy way to measure the primary voltage is to find a lightly loaded distribution transformer and measure the secondary voltage. Measure the power factor at the substation. A poor power factor greatly increases the voltage drop.

Load flows are a good tool to try out different options to improve voltage on a circuit. If possible, match voltage profiles with measurements on the circuit. Measurements provide a good sanity check. Try to measure during peak load conditions. Regulator and capacitor controllers can provide extra information if they have data logging capability. Normally, we allocate the load for the model equally by transformer kVA. This may not always be right, and measurements can help "tweak" the model. A load flow can help determine the best course of action. Where do we need a supplementary line regulator? How many? Can fixed capacitors do the job? Do we need switched capacitors? Circuits with poor power factor are the best candidates for capacitors as they will help reduce line losses as well as improve voltage.

In addition to extra regulating equipment, consider other options. Sometimes, we can move one or more circuit sections to a different feeder to reduce the loading on the circuit. If transformers have taps, investigate changing the transformer taps. Though it is expensive, we can also build new circuits, upgrade to a higher voltage, or reconductor.

6.4 Regulators

Voltage regulators are autotransformers with automatically adjusting taps. Commonly, regulators provide a range from −10 to +10% with 32 steps. Each step is 5/8%, which is 0.75 V on a 120-V scale.

A single-phase regulator has three bushings: the source (S), the load (L), and the source–load (SL). The series winding is between S and L. Figure 6.2 shows a straight regulator (ANSI type A) with the taps on the load side. An ANSI type B, the inverted design, has the taps on the source bushing. The regulator controller measures current with a current transformer (CT) at the L bushing and measures the voltage with a potential transformer (PT) between L and SL. Regulators have a reversing switch that can flip the series winding around to change back and forth between the boost and the buck connection.

Regulators are rated on current (IEEE Std. C57.15-1999). Regulators also have a kVA rating, which is the two-winding transformer rating and not the load-carrying capability. A regulator at 7.62 kV line to ground with a ±10% range and a load current rating of 100 A has a kVA rating of 0.1(7.62 kV)(100 A) = 76 kVA. The load-carrying capability is 10 times the regulator's kVA rating.

By reducing the range of regulation, we can extend the rating of the regulator. Reducing the range from ±10% to ±5% increases the rating by 60% (see Figure 6.3).

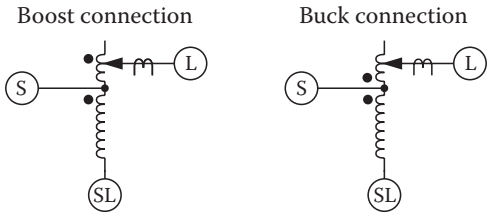

Figure 6.2 ANSI type A single-phase regulator, meaning taps on the load bushing.

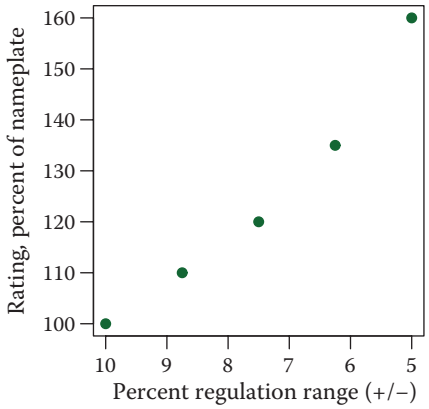

Figure 6.3 Increased regulator ratings with reduced regulation range.

The impedance is the two-winding impedance times a base value about 10 times as large. Because the impedance is so small, we can normally neglect it.

Three-phase regulators, often used in stations, are used on wye or delta systems. A three-phase regulator controls all three phases simultaneously. These are normally larger units. The normal connection internally is a wye connection with the neutral point floating.

Commonly, utilities use single-phase units, even for regulating three-phase circuits. We can connect single-phase regulators in several ways (see Figure 6.4 and Bishop et al., (1996)):

- *Line to neutral*—On four-wire systems, three-phase circuits normally have three single-phase regulators connected line to neutral. Line-to-neutral connections are also appropriate for single-phase and two-phase circuits. Each regulator independently controls voltage, which helps control voltage unbalance as well as steady-state voltage.
- *Open delta*—Only two single-phase regulators are needed, each connected phase to phase.
- *Closed delta*—Three regulators are connected phase to phase. Using the closed delta extends the regulation range by 50%, from ±10% to ±15%.

In both of the delta connections, the regulators see a current phase-shifted relative to the voltage. In the leading connection with unity power factor loads, the line current through the regulator leads the line-to-line voltage by 30°. The lagging connection has the current reversed: for a unit power factor load, the line current lags the line-to-line voltage by 30°. In the open-delta configuration, one of the units is leading

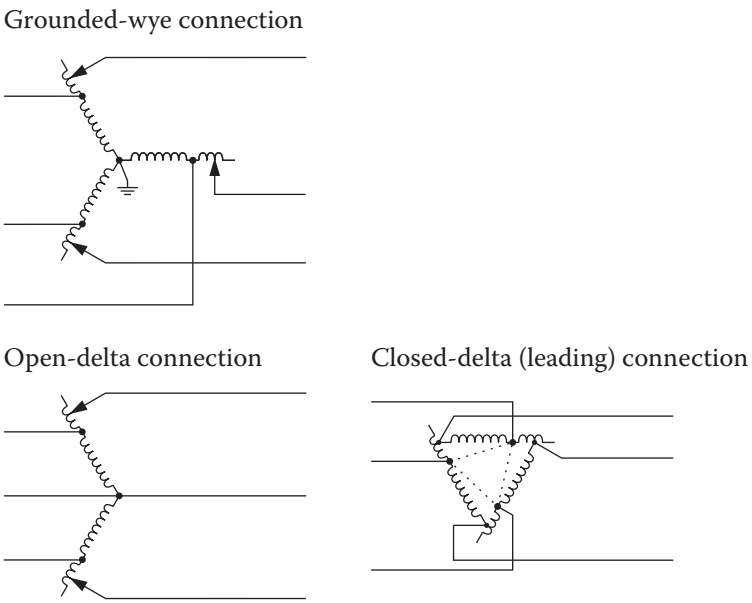

Figure 6.4 Three-phase regulator connections.

and the other is lagging. In the closed-delta arrangement, all three units are either leading or all three are lagging. Although uncommon, both of the delta connections can be applied on four-wire systems.

Regulators have a voltage regulating relay that controls tap changes. This relay has three basic settings that control tap changes (see Figure 6.5):

- *Set voltage*—Also called the set point or bandcenter, the set voltage is the desired output of the regulator.
- *Bandwidth*—Voltage regulator controls monitor the difference between the measured voltage and the set voltage. Only when the difference exceeds one half of the bandwidth will a tap change start. Use a bandwidth of at least two times the step size, 1.5 V for ±10%, 32-step regulators. Settings of 2 and 2.5 V are common.
- *Time delay*—This is the waiting time between the time when the voltage goes out of band and when the controller initiates a tap change. Longer time delays reduce the number of tap changes. Typical time delays are 30 to 60 sec.

If the voltage is still out of bounds after a tap change, the controller makes additional tap changes until the voltage is brought within bounds. The exact details vary by controller, and some provide programmable modes. In some modes, controllers make one tap change at a time. In other modes, the controller may initiate the number of tap changes it estimates are needed to bring the voltage back within bounds. The time delay relay resets if the voltage is within bounds for a certain amount of time.

A larger bandwidth reduces the number of tap changes, but at a cost. With larger bandwidth, the circuit is not as tightly regulated. We should include the bandwidth in voltage profile calculations to ensure that customers are not given over or under voltages. Voltage that was used for bandwidth can be used for voltage drop along the circuit. With a higher bandwidth, we may need more regulators on a given line. So, use at least two times the step size, but do not use excessively high bandwidths such as 3 or 3.5 V.

In addition to these basics, regulator controllers also have line-drop compensation to boost voltages more during heavy load. Controllers also may have high and low voltage limits to prevent regulation outside of a desired range of voltages. In addition to the regulator and control application information provided here, see Beckwith (1998), Cooper Power Systems (1978), General Electric (1979), and Westinghouse (1965).

Many regulators are bidirectional units; they can regulate in either direction, depending on the direction of power flow. A bidirectional regulator measures voltage on the source side using an extra PT or derives an estimate from the current. If the

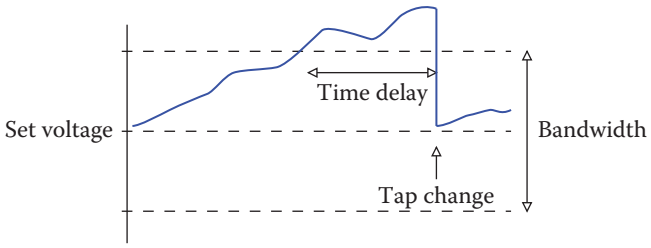

Figure 6.5 Regulator tap controls based on the set voltage, bandwidth, and time delay.

regulator senses reverse power flow, it switches to regulating the side that is normally the source side. We need reverse mode for a regulator on circuits that could be fed by an alternate source in the reverse direction. Without a reverse mode, the regulator can cause voltage problems during backfeeds. If a unidirectional regulator is fed "backwards," the regulator PT is now on the side of the source. Now, if the voltage drops, the regulator initiates a tap raise. However, the voltage the PT sees does not change because it is on the source side (very stiff). What happened was the voltage on the load side went down (but the regulator controller does not know that because it is not measuring that side). The controller still sees low voltage, so it initiates another tap raise, which again lowers the voltage on the other side of the regulator. The controller keeps trying to raise the voltage until it reaches the end of its regulation range. So, we have an already low voltage that got dropped by an extra 10% by the unidirectional regulator. If the controller initially sees a voltage above its set voltage, it ratchets all the way to the high end causing a 10% overvoltage. Also, if the incoming voltage varies above and below the bandwidth, the regulator can run back and forth between extremes. A bidirectional regulator prevents these runaways. Depending on its mode, under reverse power, a bidirectional regulator can regulate in the reverse direction, halt tap changes, or move to the neutral point (the last two do not require PTs on both sides but just power direction sensing).

Regulators also have an operations counter. The counter helps identify when a regulator is due for refurbishment. Regulators are designed to perform many tap changes, often over one million tap changes over the life of a regulator. A regulator might change taps 70 times per day, which is 25,000 times per year (Sen and Larson, 1994). A regulator counter also provides a good warning indicator; excessive operations suggest that something is wrong, such as wrong line-drop compensation settings, a bandwidth or time delay that is too small, or widely fluctuating primary voltages.

Regulators have "drag hands"—markers on the tap position indicator that show the maximum and minimum tap positions since the drag hands were last reset. The drag hands are good indicators of voltage problems. If maintenance reviews continually show the drag upper hand pegging out at +10%, the upstream voltage is probably too low. More work is needed to correct the circuit's voltage profile. Advanced controllers record much more information, including tap change records and demand metering to profile voltages, currents, and power factors.

6.4.1 Line-Drop Compensation

LTC transformer and regulator controls can be augmented with line-drop compensation. During heavy load, the controller boosts voltage the most, and during light load, voltage is boosted the least. The line-drop compensator uses an internal model of the impedance of the distribution line to match the line impedance. The user can set the R and X values in the compensator to adjust the compensation. The controller adjusts taps based on the voltage at the voltage regulating relay, which is the PT voltage plus the voltage across the line-drop compensator circuit (see Figure 6.6). With no compensation, the voltage regulating relay adjusts the taps based on the PT voltage.

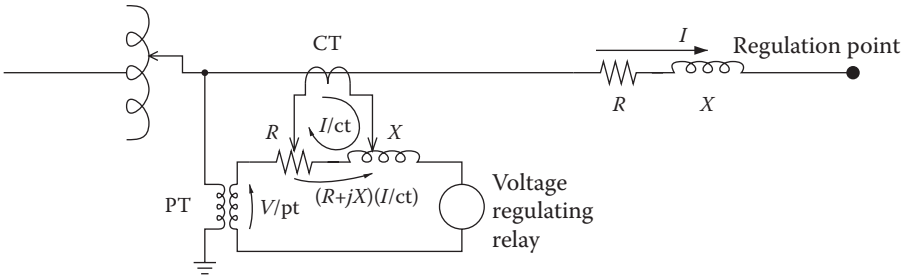

Figure 6.6 Line drop compensator circuit.

Since load on a typical distribution line is distributed, R and X compensator settings are chosen so that the maximum desired boost is obtained under heavy load while a given voltage is obtained under light load. There are two main approaches for selecting settings:

- *Load center*—The settings are chosen to regulate the voltage at a given point downstream of the regulator.
- *Voltage spread*—The R and X settings are chosen to keep the voltage within a chosen band when operating from light load to full load. The R and X settings may or may not be proportional to the line's R and X.

The main complication of all of the methods is that the load and power factors change (especially with downstream capacitor banks). Many regulators are set up without line-drop compensation. It is obviously easier and less prone to mistakes, but we are losing out on some significant capability. If we set the regulator set voltage at 120 V, and we do not get enough boost along the line, we will need more regulators. With a higher set voltage such as 126 V, we do not need as many regulators, but we have high voltages at light load and possibly overvoltages if the circuit has capacitors. With line-drop compensation, we have boost when we need it during heavy load, but not during light load (see Figure 6.7). Line-drop compensation also normally leads to a smaller range of fluctuations in voltage through the day for customers along the circuit.

6.4.1.1 Load-Center Compensation

The classic way to set compensator settings is to use the *load-center* method. Consider a line with impedances R_L and X_L with a load at the end. Now, if we pick the R_{set} and X_{set} of the compensator to match those of the line, as the load changes, the regulator responds and adjusts the regulator taps to keep the voltage constant, not at the regulator but at the load. To achieve this, we can set the R_{set} and X_{set} of the regulator as

$$R_{set} = \frac{I_{CT}}{N_{PT}} R_L$$

$$X_{set} = \frac{I_{CT}}{N_{PT}} X_L$$

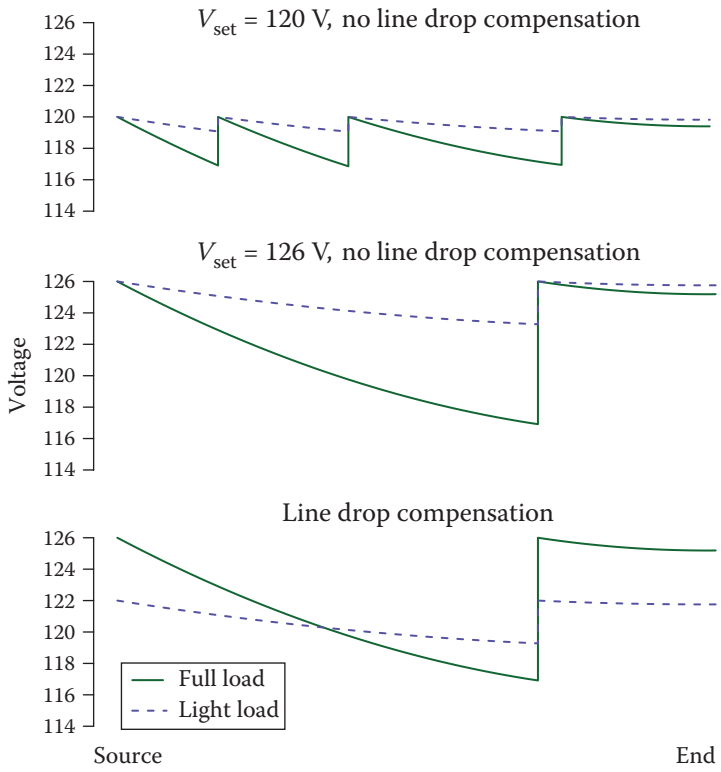

Figure 6.7 Voltage profiles on a circuit with various forms of regulation.

where

R_{set} = regulator setting for resistive compensation, V
X_{set} = regulator setting for reactive compensation, V
I_{CT} = primary rating of the current transformer, A
N_{PT} = potential transformer ratio (primary voltage/secondary voltage)
R_L = primary line resistance from the regulator to the regulation point, Ω
X_L = primary line reactance from the regulator to the regulation point, Ω

A regulator's R and X compensator settings are in units of volts. By using volts as units, we can directly see the impact of the regulator on a 120-V scale. Consider an example where the set voltage is 120 V. With a current at unity power factor and R_{set} = 6 V (X_{set} does not matter at unity power factor), the controller regulates the voltage to 120 + 6 = 126 V when the current is at the peak CT rating. If the current is at half of the CT rating, the controller regulates to the set voltage plus 3 or 123 V. Available compensator settings are normally from –24 to +24 V.

Note that the primary CT rating is an important part of the conversion to compensator settings. The CT rating may be the same as the regulator rating or it may be higher. The CT rating is given on the nameplate. Table 6.6 shows the regulator

TABLE 6.6 Regulator and Primary CT Ratings in Amperes

Regulator Current Ratings	CT Primary Current
25	25
50	50
75	75
100	100
150	150
167, 200	200
219, 231, 250	250
289, 300	300
328, 334, 347, 400	400
418, 438, 463, 500	500
548, 578, 656, 668	600
833, 875, 1000, 1093	1000
1332, 1665	1600

ratings and primary CT current rating for one manufacturer. Regulators may be applied where the nameplate voltage does not match the system voltage if they are close enough to still allow the desired regulation range at the given location. Also, some regulators have taps that allow them to be used at several voltages. Make sure to use the appropriate PT ratio for the tap setting selected.

When specifying impedances for the line-drop compensator, use the correct line impedances. For a three-phase circuit, use the positive-sequence impedance. For a single-phase line, use the loop impedance Z_S, which is about twice the positive-sequence impedance.

On a delta regulator, either an open delta or a closed delta, divide the PT ratio by $\sqrt{3}$. On a delta regulator, the PT connects from phase to phase, but the internal circuit model of the line-drop compensator is phase to ground, so we need the $\sqrt{3}$ factor to correct the voltage.

Line-drop compensation works perfectly for one load at the end of a line, but how do we set it for loads distributed along a line? If loads are uniformly distributed along a circuit that has uniform impedance, we can hold the voltage constant at the midpoint of the section by using

- 3/8 *rule*—For a uniformly distributed load, a regulator can hold the voltage constant at the midpoint of the circuit if we use line-drop compensation settings based on 3/8 of the total line impedance. A circuit with a uniformly distributed load has a voltage drop to the end of the circuit of one half of the drop had all of the loads been lumped into one load at the end of the circuit. Three-fourths of this drop is on the first half of the circuit, so (1/2)(3/4) = 3/8 is the equivalent voltage drop on a uniformly distributed load.

Make sure not to allow excessive voltages. We can only safely compensate a certain amount, and we will have overvoltages just downstream of the regulator if we

compensate too much. Check the voltage to the voltage regulating relay to ensure that it is not over limits. The maximum voltage is

$$V_{max} = V_{set} + (pf \cdot R_{set} + qf \cdot X_{set})\, I_{max}$$

where

V_{set} = regulator set voltage
R_{set} = resistive setting for compensation, V
X_{set} = reactive setting for compensation, V
pf = load power factor
qf = load reactive power factor = $\sin(\cos^{-1}(pf))$
I_{max} = maximum load current in per unit relative to the regulator CT rating

If V_{max} is more than what you desired, reduce R_{set} and X_{set} appropriately to meet your desired limit.

6.4.1.2 Voltage-Spread Compensation

In another method, the *voltage-spread* method, we find compensator settings by specifying the band over which the load-side voltage should operate. For example, we might want the regulator to regulate to 122 V at light load and 126 V at full load. If we know or can estimate the light-load and full-load current, we can find R and X compensator settings to keep the regulated voltage within the proper range. If we want the regulator to operate over a given compensation range C, we can choose settings to satisfy the following:

$$C = V - V_{set} = pf \cdot R_{set} + qf \cdot X_{set}$$

where

R_{set} = resistive setting for compensation, V
X_{set} = reactive setting for compensation, V
pf = load power factor
qf = load reactive power factor = $\sin(\cos^{-1}(pf))$
C = total desired compensation voltage, V
V_{set} = regulator set voltage, V
V = voltage that the controller will try to adjust the regulator to, V

With line current operating to the regulator CT rating limit (which is often the regulator size) and the current at the given power factor, these settings will boost the regulator by C volts on a 120-V scale. Any number of settings for R_{set} and X_{set} are possible to satisfy this equation. If we take $X_{set} = \frac{X}{R} R_{set}$, where the X/R ratio is selectable, the settings are

$$R_{set} = \frac{C}{pf + \frac{X}{R} qf}$$

$$X_{set} = \frac{\frac{X}{R}C}{pf + \frac{X}{R}qf} = \frac{X}{R}R_{set}$$

where

$\frac{X}{R} = X/R$ ratio of the compensator settings

Note that C must be given as seen on the regulator PT secondaries, on a 120-V base. As an example, if the feeder voltage should be not more than 126 V at the limit of the regulator, and the desired voltage at no load is 122 V, set the regulator set voltage at 122 V and find R_{set} and X_{set} to give $C = 4$ V. For a power factor of 0.85 and $\frac{X}{R} = 3$, the equations above give $R_{set} = 1.64$ V and $X_{set} = 4.94$ V.

To control the voltage range for a light load other than zero and for a peak load other than the regulator CT rating, we can use the following to find the voltage swing from light load to full load as

$$V_{max} - V_{min} = (pf \cdot R_{set} + qf \cdot X_{set})I_{max} - (pf \cdot R_{set} + qf X_{set})I_{min}$$

where

V_{max} = desired voltage at the maximum load current on a 120-V base, V
V_{min} = desired voltage at the minimum load current on a 120-V base, V
I_{max} = maximum load current in per-unit relative to the regulator CT rating
I_{min} = minimum load current in per-unit relative to the regulator CT rating

Now, the R and X settings are

$$R_{set} = \frac{V_{max} - V_{min}}{(pf + \frac{X}{R}qf)(I_{max} - I_{min})}$$
$$X_{set} = \frac{X}{R}R_{set}$$

And, the regulator set voltage is

$$V_{set} = V_{min} - (pf \cdot R_{set} + qf \cdot X_{set})I_{min} = V_{min} - \frac{V_{max} - V_{min}}{I_{max} - I_{min}}I_{min}$$

With a compensator X/R ratio equal to the line X/R ratio, these equations move the effective load center based on the choice of voltage and current minimums and maximums.

Just like we can choose to have the compensator X/R ratio equal the line X/R ratio, we can choose other values as well. There are good reasons why we might want to use other ratios; this is done mainly to reduce the sensitivity to power factor changes. The *zero reactance* method of selecting compensator makes $X_{set} = 0$ (and the compensator $X/R = 0$) but otherwise uses the same equations as the voltage spread method

(General Electric, 1979). By making X_{set} zero, the compensator is not sensitive to variations in power factor caused by switched capacitors or load variation; only real power changes cause regulator movement. This method also simplifies application of regulators. The equations become

$$R_{set} = \frac{V_{max} - V_{min}}{pf(I_{max} - I_{min})}$$
$$X_{set} = 0$$

And, the regulator set voltage is

$$V_{set} = V_{min} - (pf \cdot R_{set})I_{min}$$

The equations simplify more if we assume that $I_{min} = 0$ (our error with this is that voltages run on the high side during light load). A further simplification is to assume that the power factor is one. If the power factor is less than that at full load, the regulator will not boost the voltage quite as much. Often, we do not know the power factor at the regulator location anyway.

This method is useful with switched capacitor banks close to the regulator. It does not perform well for low power factors if we have assumed a power factor near unity. With this control, the regulator will not provide enough boost with poor power-factor load.

Another option is to take $X/R = 0.6$, which weights the real power flow more than the reactive power flow, but not as extremely as the zero reactance compensation method. So, although the controller is somewhat desensitized to changes in power factor, the regulator provides some action based on reactive power. Figure 6.8 shows several X/R compensator settings chosen to provide an operating band from 121 V at light load to 127 V at full load. The settings were chosen based on a power factor of 0.9, and the curves show the voltage as the power factor varies. The middle graph with $X/R = 0.6$ performs well over a wide range of power factors. The graph on the left, where $X/R = 3$, which is the line X/R ratio, has the most variation with changes in power factor. If power factor is lower than we expected, the compensator will cause high voltages.

With $X/R = 0.6$ and $pf = 0.9$, the voltage spread equations are

$$R_{set} = 0.86\frac{V_{max} - V_{min}}{(I_{max} - I_{min})}$$
$$X_{set} = 0.6R_{set}$$

And the regulator set voltage is

$$V_{set} = V_{min} - \frac{V_{max} - V_{min}}{I_{max} - I_{min}} I_{min}$$

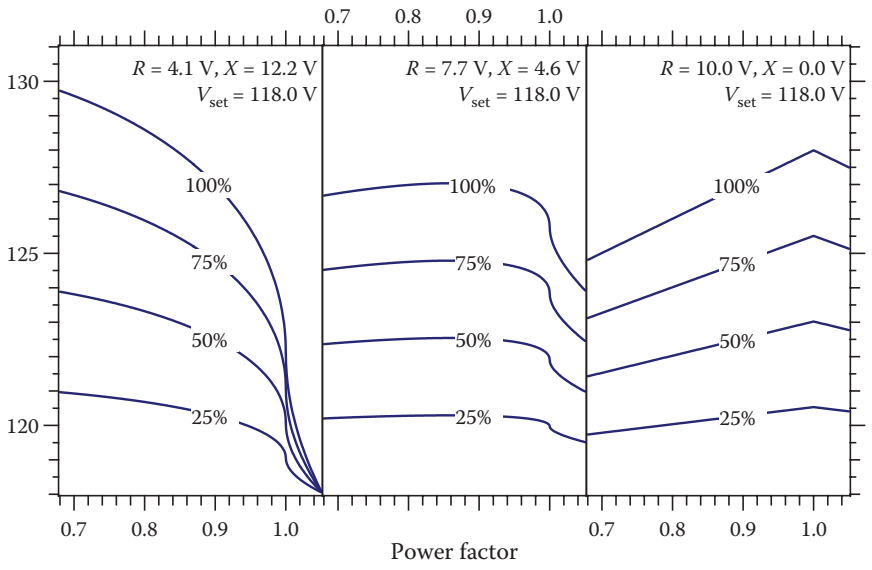

Figure 6.8 Regulated voltage based on different compensator settings and power factors with the percentage loadings given on the graph. All settings are chosen to operate from 121 V at light load (33%) to 127 V at full load (100% of the primary CT ratio) at a power factor of 0.9.

The *universal compensator* method fixes compensation at $R_{set} = 5$ V and $X_{set} = 3$ V to give a 6-V compensation range with current ranging up to the regulator CT rating (General Electric, 1979). For other voltage ranges and maximum currents, we can use

$$R_{set} = \frac{5}{I_{max}} \frac{(V_{max} - V_{min})}{6}$$
$$X_{set} = \frac{3}{I_{max}} \frac{(V_{max} - V_{min})}{6}$$

And we assume that $I_{min} = 0$, so the regulator set voltage is

$$V_{set} = V_{min}$$

To make this even more "cookbook," we can standardize on values of V_{max} and V_{min}, for example, values of 126 V and 120 V. If the full-load is the CT rating (which we might want in order to be conservative), the default settings become $R_{set} = 5$ V and $X_{set} = 3$ V. The universal compensation method is easy yet relatively robust.

With any of the voltage-spread methods of setting the R and X line-drop compensation, the peak current is an important parameter. If we underestimate the load current, the regulator can overcompensate and cause high voltages (if we do not have a voltage override limiter or if it is disabled). Check regulator loadings regularly to ensure that the compensation is appropriate.

6.4.1.3 *Effects of Regulator Connections*

On an open-delta regulator, one regulator is connected leading, and the other lagging. We need to adjust the compensator settings to account for the 30° phase shift. On the leading regulator, the current leads the voltage by 30°, so we need to subtract 30° from the compensator settings, which is the same as multiplying by 130° or (cos 30°—*j* sin 30°). Modify the settings for the leading regulator (Cooper Power Systems, 1978; Westinghouse Electric Corporation, 1965) with

$$R'_{set} = 0.866\, R_{set} + 0.5X_{set}$$

$$X'_{set} = 0.866\, X_{set} - 0.5R_{set}$$

And for the lagging regulator, we need to add 30°, which gives

$$R'_{set} = 0.866\, R_{set} - 0.5X_{set}$$

$$X'_{set} = 0.866\, X_{set} + 0.5R_{set}$$

For an X/R ratio above 1.67, R'_{set} is negative on the lagging regulator, and for a ratio below 0.58, X'_{set} is negative on the leading regulator. Most controllers allow negative compensation.

In the field, how do we tell which is the leading and which is the lagging regulator? Newer regulator controllers can tell us which is which from phase angle measurements. For older controllers, we can modify the compensator settings to find out (Lokay and Custard, 1954). Set the resistance value on both regulators to zero, and set the reactance setting on both to the same nonzero value. The unit that moves up the most number of tap positions is the lagging unit (with balanced voltages, this is the unit that goes to the highest raise position). If the initial reactance setting is not enough, raise the reactance settings until the leading and lagging units respond differently.

With a closed-delta regulator, all three regulators are connected either leading or lagging. All three regulators have the same set of compensator settings; adjust them all with either the leading or the lagging equations described for the open-delta regulator.

On a three-phase regulator, even on a delta system, the compensator settings do not need adjustment. The controller accounts for any phase shift that might occur inside the regulator.

6.4.2 Voltage Override

Use the *voltage override* feature on the regulator controller. No matter how we select the line-drop compensation settings, an important feature is an upper voltage limit on the regulation action. The regulator keeps the regulated voltage below this limit regardless of the line-drop compensation settings. Always use this feature to protect against overvoltages caused by incorrect line-drop compensation settings or

unusually high loadings. This upper voltage limiter is also called "first house protection," as it is the first few customers downstream that could have overvoltages due to regulator action. With a voltage limit, we can set line-drop compensator settings more aggressively and not worry about causing overvoltages to customers. On a regulator without an upper limit (normally older units), increase estimated peak loadings when calculating line-drop compensation settings in order to reduce the risk of creating overvoltages. Voltage override functions usually have a deadband type setting on the voltage limit to prevent repeated tap changes. For example, we might set a 126-V upper limit with a deadband of an extra 2 V. Above 128 V, the controller immediately taps the regulator down to 126 V, and between 126 and 128 V, the controller prohibits tap raises (different controllers implement this function somewhat differently; some include time delays). Even without line-drop compensation, the voltage override function helps protect against sudden changes in upstream voltages (the out-of-limit response is normally faster than normal time-delay settings programmed into regulators).

6.4.3 Regulator Placement

With no feeder regulators, the entire voltage drop on a circuit must be within the allowed primary voltage range. One feeder regulator can cover primary voltage drops up to twice the allowed voltage variation. Similarly, two supplementary regulators can cover primary voltage drops up to three times the allowed variation. For a uniformly distributed load, optimum locations for two regulators are at distances from the station of approximately 20% of the feeder length for one and 50% for the other. For one feeder regulator, the optimum location for a uniformly distributed load is at 3/8 of the line length from the station.

When placing regulators and choosing compensator settings, allow for some load growth on the circuit. If a regulator is applied where the load is right near its rating, it may not be able to withstand the load growth. However, it is more than just concern about the regulator's capability. If we want to keep the primary voltage above 118 V, and we add a regulator to a circuit right at the point where the primary voltage falls to 118 V, that will correct the voltage profile along the circuit with present loadings. If loadings increase in the future, the voltage upstream of the regulator will drop below 118 V. As previously discussed, when setting line-drop compensator settings, the maximum load on the regulator should allow room for load growth to reduce the chance that the regulator boosts the voltage too much.

Several regulators can be strung together on a circuit. Though this can meet the steady-state voltage requirements of customers, it will create a very weak source for them. Flicker problems from motors and other fluctuating loads are more likely.

Also consider the effect of dropped load on regulators. A common case is a recloser downstream of a line regulator. If the regulator is tapped up because of heavy load and the recloser suddenly drops a significant portion of the load, the voltage downstream of the regulator will pop up until the regulator controller shifts the taps back down.

6.4.4 Other Regulator Issues

Normally, voltage regulators help with voltage unbalance as each regulator independently controls its phase. If we aggressively compensate, the line-drop compensation can cause voltage unbalance. Consider a regulator set to operate between 120 V at no load and 126 V at full load. If one phase is at 50% load and the other two are at 0% load, the line-drop compensator will tap to 123 V on the loaded phase and to 120 V on the unloaded phases. Depending on customer placements, this may be fine if the voltages correct themselves along the line. But if the unbalance is due to a large tapped lateral just downstream of the regulator, the regulator needlessly unbalances the voltages.

Capacitor banks pose special coordination issues with regulators. A fixed capacitor bank creates a constant voltage rise on the circuit and a constant reactive contribution to the current. Either fixed or switched, capacitors upstream of a regulator do not interfere with the regulator's control action. Downstream capacitors pose the problem. A capacitor just downstream of a regulator affects the current that the regulator sees, but it does not measurably change the shape of the voltage profile beyond the regulator. In this case, we would like the line-drop compensation to ignore the capacitor. The voltage-spread compensation with a low compensator *X/R* or the zero-reactance compensator settings work well because they ignore or almost ignore the reactive current, so it works with fixed or switched banks downstream of the regulator. The load-center approach is more difficult to get to work with capacitors.

We do not want to ignore the capacitor at the end of a circuit section we are regulating because the capacitor significantly alters the profile along the circuit. In this case, we do not want zero-reactance compensation; we want some *X* to compensate for the capacitive current.

Switched capacitors can interact with the tap-changing controls on regulators upstream of the capacitors. This sort of interaction is rare but can happen if the capacitor is controlled by voltage (not radio, not time of day, not vars). A regulator may respond to an upstream or downstream capacitor switching, but that does not add up to many extra tap changes since the capacitor switches infrequently. Normally, the capacitor cannot cycle back and forth against the regulator. The only case might be if the regulator has negative settings for the reactive line-drop compensation.

With several regulators in series, adjustments to the time delay settings are the proper way to coordinate operations between units. Set the downstream regulator with the longest time delay so that it does not change taps excessively. For multiple regulators, increase the time delay with increasing distance from the source. Tap changes by a downstream regulator do not change the voltage upstream, but tap changes by an upstream regulator affect all downstream regulators. If a downstream regulator acts before the upstream regulator, the downstream regulator may have to tap again to meet its set voltage. Making the downstream regulator wait longer prevents it from tapping unnecessarily. Separate the time delays by at least 10 to 15 sec to allow the upstream unit to complete tap change operations.

6.5 Station Regulation

Utilities most commonly use LTCs to control distribution feeder voltages at the substation. In many cases (short, urban, thermally limited feeders), an LTC is all the voltage support a circuit needs.

An LTC or a stand-alone voltage regulator must compensate for the voltage change on the subtransmission circuit as well as the voltage drop through the transformer. Of these, the voltage drop through the transformer is normally the largest. Normally, the standard ±10% regulator can accomplish this. A regulator can hit the end of its range if the load has especially poor power factor. The voltage drop across a transformer follows:

$$V_{\text{drop}} = I_{\text{R}} \cdot R + I_{\text{X}} \cdot X$$

Since a transformer's *X/R* ratio is so high, the reactive portion of the load creates the most voltage drop across the transformer. Consider a 10% impedance transformer at full load with a load power factor of 0.8, which means the reactive power factor is 0.6. In this case, the voltage drop across the transformer is 6%. If the subtransmission voltage is 120 V (on a 120-V scale), the maximum that the regulator can boost the voltage to is 124 V. If this example had a transformer loaded to more than its base open-air rating (OA or ONAN), the regulator would be more limited in range. In most cases, we do not run into this problem as power factors are normally much better than these.

In most cases, bus regulation suffices. For cases where circuits have significant voltage drop, individual feeder regulation can be better. Individual feeder regulation also performs better on circuits with different load cycles. If commercial feeders are on the same bus as residential feeders, it is less likely that a bus regulator can keep voltages in line on all circuits. Normally, we handle this by using bus regulation and supplementary line regulators. In some cases, individual feeder regulation in the station is more appropriate.

The voltage on feeders serving secondary networks is controlled at the primary substation with LTC transformers. These circuits are short enough that feeder regulators are unnecessary. Network feeders are often supplied by parallel station transformers; paralleling LTC units raises several issues that are discussed in the next section.

6.5.1 Parallel Operation

With care, we can parallel regulators. The most common situation is in a substation where a utility wants to parallel two LTC transformers. If two paralleled transformers do not have the same turns ratio, current will circulate to balance the voltages. The circulating current is purely reactive, but it adds extra loading on the transformer.

Some of the methods to operate LTC transformers in parallel (Jauch, 2001; Westinghouse Electric Corporation, 1965) include

- *Negative-reactance control*—The reactance setting in the line-drop compensator is set to a negative value, so higher reactive current forces the control to lower taps. The transformer with the higher tap has more reactive current, and the transformer with the lower tap is absorbing this reactive current (it looks capacitive to this transformer). So, a negative-reactance setting forces the transformer with the highest tap (and most reactive current) to lower its taps and bring it into alignment with the other unit. This method limits the use of line-drop compensation and can lead to lower bus voltages.
- *Master–follower*—One controller, the master, regulates the voltage and signals the other tap changers (the followers) to match the tap setting. The master control normally gets feedback from the followers to confirm their operation.
- *Var balancing*—The controller adjusts taps as required to equalize the vars flowing in parallel transformers. Auxiliary circuitry is required. This method has the advantage that it works with transformers fed from separate transmission sources.
- *Circulating current method*—This is the most common control. Auxiliary circuitry is added to separate the load current through each transformer from the circulating current. Each transformer LTC control is fed the load current. The controller adjusts taps to minimize the difference in current between parallel units. Removing a unit does not require changing controller settings.

The complications associated with paralleling regulators are another reason utilities normally avoid closed bus ties in distribution substations.

6.5.2 Bus Regulation Settings

Although too often left unused, bus regulators (whether stand-alone regulators or LTCs) can use line-drop compensation. The concept of a load center rarely has good meaning for a bus supporting several circuits, but the voltage spread methods allow the regulator to boost voltage under heavy load.

The voltage-spread equations assume that the power factor at full load is the same as the power factor at light load. If the power factor is different at light and peak loads, we can use this information to provide more precise settings. We could solve the following to find new R and X settings with different power factors

$$V_{max} - V_{min} = (pf_{max} \cdot R_{set} + qf_{max} \cdot X_{set})I_{max} - (pf_{min} \cdot R_{set} + qf_{min} \cdot X_{set})I_{min}$$

However, it is easier to use the equations in Section 6.4.1.2 and use the average of the power factor at peak load and the power factor at light load. With line-drop compensation for bus regulation, the voltage-override feature helps to ensure that the LTC or regulator does not cause excessive voltages.

Individual substation feeder regulators are set the same as line feeder regulators. We can tune controller settings more precisely based on the individual characteristics of a given feeder. If the first part of the feeder is an express feeder with no load on

it, we could boost the voltage higher than normal, especially if the circuit is voltage limited. Our main constraint is making sure that the first customer does not have high voltage.

6.6 Line Loss and Voltage Drop Relationships

Line losses are from the line current flowing through the resistance of the conductors. After distribution transformer losses, primary line losses are the largest cause of losses on the distribution system. Like any resistive losses, line losses are a function of the current squared multiplied by the resistance (I^2R). Ways to reduce line losses include

- Use a higher system voltage
- Balance circuits
- Convert single-phase circuits to three-phase circuits
- Reduce loads
- Increase power factor (capacitors)
- Reconductor with a larger size

Because losses are a function of the current squared, most losses occur on the primary near the substation. Losses occur regardless of the power factor of the circuit. Reducing the reactive portion of current reduces the total current, which can significantly impact losses.

Approximations using uniform load distributions are useful. A uniformly distributed load along a circuit of length l has the same losses as a single lumped load placed at a length of $l/3$ from the source end. For voltage drop, the equivalent circuits are different: a uniformly distributed load along a circuit of length l has the same voltage drop as a single lumped load placed at a length of $l/2$ from the source end. This 1/2 rule for voltage drop and the 1/3 rule for losses are helpful approximations when doing hand calculations or when making simplifications to enter in a load flow program.

For a uniformly increasing load, the equivalent lumped load is at $0.53l$ of the length from the source. Figure 6.9 shows equivalent circuits for a uniform load and a uniformly increasing load.

Line losses decrease as operating voltage increases because the current decreases. Schultz (1978) derived several expressions for primary feeder I^2R losses on circuits with uniform load densities. His analysis showed that most 15 to 35-kV-class–circuits are not voltage-drop limited—most are thermally limited. As the system voltage varies, the losses change the most for voltage-limited circuits (Schultz, 1978):

$$L_2 = \left(\frac{V_1}{V_2}\right)^2 L_1 \quad \text{for a voltage-limited circuit}$$

$$L_2 = \left(\frac{V_1}{V_2}\right)^{2/3} L_1 \quad \text{for a thermally limited circuit}$$

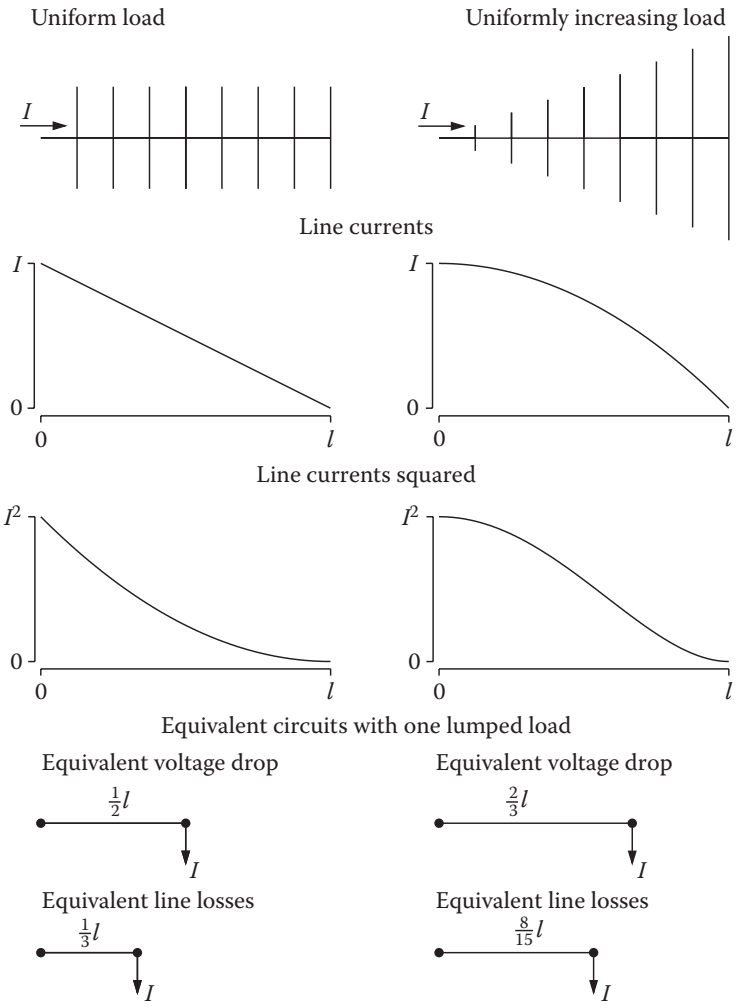

Figure 6.9 Equivalent circuits of uniform loads.

where

V_1, V_2 = voltage on circuits 1 and 2
L_1, L_2 = feeder I^2R losses on circuits 1 and 2

On a system-wide basis, losses are expected to change with voltage with an exponent somewhere between 2/3 and 2.

Losses, voltage drop, and capacity are all interrelated. Three-phase circuits have the highest power transfer capacity, the lowest voltage drop, and the lowest losses. Table 6.7 compares capacity, voltage drop, and losses of a balanced three-phase system with several other phasing configurations.

Utilities consider both peak losses and energy losses. Peak losses are important because they compose a portion of the peak demand; energy losses are the total

TABLE 6.7 Characteristics of Various Systems

System	Capacity in Per Unit	Voltage Drop in Per Unit for Equal kVA	Line Losses in Per Unit for Equal kVA
Balanced three phase	1.0	1.0	1.0
Two phases	0.5	2.0	2.0
Two phases and a multigrounded neutral	0.67	2.0–3.3	1.2–3.0
Two phases and a unigrounded neutral	0.67	2.5–4.5	2.25
One phase and a multigrounded neutral	0.33	3.7–4.5	3.5–4.0
One phase and a unigrounded neutral	0.33	6.0	6.0

Notes: The two-phase circuits assume that all loads are connected line to ground. Neutrals are the same size as the phases. Reduced neutrals increase voltage drop and (usually) line losses. The voltage drop and line loss ratios for circuits with multigrounded neutrals vary with conductor size.

kilowatt-hours wasted as heat in the conductors. The peak losses are more easily estimated from measurements and models. The average losses can be found from the peak losses using the loss factor F_{ls}:

$$F_{ls} = \frac{\text{Average losses}}{\text{Peak losses}}$$

Normally, we do not have enough information to directly measure the loss factor. We do have the load factor (the average demand over the peak demand). The loss factor is some function of the load factor squared. The most common approximation (Gangel and Propst, 1965) is

$$F_{ls} = 0.15F_{ld} + 0.85F_{ld}^2$$

This is often used for evaluating line losses and transformer load losses (which are also a function of I^2R). Load factors closer to one result in loss factors closer to one. Another common expression is $F_{ls} = 0.3F_{ld} + 0.7F_{ld}^2$. Figure 6.10 shows both relationships.

6.7 Voltage Optimization

Utilities can use voltage adjustments as a way to manage system load. Voltage reduction can reduce energy consumption and/or reduce peak demand. The term conservation voltage reduction (CVR) is normally applied to mean full-time operation for energy reductions. Voltage optimization is often used to describe application of reduced voltages, system improvements, and voltage control. The term "volt-var control" is often used to describe reactive-power control in conjunction with voltage control, often including voltage reduction (EPRI 1022004, 2011). The Pacific Northwest National Laboratory (PNNL, 2010) predicted that implementation of CVR on 100% of

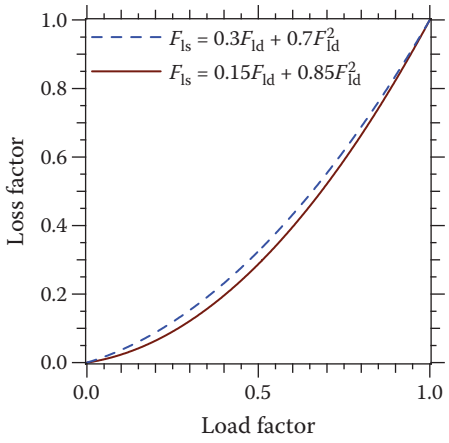

Figure 6.10 Relationship between load factor and loss factor.

U.S. distribution feeders would reduce energy consumption by 3%, and implementation on the 40% of feeders with the highest value would reduce consumption by 2.4%. Based on models of 66 circuits in the EPRI Green Circuits project, median reduction in energy from CVR was 2.34%, with upper and lower quartiles of 1.69% and 3.13% (EPRI 1023518, 2011; Arritt et al., 2012). Most of the savings in this project was on the customer side of the meter as shown in Table 6.8. No-load losses reduce significantly, and load losses stay about the same.

Voltage reduction to reduce demand has even more impact on demand than on energy. The most reduction occurs right when the voltage is reduced, and then some of the reduction is lost as some loads keep running longer than normal to compensate for lower voltage. For example, Priess and Warnock (1978) found that during a 4-hour, 5% voltage reduction, the demand on one typical residential circuit dropped by 4% initially and diminished to a 3% drop by the end of the 4-hour period.

Voltage reduction can also reduce losses, largely from lower no-load losses on transformers. Generally, load losses stay approximately the same. Even though the real-power component of current increases for some loads with reduced voltage, the reactive-power component of current decreases. These effects tend to balance, and

TABLE 6.8 Average Energy Savings from Voltage Optimization by Component

		Voltage Optimization Energy Savings	
	Breakdown of Overall Energy	Savings per Component	Portion of Total Savings by Category
No-load loss	1.6%	5.6%	4.1%
Load loss	1.8%	0.6%	0.2%
Consumption	96.6%	2.3%	95.6%

Source: From EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright © 2011. Reprinted with permission.

actual results depend on the load composition of the circuit. If volt-var control is used to improve reactive power along with voltage optimization, losses can be reduced along with flattening voltage profiles.

6.7.1 Field Results from Voltage Reduction

The impact of voltage on loads is often quantified as a CVR factor, the percent change in load for a 1% change in voltage. Kirshner and Giorsetto (1984) analyzed trials of CVR at several utilities. While results varied significantly, most test circuits had energy savings of between 0.5% and 1% for each 1% voltage reduction. Their regression analysis of the feeders found that residential energy savings were 0.76% for each 1% reduction in voltage, while commercial and industrial loads had reductions of 0.99% and 0.41% (but the correlations between load class and energy reduction were fairly small).

The Northwest Energy Efficiency Alliance (NEEA) and several utilities evaluated voltage reduction in the U.S. Pacific Northwest (NEEA, 2007). They evaluated changes at the circuit level and also changes directly to residential customers. Figure 6.11 shows evaluations of voltage changes at the circuit level; using temperature-adjusted regressions, they found an average CVR factor of 0.69 based on a substation voltage change of 2.5%.

In NEEA's measurement and evaluation of 395 residential customers, they estimated a CVR factor of 0.57 based on a voltage change of 4.3% at the customer. The NEEA study found seasonal differences. In the customer evaluation, they found a CVR factor in the winter of 0.5, compared to a summer CVR factor of 0.78. They found significant difference based on heating and cooling: customers with air conditioning

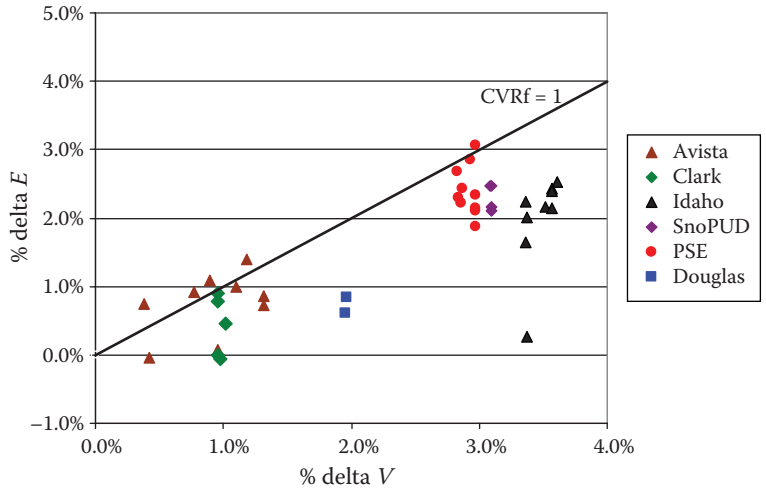

Figure 6.11 Energy savings versus voltage reduction for the NEEA study pilot feeders. (From NEEA 1207, *Distribution Efficiency Initiative*, Northwest Energy Efficiency Alliance, 2007. http://www.leidos.com/NEEA-DEI_Report.pdf. With permission.)

had an average CVR factor of 0.71, and customers with heat pump heating had an average CVR factor of 0.242, and customers with resistive heating had an average CVR factor of 0.266.

The NEEA study found even more dramatic changes in reactive power with voltage. In their feeder monitoring study, they found CVR_{var} factors between 3.0 and 3.5 (vars drop by 3% for every 1% drop in voltage). That indicates that a large component of the change is due to the reduction in magnetizing current in motors and transformers because this excitation current has a highly nonlinear response to voltage. The change in reactive power was not particularly sensitive to season. Figure 6.12 shows this nonlinear response of reactive power to voltage.

Lefebvre et al. (2008) reported on tests of voltage reduction at Hydro Quebec. They found a strongly temperature-dependent CVR factor. At 68°F (20°C), they estimated a CVR factor of 0.55, and at 14°F (–10°C), the CVR factor dropped to 0.15. Overall, for their mix of loads, they estimated a summer CVR factor of 0.67, a winter CVR factor of 0.20, and an overall CVR factor of 0.4. For residential customers, they estimated a summer CVR factor of 0.67 and a winter CVR factor of 0.06 for all-electric customers and 0.12 for not-all-electric customers.

In the EPRI Green Circuits project, several utilities implemented field trials on a total of nine circuits (EPRI 1023518, 2011; Short and Mee, 2012). Figure 6.13 compares energy reductions and voltage reductions estimated during these field trials along with the confidence intervals around the energy reduction estimates. The CVR factors had a median of 0.61 and ranged from 0.5 to 0.9. Most of the circuits were in the Southeast United States, and most had mainly residential load. Note that the voltage changes given are based on substation measurements.

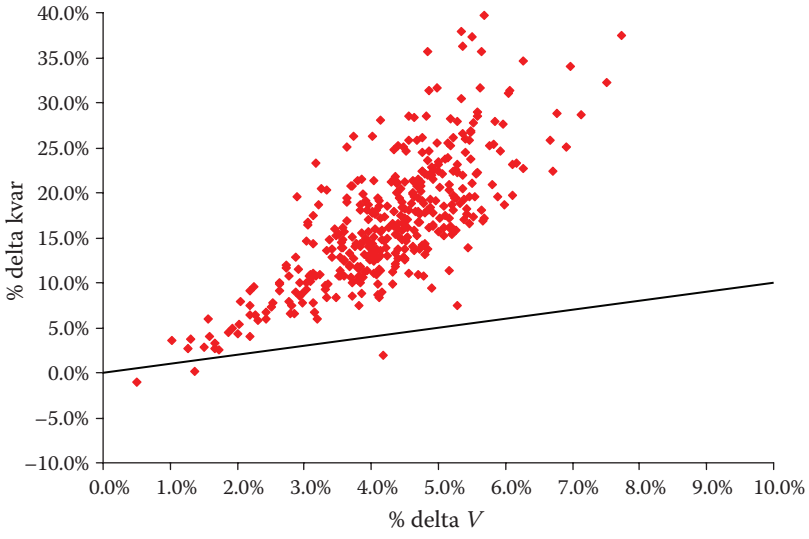

Figure 6.12 Change in reactive power in the NEEA study homes. (From NEEA 1207, *Distribution Efficiency Initiative*, Northwest Energy Efficiency Alliance, 2007. http://www.leidos.com/NEEA-DEI_Report.pdf. With permission.)

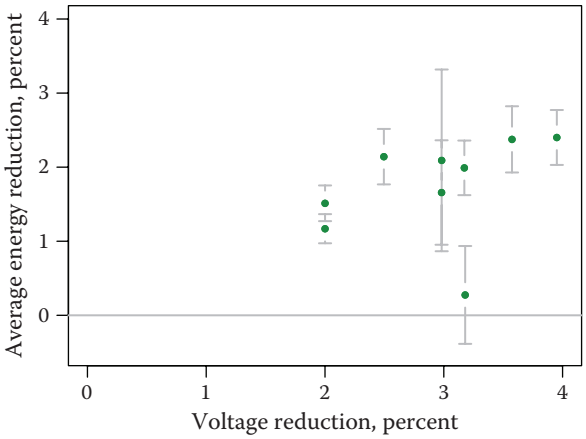

Figure 6.13 Energy reductions versus voltage reduction in the Green Circuit project. (From EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright © 2011. Reprinted with permission.)

Voltage reduction was typically less effective in the winter as shown by Figure 6.14. "Summer" is defined as June through August; "winter" is December through February; and the remaining months are "shoulder" months. The median circuit CVR factor in the winter was 0.33. The median CVR factor during the summer was 0.77.

Figure 6.15 compares CVR factors of the EPRI dataset with the feeder-level pilots from the NEEA study. Both sets of feeders showed similar results. This is important because the EPRI circuits were mainly in the Southeast United States, and the NEEA

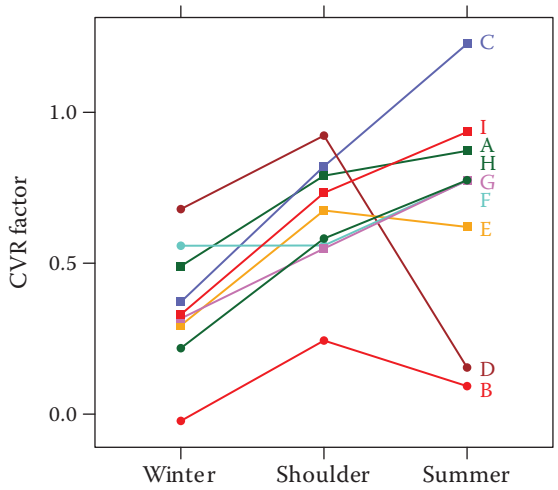

Figure 6.14 CVR factors by season. (From EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright © 2011. Reprinted with permission.)

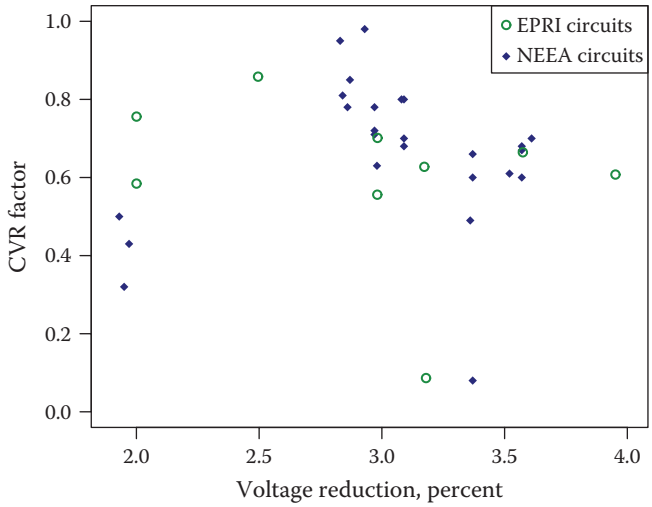

Figure 6.15 Comparison of CVR factors on EPRI feeders and NEEA feeders. (From EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright © 2011. Reprinted with permission.)

circuits were all in the U.S. Pacific Northwest. So, even in different climate areas, CVR factors have similar ranges across circuits.

Several circuits in the Green Circuits project had advanced metering infrastructure (AMI). Figure 6.16 shows statistical distributions of measured voltages on the circuits with AMI when operating in normal mode. This set of circuits had significant room for voltage reduction without additional feeder voltage flattening. The median customer meter voltage on these five circuits ranged from 122 to 123 V. Ninety-nine percent of customer voltage readings were above 117.5 V on these five circuits. This matches my experience with several utilities: many circuits have significant opportunity for reduced voltage.

One of the main questions about voltage reduction is how effective it is on commercial loads. Figure 6.17 shows a breakdown for four load classifications for the metered customers on one circuit and shows clear differences by customer type. Not surprisingly, lighting loads had the largest reduction in energy. The commercial load on this circuit was mainly shopping, bars, and restaurants. This type of commercial load appears to have had less reduction in energy than residential load.

In Figure 6.17, the right-most column of graph panels shows the energy reduction for that set of customers. The red dot marks the estimate of the energy savings with voltage reduction, and the gray line marks the 95% confidence intervals around the estimate. The left two columns of graph panels show yearly and hourly customer usage profiles for each grouping of customers.

Annual load profiles show significant difference between customers by season. Figure 6.18 compares groups of customers clustered by normalized monthly usage profiles. Clustering was done with the widely used K-means algorithm. In Figure 6.18, "summer" is defined as June, July, and August; "winter" is defined as December,

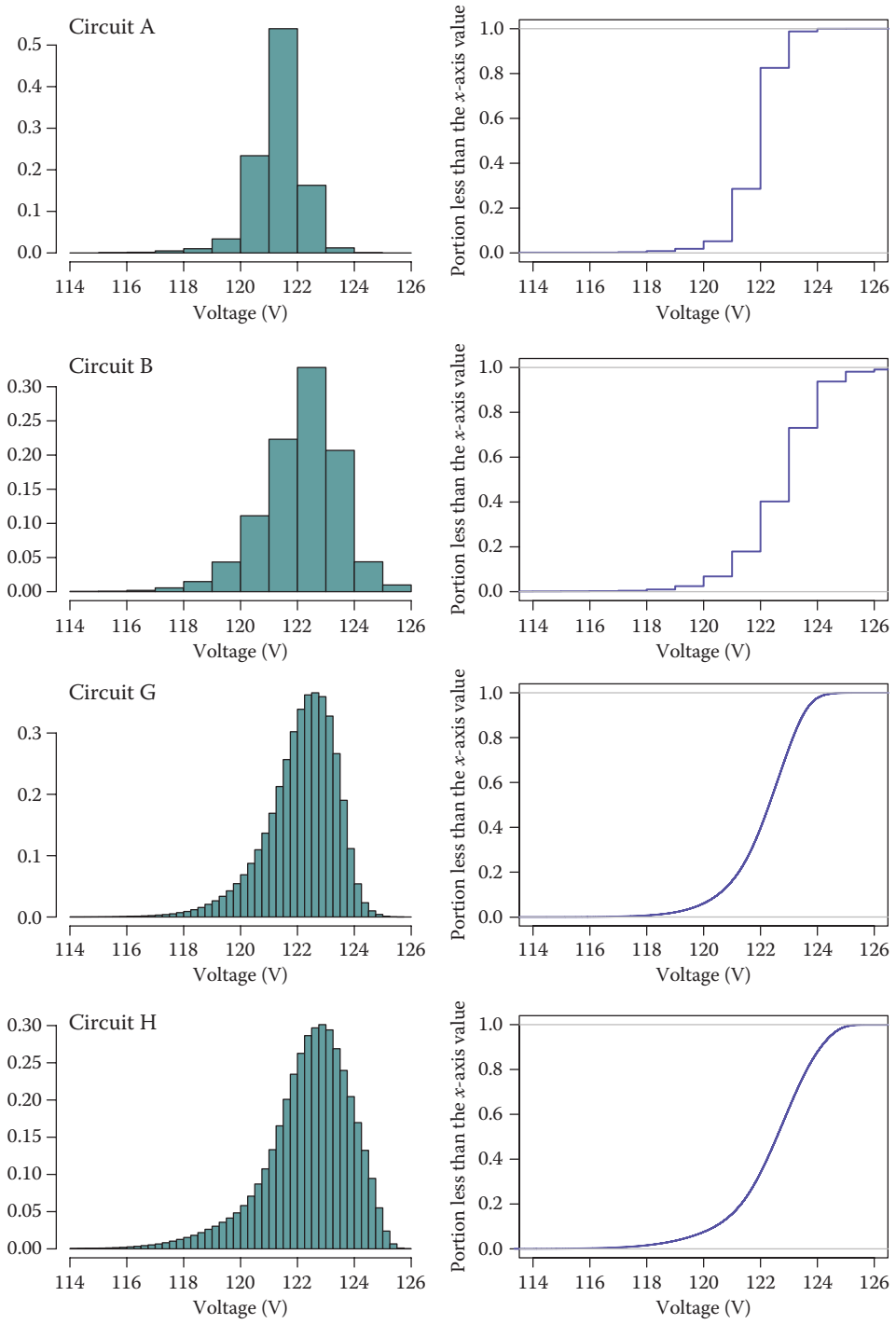

Figure 6.16 Statistical distribution of customer voltages by circuit. (From EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright © 2011. Reprinted with permission.)

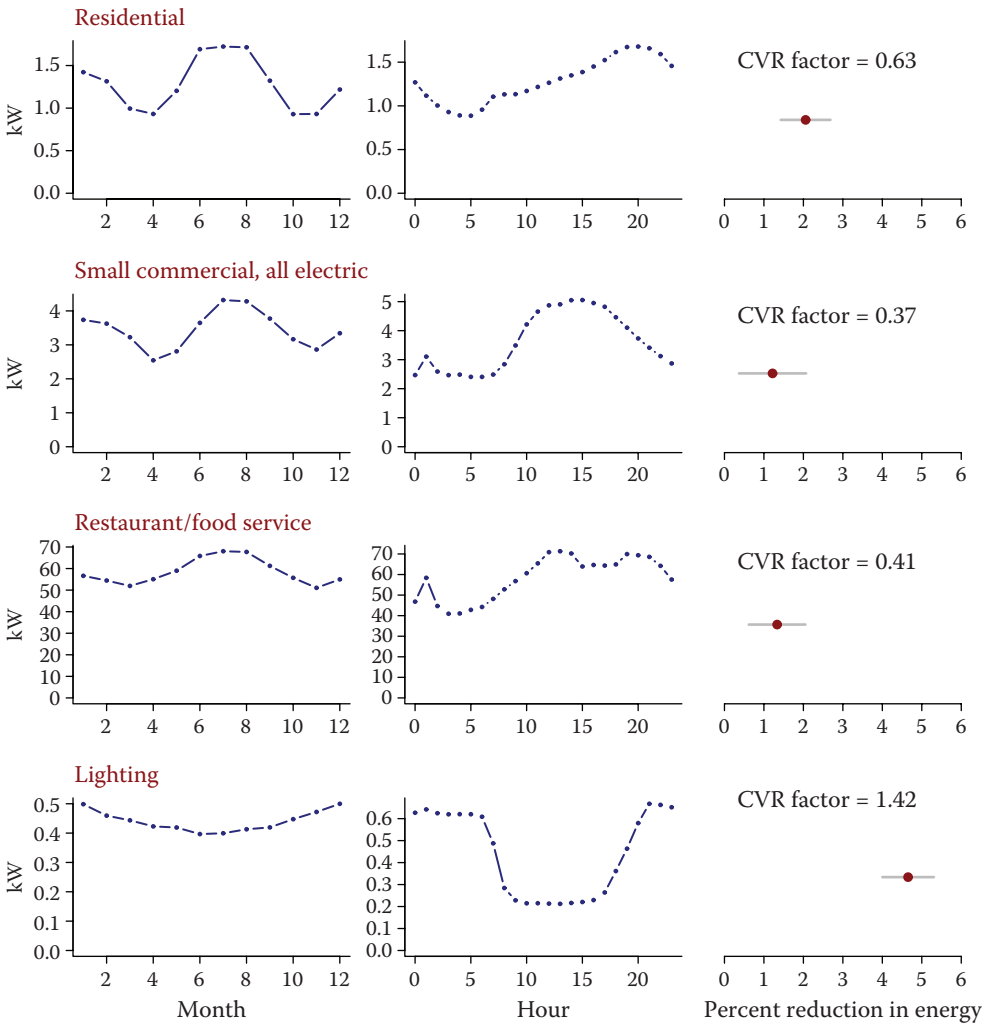

Figure 6.17 Energy usage profiles by customer class with energy reduction from voltage reduction for one circuit. (From EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright © 2011. Reprinted with permission.)

January, and February; and "shoulder" is defined as April, October, and November. All five customer categories had similar energy reductions of about 2% in the summer. The summer-peaking groupings in the top graph panels had more energy reduction than did the winter-peaking groupings in the bottom panels. Low gains in the winter for winter-peaking loads were likely from thermostatically controlled resistive heat loads, which have constant energy usage despite voltage reductions. Heat pumps were common in this service territory, and these often had resistive heating elements to boost heating on colder days. Shoulder months tended to have a higher percentage savings, possibly because there was relatively more lighting load during that time.

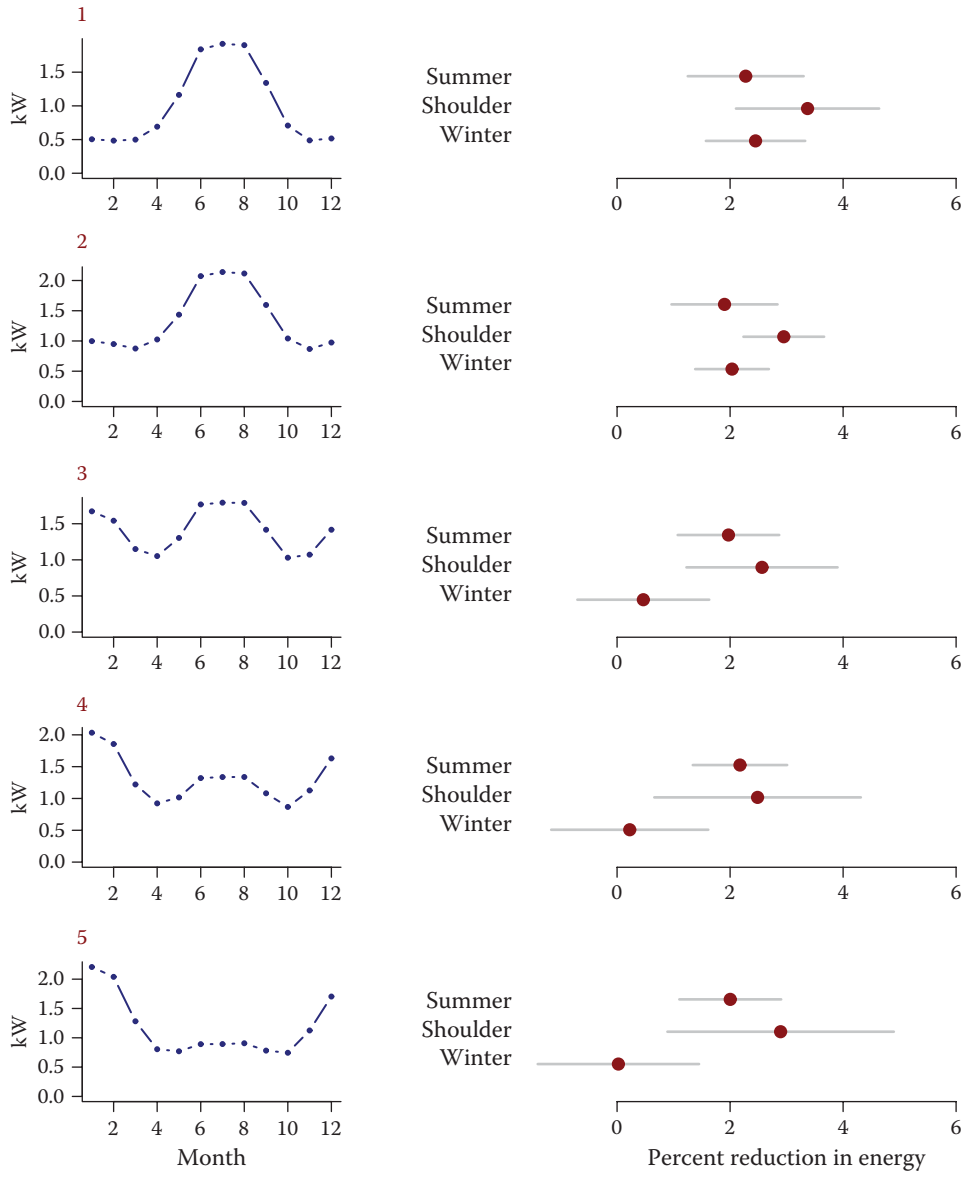

Figure 6.18 Daily profile grouping with energy reduction from voltage reduction by season for residential customers. (From EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright © 2011. Reprinted with permission.)

Low-voltage complaints are something to watch for when reducing voltage. Belvin and Short (2012) reported on a low-voltage complaint from a commercial customer during a voltage-reduction field trial. Site readings verified voltages were lower than expected. This commercial customer was near the substation. In response to an earlier high-voltage complaint, the no-load taps on the customer's transformers had been

changed to provide lower voltage. This customer had two transformers; one had been changed to lower voltages by 2.4%, and the other had been changed to lower voltages by 4.2%. This example shows the importance of considering transformer taps and ratios when implementing voltage reduction.

AMI metering can help identify voltage outliers. Figure 6.19 shows a snapshot of meter voltages at peak summer load on one circuit as a function of distance from the substation when the circuit was operating in reduced-voltage mode. Out of 2523 meters on this feeder, eight (0.3%) had voltages below 114 V (the lower ANSI range A service voltage), and two (0.08%) had voltages above 126 V (the upper ANSI range A voltage). Figure 6.19 shows that the amount of voltage reduction is limited by a small number of meters. At peak summer load, only 2.8% of meters had voltages below 117 V. This was on a short 24-kV circuit, and circuits with little voltage drop on the primary are more forgiving of transformer and secondary issues. The outliers were spread out geographically on several different transformers when located on a map.

The two meters with high voltages in Figure 6.19 are on the same transformer; this transformer is likely damaged, on a wrong tap, or has a design issue. A transformer with shorted high-side windings will produce high secondary voltages.

Reviewing peak (or near-peak) voltages from AMI can identify transformer ratio or transformer tap issues. This approach helps highlight ratio issues better than just reviewing average voltages or snapshots in time. Figure 6.20 shows another voltage profile graph for this feeder. Each point highlights the 99.9th percentile voltage. These readings are close to the peak voltage reading for each meter, and in this case, this worked better than just analyzing the maximum value because it avoided extraneous readings. Most of these near-peak measurements track the peak primary-side voltage and range from about 123.5 to 125.5 V. A small set of meters only sees near-peak voltages of between 119 and 120.5 V. The utility has both 24.94- and 23.9-kV distribution

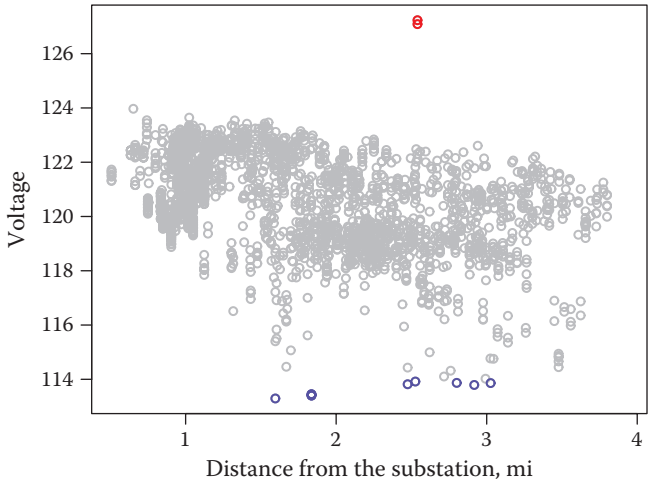

Figure 6.19 Voltage profile of meters at peak load with outliers highlighted. (Belvin, R. C. and Short, T. A., *IEEE PES Transmission and Distribution Conference and Exposition*, 2012. © 2012 IEEE.)

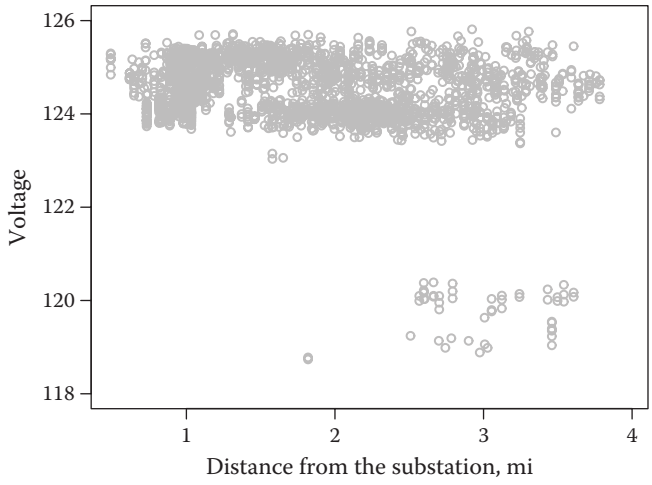

Figure 6.20 Voltage profile of the 99.9th percentile meter voltages. (Belvin, R. C. and Short, T. A., *IEEE PES Transmission and Distribution Conference and Exposition*, 2012. © 2012 IEEE.)

circuits and transformers with both 14.4- and 13.8-kV (line-to-ground) primary-side voltages. The cluster of meters with low voltage was likely from application of 14.4-kV transformers on this 13.8-kV system, or that the transformer tap is on 14.4 kV rather than 13.8 kV. The ratio of 13.8 to 14.4 kV is 0.958. This ratio is on the order of the voltage seen by this small set of meters (0.958×125 V = 119.8 V). This set of meters accounted for less than 2% of the meters on the circuit.

As we have seen with this circuit, secondary-side issues on both residential and commercial customers can limit the depth of voltage reduction. The cost of upgrading secondaries or fixing transformer or secondary issues may need to be balanced against the benefit of additional voltage reduction.

On distribution transformers, taps and/or primary-side voltage ratings are an important consideration, especially for utilities that have different system voltages that could get mixed up, for example 23.9 and 24.94 kV or 13.2 and 13.8 kV. Off-nominal taps or primary-side ratings can skew voltages and limit the amount that voltages can be reduced.

AMI can also reveal out-of-range service voltages that were unknown before implementation of AMI (many customers will not notice out-of-range service voltages).

Higher voltage distribution circuits and shorter circuits have stiff primary voltages that make them the best candidates for voltage reduction. These circuits with lower primary-side voltage drop can mask secondary-side issues.

Voltage drops through distribution transformers and secondaries are important considerations when reducing voltage. Most utilities do not model these voltage drops. A case study in the Green Circuit project with several secondaries monitored at the transformer and at customers found that voltage drops through the secondary and service drop tended to range from 0.5 to 2 V on a 120-V base at the feeder peak load (EPRI 1023518, 2011; Taylor et al., 2012). The total voltage drop across the transformer

and secondary was also evaluated: 10% of voltage drops were above 2.0 V; 5% were above 2.6 V, 1% were above 4.2 V, and 0.1% were above 6.4 V. Of course, secondary and transformer voltage drops will be highly location specific and depend on historical practices for transformer sizing, secondary lengths, and conductor sizes.

Measurement and verification of the impact of CVR is challenging. Many field pilots of CVR adjusted voltage control on alternate days. By alternating between normal mode and reduced-voltage control, after enough time operating in alternating modes, the variations due to weather and load usage should even out. Because voltage reduction changes energy consumption on the order of 1 to 3%, and loading is highly variable, it takes many months of data to be confident in results.

In the NEEA (2007) pilot feeder study, this day-on/day-off approach was used, and feeder-level energy consumption data was temperature-normalized using heating-degree hours and cooling-degree hours. The NEEA approach was similar to that by Bell (2004) that has been adapted as Protocol 1 for the Northwest Power and Conservation Council (NWPCC, 2004). A similar approach was used during the Green Circuits project (EPRI 1023518, 2011; Short and Mee, 2012), with regressions based on control circuits with comparable load profiles. Markushevich et al. (2012) outlined two strategies for measurement and verification, one based on a series of voltage changes in comparison with reference circuits with similar load, and another based on comparing test-circuit measurements with similar days on which tests were not performed.

The Northwest Power and Conservation Council has a measurement and verification procedure that focuses on voltage measurements to quantify program performance (NWPCC, 2010). This involves one week of voltage measurements prior to voltage reduction and then one week of voltage measurements after implementation of improvements and implementing reduced-voltage control. Voltages are measured at regulation points and at the end of the line. This approach assumes that CVR factors are known, and so the main focus is proving voltage reductions, and this is much easier than proving energy savings. CVR factors they assume are based on the NEEA (2007) results as a function of load composition (heating type and whether air conditioning is used) and climate zone.

6.7.2 Equipment Response to Voltage

The load response of a circuit to voltage changes ultimately comes down to the characteristics of the loads on the circuit. Voltage reduction produces the strongest response in energy with resistive loads—the power drawn by a resistive load decreases with the voltage squared. Lighting and resistive heating loads are the dominant resistive loads; these are not quite ideal resistive loads. For example, the power on incandescent lights varies as the voltage to the power of about 1.5—not quite to the power of 2, but close. Residential and commercial loads have higher percentages of resistive load. For water heaters and other devices that regulate to a temperature, reducing voltage does not reduce overall energy usage; the devices just run for longer times. This is likely why CVR factors are lower during the winter when there is significant thermostatically controlled resistive heat.

Table 6.9 shows CVR factors derived from tests of several devices published in EPRI EL-2036 (1981). These are the impact on energy (not power) for each of the devices. The CVR factors are specified for two voltage changes, one from 120 to 115 V (or 240 to 230 V) and the other from 126 to 120 V. The air conditioners and one of the motors had more energy reduction when the initial voltage was higher, suggesting somewhat diminishing returns as voltage is lowered more.

Motors are not strictly constant-power devices. A motor's efficiency and response to voltage depends on mechanical loading. At higher mechanical loading, a motor draws more current and acts more like a constant-power device, so CVR factors are lower. At light mechanical loading, a motor is like a spinning transformer, and efficiency depends strongly on voltage—CVR factors are high in this case. The results for motors in Table 6.9 are based on a mechanical torque of one per unit. For more lightly loaded motors, the CVR factor is higher as shown for one example in Figure 6.21. This graph shows efficiency. The CVR factor is proportional to the slope of the curve at a given operating voltage. At a torque of 0.7 per unit, lowering voltage improves efficiency at all operating voltages. For a torque of 1 per unit, the unit peaks in efficiency between 440 and 460 V, so reducing voltage from 460 V improves efficiency slightly. If this motor is applied on a 480-V system, then any reduction in voltage will improve efficiency, regardless of torque. This EPRI study also showed that the reactive-power consumption of motors was highly dependent on voltage.

Adjustable-speed drives are less sensitive to voltage than induction motors. In unpublished tests by EPRI, a 15-hp induction motor had a CVR factor of 1.7 at 50% loading and 0.92 at 75% loading. The same motor driven by an adjustable speed drive had a CVR factor of 0.3 at 50% loading and 0.2 at 75% loading.

The voltage response of lighting load varies considerably with technology as summarized in Table 6.10. For most lighting technologies, light output varies directly with power input. With lower voltage, power consumption drops, but illumination drops as well. For the fluorescent tubes and a high-pressure sodium vapor light measured in EPRI EL-2036 (1981), as voltage dropped, illumination dropped, but not as

TABLE 6.9 Comparison of Voltage Impact on End-Use Equipment

	CVR Factor	
Device	120 to 115 V	126 to 120 V
30-Btu air conditioner, outside temperature = 115°F	–0.12	0.34
30-Btu air conditioner, outside temperature = 95°F	0.49	0.51
30-Btu air conditioner, outside temperature = 85°F	0.26	0.73
Incandescent lamp	1.51	1.48
Fluorescent lamp	0.72	0.66
Refrigerator	2.28	2.14
3-ph 5-hp induction motor	0.26	0.40
3-ph 15-hp induction motor	0.02	0.00
3-ph 20-hp induction motor	0.02	0.00
Thermostatically controlled resistive heating load	0.00	0.00

Source: EPRI EL-2036 (1981).

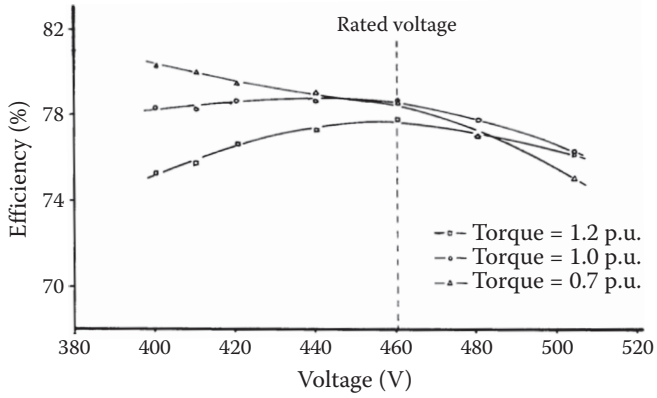

Figure 6.21 Impact of voltage and torque on a 5-hp motor. (From Electric Power Research Institute. EL-2036, *Effects of Reduced Voltage on the Operation and Efficiency of Electric Loads*. Copyright © 1991. Reprinted with permission.)

fast as consumption, so the fixture's overall efficiency at turning electricity into light improved. With incandescent bulbs, lower voltage offers longer filament life because of cooler operation.

Seasonal effects are often pronounced with voltage reduction. Thermostatically controlled electric heating has a near-zero CVR factor because heaters run longer to make up for reduced output. Because air conditioning makes up such a large portion of summer load, understanding this device is particularly important. As noted in the tests shown in Table 6.9, the response of air conditioners to voltage depends on the outside temperature. Recent tests by EPRI (not yet published) found similar results with

TABLE 6.10 CVR Factors for Various Lighting Technologies

Technology	CVR Factor	Source
Residential		
Incandescent bulbs	1.50	EPRI EL-2036 (1981)
Incandescent bulbs	1.50	PNNL (2010)
Compact fluorescent lamps	0.81	PNNL (2010)
Compact fluorescent lamps	0.76	EPRI unpublished
LED lamps	−0.11	PNNL (2010)
LED lamps	−0.02	EPRI unpublished
Commercial		
Fluorescent tubes with electronic ballasts	−0.07	EPRI unpublished
Fluorescent tubes with magnetic ballasts	0.72	EPRI EL-2036 (1981)
400-W MH street light	0.04	EPRI EL-2036 (1981)
400-W HPS street light	0.64	EPRI EL-2036 (1981)
HPS and MH with magnetic ballasts	1.20	EPRI unpublished
HPS with electronic ballasts	−0.03	EPRI unpublished
MH with electronic ballasts	−0.04	EPRI unpublished

MH = metal halide; HPS = high-pressure sodium.

modern units. At higher outside temperatures, the air conditioner compressor must work harder. This matches loading results for induction motors: lightly loaded motors have higher CVR factors. In many locations, air conditioners will spend most of their operating time in the lower temperature regions where CVR factors tend to be higher.

Power electronic devices generally have low CVR factors. In tests of two computer power supplies tested by EPRI (unpublished), the CVR factor averaged −0.03. Similar tests on LCD, LED, and plasma televisions showed average CVR factors that were just slightly negative. PNNL (2010) also reported slightly negative CVR factors for LCD and plasma displays.

The results in Table 6.9 for air conditioners do not completely explain the seasonal effects found in field trials. In addition to operating more efficiently at reduced voltage, air conditioning load performs better because reducing voltage reduces waste heat generation in a building. Almost all electrical load generates heat as a by-product of operation. Incandescent lamps convert over 95% of electricity to heat. Even compact fluorescent lamps convert over 80% of electricity to heat. Almost any appliance generates mostly heat from electricity. Reducing voltage helps reduce the amount of heat that an air conditioner has to remove from a building. Air conditioner efficiency plays a role here, too. Older, less efficient air conditioners must use more electricity to remove this waste heat.

During the winter, the opposite effect happens: CVR factors are lower because less waste heat is produced in the building with reduced voltage. Thermostatically controlled electric heat runs longer to make up for the waste heat. With resistive heating, every watt-hour of waste heat reduced will be replaced by a watt-hour of resistive heating. Heat pumps are not as bad because a heat pump can more efficiently supply this extra heat for the building. This effect helps explain the results discussed in the previous section where Hydro Quebec has very low winter CVR factors due to electric heating loads.

The no-load losses in distribution transformers are quite sensitive to voltage. From data measured on no-load losses on four distribution transformers EPRI EL-2036 (1981), the average CVR factor was 2.1 for a voltage change from 120 to 115 V. For a voltage change from 126 V to 120 V, the CVR factor was 2.7.

As load compositions change in the future, reduced consumption with lowered voltages will likely decrease. More modern technologies are not as sensitive to voltage. Electronic power supplies often do not change output with voltage (CVR factor = 0). Compact fluorescent lights have lower CVR factors than incandescents, and LEDs have a CVR factor close to zero. LCD monitors have lower CVR factors than cathode-ray tube monitors. Adjustable-speed drives are less sensitive to voltage than induction motors. Improvements in efficiency also diminish savings from voltage reduction.

6.7.3 Approaches to Voltage Optimization

Voltage reduction works best on short feeders—those that do not have much voltage drop. On these, we can control reduction just through adjustments of the station LTC regulator settings. It is straightforward to set up a system where operators can change

the station set voltage through SCADA. On longer circuits, we need extra measures. Some strategies include

- *Extra regulators*—Extra regulators can help flatten the voltage profile along the circuit. Each regulator is set with a set voltage and compensation settings appropriate for a tighter voltage range. This approach is most appropriate for energy conservation. Controlling the regulators to provide peak shaving is difficult; the communications and controls add significantly to the cost.
- *Feeder capacitors*—The vars injected by capacitors help flatten the voltage profile and allow a lower set voltage on the station LTC. On many circuits, just fixed capacitors can flatten the profile enough to reduce the station set voltage. McCarthy (2000) reported how Georgia Power used this strategy to reduce peak loads by 500 kW on circuits averaging approximately 18 MW.
- *Tighter bandwidth*—With a smaller regulator bandwidth, the voltage spread on the circuit is smaller. A smaller bandwidth requires more frequent regulator or LTC maintenance (the regulator changes taps more often) but not drastic differences. Kirshner (1990) reported that reducing the bandwidth from 3 to 1.5 V doubled the number of regulator tap changes.
- *Aggressive line-drop compensation*—An aggressive line-drop compensation scheme can try to keep the voltage at the low end (say, at 114 V) for the last customer at all times. The set voltage in the station may be 115 to 117 V, depending on the circuit voltage profile. Aggressive compensation boosts the voltage during heavy loads, while trying to keep voltages low at the ends of circuits. During lighter loads, the station voltage may drop under 120 V. This strategy helps the least at heavy load periods, so it is more useful for energy conservation than for peak shaving. Aggressive compensation makes low voltages more likely at the end of circuits. If any of the planning assumptions are wrong, especially power factor and load placement, customers at the end of circuits can have low voltages.
- *Phase balancing*—Sometimes, one phase can be the limiting factor. Improving phase balance can help balance voltage drop across phases and allow more overall voltage reduction.
- *Circuit reconfigurations*—Some reconfigurations can help reduce voltage bottlenecks.
- *Others*—Other voltage profile improvement options help when implementing a voltage reduction program, although some of these options, such as reconductoring, undergrounding, and increasing primary voltage levels, are quite expensive.

For an LTC-controlled bus, sometimes just one feeder limits reduction that is possible for the whole bus. Targeting improvements on that feeder can allow more voltage reduction.

Many of these circuit enhancements reduce losses along with improving voltage profiles. Improving voltage profiles allows greater reduction of circuit voltage, which improves end-use efficiency and reduces overall consumption. In the Green Circuits project, improvement options in combination with voltage reduction were evaluated on several circuits (EPRI 1023518, 2011; Rylander et al., 2012). An economic analysis found

- Voltage reduction provides significant economic benefit.
- Additional circuit improvements are often economical.

- Cost and efficiency of combination options generally add linearly.
- High-load circuits have the best project viability.

Note that in this economic analysis, lost billing from kilowatt hours was not taken into account. This is a complicated topic. Changes to traditional billing strategies to account for lost revenue may help advance adoption of voltage reduction.

Table 6.11 illustrates the annual levelized cost and the benefit-to-cost ratio for several improvement projects analyzed for each circuit (EPRI 1023518, 2011; Rylander et al., 2012). Multiple projects were tested under each category. As noted, project benefits strongly depend on circuit loading: the levelized cost for voltage reduction alone decreased as annual energy use increased. In all cases, the base voltage reduction had favorable benefit-to-cost ratios. Often, phase balancing and var optimization improved benefit-to-cost ratios. Phase balancing, reactive power optimization, reconductoring, and additional voltage regulation then slightly shifted the levelized cost based on additional project cost and energy savings. For the three circuits with the highest consumption and lowest levelized cost for voltage reduction (Circuit A, Circuit B, and Circuit F), even reconductoring became an economically acceptable option. The significant decrease in levelized cost for the reactive power optimization project on Circuit D was a result of low project cost due to the salvage value from the removal of three 1200-kvar pad-mounted capacitor banks used for transmission system support.

TABLE 6.11 Economic Comparisons of Improvement Options

	Circuit					
	F	B	A	C	E	D
Peak Demand, MW	29.0	15.0	13.0	7.1	5.7	5.7
Benefit-To-Cost Ratio						
Base voltage reduction	29.9	17.6	8.1	3.5	3.6	1.8
Phase balancing	25.2	17.0	9.8	3.9	3.4	2.3
Var optimization	29.0	17.2	9.5	3.3	3.1	4.1
Reconductoring	15.6	2.4	4.7	0.2	0.7	0.4
Voltage regulators	22.4				3.1	
Combinations	5.3	10.8	11.3	3.8	2.1	1.2
Annual Levelized Cost, ¢/kWh						
Base voltage reduction	0.3	0.6	1.1	2.3	2.8	5.4
Phase balancing	0.4	0.6	0.9	2.3	2.9	4.4
Var optimization	0.3	0.6	0.9	2.5	3.0	2.3
Reconductoring	0.6	4.1	2.0	47.3	14.0	24.1
Voltage regulators	0.4				3.2	
Combinations	1.7	0.9	0.8	2.4	4.6	8.8

Source: Data from EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011.

There are several ways to use the results of the efficiency/economic analysis to optimize performance. Options can include

- *Highest benefit-to-cost ratio*—Pick the option or combination of options with the highest overall benefit-to-cost ratio. Combination options that target unique efficiency areas approximately add linearly with respect to total cost and energy savings.
- *Incremental benefit-to-cost ratio greater than one*—Pick an option whose incremental benefit-to-cost ratio is greater than one. This maximizes return on incremental investment for project components.
- *Largest efficiency benefit*—Pick the option or combination of options that saves the most energy. Even though this may have a lower benefit-to-cost ratio, it squeezes the most efficiency out of the system. This is most applicable for a distribution company that can effectively sell its kilowatt-hour savings to an efficiency group. By extracting the most from this distribution resource, more is invested in the distribution system.

The most appropriate strategy will depend on the utility's goals, regulations, incentive programs, billing, and more.

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Regs? Treat them with respect. They are a transformer. Anyone who has dropped load with a tx knows that you can build a fire if you dont take the load into consideration. The difference with regs is that the load is the feeder. Get it?

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7

Capacitor Application

Contents

7.1 Capacitor Ratings 323
7.2 Benefits of Distribution Capacitors 326
7.2.1 Released Capacity and Voltage Support 326
7.2.2 Reducing Line Losses 329
7.3 Switched Banks and Automation 334
7.3.1 Local Controls 335
7.3.2 Remote, Automated Controls 337
7.4 Volt-Var Engineering and Control 339
7.5 Reliability and Failure Modes 342
7.6 Fusing and Protection 346
7.6.1 Outrush and Other Transients 350
7.6.2 Fusing Guidelines 355
7.6.3 Mechanical and Thermal Issues with Cutouts 358
7.6.4 Neutral Monitoring 361
7.7 Grounding 362
References 364

Capacitors provide tremendous benefits to distribution system performance. Most noticeably, capacitors reduce losses, free up capacity, and reduce voltage drop:

- *Losses; Capacity*—By canceling the reactive power to motors and other loads with low power factor, capacitors decrease the line current. Reduced current frees up capacity; the same circuit can serve more load. Reduced current also significantly lowers the I^2R line losses.
- *Voltage drop*—Capacitors provide a voltage boost, which cancels part of the drop caused by system loads. Switched capacitors can regulate voltage on a circuit.

If applied properly and controlled, capacitors can significantly improve the performance of distribution circuits. But if not properly applied or controlled, the reactive power from capacitor banks can create losses and high voltages. The greatest danger of overvoltages occurs under light load. Good planning helps ensure that capacitors are sited properly. More sophisticated controllers (like two-way radios with monitoring) reduce the risk of improperly controlling capacitors, compared to simple controllers (like a time clock).

Capacitors work their magic by storing energy. Capacitors are simple devices: two metal plates sandwiched around an insulating dielectric. When charged to a given voltage, opposing charges fill the plates on either side of the dielectric. The strong

attraction of the charges across the very short distance separating them makes a tank of energy. Capacitors oppose changes in voltage; it takes time to fill up the plates with charge, and once charged, it takes time to discharge the voltage.

On ac power systems, capacitors do not store their energy very long—just one-half cycle. Each half cycle, a capacitor charges up and then discharges its stored energy back into the system. The net real power transfer is zero. Capacitors provide power just when reactive loads need it. Just when a motor with low power factor needs power from the system, the capacitor is there to provide it. Then, in the next half cycle, the motor releases its excess energy, and the capacitor is there to absorb it. Capacitors and reactive loads exchange this reactive power back and forth. This benefits the system because that reactive power (and extra current) does not have to be transmitted from the generators all the way through many transformers and many miles of lines; the capacitors can provide the reactive power locally. This frees up the lines to carry real power, power that actually does work.

Capacitor units are made of series and parallel combinations of capacitor packs or elements put together as shown in Figure 7.1. Capacitor elements have sheets of polypropylene film, less than 1 mil thick, sandwiched between aluminum foil sheets. Capacitor dielectrics must withstand on the order of 2000 V/mil (78 kV/mm). No other medium-voltage equipment has such high voltage stress. An underground cable for a 12.47-kV system has insulation that is at least 0.175 in. (4.4 mm) thick. A capacitor on the same system has an insulation separation of only 0.004 in. (0.1 mm).

Utilities often install substation capacitors and capacitors at points on distribution feeders. Most feeder capacitor banks are pole mounted, the least expensive way to install distribution capacitors. Pole-mounted capacitors normally provide 300 to 3600 kvar at each installation. Many capacitors are switched, either based on a local controller or from a centralized controller through a communication medium. A line capacitor installation has the capacitor units as well as other components, possibly

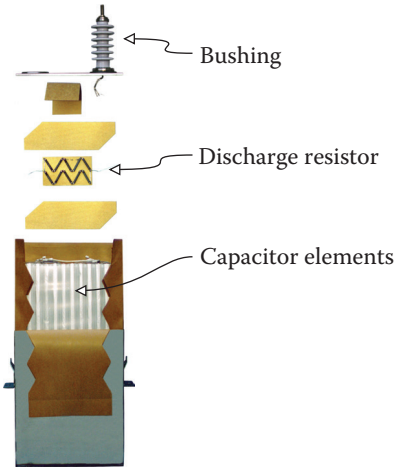

Figure 7.1 Capacitor components. (From General Electric, *Case Rupture Curves*, 2001. Downloaded from http://www.geindustrial.com. With permission.)

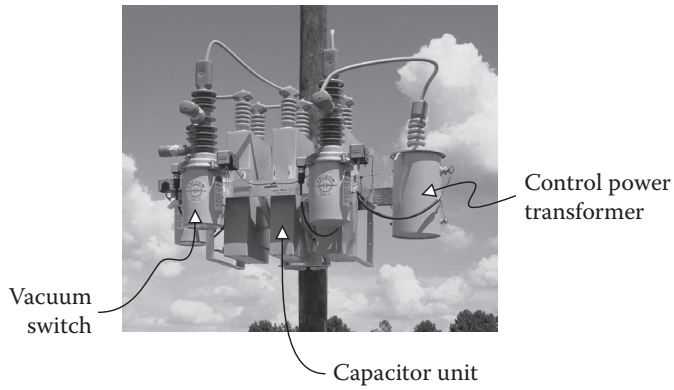

Figure 7.2 Overhead line capacitor installation. (From Cooper Power Systems, *Electrical Distribution—System Protection*, 3rd ed., 1990. With permission.)

including arresters, fuses, a control power transformer, switches, and a controller (see Figure 7.2 for an example).

While most capacitors are pole mounted, some manufacturers provide padmounted capacitors. As more circuits are put underground, the need for padmounted capacitors will grow. Padmounted capacitors contain capacitor cans, switches, and fusing in a deadfront package following standard padmounted-enclosure integrity requirements (ANSI C57.12.28-1998). These units are much larger than padmounted transformers, so they must be sited more carefully to avoid complaints due to aesthetics. The biggest obstacles are cost and aesthetics. The main complaint is that padmounted capacitors are large. Customers complain about the intrusion and the aesthetics of such a large structure (see Figure 7.3).

Substation capacitors are normally offered as open-air racks. Normally elevated to reduce the hazard, individual capacitor units are stacked in rows to provide

Figure 7.3 Example padmounted capacitor. (From Northeast Power Systems, Inc. With permission.)

large quantities of reactive power. All equipment is exposed. Stack racks require a large substation footprint and are normally engineered for the given substation. Manufacturers also offer metal-enclosed capacitors, where capacitors, switches, and fuses (normally current-limiting) are all enclosed in a metal housing.

Substation capacitors and feeder capacitors both have their uses. Feeder capacitors are closer to the loads—capacitors closer to loads more effectively release capacity, improve voltage profiles, and reduce line losses. This is especially true on long feeders that have considerable line losses and voltage drop. Table 7.1 highlights some of the differences between feeder and station capacitors. Substation capacitors are better when more precise control is needed. System operators can easily control substation capacitors wired into a SCADA system to dispatch vars as needed. Modern communication and control technologies applied to feeder capacitors have reduced this advantage. Operators can control feeder banks with communications just like station banks, although some utilities have found the reliability of switched feeder banks to be less than desired, and the best times for switching in vars needed by the system may not correspond to the best time to switch the capacitor in for the circuit it is located on.

Substation capacitors may also be desirable if a leading power factor is needed for voltage support. If the power factor is leading, moving this capacitor out on the feeder increases losses. Substation capacitors cost more than feeder capacitors. This may seem surprising, but we must individually engineer station capacitors, and the space they take up in a station is often valuable real estate. Pole-mounted capacitor installations are more standardized. Many utilities use distribution feeder capacitors for transmission level support (EPRI 1002154, 2004). These capacitors can be applied at locations that are optimal for distribution voltage support and losses (generally on the outer portions of circuits), or if they are not needed for distribution support, they can be applied near the substation.

Utilities normally apply capacitors on three-phase sections. Applications on single-phase lines are done but less common. Application of three-phase banks downstream of single-phase protectors is normally not done because of ferroresonance concerns. Most three-phase banks are connected grounded wye on four-wire multigrounded circuits. Some are connected as floating wye. On three-wire circuits, banks are normally connected as floating wye.

TABLE 7.1 Substation versus Feeder Capacitors

Advantages	Disadvantages
Feeder Capacitors	
Reduces line losses	More difficult to control reliably
Reduces voltage drop along the feeder	Size and placement important
Frees up feeder capacity	
Lower cost	
Substation Capacitors	
Better control	No reduction in line losses
Best placement if leading vars are needed for system voltage support	No reduction in feeder voltage drop
	Higher cost

Most utilities also include arresters and fuses on capacitor installations. Arresters protect capacitor banks from lightning overvoltages. Fuses isolate failed capacitor units from the system and clear the fault before the capacitor fails violently. In high fault-current areas, utilities may use current-limiting fuses. Switched capacitor units normally have oil or vacuum switches in addition to a controller. Depending on the type of control, the installation may include a control power transformer for power and voltage sensing and possibly a current sensor. Because a capacitor bank has a number of components, capacitors normally are not applied on poles with other equipment.

Properly applied capacitors return their investment very quickly. Capacitors save significant amounts of money in reduced losses. In some cases, reduced loadings and extra capacity can also delay building more distribution infrastructure.

7.1 Capacitor Ratings

Capacitor units rated from 50 to over 500 kvar are available; Table 7.2 shows the common capacitor unit ratings. A capacitor's rated kvar is the kvar at rated voltage. Three-phase capacitor banks are normally referred to by the total kvar on all three phases. Distribution feeder banks normally have one or two or (more rarely) three units per phase. Many common size banks only have one capacitor unit per phase.

TABLE 7.2 Common Capacitor Unit Ratings

Volts, rms (Terminal-to-Terminal)	kvar	Number of Phases	BIL, kV
216	5, 7 1/2, 13 1/3, 20, and 25	1 and 3	30
240	2.5, 5, 7 1/2, 10, 15, 20, 25, and 50	1 and 3	30
480, 600	5, 10, 15, 20, 25, 35, 50, 60, and 100	1 and 3	30
2400	50, 100, 150, 200, 300, and 400	1 and 3	75, 95, 125, 150, and 200
2770	50, 100, 150, 200, 300, 400, and 500	1 and 3	75, 95, 125, 150, and 200
4160, 4800	50, 100, 150, 200, 300, 400, 500, 600, 700, and 800	1 and 3	75, 95, 125, 150, and 200
6640, 7200, 7620, 7960, 8320, 9540, 9960, 11,400, 12,470, 13,280, 13,800, 14,400	50, 100, 150, 200, 300, 400, 500, 600, 700, and 800	1	95, 125, 150, and 200
15,125	50, 100, 150, 200, 300, 400, 500, 600, 700, and 800	1	125, 150, and 200
19,920	100, 150, 200, 300, 400, 500, 600, 700, and 800	1	125, 150, and 200
20,800, 21,600, 22,800, 23,800, 24,940	100, 150, 200, 300, 400, 500, 600, 700, and 800	1	150 and 200

Source: Adapted from IEEE Std. 18-2002, IEEE Standard for Shunt Power Capacitors. Copyright 2002 IEEE.

IEEE Std. 18 defines standards for capacitors and provides application guidelines. Capacitors should not be applied when any of the following limits are exceeded (IEEE Std. 18-2002):

- 135% of nameplate kvar (kvar can be higher than nameplate because of voltages above nominal and harmonics)
- 110% of rated rms voltage, and crest voltage not exceeding $1.2\sqrt{2}$ of rated rms voltage, including harmonics but excluding transients
- 135% of nominal rms current based on rated kvar and rated voltage

Capacitor dielectrics must withstand high voltage stresses during normal operation—on the order of 2000 V/mil. Capacitors are designed to withstand overvoltages for short periods of time. IEEE Std. 18-1992 allows up to 300 power-frequency overvoltages within the time durations in Table 7.3 (without transients or harmonic content). New capacitors are tested with at least a 10-sec overvoltage, either a dc-test voltage of 4.3 times rated rms or an ac voltage of twice the rated rms voltage (IEEE Std. 18-2002).

Capacitors should withstand various peak voltage and current transients; the allowable peak depends on the number of transients expected per year (see Table 7.4).

The capacitance of a unit in microfarads is

$$C_{\text{uF}} = \frac{2.65Q_{\text{kvar}}}{V_{\text{kV}}^2}$$

where

V_{kV} = capacitor voltage rating, kV

Q_{kvar} = unit reactive power rating, kvar

Capacitors are made within a given tolerance. The IEEE standard allows reactive power to range between 100% and 110% when applied at rated sinusoidal voltage and

TABLE 7.3 Maximum Permissible Power-Frequency Voltages

Duration	Maximum Permissible Voltage (Multiplying Factor to Be Applied to Rated Voltage rms)
6 cycles	2.20
15 cycles	2.00
1 sec	1.70
15 sec	1.40
1 min	1.30
30 min	1.25
Continuous	1.10

Source: Adapted from ANSI/IEEE Std. 18-1992, IEEE Standard for Shunt Power Capacitors. Copyright 1993 IEEE.

TABLE 7.4 Expected Transient Overcurrent and Overvoltage Capability

Probable Number of Transients per Year	Permissible Peak Transient Current (Multiplying Factor to be Applied to Rated rms Current)	Permissible Peak Transient Voltage (Multiplying Factor to be Applied to Rated rms Voltage)
4	1500	5.0
40	1150	4.0
400	800	3.4
4000	400	2.9

Source: Adapted from ANSI/IEEE Std. 18-1992, IEEE Standard for Shunt Power Capacitors. Copyright 1993 IEEE.

frequency (at 25°C case and internal temperature) (IEEE Std. 18-2002). Older units were allowed to range up to 115% (ANSI/IEEE Std. 18-1992). Therefore, the capacitance must also be between 100% and 110% of the value calculated at rated kvar and voltage. In practice, most units are from +0.5% to +4.0%, and a given batch is normally very uniform.

Capacitor losses are typically on the order of 0.07 to 0.15 W/kvar at nominal frequency. Losses include resistive losses in the foil, dielectric losses, and losses in the internal discharge resistor.

Capacitors must have an internal resistor that discharges a capacitor to 50 V or less within 5 min when the capacitor is charged to the peak of its rated voltage ($\sqrt{2}V_{\text{rms}}$). This resistor is the major component of losses within a capacitor. The resistor must be low enough such that the *RC* time constant causes it to decay in 300 sec as

$$\frac{50}{\sqrt{2}V} \leq e^{-300/RC}$$

where

V = capacitor voltage rating, V
R = discharge resistance, Ω
C = capacitance, F

So, the discharge resistor must continually dissipate at least the following power in watts:

$$P_{\text{watts}} = -\frac{Q_{\text{kvar}}}{113.2}\ln\left(\frac{35.36}{V}\right)$$

where Q_{kvar} is the capacitor rating (single or three phase). For 7.2-kV capacitors, the lower bound on losses is 0.047 W/kvar.

Some utilities use a shorting bar across the terminals of capacitors during shipping and in storage. The standard recommends waiting for 5 min to allow the capacitor to discharge through the internal resistor before handling.

TABLE 7.5 Maximum Ambient Temperatures for Capacitor Application

Mounting Arrangement	Ambient Air Temperature (°C) 4-hour Average[a]
Isolated capacitor	46
Single row of capacitors	46
Multiple rows and tiers of capacitors	40
Metal-enclosed or metal-housed equipment	40

Source: Adapted from IEEE Std. 18-2002, IEEE Standard for Shunt Power Capacitors. Copyright 2002 IEEE.

[a]The arithmetic average of the four consecutive highest hourly readings during the hottest day expected at that location.

Capacitors have very low losses, so they run very cool. But capacitors are very sensitive to temperature and are rated for lower temperatures than other power system equipment such as cables or transformers. Capacitors do not have load cycles like transformers; they are always at full load. Also, capacitors are designed to operate at high dielectric stresses, so they have less margin for degraded insulation. Standards specify an upper limit for application of 40°C or 46°C depending on arrangement (see Table 7.5). These limits assume unrestricted ventilation and direct sunlight. At the lower end, IEEE standard 18 specifies that capacitors shall be able to operate continuously in a −40°C ambient.

7.2 Benefits of Distribution Capacitors

7.2.1 Released Capacity and Voltage Support

In addition to reducing losses and improving voltage, capacitors release capacity. Improving the power factor increases the amount of real-power load the circuit can supply. Using capacitors to supply reactive power reduces the amount of current in the line, so a line of a given ampacity can carry more load. Figure 7.4 shows that capacitors release significant capacity, especially if the original power factor is low. Figure 7.5 shows another way to view the extra capacity, as a function of the size of capacitor added.

Capacitors are constant-impedance devices. At higher voltages, capacitors draw more current and produce more reactive power as

$$I = I_{\text{rated}} V_{\text{pu}} \quad \text{and} \quad Q_{\text{kvar}} = Q_{\text{rated}} V_{\text{pu}}^2$$

where V_{pu} is the voltage in per unit of the capacitor's voltage rating. Capacitors applied at voltages other than their rating provide vars in proportion to the per-unit voltage squared.

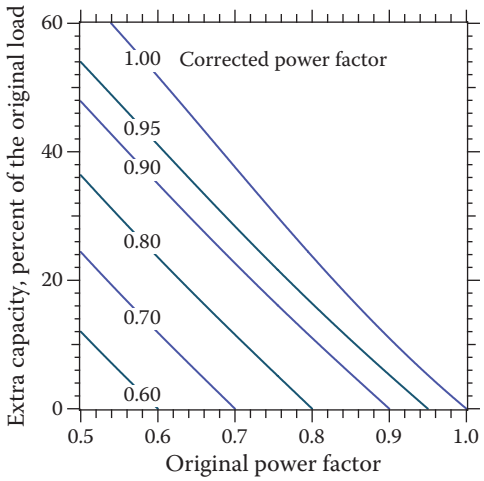

Figure 7.4 Released capacity with improved power factor.

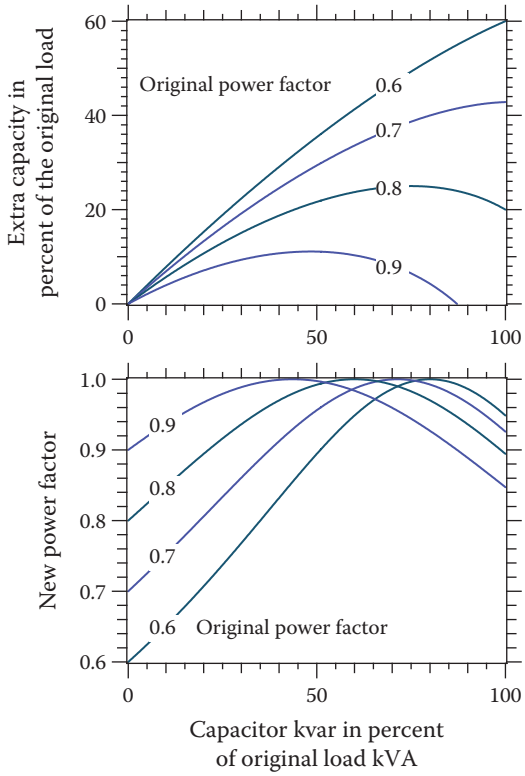

Figure 7.5 Extra capacity as a function of capacitor size.

Capacitors provide almost a fixed voltage rise. The reactive current through the system impedance causes a voltage rise in percent of

$$V_{\text{rise}} = \frac{Q_{\text{kvar}} X_L}{10\ V_{\text{kV,l–l}}^2}$$

where

X_L = positive-sequence system impedance from the source to the capacitor, Ω
$V_{\text{kV,l–l}}$ = line-to-line system voltage, kV
Q_{kvar} = three-phase bank rating, kvar

While this equation is very good for most applications, it is not exactly right because the capacitive current changes in proportion to voltage. At a higher operating voltage, a capacitor creates more voltage rise than the equation predicts.

Since the amount of voltage rise is dependent on the impedance upstream of the bank, to get the voltage boost along the entire circuit, put the capacitor at the end of the circuit. The best location for voltage support depends on where the voltage support is needed. Figure 7.6 shows how a capacitor changes the voltage profile along a circuit. Unlike a regulator, a capacitor changes the voltage profile upstream of the bank.

Table 7.6 shows the percentage voltage rise from capacitors for common conductors at different voltages. This table excludes the station transformer impedance but still provides a useful approximation. Inductance does not change much with conductor size; the voltage change stays the same over a wide range of conductor sizes.

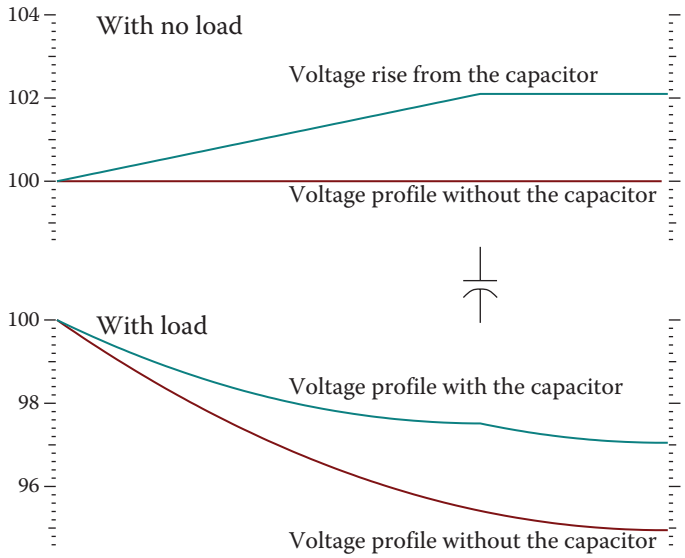

Figure 7.6 Voltage profiles after addition of a capacitor bank. (From EPRI 1001691, *Improved Reliability of Switched Capacitor Banks and Capacitor Technology*, Electric Power Research Institute, Palo Alto, CA, 2002. Copyright 2002. Reprinted with permission.)

TABLE 7.6 Percent Voltage Rise for Various Conductors and Voltage Levels

		Percent Voltage Rise per Mile with 100 kvar per Phase			
		Line-to-Line System Voltage, kV			
Conductor Size	X_L Ω/mi	4.8	12.47	24.9	34.5
4	0.792	1.031	0.153	0.038	0.020
2	0.764	0.995	0.147	0.037	0.019
1/0	0.736	0.958	0.142	0.036	0.019
4/0	0.694	0.903	0.134	0.034	0.017
350	0.656	0.854	0.127	0.032	0.017
500	0.635	0.826	0.122	0.031	0.016
750	0.608	0.791	0.117	0.029	0.015

Note: Impedances are for all-aluminum conductors with GMD = 4.8 ft.

For 15-kV class systems, capacitors increase the voltage by about 0.12% per mi per 100 kvar per phase.

On switched capacitor banks, the voltage change constrains the size of banks at some locations. Normally, utilities limit the voltage change to 3 to 4%. On a 12.47-kV circuit, a three-phase 1200-kvar bank boosts the voltage 4% at about 8 mi (5 km) from the substation. To keep within a 4% limit, 1200-kvar banks must only be used within the first 8 mi (5 km) of the station.

7.2.2 Reducing Line Losses

One of the main benefits of applying capacitors is that they can reduce distribution line losses. Losses come from current through the resistance of conductors. Some of that current transmits real power, but some flows to supply reactive power. Reactive power provides magnetization for motors and other inductive loads. Reactive power does not spin kWh meters and performs no useful work, but it must be supplied. Using capacitors to supply reactive power reduces the amount of current in the line. Since line losses are a function of the current squared, I^2R, reducing reactive power flow on lines significantly reduces losses.

Engineers widely use the "2/3 rule" for sizing and placing capacitors to optimally reduce losses. Neagle and Samson (1956) developed a capacitor placement approach for uniformly distributed lines and showed that the optimal capacitor location is the point on the circuit where the reactive power flow equals half of the capacitor var rating. From this, they developed the 2/3 rule for selecting and placing capacitors. For a uniformly distributed load, the optimal size capacitor is 2/3 of the var requirements of the circuit. The optimal placement of this capacitor is 2/3 of the distance from the substation to the end of the line. For this optimal placement for a uniformly distributed load, the substation source provides vars for the first 1/3 of the circuit, and the capacitor provides vars for the last 2/3 of the circuit (see Figure 7.7).

A generalization of the 2/3 rule for applying n capacitors to a circuit is to size each one to $2/(2n + 1)$ of the circuit var requirements. Apply them equally spaced, starting

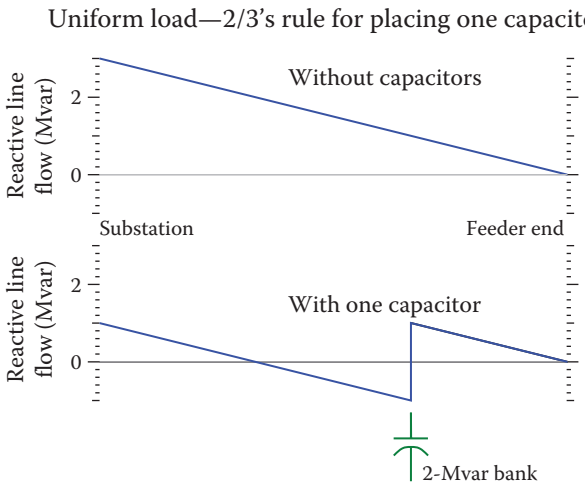

Figure 7.7 Optimal capacitor loss reduction using the two-thirds rule. (From EPRI 1001691, *Improved Reliability of Switched Capacitor Banks and Capacitor Technology*, Electric Power Research Institute, Palo Alto, CA, 2002. Copyright 2002. Reprinted with permission.)

at a distance of $2/(2n + 1)$ of the total line length from the substation and adding the rest of the units at intervals of $2/(2n + 1)$ of the total line length. The total vars supplied by the capacitors is $2n/(2n + 1)$ of the circuit's var requirements. So, to apply three capacitors, size each to 2/7 of the total vars needed, and locate them at per-unit distances of 2/7, 4/7, and 6/7 of the line length from the substation.

Grainger and Lee (1981) provide an optimal yet simple method for placing fixed capacitors on a circuit with any load profile, not just a uniformly distributed load. With the Grainger/Lee method, we use the reactive load profile of a circuit to place capacitors. The basic idea is again to locate banks at points on the circuit where the reactive power equals one half of the capacitor var rating. With this 1/2-kvar rule, the capacitor supplies half of its vars downstream, and half are sent upstream. The basic steps of this approach are

1. *Pick a size*—Choose a standard size capacitor. Common sizes range from 300 to 1200 kvar, with some sized up to 2400 kvar. If the bank size is 2/3 of the feeder requirement, we only need one bank. If the size is 1/6 of the feeder requirement, we need five capacitor banks.
2. *Locate the first bank*—Start from the end of the circuit. Locate the first bank at the point on the circuit where var flows on the line are equal to half of the capacitor var rating.
3. *Locate subsequent banks*—After a bank is placed, re-evaluate the var profile. Move upstream until the next point where the var flow equals half of the capacitor rating. Continue placing banks in this manner until no more locations meet the criteria.

There is no reason as to why we have to stick with the same size of banks. We could place a 300-kvar bank where the var flow equals 150 kvar, then apply a 600-kvar bank where the var flow equals 300 kvar, and finally apply a 450-kvar bank where the var

flow equals 225 kvar. Normally, it is more efficient to use standardized bank sizes, but different size banks at different portions of the feeder might help with voltage profiles.

The 1/2-kvar method works for any section of the line. If a line has major branches, we can apply capacitors along the branches using the same method. Start at the end, move upstream, and apply capacitors at points where the line's kvar flow equals half of the kvar rating of the capacitor. It also works for lines that already have capacitors (it does not optimize the placement of all of the banks, but it optimizes placement of new banks). For large industrial loads, the best location is often going to be right at the load.

Figure 7.8 shows the optimal placement of 1200-kvar banks on an example circuit. Since the end of the circuit has reactive load above the 600-kvar threshold for sizing 1200-kvar banks, we apply the first capacitor at the end of the circuit. (The circuit at the end of the line could be one large customer or branches off the main line.) The second bank goes near the middle. The circuit has an express feeder near the start. Another 1200-kvar bank could go in just after the express feeder, but that does not buy us anything. The two capacitors total 2400 kvar, and the feeder load is 3000 kvar. We really need another 600-kvar capacitor to zero out the var flow before it gets to the express feeder.

Fortunately, capacitor placement and sizing does not have to be exact. Quite good loss reduction occurs even if sizing and placement are not exactly optimum. Figure 7.9 shows the loss reduction for one fixed capacitor on a circuit with a uniform load. The 2/3 rule specifies that the optimum distance is 2/3 of the distance from the substation

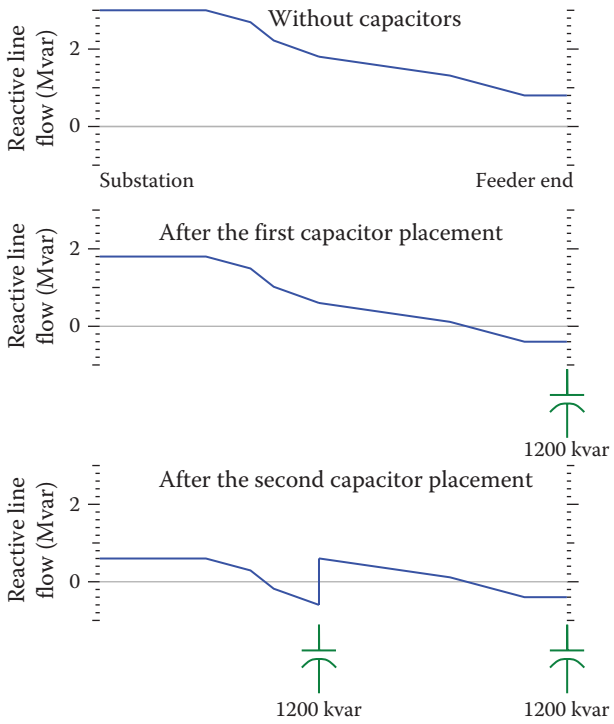

Figure 7.8 Placement of 1200-kvar banks using the 1/2-kvar method.

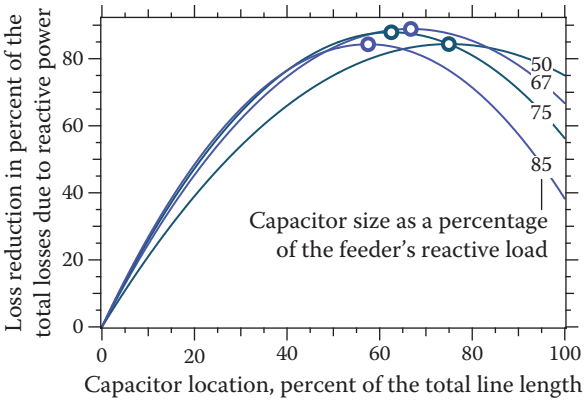

Figure 7.9 Sensitivity to losses of sizing and placing one capacitor on a circuit with a uniform load. (The circles mark the optimum location for each of the sizes shown.)

and 2/3 of the circuit's var requirement. As long as the size and location are somewhat close (within 10%), the not-quite-optimal capacitor placement provides almost as much loss reduction as the optimal placement.

Consider the voltage impacts of capacitors. Under light load, check that the capacitors have not raised the voltages above allowable standards. If voltage limits are exceeded, reduce the size of the capacitor banks or the number of capacitor banks until voltage limits are not exceeded. If additional loss reduction is desired, consider switched banks as discussed below.

Use the average reactive loading profile to optimally size and place capacitors for energy losses. If we use the peak-load case, the 1/2-kvar method optimizes losses during the peak load. If we have a load-flow case with the average reactive load, the 1/2-kvar method or the 2/3 rule optimizes energy losses. This leads to more separation between banks and less kvars applied than if we optimize for peak losses.

If an average system case is not available, then we can estimate it by scaling the peak load case by the reactive load factor, RLF:

$$\text{RLF} = \frac{\text{Average kvar demand}}{\text{Peak kvar demand}}$$

The reactive load factor is similar to the traditional load factor except that it only considers the reactive portion of the load. If we have no information on the reactive load factor, use the total load factor. Normally, the reactive load factor is higher than the total load factor. Figure 7.10 shows an example of power profiles; the real power (kW) fluctuates significantly more than the reactive power (kvar).

Primary line losses vary significantly depending on circuit and loading characteristics. Figure 7.11 shows probability distributions of primary line losses for circuits from the EPRI Green Circuits project. These are based on detailed circuit simulations using annual, 8760-hour-per-year models. Circuits with lower load density and longer lines had the highest losses.

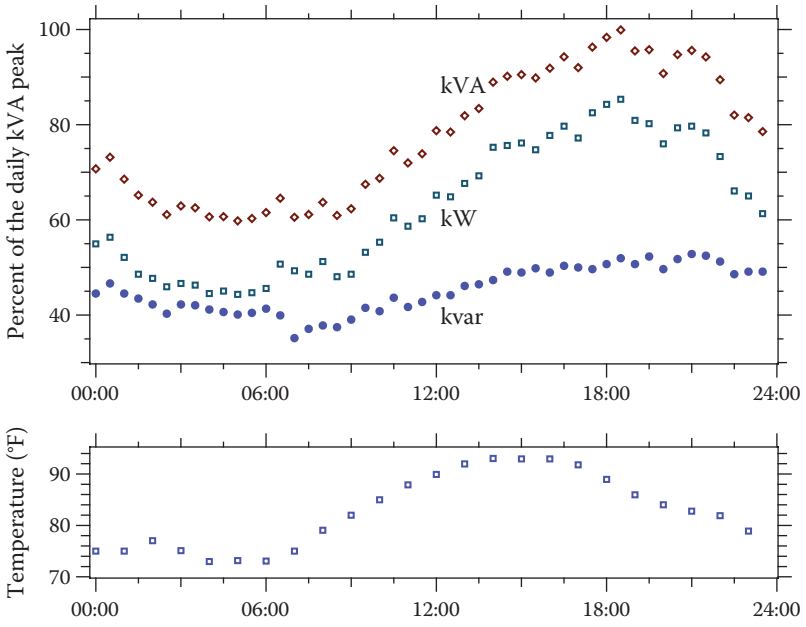

Figure 7.10 Example of real and reactive power profiles on a residential feeder on a peak summer day with 95% air conditioning. (Data from East Central Oklahoma Electric Cooperative, Inc.; RUS 1724D-112, *The Application of Capacitors on Rural Electric Systems*, United States Department of Agriculture, Rural Utilities Service, 2001.)

Most utilities manage reactive power well. Figure 7.12 shows distributions of power factors in the Green Circuits project (Arritt et al., 2012; EPRI 1023518, 2011). Most had only relatively small margins for reduced losses from better application of capacitors. The circuit in this study with the most to gain from better capacitor application had too many fixed capacitors. In this particular case, the circuit power factor was

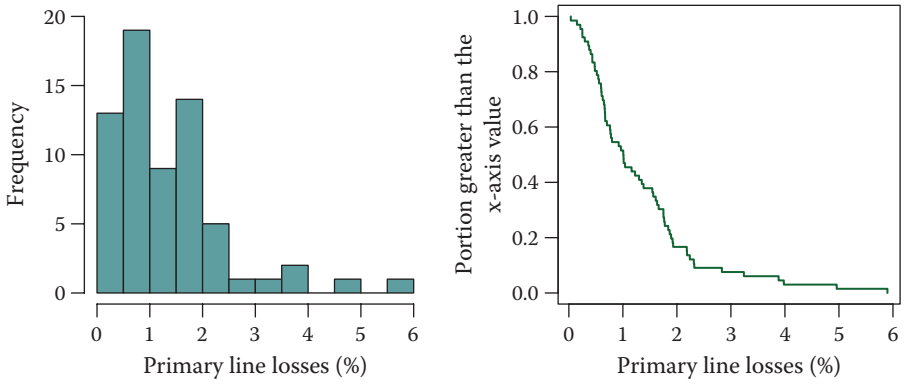

Figure 7.11 Probability distributions of primary line losses from the Green Circuit project. (Adapted from EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011.)

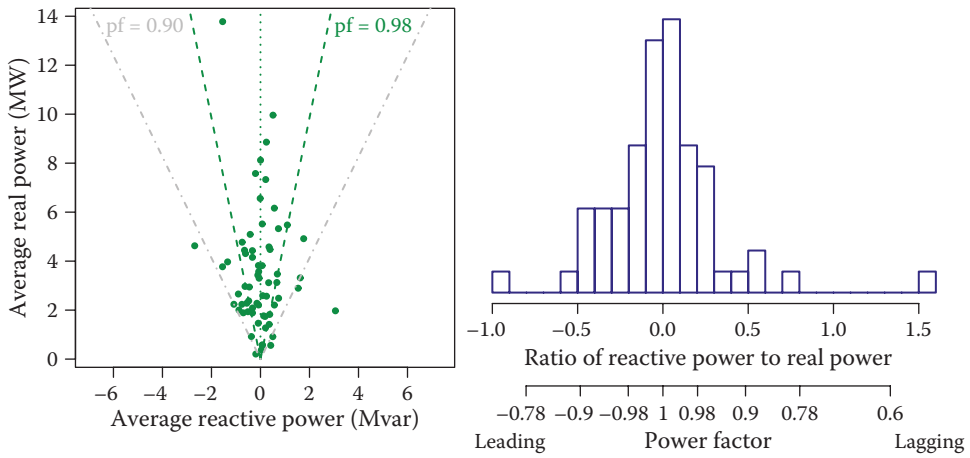

Figure 7.12 Average power factors by circuit. (From EPRI 1023518, *Green Circuits: Distribution Efficiency Case Studies*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright 2011. Reprinted with permission.)

good at peak but operated at an excessively leading power factor for most of the rest of the year. This increases the average current flow on the lines.

7.3 Switched Banks and Automation

Switched banks provide benefits under the following situations:

- *More loss reduction*—As the reactive loading on the circuit changes, we reduce losses by switching banks on and off to track these changes.
- *Voltage limits*—If optimally applied banks under the average loading scenario cause excessive voltage under light load, then use switched banks.

In addition, automated capacitors—those with communications—have the flexibility to also use distribution vars for transmission support.

Fixed banks are relatively easy to site and size optimally. Switched banks are more difficult. Optimally sizing capacitors, placing them, and deciding when to switch them are difficult tasks. Several software packages are available that can optimize this solution. This is an intensely studied area, and technical literature documents several approaches (among these Carlisle and El-Keib, 2000; Grainger and Civanlar, 1985; Shyh, 2000).

To place switched capacitors using the 1/2-kvar method, again place the banks at the location where the line kvar equals half the bank rating. But instead of using the average reactive load profile (the rule for fixed banks), use the average reactive flow during the time the capacitor is on. With time-switched banks and information on load profiles (or typical load profiles), we can pick the on time and the off time

and determine the proper sizing based on the average reactive flow between the on and off times. Or, we can place a bank and pick the on and off times such that the average reactive line flow while the bank is switched on equals half of the bank rating. In these cases, we have specified the size and either the placement or switching time. To more generally optimize—including sizing, placement, number of banks, and switching time—we must use a computer, which iterates to find a solution (see Lee and Grainger (1981) for one example).

Combinations of fixed and switched banks are more difficult. The following approach is not optimal but gives reasonable results. Apply fixed banks to the circuit with the 1/2-kvar rule based on the light-load case. Check voltages. If there are undervoltages, increase the size of capacitors, use more capacitor banks, or add regulators. Now, look for locations suitable for switched banks. Again, use the average reactive line flows for the time when the capacitor is on (with the already-placed fixed capacitors in the circuit model). When applying switched capacitors, check the light-load case for possible overvoltages, and check the peak-load case for undervoltages.

7.3.1 Local Controls

Several options for controls are available for capacitor banks:

- *Time clock*—The simplest scheme: the controller switches capacitors on and off based on the time of day. The on time and the off time are programmable. Modern controllers allow settings for weekends and holidays. This control is the cheapest but also the most susceptible to energizing the capacitor at the wrong time (due to loads being different from those expected, to holidays or other unexpected light periods, and especially to mistakenly set or inaccurate clocks). Time clock control is predictable; capacitors switch on and off at known times and the controller limits the number of switching operations (one energization and one deenergization per day).
- *Temperature*—Another simple control; the controller switches the capacitor bank on or off depending on temperature. Normally, these might be set to turn the capacitors on in the range of 85 to 90°F and turn them off at temperatures somewhere between 75°F and 80°F.
- *Voltage*—The capacitor switches on and off, based on the voltage. The user provides the threshold minimum and maximum voltages as well as time delays and bandwidths to prevent excessive operations. Voltage control is most appropriate when the primary role of a capacitor is voltage support and regulation.
- *Vars*—The capacitor uses var measurements to determine switching. This is the most accurate method of ensuring that the capacitor is on at the appropriate times for maximum reduction of losses.
- *Power factor*—Similar to var control, the controller switches capacitors on and off based on the measured power factor. This is rarely used by utilities.
- *Current*—The capacitor switches on and off based on the line current (as measured downstream of the capacitor). While not as effective as var control, current control does engage the capacitor during heavy loads, which usually corresponds to the highest needs for vars.

Many controllers offer many or all of these possibilities. Many are usable in combination; turn capacitors on for low voltage or for high temperature.

Var, power factor, voltage, or current controllers require voltage or current sensing or both. To minimize cost and complexity, controllers often switch all three phases using sensors on just one phase, normally using the same transformer that provides control power. A control power transformer is often also used to sense voltage. While unusual, Alabama Power switches each phase independently depending on the var requirements of each phase (Clark, 2001); this optimizes loss reduction and helps reduce unbalance. The main disadvantage of independent phase control is increased cost if voltages and currents are all monitored locally on all three phases (there is little difference if switching is done remotely based on substation var measurements). Independent control also increases the complexity of controllers and/or control algorithms. Because capacitor structures are rather busy, some utilities like to use voltage and/or current-sensing insulators. Meter-grade accuracy is not needed for controlling capacitors.

To coordinate more than one capacitor with switched var controls, set the most-distant unit to have the shortest time delay. Increase the time delay on successive units progressing back to the substation. This leaves the unit closest to the substation with the longest time delay. The most distant unit switches first. Upstream units see the change and do not need to respond. This strategy is the opposite of that used for coordinating multiple line voltage regulators.

For var-controlled banks, locate the current sensor on the source (substation) side of the bank. Then, the controller can detect the reactive power change when the capacitor switches. To properly calculate vars, the wiring for the current transformer (CT) and potential transformer (PT) must provide correct polarities to the controller.

One manufacturer provides the following rules of thumb for setting var control trip and close settings (Fisher Pierce, 2000):

- *Close setpoint*: 2/3 × capacitor bank size (in kvar), lagging
- *Trip setpoint*: Close setpoint—1.25 × bank size, will be leading (this assumes that the CT is on the source side of the bank)

For a 600-kvar bank application, this yields

Close setpoint: $2/3 \times 600 = +400$ kvar (lagging)
Trip setpoint: $400 - 1.25 \times 600 = -350$ kvar (leading)

For this example, the unit trips when the load kvar drops below +250 kvar (lagging). This effectively gives a bandwidth wide enough (+400 to +250 kvar) to prevent excessive switching operations in most cases.

Voltage-controlled capacitor banks have bandwidths. Normally, we want the bandwidth to be at least 1.5 times the expected voltage change due to the capacitor bank. Ensure that the bandwidth is at least 3 or 4 V (on a 120-V scale). Set the trip setting below the normal light-load voltage (or the bank will never switch off). Note that voltage control is generally incompatible with conservation voltage reduction

because voltage reduction generally will try to always keep voltages between 117 and 120 V, so capacitors will not switch on when they should for moderate to heavy load.

If a switched capacitor is located on a circuit that can be operated from either direction, make sure the controller mode can handle operation with power flow in either direction. Time-of-day, temperature, current, and voltage control are not affected by reverse power flow; var and power factor control are affected. Some controllers can sense reverse power and shift control modes. One model provides several options if it detects reverse power: switch to voltage mode, calculate var control while accounting for the effect of the capacitor bank, inhibit switching, trip and lock out the bank, or close and hold the bank in. If a circuit has distributed generation, we do not want to shift modes based on reverse power flow; the controller should shift modes only for a change in direction to the system source.

Capacitor controllers normally have counters to record the number of operations. The counters help identify when to perform maintenance and can identify control-setting problems. For installations that are excessively switching, modify control settings, time delays, or bandwidths to reduce switching. Some controllers can limit the number of switch operations within a given time period to reduce wear on capacitor switches.

Voltage control provides extra safety to prevent capacitors from causing overvoltages. Some controllers offer types of voltage override control; the primary control may be current, vars, temperature, or time of day, but the controller trips the bank if it detects excessive voltage. A controller may also restrain from switching in if the extra voltage rise from the bank would push the voltage above a given limit.

7.3.2 Remote, Automated Controls

Riding the tide of lower-cost wireless communication technologies, many utilities have automated capacitor banks. Many of the cost reductions and feature improvements in communication systems have resulted from the proliferation of cellular phones, pagers, and other wireless technologies used by consumers and by industry. Controlling capacitors requires little bandwidth, so high-speed connections are unnecessary. This technology changes quickly. The most common communications systems for distribution line capacitors are 900-MHz radio systems, pager systems, cellular phone systems, cellular telemetric systems, and VHF radio. Some of the common features of each are

- *900-MHz radio*—Very common. Several spread-spectrum data radios are available that cover 902 to 928 MHz applications. A private network requires an infrastructure of transmission towers.
- *Pager systems*—Mostly one-way, but some two-way, communications. Pagers offer inexpensive communications options, especially for infrequent usage. One-way communication coverage is widespread; two-way coverage is more limited (clustered around major cities). Many of the commercial paging networks are suitable for capacitor switching applications.

- *Cellular phone systems*—These use one of the cellular networks to provide two-way communications. Many vendors offer cellular modems for use with several cellular networks. Coverage is typically very good.
- *Cellular telemetric systems*—These use the unused data component of cellular signals that are licensed on existing cellular networks. They allow only very small messages to be sent—enough, though, to perform basic capacitor automation needs. Coverage is typically very good, the same as regular cellular coverage.
- *VHF radio*—Inexpensive one-way communications are possible with VHF radio communication. VHF radio bands are available for telemetry uses such as this. Another option is a simulcast FM signal that uses extra bandwidth available in the commercial FM band.

Standard communication protocols help ease the building of automated infrastructures. Equipment and databases are more easily interfaced with standard protocols. Common communication protocols used today for SCADA applications and utility control systems include DNP3, IEC 870, and Modbus.

DNP 3.0 (Distributed Network Protocol) is the most widely used standard protocol for capacitor controllers (DNP Users Group, 2000). It originated in the electric industry in America with Harris Distributed Automation Products and was based on drafts of the IEC870-5 SCADA protocol standards (now known as IEC 60870-5). DNP supports master–slave and peer-to-peer communication architectures. The protocol allows extensions while still providing interoperability. Data objects can be added to the protocol without affecting the way that devices interoperate. DNP3 was designed for transmitting data acquisition information and control commands from one computer to another. (It is not a general-purpose protocol for hypertext, multimedia, or huge files.)

One-way or two-way—we can remotely control capacitors either way. Two-way communication has several advantages:

- *Feedback*—A local controller can confirm that a capacitor has been switched on or off successfully. Utilities can use the feedback from two-way communications to dispatch crews to fix capacitor banks with blown fuses, stuck switches, misoperating controllers, or other problems.
- *Voltage/var information*—Local information on line var flows and line voltages allows the control to more optimally switch capacitor banks to reduce losses and keep voltages within limits.
- *Load flows*—Voltage, current, and power flow information from pole-mounted capacitor banks can be used to update and verify load-flow models of a system. The information can also help when tracking down customer voltage complaints, stray voltage, or other power quality problems. Loading data helps utilities monitor load growth and plan for future upgrades. One utility even uses capacitor controllers to capture fault location information helping crews to locate faults.

When a controller only has one-way communications, a local voltage override control feature is often used. The controller blocks energizing a capacitor bank if doing so would push the voltage over limits set by the user.

Several schemes and combinations of schemes are used to control capacitors remotely:

- *Operator dispatch*—Most schemes allow operators to dispatch distribution capacitors. This feature is one of the key reasons utilities automate capacitor banks. Operators can dispatch distribution capacitors just like large station banks. If vars are needed for transmission support, large numbers of distribution banks can be switched on. This control scheme is usually used in conjunction with other controls.
- *Time scheduling*—Capacitors can be remotely switched, based on the time of day and possibly the season or temperature. While this may seem like an expensive time control, it still allows operators to override the schedule and dispatch vars as needed.
- *Rules-based control using substation var measurements*—A common way to control feeder capacitors is to dispatch based on var/power factor measurements in the substation. If a feeder has three capacitor banks, they are switched on or off in some specified order based on the power factor on the feeder measured in the substation.
- *Model-based control*—With an operational model of the distribution system along with substation SCADA measurements, capacitor banks can be switched to optimize voltage profiles and reactive power flows based on different priorities. This volt-var control is the most advanced form of capacitor control, and the control can also include regulators and LTCs. This is normally done using a distribution management system (DMS).

Another benefit of centralized control is the enhanced ability to detect misoperations and bank failures. Kansas City Power & Light used their automated capacitor bank system to perform a detailed analysis of switched capacitor bank reliability (Goeckeler, 1999). Two-way communication provides the added benefit of positive confirmation that the switching operation was successful. Alternatively, if only one-way communication is available, then substation reactive-power flows can be monitored to verify capacitor switching.

7.4 Volt-Var Engineering and Control

The voltage boosting properties of capacitor banks generally flatten voltage profiles along a circuit. When used in conjunction with voltage regulators, capacitors can help manage customer voltages for demand-based voltage reduction, conservation voltage reduction, and for better voltage balance. Coordinating voltage regulator placement and control along with capacitor sizing, placement, and control allows a utility to optimize voltage profiles and losses. Basic integrated volt-var management can be evaluated using most distribution powerflow programs.

As one example, Farmer et al. (2011) describe two case studies for volt-var management and control on two rural circuits, circuits that are normally voltage limited and provide challenges and opportunities for voltage and reactive-power control. Their improvements to volt-var support involved phase balancing by moving single-phase taps to other phases, addition of regulators, and adjustment of capacitors. McCarthy and Josken (2003) describe Georgia Power's approach to applying capacitors to flatten

circuit profiles to enable peak shaving using voltage reduction. Flatter profiles allow a deeper voltage reduction and more peak energy savings. Progress Energy Carolinas implemented a volt-var control system to defer 1000 MW of generation by using voltage reduction at peak (Lampley, 2010). Their approach involved adding two-way communications to all capacitor banks and voltage regulators, and these plus substation regulators and capacitors are under the control of a DMS.

Vukojevic et al. (2013) describes a volt-var system undergoing pilot implementation at Baltimore Gas and Electric. Their distribution system is unusual in that they have many circuits without LTCs or voltage regulators, and they rely on capacitors for voltage and var control. They describe pilots of two styles of volt-var control, one with added single-phase voltage regulators and one with capacitor-only control based on capacitors that can switch phases independently. Their optimization goals are conservation voltage reduction and a voltage balancing index and implemented using a rules-based approach.

There are several approaches to volt-var control. Some options include (EPRI 1022004, 2011)

- Local control
- Rules-based control based on measurements
- Model-based control

Local control is the simplest approach; capacitor banks and voltage regulators operate based on local measurements. Utilities have a long history of operating with local control and operations personnel are familiar with this. Because there is no direct feedback or other information on downstream voltages, undervoltages are more likely in a reduced-voltage mode, so settings have to be conservative enough to limit undervoltage scenarios. This limits the average amount of voltage reduction.

Local control of voltage regulators or LTCs can be enhanced with line-drop compensation to adjust voltages based on load. For local control of capacitor banks, control modes need to be reviewed. Voltage-based control of switched capacitor banks is difficult to coordinate with voltage reduction. Most capacitor banks are placed on the outer portions of circuits, and at these locations, if voltage reduction is applied properly, voltages will always be in the range around 117 to 119 V. Switching based on voltage will not work well because voltage is no longer a good indicator of circuit loading: line-drop compensation in regulator controllers is adjusting voltage based on load. The best way to control switched capacitors is with var control or current control, so that capacitors switching operations match circuit loadings.

Rules-based control relies on communications to measurement points and possibly regulators and/or capacitors out on distribution feeders. Voltages can be controlled using logic based on measurement inputs. The simplest example is a substation voltage regulator or LTC controlled to lower voltages based on one or more end-of-line measurement values. A more complex example could coordinate the operation of distribution line capacitors and regulators. This approach allows more aggressive voltage reduction because of the feedback provided about voltage at remote parts of the circuit. Control rules can factor in number of regulator operations in addition

to voltage levels. The main disadvantage of this approach is that metering and communications are needed. Devices are normally interfaced to SCADA, often termed DSCADA (distribution SCADA). The control can be based at substations or be centralized. On circuits with loops or other interconnects between circuits, the logic can become complicated, possibly untenable, depending on complexity. The logic must be changed as equipment is added and as circuit conditions change. Adaptive approaches are also possible in place of fixed logic.

Model-based control uses an electrical model of the distribution system to control devices based on an online powerflow model. Model-based control is often a part of an integrated DMS. The model-based, DMS-style control is the most complex approach but controls can adapt to changing feeder configurations. Utilities can also implement different operating modes and optimization priorities. A utility could have a conservation voltage reduction mode, a mid-range voltage mode, a transmission support mode, a peak-shaving mode, and more. Capacitor switching operations, regulator operations, substation power factor, line losses, substation transformer losses, voltage unbalance, and voltage limits are all parameters that can have different weights in optimization for a given operating mode.

Developing an accurate model is a major challenge with model-based control. The load allocation for real and reactive power is key for accurate estimates of voltage profiles and line currents. In the simplest scenarios where only a substation regulator is being controlled, communications to distribution feeder devices are not needed, but if capacitors and line regulators are to be integrated and controlled, control signaling is needed to these. BC Hydro is one of the leaders in developing volt-var control; they use a model to control substation LTCs and line capacitor banks (Dabic et al., 2010). As part of lessons learned in their pilots, they found that commissioning metering in the substation first was important because that information gave them better information on where additional field devices might be needed. They also found that it was important for local LTC control to have a default setpoint for use when communications are lost.

Combinations of methods are also possible. For example, voltage feedback can be used to control substation voltage regulators, but capacitors can be left on local control. A model-based control could be used with inputs from feeder monitoring points (like reclosers) to better adapt the model for actual real-time load conditions.

Automated metering infrastructure (AMI) data can help improve several volt-var control methods. Customer voltage readings can be used to evaluate the performance of a local control system, either through manual review or through an automated review program that checks voltages. Based on results, the local control settings could be changed. For a model-based approach, AMI can help supply loading data for better allocation of watts (and possibly vars) throughout the circuit (Markushevich and Luan, 2011). AMI can be used as the measurement feedback for the rules-based approach. Dominion Virginia Power uses 15-min voltage data from AMI meters to adjust the setpoint of substation LTC's (Peskin et al., 2012). They use the average of 10 meters per circuit that were selected to represent the lowest voltages on that circuit. These were selected based on the average and minimum voltages over a 30-day period. Their algorithm raises or lowers the setpoint to keep the average of

the 10 meters at 118 V. On a pilot circuit, they noted that the lowest customer voltages were not at the ends of the line; they were at other locations due to transformer and secondary voltage drops.

The best method for voltage control or volt-var control for a utility depends on goals and priorities as well as infrastructure in place and planned for the future, including DSCADA, a DMS, and AMI.

7.5 Reliability and Failure Modes

Several problems contribute to the overall reliability or unreliability of capacitor banks. In a detailed analysis of Kansas City Power & Light's automated capacitor banks, Goeckeler (1999) reported that blown fuses are KCP&L's biggest problem, but several other problems also exist (Table 7.7). Their automation with two-way communications allowed them to readily identify bank failures. The failure rates in Table 7.7 are high, much higher than most distribution equipment. Capacitor banks are complicated; they have a lot of equipment to fail; yet, failure rates should be significantly better than this.

An EPRI survey on capacitor reliability found wide differences in utilities' experience with capacitors (EPRI 1001691, 2002). Roughly one-third of survey responses found feeder capacitors "very good," another one-third found them "typical of line equipment," and the final third found them "problematic." The survey, along with follow-up contacts, highlighted several issues:

- *Misoperation of capacitor fuses*—Many utilities have operations of fuses where the capacitor bank is unharmed. This can unbalance circuit voltages and reduce the number of capacitors available for var support. Review fusing practices to reduce this problem.
- *Controllers*—Controllers were found "problematic" by a significant number of utilities. Some utilities had problems with switches and with the controllers themselves.
- *Lightning and faults*—In high-lightning areas, controllers can fail from lightning. Controllers are quite exposed to lightning and power-supply overvoltages during faults. Review surge protection practices and powering and grounding of controllers.

TABLE 7.7 Maintenance Needs Identified by Kansas City Power & Light's Capacitor Automation System Based on Two Years of Data

Problem	Annual Percent Failures
Primary fuse to capacitor blown (nuisance fuse operation)	9.1
Failed oil switches	8.1
Hardware accidentally set to "Local" or "Manual"	4.2
Defective capacitor unit	3.5
Miscellaneous	2.4
Control power transformer	1.5
Total	28.8

Source: Data from Goeckeler, C., *Progressive Capacitor Automation Yields Economic and Practical Benefits at KCPL*, Utility Automation, October 1999.

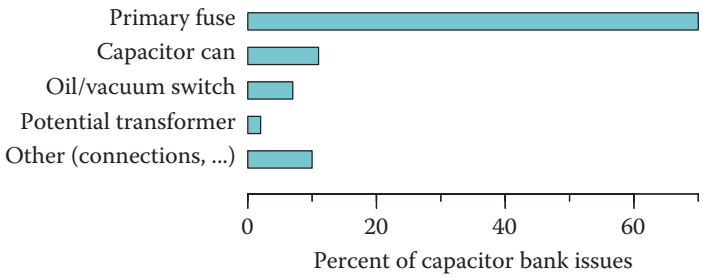

Figure 7.13 Capacitor bank issues by cause. (Data from Holsomback, V., *Transmission & Distribution World*, 49–53, February 1, 2013.)

- *Human element*—Many controllers are set up incorrectly. Some controllers are hard to program. And, field crews often do not have the skills or proper attitudes toward capacitors and their controls. At some utilities, crews often manually switch off nearby capacitors (and often forget to turn them back on after finishing their work). To reduce these problems, properly train crews and drive home the need to have capacitors available.

Georgia Power reported a high rate of fuse operations as shown in Figure 7.13 (Holsomback, 2013). Using data supplied by Georgia Power, their overall rate of problems on fixed banks is on the order of 15% annually with an equivalent annual rate of 20% during summer months and 11% during the rest of the year.

Capacitors can fail in two modes:

- *Low current, progressive failure*—The dielectric fails in one of the elements within the capacitor (see Figure 7.14). With one element shorted, the remaining elements in the series string have increased voltage and higher current (because the total capacitive impedance is lower). With more stress, another element may short out. Failures can cascade until the whole string shorts out. In this scenario, the current builds up slowly as elements successively fail.
- *High current*—A low-impedance failure develops across the capacitor terminals or from a phase terminal to ground. A broken connector could cause such a fault.

Most failures are progressive. Sudden jumps to high current are rare. To detect progressive failures quickly, fusing must be very sensitive. Film-foil capacitors have

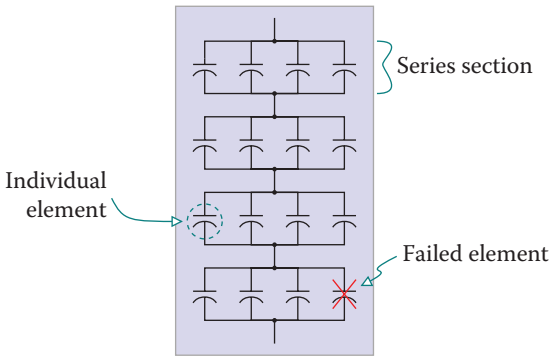

Figure 7.14 Capacitor unit with a failed element.

few case ruptures—much less than older paper units. An EPRI survey of utilities (EPRI 1001691, 2002) found that film-foil capacitor ruptures were rare to nonexistent. This contrasts sharply with paper capacitors, where Newcomb (1980) reported that film/paper capacitors ruptured in 25% of failures.

Paper and paper-film capacitors have an insulating layer of paper between sheets of foil. When a breakdown in a pack occurs, the arc burns the paper and generates gas. In progressive failures, even though the current is only somewhat higher than normal load current, the sustained arcing can create enough gas to rupture the enclosure. Before 1975, capacitors predominantly used polychlorinated biphenyls (PCB) as the insulating liquid. Environmental regulations on PCB greatly increased the costs of cleanup if these units ruptured (US Environmental Protection Agency 40 CFR Part 761 Polychlorinated Biphenyls (PCBs) Manufacturing, Processing, Distribution in Commerce, and Use Prohibitions). The environmental issues and safety concerns led utilities to tighten up capacitor fusing.

In modern film-foil capacitors, sheets of polypropylene film dielectric separate layers of aluminum foil. When the dielectric breaks down, the heat from the arc melts the film; the film draws back; and the aluminum sheets weld together. With a solid weld, a single element can fail and not create any gas (the current is still relatively low). In film-foil capacitors, the progressive failure mode is much less likely to rupture the case. When all of the packs in series fail, high current flows through the capacitor. This can generate enough heat and gas to rupture the capacitor if it is not cleared quickly.

Figure 7.15 shows capacitor rupture curves from several sources. Most case rupture curves are based on tests of prefailed capacitors. The capacitors are failed by applying excessive voltage until the whole capacitor is broken down. The failed capacitor is then subjected to a high-current short-circuit source of known amperage for a given time. Several such samples are tested to develop a case rupture curve.

The case rupture curves do not represent all failure modes. Such curves do not show the performance during the most common failures: low-current and progressive element failures (before all elements are punctured). Although, thankfully, rare, high-current faults more severe than those tested for the rupture curves are possible. An arc through the insulating dielectric fluid can generate considerable pressure. Pratt et al. (1977) performed tests on film/foil capacitor units with arc lengths up to 3 in. (7.6 cm) in length. They chose 3 in. as the maximum realistic arc length in a capacitor as the gap spacing between internal series section terminals. Under these conditions, they damaged or ruptured several units for currents and times well below the capacitor rupture curves in Figure 7.15.

Also consider other equipment at a capacitor bank installation. Capacitor switches, especially oil switches, are vulnerable to violent failure. This type of failure has not received nearly the attention that capacitor ruptures or distribution transformer failures have. Potential transformers, current transformers, controller power-supply transformers, and arresters: these too can fail violently. Any failure in which an arc develops inside a small enclosure can rupture or explode. In areas with high fault current, consider applying current-limiting fuses. These will help protect against violent failures of capacitor units, switches, and other accessories in areas with high fault current.

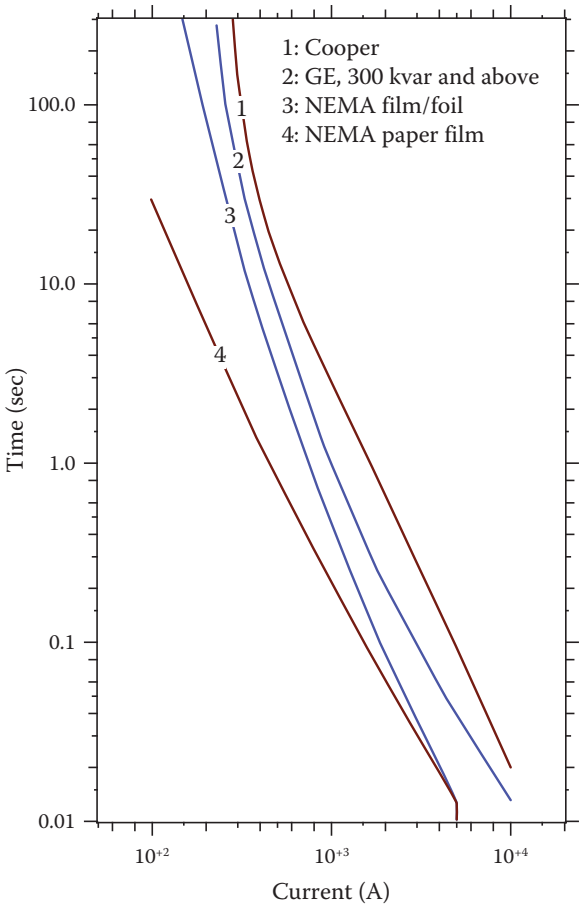

Figure 7.15 Capacitor rupture curves. (Data from ANSI/IEEE Std. 18-1992, IEEE Standard for Shunt Power Capacitors; Cooper Power Systems, *Electrical Distribution—System Protection*, 3rd ed., 1990; General Electric, *Case Rupture Curves*, 2001. Downloaded from http://www.geindustrial.com.)

When one element fails and shorts out, the other series sections have higher voltage, and they draw more current. Capacitor packs are designed with a polypropylene film layer less than 1 mil thick (0.001 in. or 0.025 mm), which is designed to hold a voltage of 2000 V. Table 7.8 shows the number of series sections for several capacitors as reported by Thomas (1990). More recent designs could have even fewer groups. One manufacturer uses three series sections for 7.2 to 7.96-kV units and six series sections for 12.47 to 14.4-kV units. As series sections fail, the remaining elements must hold increasing voltage, and the capacitor draws more current in the same proportion. Figure 7.16 shows the effect on the per-unit current drawn by a failing unit and the per-unit voltage on the remaining series sections.

If a capacitor bank has multiple units on one phase and all units are protected by one fuse (group fusing), the total bank current should be considered. Consider a bank with two capacitor units. If one unit loses half of its series sections, that unit will draw

TABLE 7.8 Number of Series Sections in Different Voltage Ratings

	Manufacturer		
Unit Voltage, V	A	B	C
2400	2	2	2
7200	4	4	4
7620	5	5	4
13,280	8	8	7
13,800	8	8	–
14,400	8	8	8

Source: Thomas, E. S., Determination of neutral trip settings for distribution capacitor banks, *IEEE Rural Electric Power Conference*, 1990. Copyright 1990 IEEE. With permission.

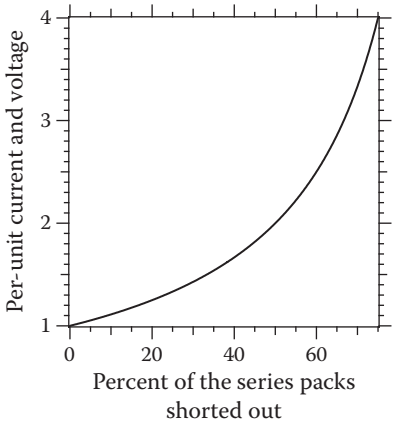

Figure 7.16 Per-unit current drawn by a failing bank depending on the portion of the bank that is failing (assuming an infinite bus). This is also the per-unit voltage applied on the series sections still remaining.

twice its nominal current. The group—the two units together—will draw 1.5 times the nominal bank load. (This is the current that the fuse sees.)

7.6 Fusing and Protection

The main purpose of the fuse on a capacitor bank is to clear a fault if a capacitor unit or any of the accessories fails. The fuse must clear the fault quickly to prevent any of the equipment from failing violently. Ruptures of capacitors have historically been problematic, so fusing is normally tight. Fuses must be sized to withstand normal currents, including harmonics.

A significant number of utilities have problems with nuisance fuse operations on capacitor banks. A fuse is blown, but the capacitors themselves are still functional.

Figure 7.17 Capacitor bank with a blown fuse. (From EPRI 1001691, *Improved Reliability of Switched Capacitor Banks and Capacitor Technology*, Electric Power Research Institute, Palo Alto, CA, 2002. Copyright 2002. Reprinted with permission.)

These blown fuses may stay on the system for quite some time before they are noticed (see Figure 7.17). Capacitors with blown fuses increase voltage unbalance, can increase stray voltages, and increase losses. Even if the capacitor controller identifies blown fuses, replacement adds extra maintenance that crews must do.

IEEE guides suggest selecting a fuse capable of handling 1.25 to 1.35 times the nominal capacitor current (IEEE Std. C37.48-1997); a 1.35 factor is most common. Three factors can contribute to higher than expected current:

- *Overvoltage*—Capacitive current increases linearly with voltage, and the reactive vars increase as the square of the voltage. When estimating maximum currents, an upper voltage limit of 110% is normally assumed.
- *Harmonics*—Capacitors can act as a sink for harmonics. This can increase the peak and the rms of the current through the capacitor. Additionally, grounded three-phase banks absorb zero-sequence harmonics from the system.
- *Capacitor tolerance*—Capacitors were allowed to have a tolerance to +15% above their rating (which would increase the current by 15%).

Most fusing practices are based on fusing as tightly as possible to prevent case rupture. So, the overload capability of fuse links is included in fuse sizing. This effectively allows a tighter fusing ratio. K and T tin links can be overloaded to 150%, so for these links with a 1.35 safety factor, the smallest size fuse that can be used is

$$I_{\min} = \frac{1.35 I_1}{1.5} = 0.9 I_1$$

where

$I_{\min}$ = minimum fuse rating, A
I_1 = capacitor bank current, A

Table 7.9 shows one manufacturer's recommendations based on this tight-fusing approach.

With this tight-fusing strategy, fuses must be used consistently. If silver links are used instead of tin links, the silver fuses can blow from expected levels of current because silver links have no overload capability.

Prior to the 1970s, a fusing factor of 1.65 was more common. Owing to concerns about case ruptures and PCBs, the industry went to tighter fusing factors, 1.35 being the most common. Because of the good performance of all-film capacitors and problems with nuisance fuse operations, consider a looser fusing factor, possibly returning to the 1.65 factor. Slower fuses should also have fewer nuisance fuse operations.

Capacitors are rated to withstand 180% of rated rms current, including fundamental and harmonic currents. Fusing is normally not based on this limit, and is normally much tighter than this, usually from 125% to 165% of rated rms current. Occasionally, fuses in excess of 180% are used. In severe harmonic environments (usually in commercial or industrial applications), normally fuses blow before capacitors fail, but sometimes capacitors fail before the fuse operates. This depends on the fusing strategy.

TABLE 7.9 Fusing Recommendations for ANSI Tin Links from One Manufacturer

3-Phase Bank kvar	System Line-to-Line Voltage, kV							
	4.2	4.8	12.5	13.2	13.8	22.9	24.9	34.5
Recommended Fuse Link								
150	20 T	20 T	8 T	6 T	6 T			
300	40 K	40 K	15 T	12 T	12 T	8 T	8 T	5 T
450	65 K	50 K	20 T	20 T	20 T	10 T	10 T	8 T
600	80 K	65 K	25 T	25 T	25 T	15 T	15 T	10 T
900		100 K	40 K	40 K	40 K	20 T	20 T	15 T
1200			50 K	50 K	50 K	30 T	25 T	20 T
1800			80 K	80 K	80 K	40 K	40 K	30 K
2400			100 K	100 K	100 K	65 K	50 K	40 K
Fusing Ratio for the Recommended Link (Link Rating/Nominal Current)								
150	0.96	1.11	1.15	0.91	0.96			
300	0.96	1.11	1.08	0.91	0.96	1.06	1.15	1.00
450	1.04	0.92	0.96	1.02	1.06	0.88	0.96	1.06
600	0.96	0.90	0.90	0.95	1.00	0.99	1.08	1.00
900		0.92	0.96	1.02	1.06	0.88	0.96	1.00
1200			0.90	0.95	1.00	0.99	0.90	1.00
1800			0.96	1.02	1.06	0.88	0.96	1.00
2400			0.90	0.95	1.00	1.07	0.90	1.00

Source: Adapted from Cooper Power Systems, *Electrical Distribution—System Protection*, 3rd ed., 1990.

Note: This is not the manufacturer's most up-to-date fusing recommendation. It is provided mainly as an example of a commonly applied fusing criteria for capacitors.

If a capacitor bank has a blown fuse, crews should test the capacitors before refusing. A handheld digital capacitance meter is the most common approach and is accurate. Good multimeters can also measure a capacitance high enough to measure the capacitance on medium-voltage units. There is a chance that capacitance-testers may miss some internal failures requiring high voltage to break down the insulation at the failure. Measuring the capacitance on all three phases helps identify units that may have partial failures. Partial failures show up as a change in capacitance. In a partial failure, one of several series capacitor packs short out; the remaining packs appear as a lower impedance (higher capacitance). As with any equipment about to be energized, crews should visually check the condition of the capacitor unit and make sure there are no bulges, burn marks, or other signs that the unit may have suffered damage.

Some utilities have problems with nuisance fuse operations on distribution transformers. Some of the causes of capacitor fuse operations could be the same as transformer fuse operations, but some differences are apparent:

- Capacitor fuses see almost continuous full load (when the capacitor is switched in).
- Capacitor fuses tend to be bigger. The most common transformer sizes are 25 and 50 kVA, usually with less than a 15-A fuse. Typical capacitor sizes are 300 to 1200 kvar with 15- to 65-A fuses.
- Both have inrush; a capacitor's is quicker.
- Transformers have secondary faults and core saturation that can contribute to nuisance fuse operations; capacitors have neither.

Some possible causes of nuisance fuse operations are

- *Lightning*—Capacitors are a low impedance to the high-frequency lightning surge, so they naturally attract lightning current, which can blow the fuse. Smaller, faster fuses are most prone to lightning. Given that the standard rule of thumb that a fuse at least as big as a 20 K or a 15 T should prevent nuisance operations, it is hard to see how lightning itself could cause a significant number of fuse operations (as most capacitor bank fuses are larger than this).
- *Outrush to nearby faults*—If a capacitor dumps its stored charge into a nearby fault, the fuse can blow. Capacitor banks also have inrush every time they are switched in, but this is well below the melt point of the fuse.
- *Severe harmonics*—Harmonics increase the current through the fuse.
- *Animal or other bushing faults*—A fault across a bushing due to an animal, contamination on the bushing, or tree contact can blow a fuse. By the time anyone notices the blown fuse, the squirrel or branch has disappeared. Use animal guards and covered jumpers to reduce these.
- *Mechanical damage and deterioration*—Corrosion and vibration can weaken fuse links. On fuse links collected from the field on transformers, Ontario Hydro found that 3% had broken strain wires (CEA 288 D 747, 1998). Another 15% had braids that were brittle and had broken strands. Larger fuses used in capacitors should not have as much of a problem.
- *Installation errors*—Fuses are more likely to blow if crews put in the wrong size fuse or wrong-type fuse or do not properly tighten the braid on the fuse.

7.6.1 Outrush and Other Transients

Outrush is highlighted as a possible failure mode that has been neglected by the industry. Outrush is sometimes considered for station banks to calculate the probability of a fuse operation from a failure of an adjacent parallel unit. But for distribution fuses, nearby faults have not been considered in regard to the effects on fuse operations.

The energy input into the fuse during outrush depends on the line resistance between the capacitor and the fault (see Figure 7.18). The capacitor has stored energy; when the fault occurs, the capacitor discharges its energy into the resistance between the capacitor and the fault. Closer faults cause more energy to go into the fuse. The I^2t that the fuse suffers during outrush to a line-to-ground fault is

$$I^2t = \frac{1/2CV_{pk}^2}{R} = \frac{2.65Q_{kvar}}{R}V_{pu}^2$$

where

C = capacitance of one unit, μF
V_{pk} = peak voltage on the capacitor at the instant of the fault, kV
R = resistance between the capacitor and the fault, Ω
Q_{kvar} = single-phase reactive power, kvar
V_{pu} = voltage at the instant of the fault in per unit of the capacitor's rated voltage

Table 7.10 shows several sources of fuse operations and the I^2t that they generate for a 900-kvar bank at 12.47 kV. The nominal load current is 41.7 A. Utilities commonly use 40- or 50-A fuses for this bank. The table shows the minimum melt I^2t of common fuses. Outrush to nearby faults produces high enough energy to blow common fuses, especially the K links. Of the other possible causes of fuse operation, none are particularly high except for a lightning first stroke. The lightning data is misleading because much of the first stroke will go elsewhere—usually, the line flashes over, and much of the lightning current diverts to the fault.

Use Figure 7.19 to find outrush I^2t for other cases. Two factors make outrush worse:

- *Higher system voltages*—The outrush I^2t stays the same with increases in voltage for the same size capacitor bank. The line impedance stays the same for different voltages. But higher-voltage capacitor banks use smaller fuses, with lesser I^2t capability.

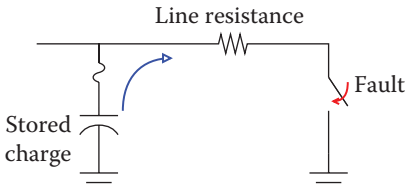

Figure 7.18 Outrush from a capacitor to a nearby fault.

TABLE 7.10 Comparison of I^2t of Events That Might Blow a Fuse to the Capability of Common Fuses for a Three-Phase, 900-kvar Bank at 12.47 kV (I_{load} = 41.7 A)

Source	I^2t, A^2-sec
Lightning, median 1st stroke	57,000
Lightning, median subsequent stroke	5500
Inrush at nominal voltage (I_{SC} = 5 kA, X/R = 8)	4455
Inrush at 105% voltage	4911
Outrush to a fault 500-ft away (500-kcmil AAC)	20,280
Outrush to a fault 250-ft away (500-kcmil AAC)	40,560
Outrush to a fault 250-ft away with an arc restrike[a]	162,240
40 K fuse, minimum melt I^2t	36,200
50 K fuse, minimum melt I^2t	58,700
40 T fuse, minimum melt I^2t	107,000

[a]Assumes that the arc transient leaves a voltage of 2 per unit on the capacitor before the arc restrikes.

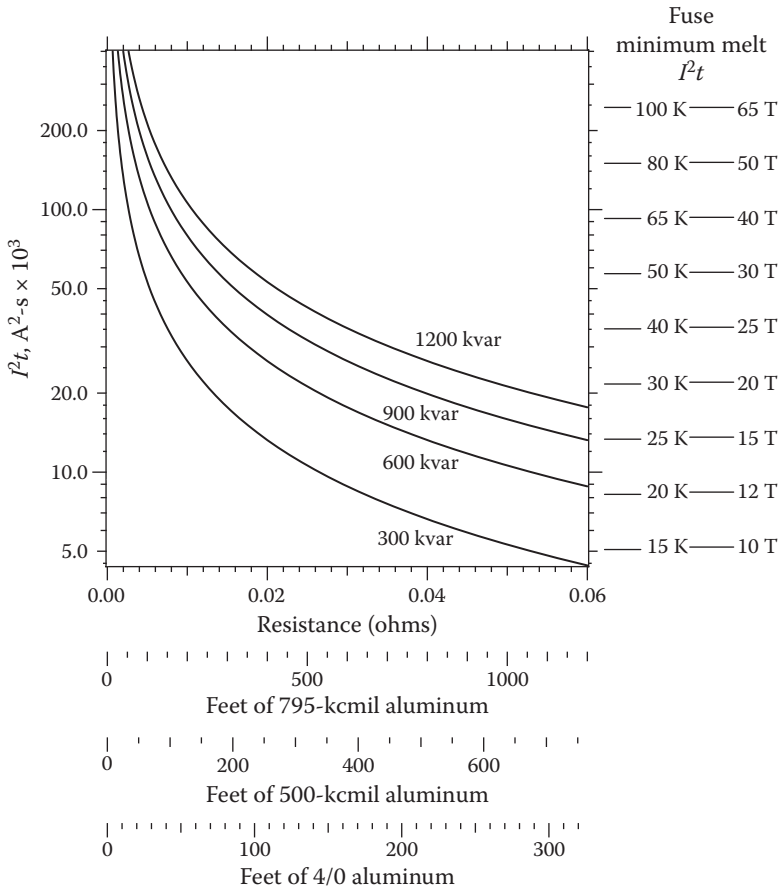

Figure 7.19 Outrush as a function of the resistance to the fault for various size capacitor banks (the sizes given are three-phase kvar; the resistance is the resistance around the loop, out and back; the distances are to the fault).

So, a 25-kV capacitor installation is more likely to have nuisance fuse operations than a 12.5-kV installation.
- *Larger conductors*—Lower resistance.

Consider a 1200-kvar bank with 500-kcmil conductors. At 12.47 kV (I_{load} = 55.6 A) with a 65 K fuse, the fuse exceeds its minimum melt I^2t for faults up to 150 ft away. At 24.94 kV (I_{load} = 27.8 A) with a 30 K fuse, the fuse may melt for faults up to 650 ft away. At 34.5 kV (I_{load} = 20.1 A) with a 25 K fuse, the location is off this chart (it is about 950 ft). Note that the distance scales in Figure 7.19 do not include two important resistances: the capacitor's internal resistance and the fuse's resistance. Both will help reduce the I^2t. Also, the minimum melt I^2t values of the fuses in Figure 7.19 are the 60-Hz values. For high-frequency currents like an outrush discharge, the minimum melt I^2t of expulsion fuses is 30 to 70% of the 60-Hz I^2t (Burrage, 1981).

As an estimate of how much outrush contributes to nuisance fuse operations, consider a 900-kvar bank at 12.47 kV with 40 K fuses. We will estimate that the fuse may blow or be severely damaged for faults within 250 ft (76 m). Using a typical fault rate on distribution lines of 90 faults/100 mi/year (56 faults/100 km/year), faults within 250 ft (75 m) of a capacitor occur at the rate of 0.085 per year. This translates into 8.5% fuse operations per capacitor bank per year, a substantial number.

The stored energy on the fault depends on the timing of the fault relative to the point on the voltage wave. Unfortunately, most faults occur at or near the peak of the sinusoid.

Several system scenarios could make individual instances worse; most are situations that leave more than normal voltage on the capacitor before it discharges into the fault:

- *Regulation overvoltages*—Voltages above nominal increase the outrush energy by the voltage squared.
- *Voltage swells*—If a line-to-ground fault on one phase causes a voltage swell on another and the fault jumps to the "swelled" phase, higher-than-normal outrush flows through the fuse.
- *Arc restrikes*—If a nearby arc is not solid but sputters, arc restrikes, much like restrikes of switches, can impress more voltage on the capacitor and subject the fuse to more energy, possibly much larger voltage depending on the severity.
- *Lightning*—A nearby lightning strike to the line can charge up the capacitor (and start the fuse heating). In most cases, the lightning will cause a nearby flashover, and the capacitor's charge will dump right back through the fuse.
- *Multiple-phase faults*—Line-to-line and three-phase faults are more severe for two reasons: the voltage is higher, and the resistance is lower. For example, on a line-to-line fault, the voltage is the line-to-line voltage, and the resistance is the resistance of the phase wires (rather than the resistance of a phase wire and the neutral in series).

These estimates are conservative in that they do not consider skin effects, which have considerable effect at high frequencies. Skin effects increase the conductor's resistance. The transients oscillate in the single-digit kilohertz range. At these frequencies, conductor resistance increases by a factor of two to three. On the negative

TABLE 7.11 Ratio of High-Frequency to Normal-Frequency Minimum-Melt I^2t

Fuse	Minimum-melt I^2t at 8 kHz / Minimum-melt I^2t at 60 Hz
20 T	0.67
20 K	0.64
50 T	0.60
6 T	0.50
6 K	0.37

Source: Data from Burrage, L. M., High frequency characteristics of capacitors and fuses—Applied in high-voltage shunt banks, *IEEE/PES Transmission and Distribution Conference*, 1981.

Note: For tin links.

side, the fuse element is impacted by skin effects, too—higher-frequency transients causes the fuse to melt more quickly.

A fuse has a resistance that varies with frequency. The fuse's energy withstand capability also varies with frequency, as the two are interrelated. Under a high-frequency transient, a fuse is damaged more readily. CEA 288 D 747 (1998) describes three main causes: resistivity change, partial melting, and cracking. At higher frequencies, skin effect causes higher resistances. Partial melting is a damage mechanism where a portion of the link melts and resolidifies. Because many capacitor fuses are fused so tightly, normal capacitor current may drive a partially damaged link into thermal runaway. Mechanical forces during a transient and also recrystalization in the fuse link can crack the fuse. Table 7.11 shows ratios of high-frequency melt times to normal melt times. The ratios vary widely—from 0.37 to 0.67 but tend to the higher range for larger fuses.

Figure 7.20 shows a field measurement of outrush from a 1200-kvar capacitor bank into a fault. This event caused two fuse operations within 45 min. The power-quality monitor was approximately 680 ft (262 m) upstream of the capacitor, and the fault was estimated to be 330 ft (100 m) upstream of the monitor, giving a total distance from the capacitor to the fault of 1190 ft (362 m). This fault event was the first of a series of faults and transients in the 45 min before the two fuses separated. The two fuses that operated were the fuses on the phases that first faulted together. The fault started as a phase-to-phase fault (note that the voltages in Figure 7.20 are phase to phase). The fault had high arc voltage, and initiated outrush at each current zero crossing. The fault had lower I^2t than would have been expected to melt the fuses. The fuse size is not known, but a 50 K link has a minimum melt I^2t of just under 60 A^2-s $\times 10^3$. The initial event was just over 3 A^2-s $\times 10^3$, and the total of all events covering the several minutes was approximately 14 A^2-s $\times 10^3$. This is well under the minimum melt value of a 50 K link, so other factors may have come into play such as prior damage or heating from cutout issues. Over a 5-year period, four separate "fuse-opening" events were recorded at this monitor, indicating there may be a recurring problem.

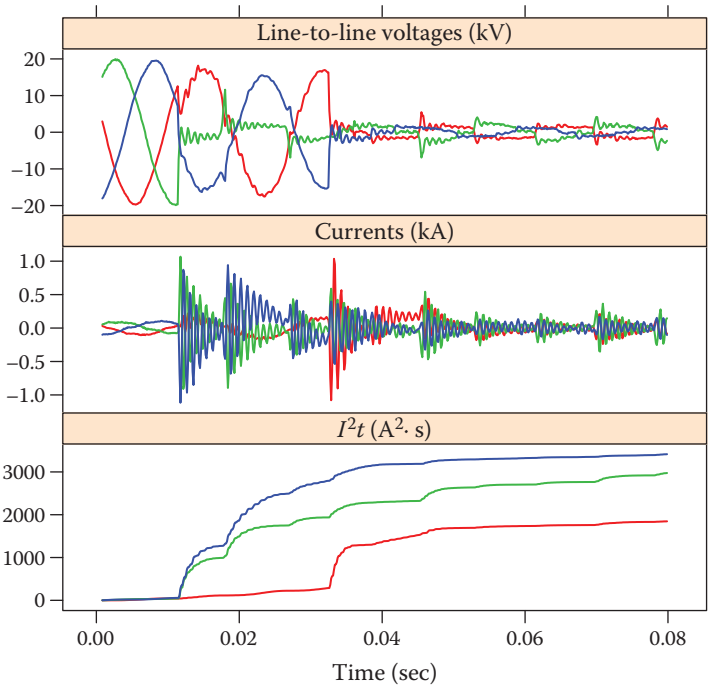

Figure 7.20 Field measurement of outrush from a capacitor to a fault.

Capacitors also have inrush every time they are energized. Inrush into grounded banks has a peak current (IEEE Std. 1036-1992) of

$$I_{pk} = 1.41\sqrt{I_{SC} I_1}$$

where

I_{pk} = peak value of inrush current, A
I_{SC} = available three-phase fault current, A
I_1 = capacitor bank current, A

The energy into a fuse from inrush is normally very small. It subjects the capacitor fuse to an I^2t (in A^2-s) (Brown, 1979) of

$$I^2t = 2.65\sqrt{1 + k^2}\, I_{SC} I_1 / 1000$$

where

$k = X/R$ ratio at the bank location

Inrush is much worse if a capacitor is switching into a system with a nearby capacitor. The outrush from the already-energized bank dumps into the capacitor coming on line. Fuses at both banks see this transient. In substation applications, this

back-to-back switching is a major design consideration, often requiring insertion of reactors between banks. For distribution feeder capacitors, the design constraints are not as large. A few hundred feet of separation is enough to prevent inrush/outrush problems. For back-to-back switching, the I^2t is almost the same as that for outrush:

$$I^2t = \frac{1/2CV_{pk}^2}{R} = \frac{2.65Q_{kvar}}{R}V_{pu}^2$$

The only difference is that the capacitance is the series combination of the two capacitances: $C = C_1C_2/(C_1 + C_2)$ and $Q_{kvar} = Q_1Q_2/(Q_1 + Q_2)$. For the same size banks, $C = C_1/2$ and $Q_{kvar} = Q_1/2$. Figure 7.19 applies if we double the kvar values on the curves. In most situations, maintaining a separation of 500 ft between capacitor banks prevents fuse operations from this inrush/outrush. Separate capacitor banks by 500 ft (150 m) on 15-kV class circuits to avoid inrush problems. Large capacitor banks on higher voltage distribution systems may require modestly larger separations.

A capacitor reliability survey (EPRI 1001691, 2002) showed some correlation between reported nuisance fuse operations and lightning. Utilities in higher-lightning areas reported more problems with nuisance fuse operations. Nuisance fuse operations are understandably affected by lightning. Lightning current through the fuse itself can contribute to failures. In addition, utilities in high-lightning areas normally also have higher overall fault rates (more severe weather). This increases the number of outrush events to nearby faults. Combinations of outrush and lightning could contribute to this effect.

Very close to a capacitor, the lightning stroke current will rush into the capacitor. The capacitor represents a low impedance to high frequencies, so the capacitor is almost like a short circuit to the front portion of the lightning current wavefront. Even with lightning arresters and capacitors near the strike, the circuit is still likely to flash over on one or more adjacent poles. These flashovers will create outrush-like transients that contribute to fuse heating. For strikes more than a pole span from a capacitor, there will usually be a line flashover between the capacitor bank and the strike location. The flashover will reduce the amount of lightning current that will flow through the fuse. But, flashovers near capacitors will cause outrush-type transients. In addition, lightning can cause a series of flashovers on the same line and the same phase, so even a lightning strike to the line more than a mile from the capacitor bank can cause a fault near the capacitor (see Chapter 13). Transient simulations in EPRI 1002154 (2004) found that lightning can contribute to fuse operations, especially for smaller banks, which have smaller fuses. It is probably not severe enough to explain all nuisance fuse operations.

7.6.2 Fusing Guidelines

Because of the industry issues with nuisance fuse operations, EPRI recommended using both a larger fuse and a slower fuse than is normally used (EPRI 1002154, 2004;

EPRI 1010655, 2005). With these guidelines, pick the next largest fuse current rating meeting the following criteria:

- K links: 1.65 × capacitor rated current
- T links: 1.35 × capacitor rated current

Do not use the overload capability of the fuse in any case. Do not use less than a 15 T or 20 K fuse. For candidate fuses larger than a 65 T or 80 K, make sure that the fuse total clearing curve coordinates with capacitor rupture curves. Table 7.12 shows an example application of these guidelines on a 12.47-kV system. These guidelines are not for ungrounded banks or paper or film/paper capacitors. In addition, these guidelines are only for distribution line capacitors with one capacitor unit per phase. For group fusing with one fuse protecting more than one capacitor unit, refer to rupture curves to ensure proper protection.

Larger, slower fuses should help with lightning, outrush to faults, harmonics, and steady-state overvoltages.

In an informal survey of utility capacitor fusing schedules, most utilities fuse capacitors tightly. Figure 7.21 compares EPRI and IEEE fusing criteria to fusing ratios used by several different utilities as a function of capacitor bank size (survey source: EPRI 1002154, 2004). Several utility data points are below even the 0.9 fusing ratio.

Preventing case ruptures is a primary goal of fusing—the fuse should clear before capacitor cases fail. Figure 7.22 shows capacitor rupture curves compared against fuse clearing curves. The graph shows that there is considerable margin between rupture curves and fuse sizes traditionally used. Consider a 12.47-kV, 900-kvar bank of three 300-kvar units, which has a nominal current of 41.7 A. Utilities commonly use a 40- or 50-K fuse for this bank. The EPRI fusing guidelines of a 65 T or an 80 K are below the rupture curves in Figure 7.22 for short circuits under 9 kA, and even an 80 T coordinates below 8 kA. An EPRI survey found that case ruptures on modern film-foil capacitors are rare (EPRI 1001691, 2002). This gives us confidence that we can loosen fusing practices without having rupture problems.

In areas of high fault current, current-limiting fuses provide extra safety. Either a backup current-limiting fuse in series with an expulsion link or a full-range current-limiting fuse is an appropriate protection scheme in high fault-current areas. While it

TABLE 7.12 Example Fuse Application Guidelines for a 12.47/7.2-kV System

Three-Phase kvar	Rated Capacitor Current, A	Traditional Fuse	New Fuse Guidelines	
			K	T
150	6.9	8 T	20 K	15 T
300	13.9	15 T	25 K	20 T
450	20.8	20 T	40 K	30 T
600	27.8	25 T	50 K	40 T
900	41.7	40 K	80 K	65 T
1200	55.6	50 K	80 K or 100 K[a]	80 T[a]

Source: From EPRI 1002154, Improved Reliability of Switched Capacitor Banks and Capacitor Technology: Fusing Recommendations and Using Distribution Capacitors for Transmission Support, Electric Power Research Institute, Palo Alto, CA, 2004. Copyright 2004. Reprinted with permission.

[a]Check capacitor rupture curves.

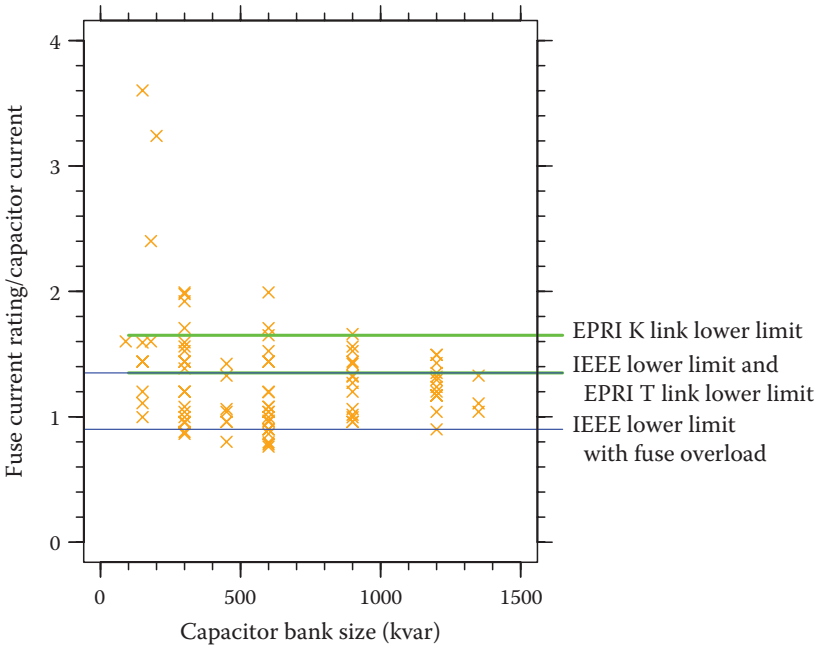

Figure 7.21 Fusing ratios for capacitor banks. (From EPRI 1002154, *Improved Reliability of Switched Capacitor Banks and Capacitor Technology: Fusing Recommendations and Using Distribution Capacitors for Transmission Support*, Electric Power Research Institute, Palo Alto, CA, 2004. Copyright 2004. Reprinted with permission.)

may seem that expulsion fuses provide adequate protection even to 8 kA (depending on which rupture curve we use), current-limiting fuses provide protection for those less frequent faults with longer internal arcs. They also provide protection against failures in the capacitor switches and other capacitor-bank accessories. Utilities that apply current-limiting fuses on capacitors normally do so for areas with fault currents above 3–5 kA.

With backup current-limiting fuses, it is important that crews check the backup fuse whenever the expulsion link operates. On transformers, crews can get away with replacing the expulsion link. If the transformer still does not have voltage, they will quickly know that they have to replace the backup link. But, on capacitors, there is no quick indication that the backup fuse has operated. Crews must check the voltage on the cutout to see if the backup fuse is operational, or crews should check the capacitor neutral current after replacing the expulsion link to make sure it is close to zero (if all three phases are operational, the balanced currents cancel in the neutral). In addition to not fixing the problem, failing to replace a blown backup fuse could cause future problems. The backup fuse is not designed to hold system voltage continuously—they are not an insulator. Eventually, they will track and arc over.

Because of utility problems with nuisance fuse operations, loosening of fusing practices is in order. For most of the possible causes of nuisance-fuse operations, increasing the fuse size will decrease the number of false operations. Going to a slower fuse, especially, helps with outrush and other fast transients.

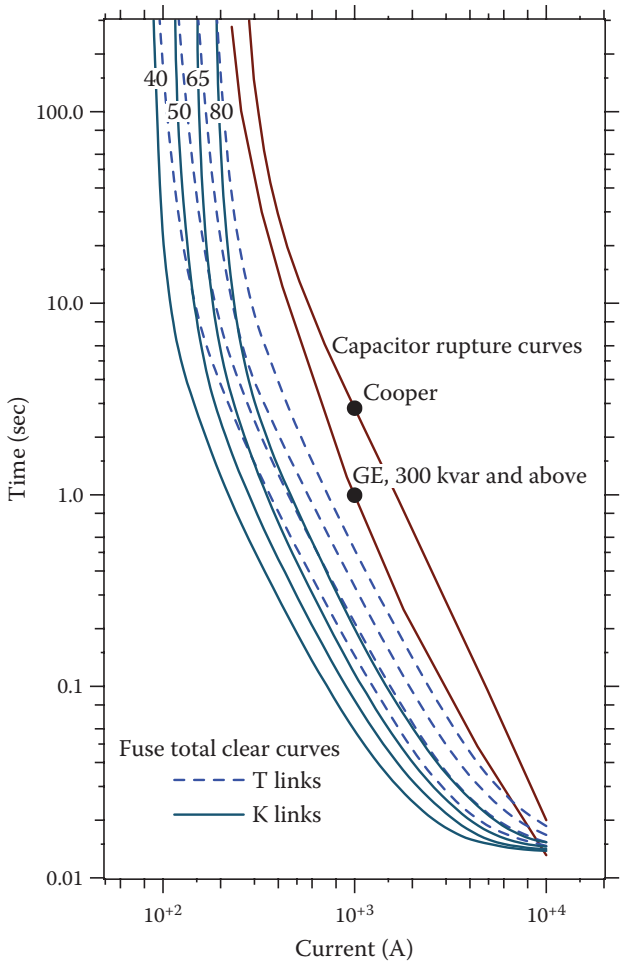

Figure 7.22 Fuse curves with capacitor rupture curves. (From EPRI 1002154, *Improved Reliability of Switched Capacitor Banks and Capacitor Technology: Fusing Recommendations and Using Distribution Capacitors for Transmission Support*, Electric Power Research Institute, Palo Alto, CA, 2004. Copyright 2004. Reprinted with permission.)

7.6.3 Mechanical and Thermal Issues with Cutouts

Cutout-related issues are important considerations for capacitor banks. Williams (2009) reported that Progress Florida has had 20 feeder lockouts in one year due to capacitor fuses failing to clear. Progress Florida's tests and investigations found two main problems:

- *Water entry*—Fuses left open in cutouts can fill with water. Water entering the fuse-holder can damage the fuse tube lining. With a damaged lining, a fuse can have trouble clearing low-current faults.
- *Loose fuse connections*—If crews do not tighten the cap of the fuse barrel enough, the barrel of the cutout will get heated excessively because the threads of the barrel make a high-resistance connection.

Many utilities switch capacitors seasonally. The most common way is for crews to open cutouts. The best way to do this is to remove each fuseholder from its cutout and hang the fuseholders by their pull rings. If left open in the cutout, water can easily enter through the open end. Water can damage the fuse tube liner and the cardboard tube surrounding the fuse element. These two elements both help when clearing low-current faults. Expulsion fuses have the most difficult time clearing high fault currents and low fault currents. For low fault currents, the fuse liner and the cardboard tube melt to release nonionized gas that helps quench the arc.

On capacitors, a partial unit failure causes a low-current fault. If the water-degraded cutout cannot clear the fault, the fuse assembly may melt down, causing a fault on the system.

Heat from loose fuse connections can also facilitate cutout failure. Heat can weld the cutout's contacts, so it cannot drop clear. If the cutout cannot drop clear, the whole assembly can fail. If the fuse clears, but the cutout sticks, the fuse tube will be supporting line-to-neutral voltage. Since the fuse tube is not rated to support this voltage, tracking will start and eventually lead to flashover.

Williams (2009) reported field temperatures approaching 200°F (93°C) for a fuse tube with a loose cap. Williams recommends tightening caps to 20 ft-lbs. Fuses with removable buttonheads should also be tightened. Sullivan (2002) reported that loose fuseholder caps were the most common problem found from infrared thermal inspections. Sullivan also found other issues at cutouts, including cutouts with a design issue that allowed overtravel, so the fuse barrel could overlatch, reducing the contact area. Sullivan also identified issues with hinges with improperly seated fuseholders, loose clamping nuts on the tail of the fuse, and poor connections where the incoming lead was connected. Contamination—dirt, for example—between the cap of the fuseholder and the cutout can also cause heating as shown in Figure 7.23. Any of these causes of poor connections can cause heating as shown in Figure 7.24. One utility that had problems with cutouts on capacitor banks had better results with dual-venting fuse-holders.

Heat can burn away the cardboard tube surrounding the fuse element. The cardboard tube provides the fusing assembly with extra ability to clear low-current faults.

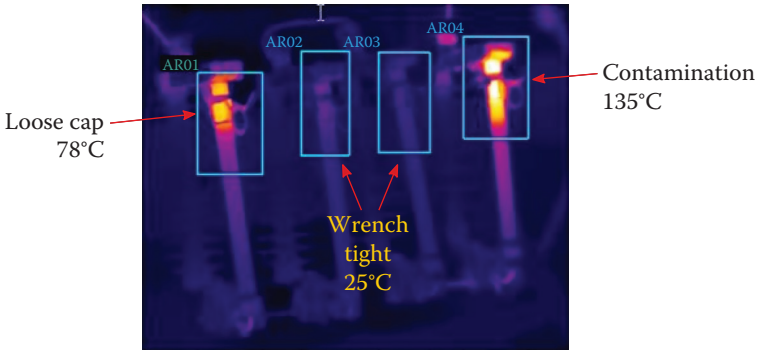

Figure 7.23 Infrared image of cutouts under test. (From Electric Power Research Institute. Copyright 2013. With permission.)

Figure 7.24 Hot capacitor cutout. Note the blown fuse on another phase. (Courtesy of Osmose Utilities Services, Inc.)

Extra heating is more likely in a capacitor cutout because a capacitor is always running at nearly full load. Heat may also allow the spring in the top of the cutout to relax, which could lead to even worse contact between the fuseholder and the top of the cutout. In severe cases, arcing may damage the cutout as in Figure 7.25.

Cutout thermal issues can increase the chance of nuisance fuse operations. The extra heat could force the system into thermal runaway and operate the fuse, especially if the fuse is subject to another stress—overvoltage, harmonics, or a transient. The "preload" from heat due to poor connections can make a fuse much more likely to operate from outrush for example. Excess heat can also melt the solder joint in some fuse links, so the link can pull apart even though the fuse element has not melted.

Figure 7.25 Cutout damaged by arcing in the field.

Ways to reduce problems with cutouts include

- *Tighten fuseholder caps*—Make sure crews tighten the fuseholder cap with a wrench.
- *Tighten other connections*—Connections that might affect the thermal performance of the fuse include: the button on the top of screw-on fuse links, the connection at the top of the cutout, and the clamping nut holding the tail of the fuse.
- *Alignment*—Watch for overtravel, a problem on certain cutouts, as well as other factors that can cause poor contacts.
- *Conductive grease*—Used between the fuseholder cap and the top of the cutout, grease can help maintain good contact between the fuse tube and the top of the cutout and reduce contamination.
- *Infrared inspections*—Many cutout-related issues can be found.
- *Do not leave fuses open in cutouts*—Have crews hang fuseholders by the pull ring.
- *Fuse liner*—Crews should inspect the fuse liner whenever they replace the fuse element, and replace it if the liner has deteriorated. A water-resistant synthetic fuse liner is another option to investigate for reducing the possibility of water damage to fuse liners.
- *Arcing damage*—If crews identify arcing damage on the fuse cap, it should be replaced or burrs should be filed down, or the damaged fuseholder cap will continue to cause heating issues.

Before reinstalling fuses on capacitors, crews should check that the capacitor cans are intact with no bulging or otherwise deformed capacitor cans and that switches do not show outward signs of problems. Many of these suggestions also apply to cutouts on other parts of the distribution system, but they are most applicable to distribution capacitors because of their history with problems.

7.6.4 Neutral Monitoring

Neutral monitoring (Figure 7.26) is another protection feature that some capacitor controllers offer. Neutral monitoring can detect several problems:

- *Blown fuse*—When one capacitor fuse blows, the neutral current jumps to a value equal to the phase current.
- *Failing capacitor unit*—As a capacitor fails, internal groups of series packs short out. Prior to complete failure, the unit will draw more current than normal. Figure 7.27

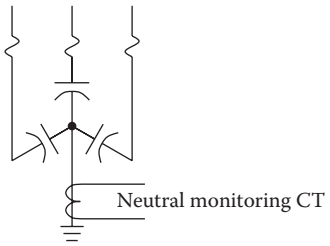

Figure 7.26 Neutral monitoring of a capacitor bank.

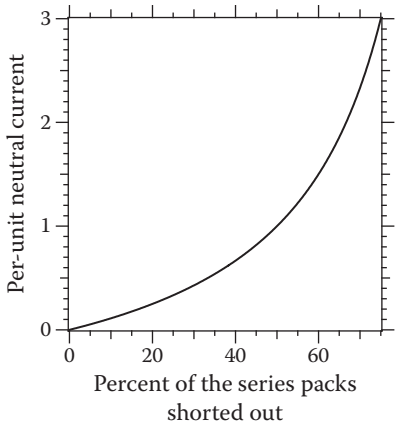

Figure 7.27 Neutral current drawn by a failing grounded-wye bank depending on the portion of the bank that is failed (the neutral current is in per unit of the nominal capacitor current).

shows how the neutral current changes when a certain portion of the capacitor shorts out. Capacitors rated from 7.2 to 7.96 kV normally have three or four series sections, so failure of one element causes neutral currents of 25% (for four in series) or 34% (for three in series) of the phase current. Failure of more than half of the series sections causes more than the capacitor's rated current in the neutral.

- *High harmonic current*—Excessive neutral current may also indicate high harmonic currents.

Neutral monitoring is common in substation banks, and many controllers for switched pole-mounted banks have neutral-monitoring capability. Neutral-current monitors for fixed banks are also available, either with a local warning light or a wireless link to a centralized location.

Neutral monitoring can help reduce operations and maintenance by eliminating regular capacitor patrols and field checks. Quicker replacement of blown fuses also reduces the time that excessive unbalance is present (and the extra losses and possibility of stray voltage). This can lead to more reliable var regulation, and even reduce the number of capacitor banks needed. Georgia Power developed a low-cost neutral monitor based on an AMI meter and a meter socket adapted with a current transformer (EPRI 1026447, 2012; Holsomback, 2013). See Figure 7.28. They used a 15-A threshold to detect problems. This installation allowed Georgia Power to find and fix capacitor issues more quickly and to eliminate annual patrols. Georgia Power also developed a mobile app that field personnel can use to enter failure information.

7.7 Grounding

Three-phase capacitors can be grounded in a wye configuration or ungrounded, in either a floating wye or a delta. For multigrounded distribution systems, a grounded-wye capacitor bank offers advantages and disadvantages:

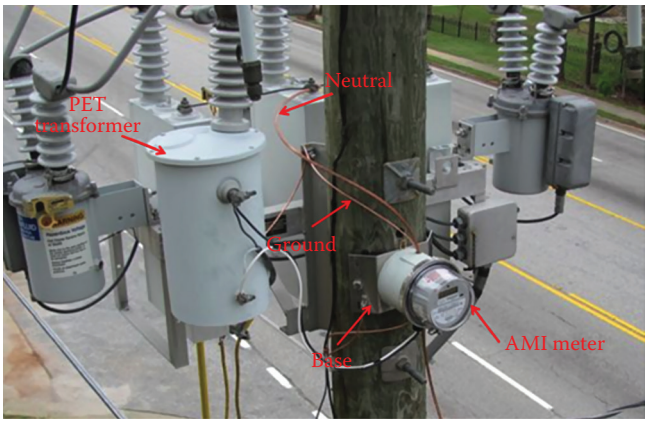

Figure 7.28 Neutral current monitor using AMI. (Courtesy of Georgia Power.)

- *Unit failure and fault current*—If a unit fails, the faulted phase draws full fault current. This allows the fuse to blow quickly, but requires fuses to be rated for the full fault current.
- *Harmonics*—The grounded-wye bank can attract zero-sequence harmonics (balanced 3rd, 9th, 15th, . . .). This problem is often found in telephone interference cases.

The advantages and disadvantages of the floating-wye, ungrounded banks include

- *Unit failure*—The collapse of voltage across a failed unit pulls the floating neutral to phase voltage. Now, the neutral shift stresses the remaining capacitors with line-to-line voltage, 173% of the capacitor's rating.
- *Fault current*—When one unit fails, the circuit does not draw full fault current—it is a high-impedance fault. This is an advantage in some capacitor applications.
- *Harmonics*—Less chance of harmonic problems because the ungrounded, zero-sequence harmonics (balanced 3rd, 9th, 15th, . . .) cannot flow to the ground through the capacitor.

The response of the floating-wye configuration deserves more analysis. During a progressive failure, when one series section shorts out, the shift of the neutral relieves the voltage stress on the remaining series sections. In the example in Figure 7.29, for a floating-wye bank with half of the series sections shorted, the line-to-neutral voltage becomes 0.75 per unit. The remaining elements normally see 50% of the line-to-neutral voltage, but now they see 75% (1.5 per unit, so the current is also 1.5 times normal). The reduction in voltage stress due to the neutral shift prolongs the failure—not what we want. The excess heating at the failure point increases the risk of gas generation and case rupture. When one element fails, we really want the fuse (or other protection) to trip quickly. The neutral shift also increases the voltage stress on the units on the other phases.

Floating-wye configurations are best applied with neutral detection—a potential transformer measuring voltage between the floating neutral and ground can detect a

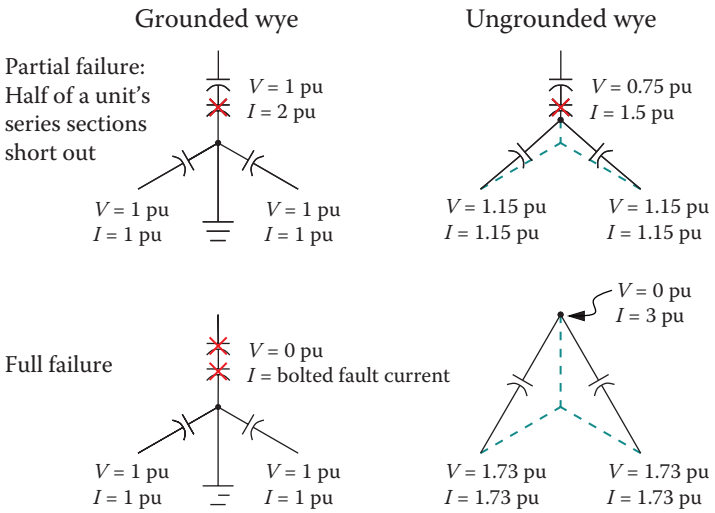

Figure 7.29 Comparison of grounded-wye and ungrounded-wye banks during a partial and full failure of one unit. (From EPRI 1001691, *Improved Reliability of Switched Capacitor Banks and Capacitor Technology*, Electric Power Research Institute, Palo Alto, CA, 2002. Copyright 2002. Reprinted with permission.)

failure of one unit. When one unit fails, a relay monitoring the neutral PT should trip the capacitor's oil or vacuum switch (obviously, this only works on switched banks).

Standard utility practice is to ground banks on multigrounded systems. Over 80% of the respondents to an EPRI survey used grounded-wye capacitor connections (EPRI 1001691, 2002). On three-wire systems, utilities use both ungrounded-wye and delta configurations.

Most utilities use two-bushing capacitors, even though most also use a grounded neutral. Having two bushings allows crews to convert capacitor banks to a floating neutral configuration if telephone interference is a problem.

Utilities universally ground capacitor cases on pole-mounted capacitors (even though it is not strictly required by the National Electrical Safety Code [IEEE C2-2012]). In rare cases, banks with single-bushing capacitors are floated when it becomes necessary to convert a bank to a floating-wye. Avoid this if possible.

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Closing in on a capacitor w/a 8' stick is banned on our property.

I hate capacitor's so bad.

Use a loadbuster next time!!

That's what 25ft sally sticks are for

In response to a picture of a fireball above a capacitor bank when closed in from a bucket.

www.facebook.com/ThePowerLineman/posts/10152268170973029
http://goo.gl/m9QryM

8

Faults

Contents

8.1 General Fault Characteristics 368
8.2 Fault Calculations 373
8.2.1 Transformer Connections 378
8.2.2 Fault Profiles 379
8.2.3 Effect of *X/R* Ratio 380
8.2.4 Secondary Faults 384
8.2.5 Primary-to-Secondary Faults 385
8.2.6 Underbuilt Fault to a Transmission Circuit 389
8.3 Fault Location 392
8.4 Limiting Fault Currents 400
8.5 Arc Characteristics 401
8.5.1 Arc Movement and Evolving Faults 403
8.5.2 Damage from Arcs 405
8.5.3 Arc Voltages 408
8.5.4 Arc Voltages and Fault Type 409
8.6 High-Impedance Faults 412
8.7 Equipment Faults 416
8.7.1 Faults in Equipment 417
References 421

Faults kill. Faults start fires. Faults force interruptions. Faults create voltage sags. Tree trimming, surge arresters, animal guards, and cable replacements: these tools reduce faults. We cannot eliminate all faults, but appropriate standards and maintenance practices help in the battle. When faults occur, we have ways to reduce their impacts. This chapter focuses on the general characteristics of faults and specific analysis of common fault types with suggestions on how to reduce them. One of the definitions of a fault is (ANSI/IEEE Std. 100-1992).

Fault: A physical condition that causes a device, a component, or an element to fail to perform in a required manner; for example, a short circuit or a broken wire.

A fault almost always involves a short circuit between energized phase conductors or between a phase and ground. A fault may be a bolted connection or may have some impedance in the fault connection. The term "fault" is often used synonymously with the term "short circuit" defined as (ANSI/IEEE Std. 100-1992)

Short circuit: An abnormal connection (including an arc) of relatively low impedance, whether made accidentally or intentionally, between two points of different potential. (*Note:* The term *fault* or *short-circuit fault* is used to describe a short circuit.)

When a short-circuit fault occurs, the fault path explodes in an intense arc. Local customers endure an interruption, and customers farther away, a voltage sag; faults cause most reliability and power quality problems. Faults kill and injure line operators. Crew operating practices, equipment, and training must account for where fault arcs are likely to occur and must minimize crew exposure.

8.1 General Fault Characteristics

There are many causes of faults on distribution circuits. A large EPRI study was done to characterize distribution faults in the 1980s at 13 utilities monitoring 50 feeders (Burke and Lawrence, 1984; EPRI 1209-1, 1983). The distribution of permanent fault causes found in the EPRI study is shown in Figure 8.1. Many of the fault causes are discussed in more detail in this chapter. Approximately 40% of faults in this study occurred during periods of adverse weather, which included rain, snow, and ice.

Distribution faults occur on one phase, on two phases, or on all three phases. Single-phase faults are the most common. Almost 80% of the faults measured involved only one phase either in contact with the neutral or with ground (see Table 8.1). As another data point, measurements on 34.5-kV feeders found that 75% of faults involved ground (also 54% were phase to ground, and 15% were phase to phase) (Johnston et al., 1978). Most faults are single phase because most of the overall length of distribution lines is single phase, so any fault on single-phase sections would only involve one phase. Also, on three-phase sections, many types of faults tend to occur from phase to ground. Equipment faults and animal faults tend to cause line-to-ground faults. Trees can also cause line-to-ground faults on three-phase structures,

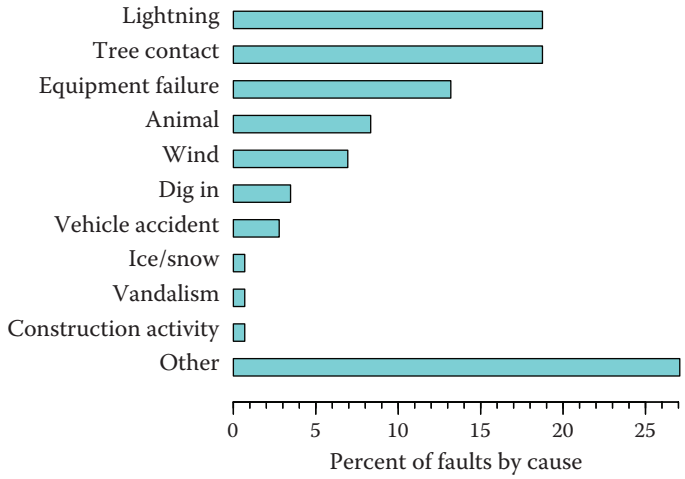


Figure 8.1 Fault causes measured in the EPRI fault study. (Data from Burke, J. J. and Lawrence, D. J., *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-103, no. 1, pp. 1–6, January 1984; EPRI 1209-1, *Distribution Fault Current Analysis*, Electric Power Research Institute, Palo Alto, CA, 1983.)

TABLE 8.1 Number of Phases Involved in Each Fault Measured in the EPRI Fault Study

Fault	Percentage
One phase to neutral	63%
Phase to phase	11%
Two phases to neutral	2%
Three phase	2%
One phase on the ground	15%
Two phases on the ground	2%
Three phases on the ground	1%
Other	4%

Source: Data from Burke, J. J. and Lawrence, D. J., *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-103, no. 1, pp. 1–6, January 1984; EPRI 1209-1, *Distribution Fault Current Analysis*, Electric Power Research Institute, Palo Alto, CA, 1983.

but line-to-line faults are more common. Lightning faults tend to be two or three phases to ground on three-phase structures.

Figure 8.2 shows fault rates found in various studies for predominantly overhead circuits. Ninety faults per 100 mi per year (55 faults/100 km/year) is common for utilities with moderate lightning. Fault rates increase significantly in higher lightning areas. This type of data is difficult to obtain. Utilities more commonly track faults that cause sustained interruptions, interruptions that contribute to reliability indices such as SAIDI (some data on these faults is shown in Figure 8.3). The actual fault rates are higher than this because many temporary faults are cleared by reclosing circuit breakers or reclosers.

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

A temporary fault does not permanently damage any system equipment. If the circuit is interrupted and then reclosed after a delay, the system operates normally.

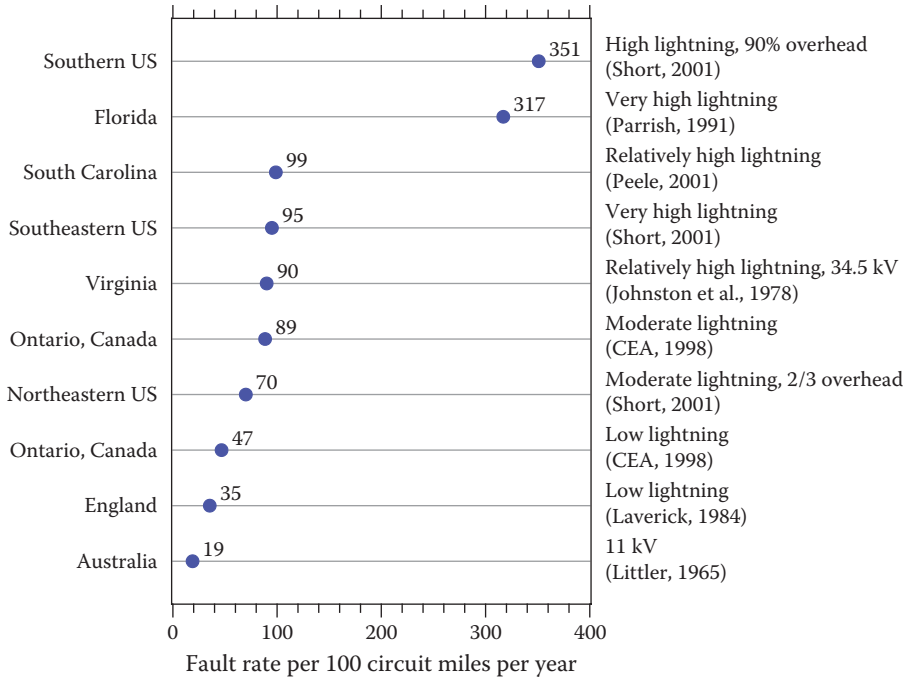


Figure 8.2 Fault rates found in different studies.

Temporary (nondamage) faults make up 50 to 80% of faults on overhead distribution systems. The causes of temporary faults include lightning, conductors slapping together in the wind, tree branches that fall across conductors and then fall or burn off, animals that cause faults and fall off, and insulator flashovers caused by pollution. Temporary faults are the main reason that reclosing is used almost universally on distribution circuit breakers and reclosers (on overhead circuits). Temporary faults will cause voltage sags for customers on the circuit with the fault and possibly for customers on adjacent feeders. Temporary faults cause sustained interruptions if the fault is downstream of a fuse, and fuse saving is not used or is not successful. For temporary faults on the feeder backbone, all customers on the circuit are momentarily interrupted. Faults that are normally temporary can turn into permanent faults. If the fault is allowed to remain too long, the fault arc can do permanent damage to conductors, insulators, or other hardware. In addition, the fault current flowing through equipment can do damage. The most common damage of this type is to connectors or circuit interrupters such as fuses.

The majority of faults on overhead distribution circuits are temporary. The data in Figure 8.4 confirms the widely held belief that 50–80% of faults are temporary. This very limited dataset shows high-lightning areas with lower percentages of temporary faults. This contradicts the notion that temporary faults are higher in areas with more lightning. Storms with lightning and wind should cause more temporary faults.

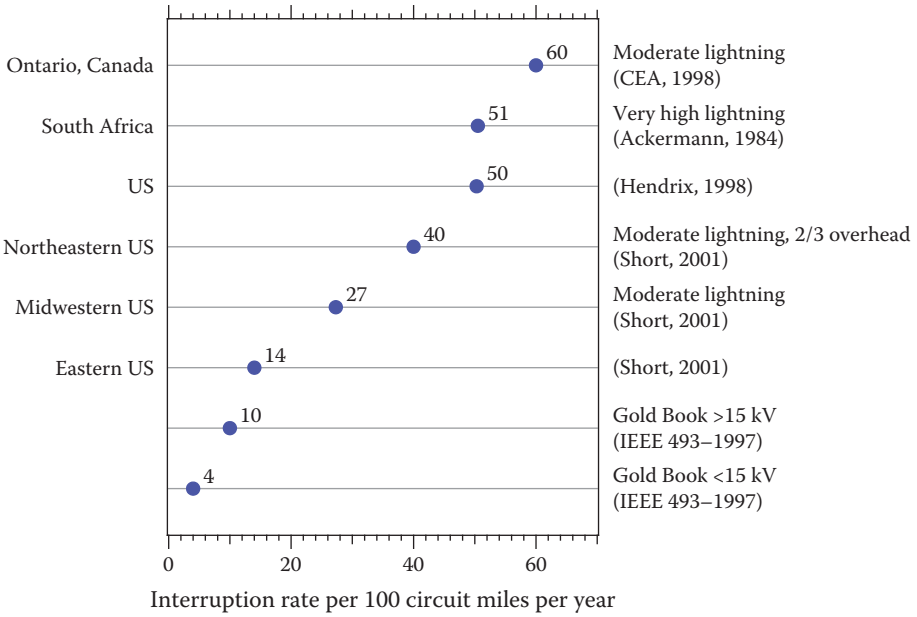


Figure 8.3 Fault rates for faults that cause sustained interruptions.

Determining the percentage of faults that are temporary versus permanent is complicated. For faults that operate fuses, it is easy. If it can be successfully re-fused without any repair, the fault is temporary:

$$\text{Percent permanent} = \frac{\text{Fuses replaced after repair}}{\text{Total number of fuse operations}} \times 100\%$$

Circuit breaker or recloser operations are difficult. If *fuse blowing* is used, where tap fuses always operate before the circuit breaker or recloser, the percentage of temporary faults cleared by circuit breakers and reclosers is

$$\text{Percent permanent} = \frac{\text{Number of lockouts}}{\text{Number of lockouts} + \text{Number of successful reclose sequences}} \times 100\%$$

A SCADA system produces these numbers, but if this information is not available, the percentage can be approximated using circuit breaker count numbers:

$$\text{Percent permanent} = \frac{l}{n - r \cdot l} \times 100\%$$

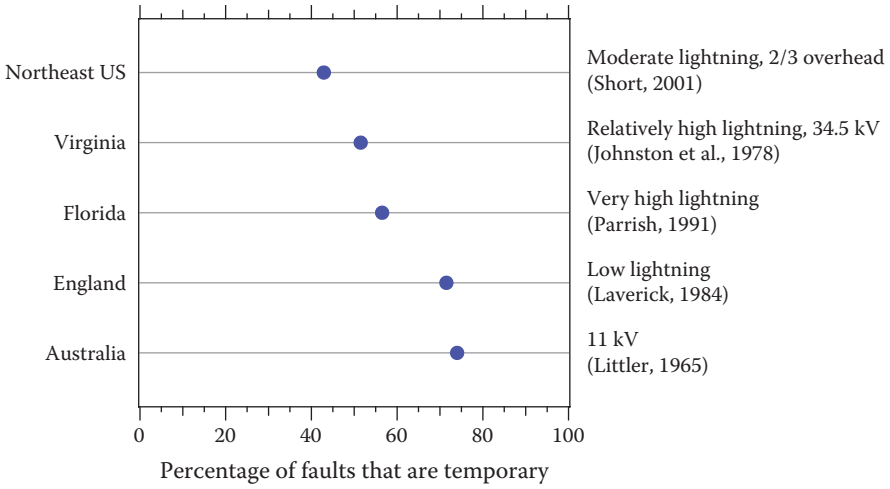


Figure 8.4 Percentage of faults that are permanent (on predominantly overhead circuits).

where

n = total number of circuit breaker (or recloser) operations
r = number of reclose attempts before lockout (there are $r + 1$ circuit breaker operations during a lockout cycle)
l = number of lockouts

If *fuse saving* is used, where the circuit breaker operates before lateral fuses, then it is more difficult to estimate the number of temporary faults. For the whole circuit (it is not possible to separate the faults on the mains from the faults on the taps), we can estimate the percentage as follows:

$$\text{Percent permanent} = \frac{l + f}{l + s + f_2} \times 100\%$$

where

s = number of successful reclose sequences
f = number of fuses replaced following repair (not including nuisance fuse operations)
f_2 = number of fuse operations that are not coincident with circuit breaker trips

f_2 should be close to zero, since the circuit breaker should operate for all faults. Assuming f_2 is zero (which may have to be done, since this is a difficult number to obtain) implies no nuisance fuse operations without a circuit breaker operation. It is difficult for an outage data management system to properly determine the number of temporary faults.

Faults frequently occur near the peak of the voltage waveform as shown in Figure 8.5. About 60% of the faults in the EPRI fault study occurred when the voltage was

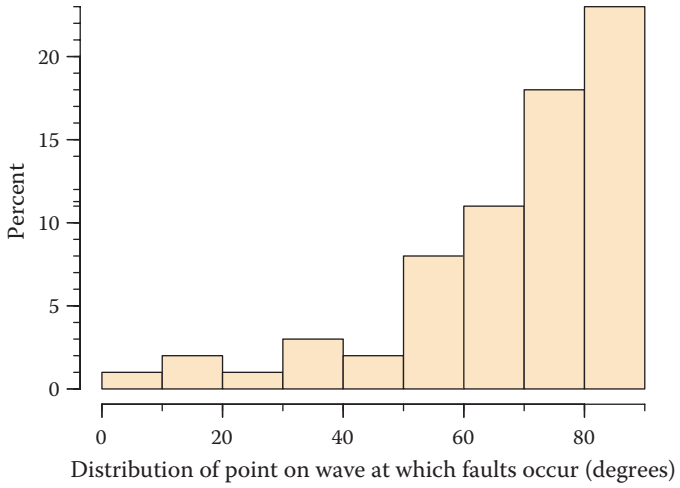


Figure 8.5 Point of fault on the voltage waveform. (Data from Burke, J. J. and Lawrence, D. J., *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-103, no. 1, pp. 1–6, January 1984; EPRI 1209-1, *Distribution Fault Current Analysis*, Electric Power Research Institute, Palo Alto, CA, 1983.)

within 5% of the peak prefault voltage (where the angle was 70 to 90°). This is reasonable. Any insulation failure, whether it be a squirrel breaching a bushing or a failure in a cable, more likely strikes with the voltage at or near its peak. Some faults defy this pattern. Lightning faults happen at any point on the voltage waveform because the fault occurs when the lightning strikes (although lightning can cause a flashover but not a fault if the voltage is very close to a zero-crossing of the power-frequency voltage). Two-phase and three-phase faults create more instances in which the voltage is not near its peak.

8.2 Fault Calculations

The magnitude of fault current is limited only by the system impedance and any fault impedance. The system impedance includes the impedances of wires, cables, and transformers back to the source. For faults involving ground, the impedance includes paths through the earth and through the neutral wire. The impedance to the fault depends on the type of fault.

Most distribution primary circuits are radial, with only one source and one path for fault currents. Figure 8.6 shows equations for calculating fault currents for common distribution faults.

The equations in Figure 8.6 assume that the positive-sequence impedance is equal to the negative-sequence impedance. As an example, the impedance term due to the sequence components for a line-to-line fault is $(Z_1 + Z_2)$, which simplifies to $2Z_1$ when the impedances are assumed to be equal. This is accurate for virtually all distribution circuits. With a large generator nearby, the equivalent circuit may have different

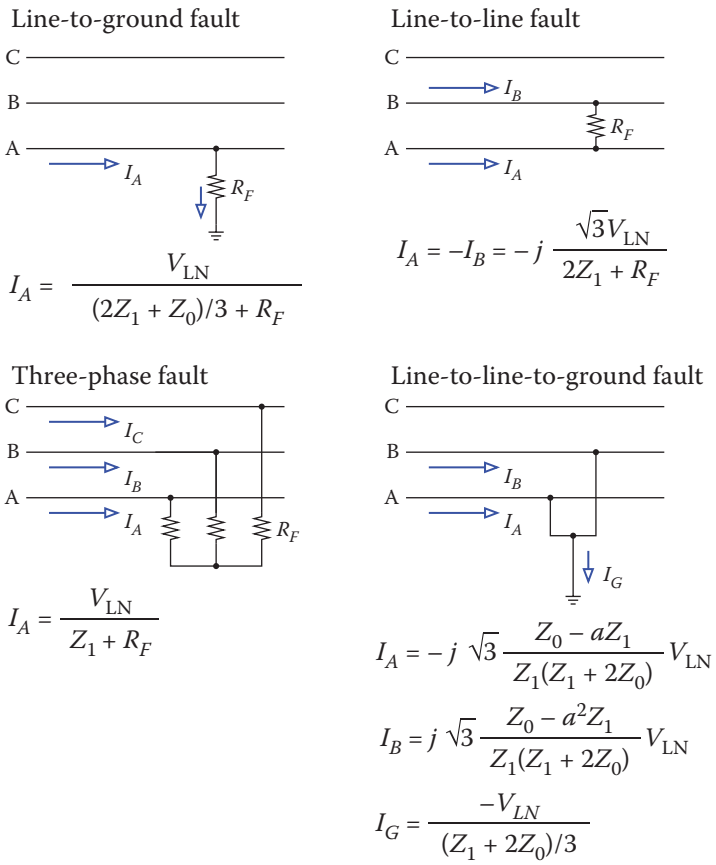


Figure 8.6 Fault-current calculations.

positive- and negative-sequence impedances (but that case is usually done on the computer and not with hand calculations). The maximum currents occur with a bolted fault where R_F is zero. The maximum current for a line-to-line fault is 86.6% of the maximum three-phase fault current. In all cases, the load current is ignored. In most cases, load will not significantly change results.

The three-phase fault current is almost always of the highest magnitude. On most circuits, the zero-sequence impedance is significantly higher than the positive-sequence impedance. One important location where the line-to-ground fault current may be higher is at the substation. There are two reasons for this:

1. A delta–wye transformer is a zero-sequence source. The positive-sequence impedance includes the impedance of the subtransmission and transmission system. The zero-sequence impedance does not. Figure 8.7 shows the sequence diagrams for the positive and zero sequences. The delta–wye connection forms a zero-sequence source while the positive-sequence impedance includes the subtransmission equivalent impedance.

2. If the substation transformer has three-legged core-form construction, the zero-sequence impedance is lower than its positive-sequence impedance. Typically, the zero-sequence impedance is 85% of the positive-sequence impedance, which increases ground-fault currents by 5.2%.

In cases where the zero-sequence impedance is less than the positive-sequence impedance, the line-to-ground fault gives the highest phase current. The double line-to-ground fault produces the highest-magnitude ground current.

In order to reduce fault currents for line-to-ground faults, a neutral reactor on the station transformer is sometimes used. Figure 8.8 shows the equations for faults involving ground for circuits with a neutral reactor (the line-to-line fault and the three-phase fault are not affected). A common value for a neutral reactor is 1 Ω for 15-kV class distribution circuits.

The impedance seen by line-to-ground faults is a function of both the positive- and zero-sequence impedances. This important loop impedance is $Z_S = (2Z_1 + Z_0)/3$. The sequence impedances, Z_1 and Z_0, used in the fault calculations include the sum of the impedances with both resistance and reactance along the fault current path. Some of the common branch impedances are given below, including some rule-of-thumb values that are useful for hand calculations:

- Overhead lines:
  - $|Z_1| = 0.5$ Ω/mi (0.3 Ω/km)
  - $|Z_S| = 1$ Ω/mi (0.6 Ω/km)
- Underground cables:
  - $|Z_1| = 0.6$ Ω/mi (0.35 Ω/km)
  - $|Z_S| = 0.5$ Ω/mi (0.3 Ω/km)
- Substation transformer:
  - $|Z_1| = |Z_S| = 1$ Ω

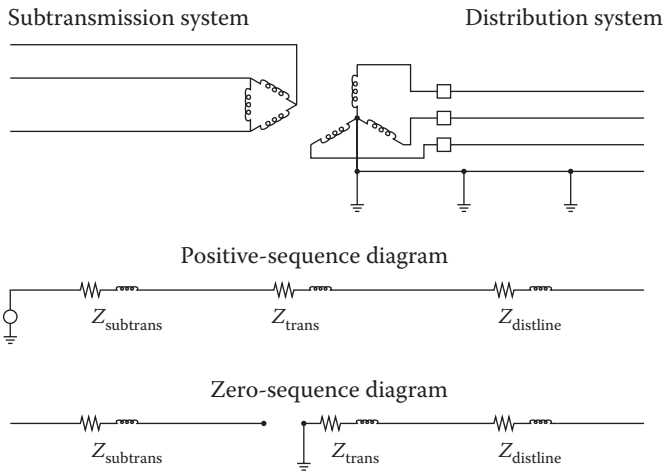


Figure 8.7 Positive- and zero-sequence diagrams for a delta–wye substation transformer.

- A typical 15-kV substation transformer impedance is 1 Ω, which corresponds to a bus fault current of 7.2 kA for a 12.47-kV circuit
- Subtransmission equivalent: often can be ignored

See Smith (1980) for an excellent paper on fault calculations for additional information. Include impedances for step-down transformer banks, series reactors, and voltage regulators. Use the rule-of-thumb numbers above for back-of-the-envelope calculations and as checks for computer modeling.

The simplified equation for a transformer impedance is

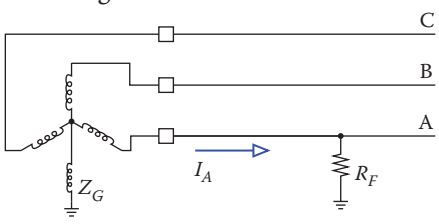
$$Z_1 = Z_0 = j\frac{kV^2}{MVA}Z_{\%}$$

where

kV = line-to-line voltage
MVA = transformer base rating—open air (OA) rating
$Z_{\%}$ = transformer impedance, per unit

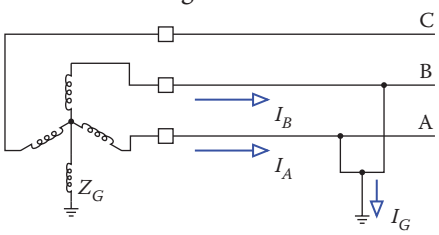
We ignore the resistive component since the X/R ratio of station transformers is generally greater than 10 and often in the range of 20 to 30. The transmission/subtransmission equivalent is usually small, and we often ignore it (especially for calculating maximum fault currents). Include the transmission system impedance for weak subtransmission systems such as 34.5-, 46-, or 69-kV circuits, or for very large substations. Find the transmission equivalent from the per unit impedances

Line-to-ground fault



$$I_A = \frac{V_{\text{LN}}}{(2Z_1 + Z_0)/3 + R_F + Z_G}$$

Line-to-line-to-ground fault



$$I_A = -j\sqrt{3}\frac{Z_0 + 3Z_G - aZ_1}{Z_1(Z_1 + 2Z_0 + 6Z_G)}V_{\text{LN}}$$

$$I_B = j\sqrt{3}\frac{Z_0 + 3Z_G - a^2Z_1}{Z_1(Z_1 + 2Z_0 + 6Z_G)}V_{\text{LN}}$$

$$I_G = \frac{-V_{\text{LN}}}{(Z_1 + 2Z_0 + 6Z_G)/3}$$

Figure 8.8 Fault-current calculations with a neutral reactor on the substation transformer.

(r_1, x_1, r_0, and x_0) on a given MVA base referred to the distribution voltage (Smith, 1980) as

$$Z_1 = (r_1 + jx_1)\frac{kV_s^2}{MVA_b}\left(\frac{kV_{pb}}{kV_p}\right)^2$$
$$Z_0 = (r_0 + jx_0)\frac{kV_s^2}{MVA_b}\left(\frac{kV_{pb}}{kV_p}\right)^2$$

where

MVA_b = base MVA at which the r and x impedances are given
kV_s = line-to-line voltage in kV on the secondary side of the station transformer
kV_p = line-to-line voltage in kV on the primary
kV_{pb} = base line-to-line voltage on the primary used to calculate MVA_b (often equal to kV_p)

If the transmission impedances are available as a fault MVA with a power factor, find the transmission equivalent (Smith, 1980) with

$$Z_1 = \frac{kV_s^2}{MVA}(pf + j\sqrt{1 - pf^2})\left(\frac{kV_{\text{pb}}}{kV_p}\right)^2$$
$$Z_0 = \frac{\sqrt{3}kV_s^2}{kI_g \cdot kV_{\text{pb}}}(pf_g + j\sqrt{1 - pf_g^2})\left(\frac{kV_{\text{pb}}}{kV_p}\right)^2 - 2Z_1$$

where

MVA = three-phase short-circuit MVA at the primary terminals of the station transformer (see Table 8.2 for typical maximum values)
kI_g = available ground-fault current in kA at the primary terminals of the station transformer
pf = power factor in per unit for the available three-phase fault current
pf_g = power factor in per unit for the available single-phase fault current

While almost all distribution circuits are radial, there may be other fault current sources. We ignore these other sources most of the time, but occasionally, we consider motors and generators in fault calculations. Synchronous motors and generators contribute large currents relative to their size. On a typical 15-kV class distribution circuit, 1 or 2 MW worth of connected synchronous units are needed to significantly affect fault currents. On weaker circuits, smaller units can impact fault currents. Induction motors and generators also feed faults. Inverter-based distributed generation can contribute fault current, but generally much less than

TABLE 8.2 Typical Maximum Transmission/Subtransmission Fault Levels

Transmission Voltage, kV	Maximum Symmetrical Fault, MVA
69	3000
115	5000
138	6000
230	10,000

synchronous or induction units. Of course, on feeders that have network load, current through network transformers backfeeds faults until the network protectors operate.

8.2.1 Transformer Connections

The fault current on each side of a three-phase transformer connection can differ in magnitude and phasing. In the common case of a delta–grounded-wye connection, the current on the source side of the transformer differs from the currents on the fault side for line-to-ground or line-to-line faults (see Figure 8.9). For a line-to-ground fault on the primary side of the transformer, the current appears on two phases on the primary with a per unit current of 0.577 (which is $1/\sqrt{3}$).

These differences are often needed when coordinating a primary-side protective device and a secondary-side device. In distribution substations, this is commonly a fuse on the primary side and a relay controlling a circuit breaker on the secondary side. The line-to-line fault must be considered—this gives more per-unit current on one phase in the primary, 1.15 per unit ($2/\sqrt{3}$) in one of the phases (see Figure 8.9). To make sure a primary fuse coordinates with a secondary device, shift the minimum-melting time–current curve of the primary-side fuse to the left by a factor of $0.866 = \sqrt{3}/2$ (after also adjusting for the transformer turns ratio). The current differences also mean that the transformer is not protected as well for single-phase faults; a primary-side fuse takes longer to clear the single-phase fault since it sees less current than for a three-phase or line-to-line fault.

Fault currents are only different for unbalanced secondary currents. For a three-phase secondary fault, the per-unit currents on the primary equal those on the secondary (with the actual currents related by the turns ratio of the transformer). A

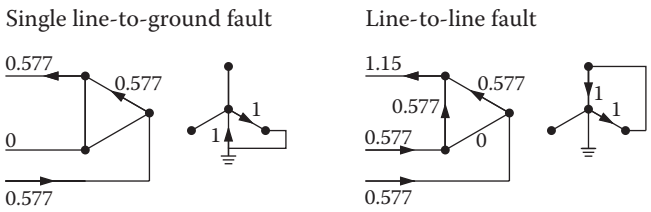


Figure 8.9 Per-unit fault currents on both sides of a delta–grounded-wye transformer.

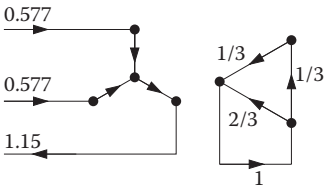


Figure 8.10 Per-unit fault currents on both sides of a wye–delta transformer.

wye–wye transformer does not disturb the current relationships; the per-unit currents on both sides of the transformer are equal.

In a floating wye–delta, similar current relationships exist; a line-to-line secondary fault shows up on the primary side on all three phases, one of which is 1.15 per unit (see Figure 8.10). For a floating-wye–delta transformer with a larger center-tapped lighting leg and two power legs, fault current calculations are difficult. Faults can occur from phase to phase and from phase to the secondary neutral, and the lighting transformer will have a different impedance than the power leg transformers. For an approach to modeling this, see Kersting and Phillips (1996).

8.2.2 Fault Profiles

Fault profiles show fault current with distance along a circuit. Determining where thermal or mechanical short-circuit limits on equipment may be exceeded, helping select or check interrupting capabilities of protective equipment, and coordinating protective devices are important uses of fault profiles. Figures 8.11 and 8.12 show typical fault current profiles of distribution circuits.

Some general trends that the fault profiles show are

- *Distance*—The fault current drops off as the inverse of distance ($1/d$).
- *Ground faults*—On overhead circuits, the ground-fault current falls off faster (and the ground-fault current is generally lower) than the three-phase fault current. The zero-sequence reactance is generally over three times the positive-sequence reactance, and the zero-sequence resistance is also higher than the positive-sequence resistance.
- *System voltage*—On higher-voltage distribution systems, the fault current drops off more slowly. The actual line impedance does not change with voltage ($Z_S \approx 1\ \Omega$/mi), and since $I = V_{LN}/Z$, it takes more impedance (more circuit length) to reduce the fault current.
- *Cables*—Underground cables have much lower reactance than overhead circuits, so the fault current does not fall off as fast on underground circuits. Also, note that X/R ratios are lower on cables.
- *Profiles*—The three-phase and ground-fault profiles of underground cables are similar. The zero-sequence reactance can actually be smaller than the positive-sequence reactance (but the zero-sequence resistance is larger than the positive-sequence resistance).

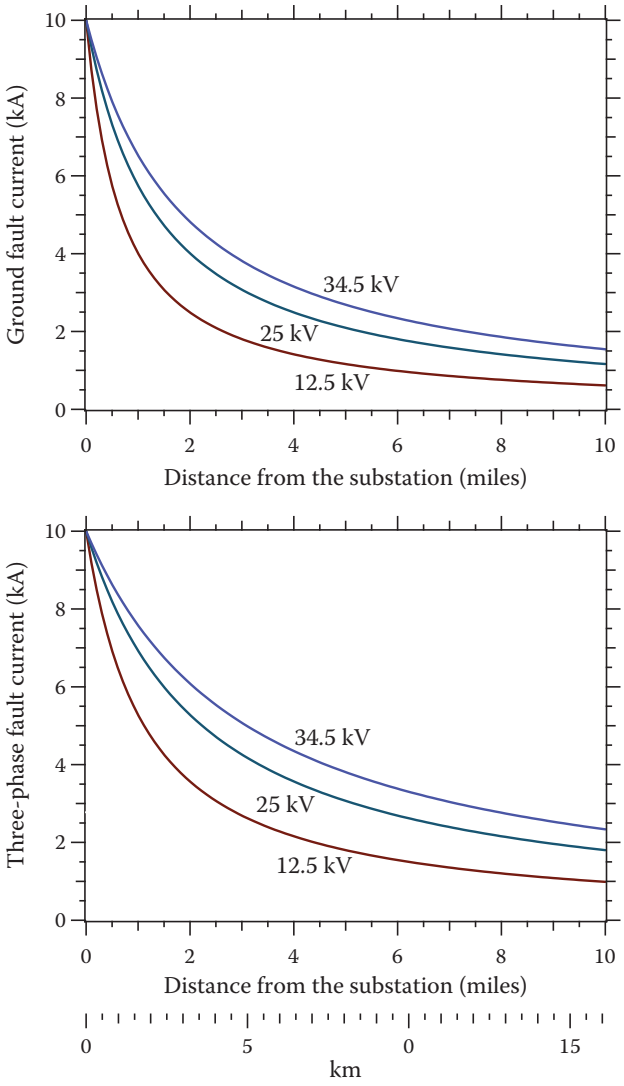


Figure 8.11 Fault-current profiles for line-to-ground faults and for three-phase faults for an overhead circuit. Phase characteristics: 500 kcmil, all-aluminum, GMD = 4.69 ft (1.43 m). Neutral characteristics: 3/0 all-aluminum, 4-ft (1.22-m) line-neutral spacing. $Z_1 = 0.207 + j0.628\ \Omega$/mile ($0.1286 + j0.3901\ \Omega$/km), $Z_0 = 0.720 + j1.849\ \Omega$/mile ($0.4475 + j1.1489\ \Omega$/km), $Z_S = 0.378 + j1.035\ \Omega$/mile ($0.2350 + j0.6430\ \Omega$/km).

8.2.3 Effect of X/R Ratio

In a reactive circuit (high *X/R* ratio), it is naturally more difficult for a protective device such as a circuit breaker to clear a fault. Protective devices clear a fault at a current zero. Within the interruptor, dielectric strength builds up to prevent the arc from reigniting after the current zero. In a resistive circuit (low *X/R* ratio), the voltage

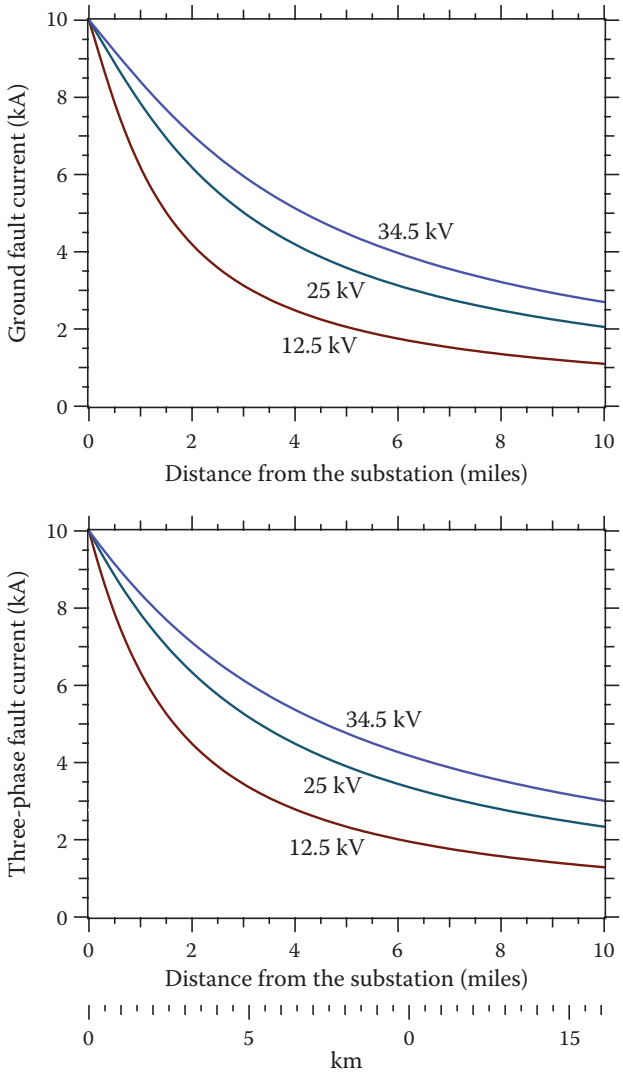


Figure 8.12 Fault-current profiles for line-to-ground faults and for three-phase faults for an underground cable circuit. 500-kcmil aluminum conductor, 220-mil XLPE insulation, 1/3 neutrals, flat spacing, 7.5 in. between cables. $Z_1 = 0.3543 + j0.3596\ \Omega$/mile (0.2201 + j0.2234 Ω/km), $Z_0 = 0.8728 + j0.2344\ \Omega$/mile (0.5423 + j0.1456 Ω/km), $Z_S = 0.5271 + j0.3178\ \Omega$/mile (0.3275 + j0.1975 Ω/km).

and current are in phase, so, after a current zero, a quarter cycle passes before the voltage across the protective device (called the *recovery voltage*) reaches its peak. In a reactive circuit, the fault current naturally lags the voltage by 90°; the voltage peaks at a current zero. Therefore, the recovery voltage across the protective device rises to its peak in much less than a quarter cycle (possibly in 1/20th of a cycle or less), and the fault arc is much more likely to reignite.

Another factor that makes it more difficult for protective devices to clear faults is asymmetry. Circuits with inductance resist a change in current. A short circuit creates a significant change in current, possibly creating an offset. If the fault occurs when the current would naturally be at its negative peak, the current starts at that point on the waveshape but is offset by 1.0 per unit. The dc offset decays, depending on the *X*/*R* ratio. The offset is described by the following equation:

$$i(t) = \underbrace{\sqrt{2}I_{\text{rms}} \sin(2\pi ft + \beta - \theta)}_{\text{ac component}} - \underbrace{\sqrt{2}I_{\text{rms}} \sin(\beta - \theta)e^{-\frac{2\pi ft}{X/R}}}_{\text{decaying dc component}}$$

where

$i(t)$ = instantaneous value of current at time t

I_{rms} = root mean square (rms) value of the ac component of current, $I_{\text{rms}} = V/\sqrt{R^2 + X^2}$

β = the closing angle that defines the point on the waveform at which the fault is initiated

θ = system impedance angle = $\tan^{-1}\frac{X}{R}$

f = system frequency, Hz

t = time, sec

Asymmetry is higher with higher *X*/*R* ratios. The worst-case offset with $X/R = \infty$ is 2 per unit. Figure 8.13 shows an example of an offset fault current.

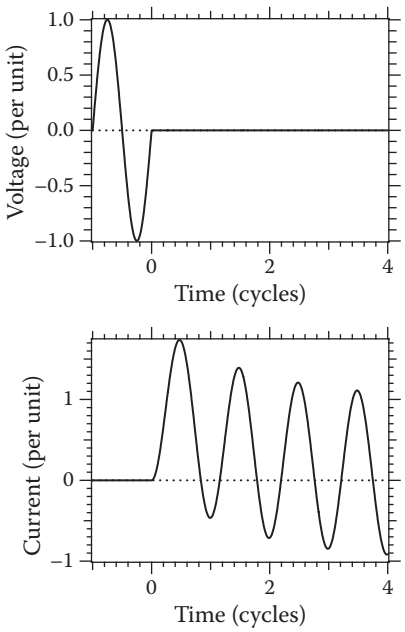


Figure 8.13 Example of an asymmetric fault with $X/R = 10$ that initiated when the closing angle $\beta = 0$, which is when the voltage crosses zero.

If a phase faults at the natural zero crossing ($\beta = \theta$), no offset occurs. The highest magnitude of the dc component occurs when the fault happens 90° from the natural zero crossing of the circuit (when $\beta = \theta \pm \pi/2$). The highest dc offset does not align with the highest peak asymmetric current (which is the sum of the ac and decaying dc component). The peak current occurs when the closing angle $\beta = 0$ for all X/R ratios ($\beta = 0$ when the fault occurs at a voltage zero crossing). The ratio of the peak current I_p to the rms current I_{rms} can be approximated by

$$\frac{I_p}{I_{\text{rms}}} = \sqrt{2}\left[1 + e^{-(\theta+\pi/2)\frac{R}{X}} \sin\theta\right] = \sqrt{2}\left[1 + e^{-\pi\frac{R}{X}}\right] \quad \text{for } \theta = \pi/2$$

This is the most industry-accepted approximation that is used, but it gives an approximation that is slightly low. A more accurate approximation can be found (St. Pierre, 2001) with

$$\frac{I_p}{I_{\text{rms}}} = \sqrt{2}\left[1 + e^{-2\pi\frac{R}{X}\tau}\right]$$

where τ is a fictitious time found with

$$\tau = 0.49 - 0.1e^{-\frac{1}{3}\frac{X}{R}}$$

In addition to causing a higher peak magnitude, asymmetry also causes a longer first half cycle (important for fuse operating time) and much higher first half cycle $\int I^2\,dt$. The occurrence of asymmetry is reduced by the fact that most faults occur when the voltage is near its peak (Figure 8.5). In a circuit with a high X/R ratio, when the voltage is at its peak, the fault current is naturally near zero. Therefore, for most faults, the asymmetry is small, especially for line-to-ground faults. For two- or three-phase faults where each phase is faulted simultaneously (as can happen with lightning), asymmetry is much more likely.

Asymmetry is important to consider for application of cutouts, circuit breakers, and other equipment with fault current ratings. Equipment is generally tested at a given X/R ratio. If the equipment is applied at a location where the X/R ratio is higher, then the equipment may have less capability than the rating indicates. Equipment often has a momentary duty rating, which is the short-time (first-cycle) withstand capability. This is strongly influenced by asymmetry.

Other impacts of asymmetry include

- Asymmetry can saturate current transformers (CTs). On distribution circuits, overcurrent relays should still operate although they could be more susceptible to miscoordination.
- Fuses respond to $\int I^2 dt$, so asymmetrical current melts the link significantly faster.
- Asymmetry can foul up fault-location algorithms in digital relays and fault recorders.

8.2.4 Secondary Faults

Secondary faults vary depending on the transformer connection and the type of fault on the secondary. For a standard single-phase 120/240-V secondary for residential service, two faults are of interest: a fault from a phase to the neutral and a fault from one of the hot legs to the other across the full 240 V. The impedance to the fault includes the transformer plus the secondary impedance. The secondary current for a bolted fault across the 240-V legs (between the two hot legs) is

$$I_{240} = \frac{240}{\sqrt{\left(R_T + \frac{R_S L}{1000}\right)^2 + \left(X_T + \frac{X_S L}{1000}\right)^2}}$$

where

I_{240} = secondary current, symmetrical A rms for a 240-V fault (phase-to-phase)
R_T = transformer full-winding resistance, Ω at 240 V (from terminals X1 to X3)
X_T = transformer full-winding reactance, Ω at 240 V (from terminals X1 to X3)
R_S = secondary conductor resistance to a 240-V fault, Ω/1000 ft
X_S = secondary conductor reactance to a 240-V fault, Ω/1000 ft
L = Distance to the fault, ft

and

$$R_T = 0.0576 \frac{W_{\text{CU}}}{S_{\text{kVA}}^2}$$

$$Z_T = 0.576 \frac{Z_{\%}}{S_{\text{kVA}}}$$

$$X_T = \sqrt{Z_T^2 - R_T^2}$$

where

S_{kVA} = transformer rating, kVA
$W_{\text{CU}} = W_{\text{TOT}} - W_{\text{NL}}$ = load loss at rated load, W
W_{TOT} = total losses at rated load, W
W_{NL} = no-load losses, W
$Z_{\%}$ = nameplate impedance magnitude, %

For a short circuit from one of the hot legs to the neutral, both the transformer and the secondary have different impedances. For the transformer, the half-winding impedance must be used; for the secondary, the loop impedance through the phase and the neutral should be used.

$$I_{120} = \frac{120}{\sqrt{\left(R_{T1} + \frac{R_{S1} L}{1000}\right)^2 + \left(X_{T1} + \frac{X_{S1} L}{1000}\right)^2}}$$

where

I_{120} = secondary current in symmetrical A rms for a 120-V fault (phase-to-neutral)
R_{T1} = transformer half-winding resistance, Ω at 120 V (from terminals X1 to X2)
X_{T1} = transformer half-winding reactance, Ω at 120 V (from terminals X1 to X2)
R_{S1} = secondary conductor resistance to a 120-V fault, Ω/1000 ft
X_{S1} = secondary conductor reactance to a 120-V fault, Ω/1000 ft
L = distance to the fault, ft

In the absence of better information, use the following impedances for transformers with an interlaced secondary winding:

$$R_{T1} = 0.375R_T \quad \text{and} \quad X_{T1} = 0.3X_T$$

And use the following impedances for transformers with noninterlaced secondary windings:

$$R_{T1} = 0.4375R_T \quad \text{and} \quad X_{T1} = 0.625X_T$$

Figure 8.14 shows fault profiles for secondary faults on various size transformers. The secondary is triplex with 3/0 aluminum conductors and a reduced neutral. It has impedances of

$$R_S = 0.211\ \Omega/1000\ \text{ft} \quad X_S = 0.0589\ \Omega/1000\ \text{ft}$$
$$R_{S1} = 0.273\ \Omega/1000\ \text{ft} \quad X_{S1} = 0.0604\ \Omega/1000\ \text{ft}$$

The secondary has significant impedances; fault currents drop quickly from the transformers. Close to the transformer, line-to-neutral faults are higher magnitude. At large distances from the transformer, the secondary impedances dominate the fault currents. Faults across 240 V are normally of higher magnitude than line-to-neutral faults.

Normally in secondary calculations, we can ignore the impedance offered by the distribution primary. The primary-system impedance is usually small relative to the transformer impedance, and neglecting it is conservative for most uses. On weak distribution systems or with large, low-impedance distribution transformers, the distribution system impedance plays a greater role.

8.2.5 Primary-to-Secondary Faults

Faults from the distribution primary to the secondary can subject end-use equipment to significant overvoltages. Figure 8.15 shows a circuit diagram of a fault from the primary to a 120/240-V secondary. This type of fault can occur in several ways: a high-to-low fault within the transformer, a broken primary wire falling into the secondary, or a broken primary jumper. As we will discuss, the transformer helps limit the overvoltage. Having the primary fall on the secondary does not automatically mean primary-scale voltages in customers' homes and facilities.

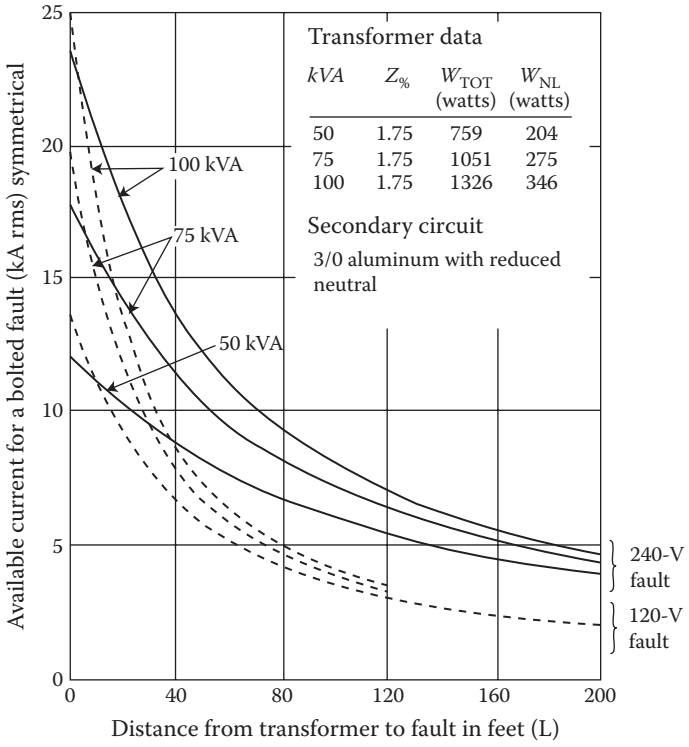


Figure 8.14 Fault profiles for 120/240-V secondary faults ($R_{T1} = 0.375R_T$, and $X_{T1} = 0.5X_T$). (Adapted from ABB Inc., Distribution Transformer Guide, 1995. With permission.)

The per-unit secondary voltage for a fault from the primary to the secondary (PTI, 1999) is

$$V_s = \frac{n}{1 + (n-1)^2 \dfrac{S_{\text{kVA}}}{10\, V_{\text{kV}}\, I_{\text{kA}}\, Z_{\%}}}$$

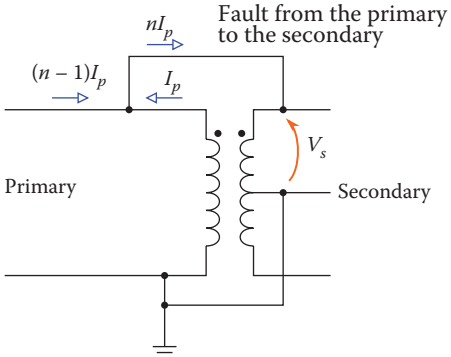


Figure 8.15 Fault from the primary to a 120/240-V secondary circuit.

where

V_s = secondary voltage, per unit at 120 V
n = transformer turns ratio from the primary voltage to the half-voltage secondary rating (normally 120 V)
I_{kA} = available primary fault current for a single line-to-ground fault, kA
S_{kVA} = transformer rating, kVA
$Z_{\%}$ = half-winding impedance of the transformer, %
V_{kV} = primary line-to-ground winding rated voltage, kV

Figure 8.16 shows the per-unit overvoltage for various transformer sizes. Surprisingly, the primary voltage does not impact the overvoltage significantly. The overvoltage equation in per unit reduces (PTI, 1999) to approximately

$$V_s \approx \frac{1.2 Z_{\%} I_{kA}}{S_{kVA}}$$

The overvoltage increases with higher available fault current, higher impedance transformers, and smaller transformers. For all but the smallest transformers with the highest impedance, the overvoltage is not too hazardous. But, if a fuse operates to separate the transformer from the circuit but leaves the primary-to-secondary fault, the fault imposes full primary voltage on the secondary (at least until the first failure on the secondary system). Such a condition can occur when the fault starts on the primary side above the transformer fuse (see Figure 8.17). If the transformer fuse

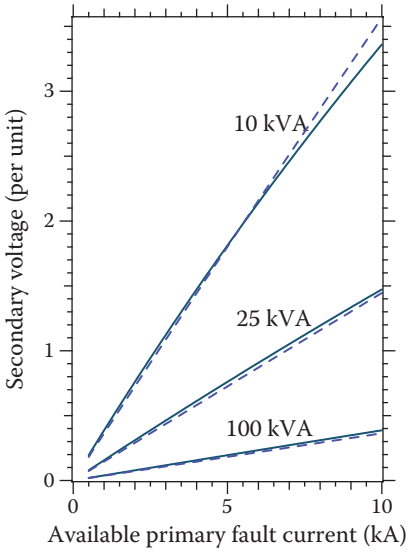


Figure 8.16 Secondary voltage during a fault from the primary to a 120/240-V secondary circuit. The solid lines are for a 4.8-kV circuit, and the dashed lines are for a 34.5-kV circuit. The results assume that $Z_{\%} = 3\%$.

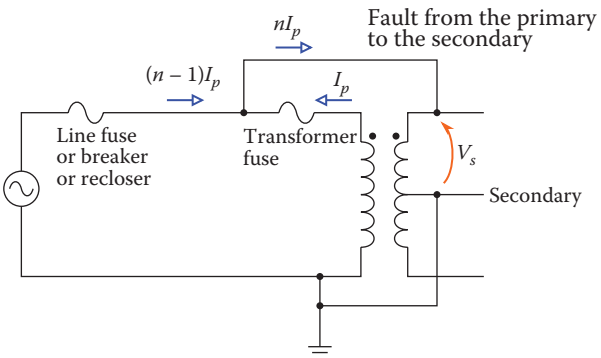


Figure 8.17 Fault from the primary to a 120/240-V secondary circuit.

blows before the upstream line fuse, the secondary voltage rises to the primary voltage. If the fault is below the transformer fuse, it does not matter which fuse blows first; either clears the fault.

The example in Figure 8.15 shows a fault to the secondary leg that is in phase with the primary (off of the *X*1 bushing of the transformer). A fault to the other secondary leg (off of *X*3) has very similar effects; the voltages and currents are almost the same, so the equations and graphs in this section also apply.

Although the transformer helps hold down the overvoltage, the primary-to-secondary fault may initiate a sizeable switching transient that could impact end-use equipment.

With most line fuses and transformer fuses used, the line fuse will clear before the transformer fuse and before the transformer suffers damage (good news on both counts). Even though the upstream fuse is larger, it sees $(n - 1)$ times the fault current. With the primary fault above the transformer fuse, the transformer fuse is more likely to operate before the line fuse with

- *Small transformer fuses*—Another reason not to fuse transformers too tightly; smaller, fast transformer fuses are more likely to clear before an upstream device.
- *Upstream breaker or recloser*—If the upstream device is a circuit breaker or recloser instead of a fuse, the tripping time is much longer, especially on a time-delayed trip (but even a fast trip is relatively long). If a circuit breaker is upstream of the transformer, the transformer fuse is likely to blow before the circuit breaker for locations with high fault currents and with small transformer fuses.

A more detailed analysis of the coordination of the two devices requires using the time–current characteristics of each of the protective devices along with the currents. The current into the primary winding, I_p in kA is

$$I_p = \frac{I_{\text{kA}}}{(n-1) + \dfrac{10I_{\text{kA}}}{(n-1)}\dfrac{V_{\text{kV}}}{S_{\text{kVA}}}Z_{\%}} \approx \frac{I_{\text{kA}}}{n}$$

Again, the upstream device sees $(n - 1)I_p$, which is almost the full available current for a single line-to-ground fault, I_{kA}.

A transformer with a secondary circuit breaker (as in a completely self-protected transformer, a CSP) has another possible mode where the transformer separates. If the secondary circuit breaker opens before the upstream primary device, the high-to-low fault raises the secondary voltage to the primary voltage. The secondary circuit breaker may not be able to clear the fault because the arc recovery voltage is much higher than the rating for the secondary circuit breaker; this is good news in that it helps protect end-use equipment from extreme overvoltages, but the secondary circuit breaker may fail trying to clear the fault. If the upstream device is a fuse, the fuse will probably clear before the secondary circuit breaker opens, but if the upstream device is a circuit breaker, the secondary circuit breaker will probably try to open first.

8.2.6 Underbuilt Fault to a Transmission Circuit

Faults from overbuilt transmission circuits or higher-voltage distribution lines to underbuilt distribution circuits are another hazard that can subject distribution equipment and customer equipment to extremely high voltages. Consider the example in Figure 8.18 of a fault from a subtransmission circuit to a distribution circuit.

As is the case for primary-to-secondary faults discussed in the previous section, overvoltages are not extremely high as long as the distribution circuit stays connected. But if a distribution interrupter opens the circuit, the voltage on the faulted distribution conductor jumps to the full transmission-line voltage. With voltage at several times normal, something will fail quickly. Such a severe overvoltage is also likely to damage end-use equipment. The distribution interrupter, either a circuit breaker or recloser, may not be able to clear the fault (the recovery voltage is many times normal); it may fail trying.

Faults further from the distribution substation cause higher voltages, with the highest voltage at the fault location. Current flowing back toward the circuit causes a voltage rise along the circuit.

While one can use a computer model for an exact analysis (but it is not possible with most standard distribution short-circuit programs), a simplified single-phase

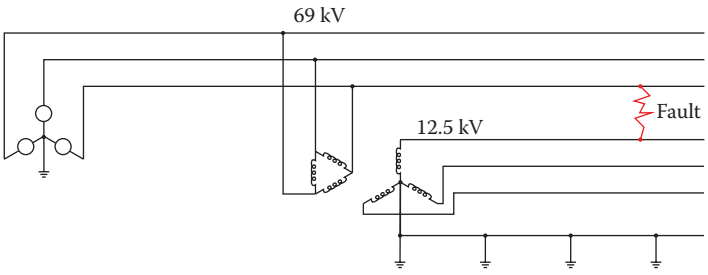


Figure 8.18 Example of a fault from a transmission conductor to a distribution conductor.

analysis (assuming a wye–wye transformer) helps frame the problem. The fault current is approximately

$$I = \frac{V_S}{\frac{(n-1)}{n}Z_A + \frac{n}{(n-1)}Z_B} \approx \frac{V_S}{Z_A + Z_B}$$

where

n = ratio of the transmission to distribution voltage ($n = 69/12.5 = 5.5$ in the example)
V_S = rms line-to-ground transmission source voltage (40 kV in the example)
Z_A = loop impedance from the transmission source to the high side of the distribution station
Z_B = loop impedance from the high side at the distribution station out to the fault and back to the distribution low side of the distribution substation

And, the 69-kV impedance often dominates, so the fault current is really determined by Z_A. For the distribution and transmission line impedances, Z_A and Z_B, you can use 1 Ω/mi for quick approximations. The worst case is with a small Z_A, a stiff subtransmission system.

The voltage at the fault is

$$V = I\frac{Z_B}{2} + V_d$$

where

V_d = line-to-ground voltage on the distribution circuit at the substation (as a worst case, assume that it is the nominal voltage; it will usually be less because of the sag that pulls down the voltages)

Figure 8.19 shows results from a series of computer simulations on a 12.5-kV circuit for various fault locations and subtransmission source stiffnesses. Results only modestly differ for other configurations: a 69-kV source in the opposite direction, a looped transmission source, a different substation transformer configuration, or different phases faulted. The worst cases are for stiff transmission systems.

If a distribution interrupter opens to leave transmission voltage on the distribution circuit, distribution transformers would saturate and metal-oxide arresters would move into heavy conduction. Transformer saturation distorts the voltage but may not appreciably reduce the peak voltage. Arresters can reduce the peak voltage, but they could still allow quite high voltages to customers. Arresters with an 8.4-kV maximum continuous operating voltage start conducting for power-frequency voltages at about 11 to 12 kV (1.5 to 1.6 times the nominal system line-to-ground voltage). At higher voltages, the arresters will draw more current. Depending on the number of arresters, a stiff transmission source can still push the voltage to between 3 and 4 per unit, which is 20 to 30 kV (until an arrester or something else fails). In fact, the best protection happens when the arrester fails as fast as possible; the arrester becomes

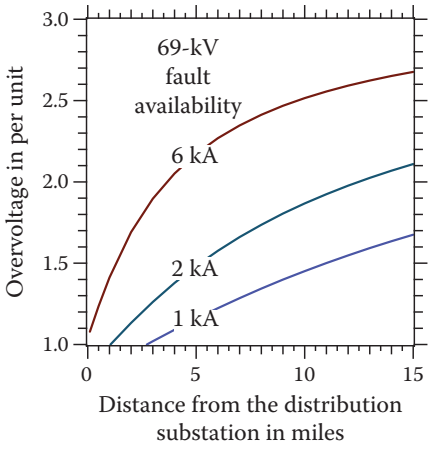


Figure 8.19 Results of simulations of a fault from a 69-kV circuit to a 12.5-kV circuit (before the distribution substation breaker trips).

a sacrificial protector. Normal-duty arresters fail faster than heavy-duty arresters, which limits the duration of overvoltages. Goedde et al. (2002) propose using gapped arresters; their lab tests found that gapped arresters clip the overvoltage to a lower magnitude and fail faster during overvoltages.

Ward (2010) proposes using station-class arresters without an isolator to protect the lower-voltage circuit. Because station-class arresters have lower discharge voltages than other arrester classes, these will go into conduction before other arresters. This should protect other arresters and allow the station-class arresters to fail first. Because these arresters do not have an isolator, they will remain in the circuit and keep the lower-voltage circuit grounded. Ward describes an installation where these were installed when a 34.5-kV circuit fell into an underbuilt 13.2-kV circuit. Two of the station arresters failed, and no customers reported damage. Dominion has since installed these at over 30 locations.

In addition to station-class arresters, other experimental options to reduce the hazard of underbuilt distribution lines include

- *Fuses*—Try to avoid using fuses or reclosers where it leaves significant downstream exposure underbuilt. The fast operation of fuses and reclosers are more likely to clear the distribution circuit before the overbuilt circuit.
- *Directional relays*—In faults to a transmission circuit, the power flows from the fault into the distribution station transformer (the opposite direction of power flow for normal faults). Tripping the distribution circuit breaker only for faults with forward power flow leaves the circuit breaker in for subtransmission faults.
- *Disable the instantaneous*—Without the instantaneous trip on the distribution feeder, the circuit breaker will wait longer before tripping. The transmission circuit is more likely to trip first.
- *Coordinate devices*—Coordinate the transmission-line protection to clear before the distribution circuit operates over the range of fault currents that can occur. Include the effects of multiple reclose operations on the transmission circuit. Evaluate the substation recloser or circuit breaker, and also, consider feeder protective devices

(normally reclosers). Try to speed up clearing times on the transmission circuit as much as possible (both ends for looped subtransmission circuits).

- *Ground switch (very experimental)*—Whenever the distribution circuit breaker opens, engage a grounding switch on the load side of the distribution circuit breaker. This grounds the fault, preventing overvoltages and sustaining the fault on the transmission circuit.
- *Structures*—As much as possible, design the common structure to minimize the chance of faults between circuits. Use wide spacings between the two circuits, and build the subtransmission circuit to high mechanical standards to reduce the chance of broken conductors or crossarms or braces. More extreme protection could be provided by stringing a grounded conductor and placing it between the subtransmission and the distribution circuits. If the ground is involved in the fault, it will prevent overvoltages. These options are obviously difficult to retrofit, but these issues should be considered when designing new circuits.

Thoroughly review such options before implementation. Normally, utilities treat underbuilt circuits the same as any other circuit. Most of the options above are experimental approaches. The use of station-class arresters as suggested by Ward (2010) is a sound option with utility experience.

8.3 Fault Location

Using measurements from digital relays or other monitors, it is possible to estimate fault locations. These can improve restoration times. The most dramatic improvements will be for main feeder lockouts where the whole mainline would normally have to be patrolled. With reasonably confident location estimates, crews can start switching to restore some customers before the actual damage location is found. This type of fault location augments the information received from an outage management system. Fault location also helps for circuits with repeated momentary interruptions—one can pinpoint what section of the circuit has the problem that is causing the repeated operations. The most advanced automated systems collect monitoring data, calculate a fault location, and display a location for operators. Manual data collection and calculations are also useful. Having a fault location system also helps instill a switch-before-repair mentality; with accurate location estimates, crews can start switching to restore customers before even finding the actual damage location.

If we know the voltages and currents during a fault, we can use these to estimate the distance to the fault. The equation is very simple, just Ohm's law (see Figure 8.20):

$$d = \frac{V}{I \cdot Z_l}$$

where

V = voltage during the fault, V
I = current during the fault, A
Z_l = line impedance, Ω/length unit
d = distance to the fault, length unit such as mi

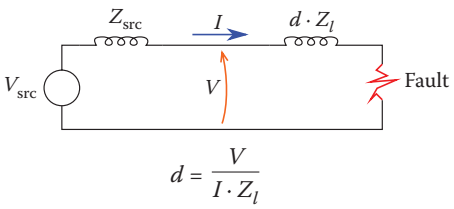


Figure 8.20 Fault location calculations.

With complex values entered for the voltages and impedances and currents, the distance estimate should come out as a complex number. The real component should be a realistic estimate of the distance to the fault; the imaginary component should be close to zero. If not, then something is wrong.

While the idea is simple, a useful implementation is more difficult. Different fault types are possible (phase-to-phase, phase-to-ground, etc.), and each type of fault sees a different impedance. Fault currents may have offsets. The fault may add impedance. There are uncertainties in the impedances, especially the ground return path. Conductor spacing or size changes also make location more difficult.

Many relays or power quality recorders or other instruments record fault waveforms. Some relays have fault-locating algorithms built in.

The Ohm's law equation is actually overdetermined. We have more information than we really need. The distance is a real quantity, but the voltages, currents, and impedances are complex, so the real part of the result is the distance, and the reactive part is zero. Most fault-locating algorithms use this extra information, allow the fault resistance to vary, and find the distance that provides the optimal fit (Girgis et al., 1993; Santoso et al., 2000). The problem with this approach is that the fault resistance soaks up the error in other parts of the data. It does not necessarily mean a better distance estimation. Most fault arcs have a resistance that is very close to zero. In most cases, we are better off assuming zero fault resistance. There are algorithms that can directly estimate the arc voltage (EPRI 1012438, 2006; EPRI 1013825, 2008; Short, 2011).

The most critical input to a fault location algorithm is the impedance data. Be sure to use the impedances and voltages and currents appropriate for the type of fault. For line-to-ground faults, use line-to-ground quantities, and for others, use phase-to-phase quantities:

- Line-to-ground fault

$$V = V_a,\ I = I_a,\ Z = Z_S = (2Z_1 + Z_0)/3$$

- Line-to-line, line-to-line-to-ground, or three-phase faults

$$V = V_{ab},\ I = I_a - I_b,\ Z = Z_1$$

Remember that these are all complex quantities. It helps to have software that automatically calculates complex phasors from a waveform. Several methods are available

to calculate the rms values from a waveform; a Fourier transform is most common. Some currents have significant offset that can add error to the result. Try to find the magnitudes and angles after the offset has decayed (this is not possible on some faults cleared quickly by fuses).

If potential transformers are connected phase to phase, we can still estimate locations for ground faults if we know the zero-sequence source impedance. Schweitzer (1990) shows that the phase-to-ground voltage is

$$V_a = 1/3(V_{ab} - V_{ca}) - Z_{0,src}I_0$$

where

$Z_{0,src}$ = zero-sequence impedance of the source, Ω
I_0 = zero-sequence current measured during the fault = $I_a/3$ for a single line-to-ground fault on phase A

Although the voltages and currents are complex, we can also estimate the distance just using the absolute values. Although we lose some information on how accurate our solution is because we lose the phase angle information, in many cases it is as good as using the complex quantities. So, the simple fault location solution with absolute values is

$$d = \frac{V}{I \cdot Z_l}$$

where

V = absolute value of the rms voltage during the fault, V
I = absolute value of the rms current during the fault, A
Z_l = absolute value of the line impedance, Ω/length unit
d = distance to the fault, length unit such as mi

With this simple equation, we can estimate answers with voltage and current magnitudes. For a ground fault, $Z_l = Z_S$ is about 1 Ω/mi. If the line-to-ground voltage, V = 5000 V, and the fault current, I = 1500 A, the fault is at about 3.3 mi (5000/1500). Remember to use the phase-to-phase voltage and $|I_a - I_b|$ (and not $|I_a| - |I_b|$) for faults involving more than one phase.

We can calculate the distance to the fault using only the magnitude of the current (no phase angles needed and only prefault voltage needed) and the line and source impedances involved. If we know the absolute value of the fault current and the prefault voltage and the source impedance, the distance to the fault is a solution to the quadratic equation

$$d = \frac{-b + \sqrt{b^2 - 4ac}}{2a}$$

where

$$a = Z_l^2$$
$$b = 2R_lR_{\text{src}} + 2X_lX_{\text{src}}$$
$$c = Z_{\text{src}}^2 - \left(\frac{V_{\text{prefault}}}{I_{\text{fault}}}\right)^2$$

and

R_{src} = source resistance, Ω
X_{src} = source reactance, Ω
Z_{src} = absolute value of the source impedance, Ω
R_l = line resistance, Ω/unit distance
X_l = line reactance, Ω/unit distance
Z_l = absolute value of the line impedance, Ω/unit distance
I_{fault} = absolute value of the rms current during the fault, A
V_{prefault} = absolute value of the rms voltage just prior to the fault, V

In this case, we are doing the same thing as taking a fault current profile (such as Figure 8.11) and interpolating the distance. In fact, it is often much easier to use a fault current profile developed from a computer output rather than this messy set of equations. If the prefault voltage is missing, assume that it is equal to the nominal voltage. If we have the prefault voltage, divide the current by the per-unit prefault voltage before interpolating on the fault current profile. Using a fault current profile also allows changes in line impedances along the length of the line. Carolina Power & Light (now a part of Duke Energy) used this approach, and Lampley (2002) reported that their locations were accurate to within 0.5 mi 75% of the time, and in most of the remaining cases, the fault was usually no more than 1 to 2 mi from the estimate.

Using fault currents with a short-circuit program is another easy way to estimate fault locations. Apply faults of the same type measured (line-to-line, line-to-ground, etc.) at different locations and iterate until the modeled fault location matches that recorded.

We can also just use voltages. If we know the source impedance, we do not need current. The distance calculation is another quadratic formula solution, this time with

$$d = \frac{-b - \sqrt{b^2 - 4ac}}{2a} \text{ (the negative root because } a \text{ is negative)}$$

where

$$a = Z_l^2 - Z_l^2\left(\frac{V_{\text{prefault}}}{V_{\text{fault}}}\right)^2$$
$$b = 2R_lR_{\text{src}} + 2X_lX_{\text{src}}$$
$$c = Z_{\text{src}}^2$$

and

V_{fault} = absolute value of the rms voltage during the fault, V

As with the fault current approach, rather than using this equation, we can interpolate a voltage profile graph to find the distance to the fault (such as those in Figure 11.6). Again, we are assuming that the arc impedance is zero.

Fault locations of line-to-line and three-phase faults are most accurate because the ground path is not included. The ground return path has the most uncertainties. The impedance of the ground return path depends on the number of ground rods, the earth resistivity, and the presence of other objects in the return path (cable TV, buried water pipes, etc.). The ground return path is also nonuniform with length.

Feeder-level monitors are the best, but good fault location can be achieved with bus-level monitors. For line-to-ground faults, the key to achieving good location accuracy is using the residual current ($I_A + I_B + I_C$). This avoids most of the load current. Figure 8.21 shows the result of automated fault location result where fault estimates are shown on a map. Multiple locations can be identified because of branching on radial circuits. In this case, the feeder locked out, so the location on the mainline is where crews should look. If this was for a problem momentary, it still gives crews a general area on where to search. This example was based on bus-level monitoring, and the residual current is 91% of the phase-C current measurement.

While not usually needed, for faults measured where there is significant load in parallel (bus-level monitors, for example), the fault current can be separated from the load current to locate most accurately. During a fault, the voltage will sag. The response of the load current to the voltage sag can be used to "subtract out" the effect of the load. The standard models for load response are constant power, constant current, and constant impedance. Consider the constant-impedance model shown in Figure 8.22. With the constant-impedance load model, the impedance of the load is determined from the prefault voltage and prefault current:

$$Z_{load} = V_{prefault}/I_{prefault}$$

The total impedance (Z_{total}) is determined from the voltage and current during the fault:

$$Z_{total} = V_{fault}/I_{fault}$$

With these two parameters, the impedance to the fault can be found using the current divider equation in Figure 8.22. The constant-current model is also commonly assumed. Reineri and Alvarez (1999) tested various end-use devices to better determine load models for use in fault-locating algorithms. They found that with motors, current can increase during a voltage sag. On devices with dc power supplies such as computers, the current can drop significantly during a deep sag. For moderate sags to about 60%, a constant impedance model is relatively accurate.

It is most accurate to collect waveforms from monitors or relays and use those to estimate locations, but just collecting rms fault currents which allows useful results.

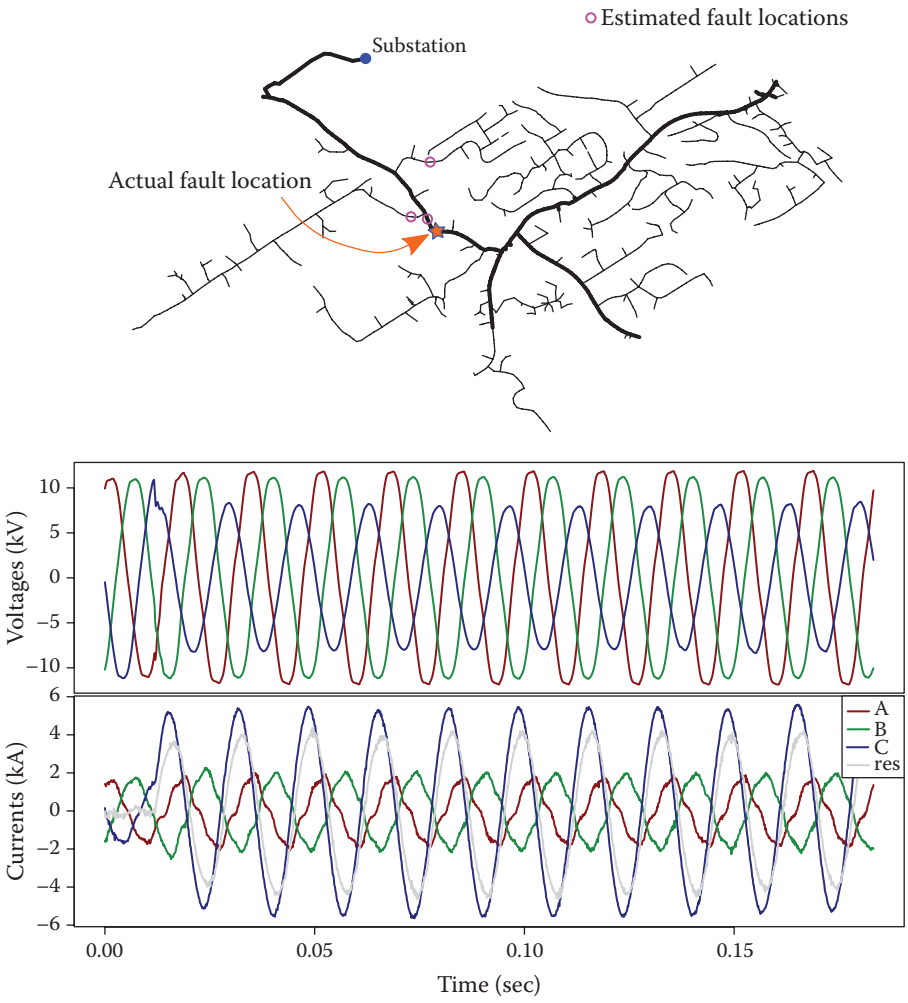


Figure 8.21 Example fault location result.

Waveforms allow for more sophisticated processing to account for arc impedance or various load models that may be developed, but rms data are much easier to transfer and process. One of the key parts of a fault-location algorithm is identifying a good portion of the fault to use in calculations. When using rms data from instrumentation, that estimation is left up to the given piece of equipment. For circuit lockouts that may be composed of multiple faults, use the first fault in the sequence of events to avoid issues with inrush events or complicated waveshapes that may happen as the event unfolds. It is sometimes useful to analyze all events as this can reveal special issues like conductor-slapping faults caused by downstream faults. When collecting fault currents from relays, identifying the fault type is important, so that the correct fault can be modeled.

This type of fault location is useful for approximate locations. For permanent faults, a location estimate helps shorten the lengths of circuit patrolled. Distance

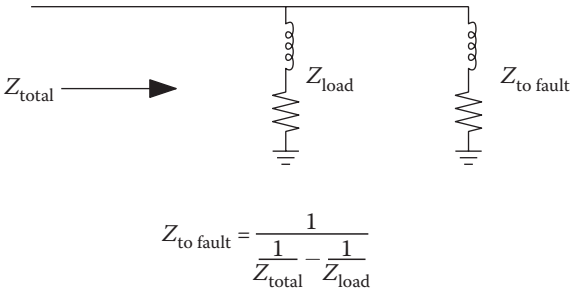


Figure 8.22 Constant-impedance load model.

estimates can also help find those irksome recurring temporary faults that cause repeated momentary interruptions. Fault locations are most accurate when the fault is within 5 mi of the measurement; beyond that, the voltage profile and fault current profiles flatten out considerably, which increases error. Fault location is difficult if a circuit has many branches. If a fault is 2 mi from the source on phase B, but there are 12 separate circuits that meet that criteria, the location information is not as useful. Fault location is also difficult on circuits with many wire-size changes; it works best on circuits with uniform mainline impedances with relatively short taps. Impedance-based location methods produce closer but not pinpointed results. For underground faults, we would like to know exactly where to dig, but these methods do not have that accuracy.

Table 8.3 and Figure 8.23 show comparisons of outage data locations to estimated fault locations from a dataset of 211 fault events from bus-level power-quality monitors at 128 samples per cycle in a mainly suburban area. The median error (half of predictions) of most algorithms is less than 0.25 mi (0.4 km), and for most algorithms, 75% of the predictions are off by less than 0.46 mi (0.74 km). Accuracy is highest for faults closest to the substation.

Fault location works well in urban systems as well as suburban and rural areas. Con Edison has a fault location system based on power quality monitors and digital relays on an urban system (Stergiou, 2006; Sabin et al., 2009). Operators can view

TABLE 8.3 Distance Error of Several Fault Location Algorithms

	Error in Prediction of Distance to the Fault, miles			
Fault Location Algorithm	Average	Median	75%	90%
Absolute value of impedance (Z)	0.34	0.25	0.46	0.70
Reactance to the fault (X)	0.29	0.21	0.37	0.64
Fault current magnitude	0.32	0.27	0.47	0.66
Voltage sag	0.52	0.32	0.60	1.16
Takagi	0.35	0.20	0.43	0.75
Impedance with a nonlinear arc	0.29	0.20	0.37	0.64

Source: From EPRI 1016046, *Distribution Fault Location: PQView Implementation Details*, Electric Power Research Institute, Palo Alto, CA, 2009. Copyright 2009. Reprinted with permission.

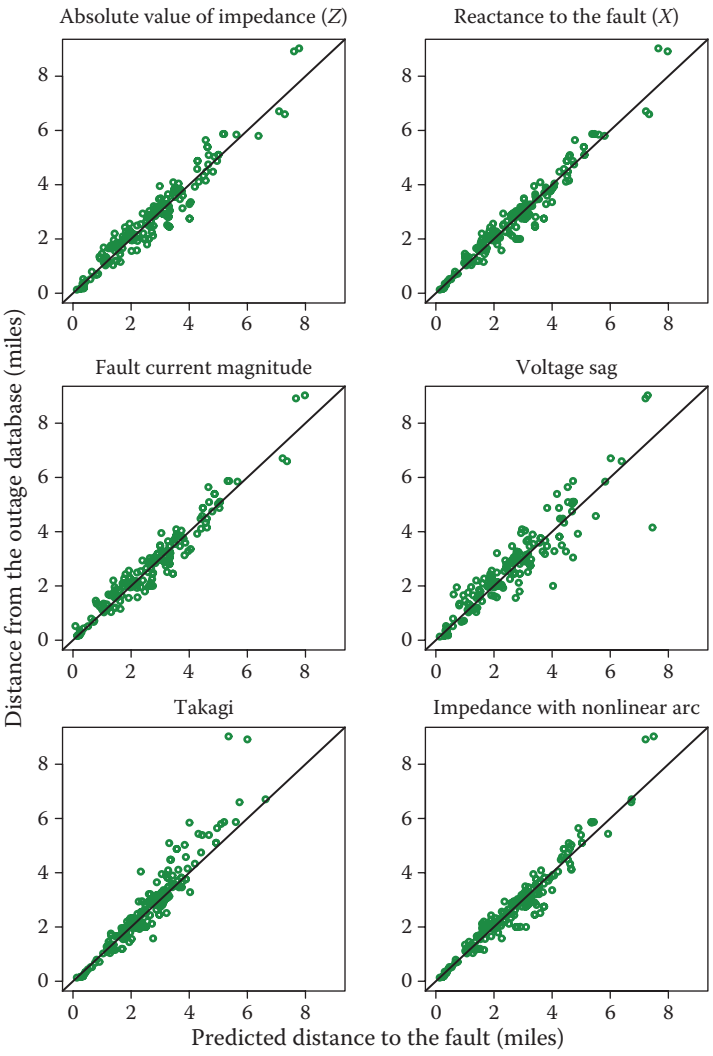


Figure 8.23 Predicted versus actual distance to the fault. (From EPRI 1016046, *Distribution Fault Location: PQView Implementation Details*, Electric Power Research Institute, Palo Alto, CA, 2009. Copyright 2009. Reprinted with permission.)

maps with estimated fault locations to help direct crews to finding damage. They use the reactance-to-the-fault method of locating faults. They find the reactive part of the impedance to the fault and compare that with the reactance from the substation to the fault based on their circuit models. They use the residual current to pick out ground faults. This is particularly effective for them because their load is mainly secondary network load connected through line-to-ground transformers. Because the load is connected phase to phase, the ground current does not have load current mixed in. Their system models do not include zero-sequence impedances, so they use adjustment factors (*k*-factors) tuned for each site to adjust for the differences between

the loop impedance to line-to-ground faults and the positive-sequence impedance. Stergiou (2006) reported that in an examination of 27 events at one location, 70% were within three manholes, and 85% were within five manholes. It is also possible to use waveform processing to estimate the location of failing splices that can cause repeated half-cycle blips (EPRI 1013825, 2008). Identifying and locating these can allow crews to repair them before they impact customers.

8.4 Limiting Fault Currents

Limiting fault current has many benefits, which improve the safety and reliability of distribution systems:

- *Failures*—Overhead line burndowns are less likely, cable thermal failures are less likely, violent equipment failures are less likely.
- *Equipment ratings*—We can use reclosers and circuit breakers with less interrupting capability and switches and elbows with less momentary and fault close ratings. Lower fault currents reduce the need for current-limiting fuses and for power fuses and allow the use of cutouts and under-oil fuses.
- *Shocks*—Step and touch potentials are less severe during faults.
- *Conductor movement*—Conductors move less during faults (this provides more safety for workers in the vicinity of the line and makes conductor slapping faults less likely).
- *Coordination*—Fuse coordination is easier. Fuse saving is more likely to work.

At most distribution substations, three-phase fault currents are limited to less than 10 kA, with many sites achieving limits of 7 to 8 kA. The two main ways that utilities manage fault currents are

- *Transformer impedance*—Specifying a higher-impedance substation transformer limits the fault current. Normal transformer impedances are around 8%, but utilities can specify impedances as high as 20% to reduce fault currents.
- *Split substation bus*—Most distribution substations have an open tie between substation buses, mainly to reduce fault currents (by a factor of two).

Line reactors and a neutral reactor on the substation transformer are two more options used to limit fault currents, especially in large urban stations where fault currents may exceed 40 kA.

There are drawbacks of increasing impedance to reduce fault currents. Higher impedance reduces the stiffness of the system: voltage sags are worse, voltage flicker is worse, harmonics are worse, and voltage regulation is more difficult.

A reactor in the substation transformer neutral limits ground fault currents. Even though the neutral reactor provides no help for phase-to-phase or three-phase faults, it provides many of the benefits of other methods of fault reduction. Neutral reactors cost much less than line reactors. Ground faults are the most common faults, and for many types of single-phase equipment, the phase-to-ground fault is the only possible

failure mode. A neutral reactor does not cause losses or degrade voltage regulation to the degree of phase reactors. On the downside, a neutral reactor has a cost and uses substation space, and a neutral reactor reduces the effectiveness of the grounding system (see Chapter 14).

Several advanced fault-current limiting devices have been designed (EPRI EL-6903, 1990). Most use some sort of nonlinear elements—arresters, saturating reactors, superconducting elements, or power electronics such as a gate-turn-off thyristor—to limit the fault current either through the physics of the device or through computer control. Since most distribution systems have managed fault currents sufficiently well, these devices have not found a market. Given that, the EPRI study surveyed utilities and found evidence that a market for fault-current limiters exists if a device had low-enough cost and was robust enough.

8.5 Arc Characteristics

Many distribution faults involve arcs through the air, either directly through the air or across the surface of hardware. Although a relatively good conductor, the arc is a very hot, explosive fireball that can cause further damage at the fault location (including fires, wire burndowns, and equipment damage). This section discusses some of the physical properties of arcs, along with the ways in which arcs can cause damage.

Normally, the air is a relatively good insulator, but when heavily ionized, the air becomes a low-resistance conductor. An arc stream in the air consists of highly ionized gas particles. The arc ionization is due to *thermal* ionization caused by collisions from the random velocities of particles (between electrons, photons, atoms, or molecules). Thermal ionization increases with increasing temperature and with increasing pressure. The heat produced by the current flow (I^2R) maintains the ionization. The arc stream has very low resistance because there is an abundance of free, charged particles, so current flow can be maintained with little electric field. Another type of ionization caused by acceleration of electrons from the electric field may initially start the ionization during the electric-field breakdown, but once the arc is created, electric-field ionization plays a less significant role than thermal ionization.

One of the characteristics that is useful for estimating arc-related phenomenon is the arc voltage. The voltage across an arc remains constant over a wide range of currents and arc lengths, so the arc resistance decreases as the current increases. The voltage across an arc ranges between 25 and 40 V/in. (10 to 16 V/cm) over the current range of 100 A to 80 kA (Goda et al., 2000; Strom, 1946). The arc voltage is somewhat chaotic and varies as the arc length changes. More variation exists at lower currents. As an illustration of the energy in an arc, consider a 3-in. (7.6-cm) arc that has a voltage of about 100 V. If the fault current is 10 kA, the power in the arc is $P = V \cdot I = 100$ V.10 kA = 1 MW. Yes, 1 MW! Arcs are explosive and as hot as the surface of the sun.

An upper bound of roughly 10,000 to 20,000 K on the temperature of the arc maintains the relatively constant arc voltage per unit length. For larger currents, the arc responds by increasing the volume of gas ionized (the arc expands rather than

increasing the arc-stream temperature). Higher currents increase the cross-sectional area of the arc, which reduces the resistance of the arc column; the current density is the same, but the area is larger. So, the voltage drop along the arc stream remains roughly constant. The arc voltage depends on the type of gas and the pressure. One of the reasons an arc voltage under oil has a higher voltage gradient than an arc in air is because the ionizing gas is mainly hydrogen, which has a high heat conductivity. A high heat conductivity causes the arc to restrict and creates a higher-density current flow (and more resistance). The arc voltage gradient is also a function of pressure. For arcs in nitrogen (the main ionizing gas of arcs in air), the arc voltage increases with pressure as $V \propto P^k$, where k is approximately 0.3 (Cobine, 1941).

Another parameter of interest is the arc resistance. A 3-ft (1-m) arc has a voltage of about 1400 V. If the fault current at that point in the line was 1000 A, then the arc resistance is about 1.4 Ω. A 1-ft (0.3-m) arc with the same fault current has a resistance of 0.47 Ω. Most fault arcs have resistances of 0 to 2 Ω. Figure 8.24 shows that the impact of an arc on the fault currents along the line is fairly minor.

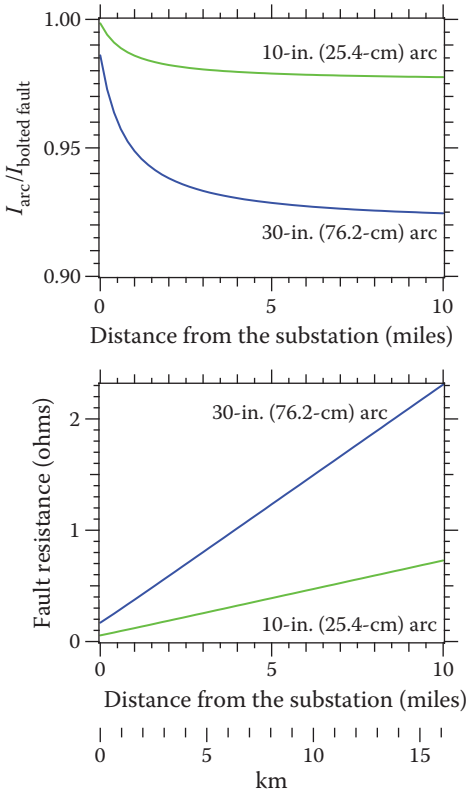


Figure 8.24 Ratio of fault current with and without an arc of the given length on a 12.47-kV circuit. This assumes the same system parameters as the fault profile in Figure 8.11 with the following additional assumptions: the arc voltage gradient equals 40 V/in. (16 V/cm), the arc voltage is all resistive, and the nonlinearity of the arc voltage is ignored.

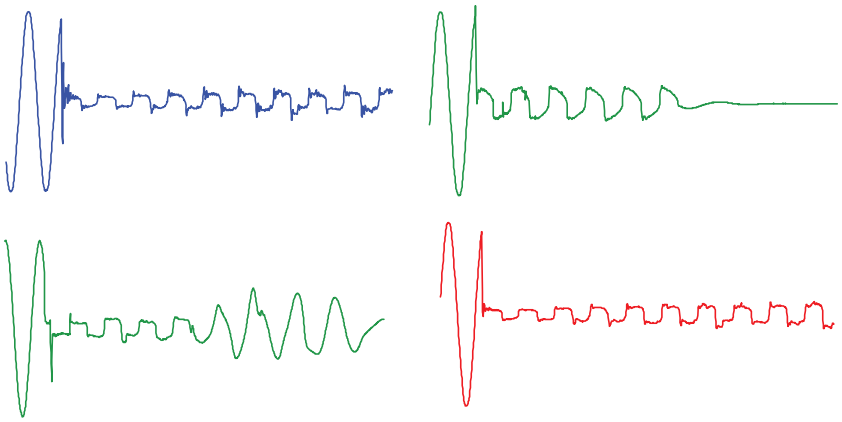


Figure 8.25 Arcing faults measured during the EPRI DPQ study. (From EPRI 1012438, *Distribution Fault Location: Field Data and Analysis*, Electric Power Research Institute, Palo Alto, CA, 2006. Copyright 2006. Reprinted with permission.)

An arc voltage waveform has distinguishing characteristics. Figure 8.25 shows arcing fault voltages that measured during the EPRI DPQ project. The voltage on the arc is in phase with the fault current (it is primarily resistive). When the arc current goes to zero, the arc will extinguish. The recovery voltage builds up quickly because of the stored energy in the system inductance. Voltage builds to a point where it causes arc reignition. The reason for the blip at the start of the waveform (it is not a straight square wave) is that the arc cools off at the current zero. Cooling lowers the ionization rate and increases the arc resistance. Once it heats up again, the voltage characteristic flattens out. The waveform is high in the odd harmonics and for many purposes can be approximated as a square wave.

8.5.1 Arc Movement and Evolving Faults

The movement and growth of an arc is primarily in the vertical direction. Tests at IREQ in Quebec showed that the primary reason that the arc elongates and moves vertically is the rising hot gases of the arc (Drouet and Nadeau, 1979). The magnetic forces ($J \times B$) did not dominate the direction or elongation. As a first approximation over a range of currents between 1 and 20 kA, arc voltages up to 18 kV, and durations up to 0.5 sec, the arc length can be expressed as a function of the duration only as

$$l = 30\ t$$

where

l = arc length, m
t = fault duration, sec

The arc movement is a consideration for underbuilt distribution and for vertical construction. The equation above can be used as an approximation to determine if an

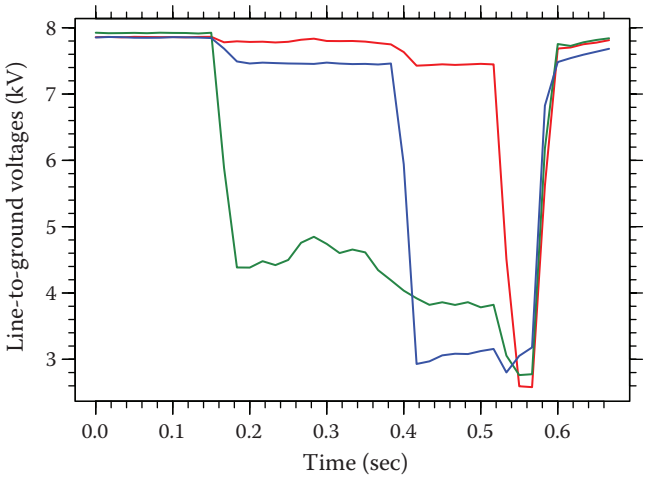


Figure 8.26 Voltage waveform from a fault that started as a single-phase fault, evolved to a double-line-to-ground fault, and finally evolved to a three-phase-to-ground fault.

underbuilt distribution circuit could evolve and fault a distribution or transmission circuit above. It also gives some idea of how faults can evolve to more than one phase. Figure 8.26 shows an example of a fault evolving from one to three phases over the course of about 0.4 sec. Vertical designs are likely to be more prone to having faults evolve to more than one phase because of the vertical movement of a fault current arc. We might think that a fault evolving to include other phases is not a concern since the three-phase circuit has to be opened anyway, whether it is a single- or three-phase fault. But, the voltage sag during the fault is more severe if more than one phase is involved, which is a good reason to use designs that do not tend to propagate to more than one phase (and to use relaying or fusing that operates quickly enough to prevent it from happening). If a single line-to-ground fault becomes multiphase, two things happen: (1) fault current likely increases, and (2) relays may operate more slowly. For example, once a fault jumps to two phases, the ground element (normally set lower than a phase element) may not see enough current to operate. Arc energies will be higher with multiple arcs, and more arcs may cause more damage to equipment.

If we know how likely faults are to evolve to multiple phases and how long that takes, it can help us with overcurrent protection strategies. Table 8.4 summarizes fault data from two monitoring datasets for faults that lasted longer than 0.5 sec. Of these longer events that started as single line-to-ground faults, 37% became multiphase faults for utility X, and 48% became multiphase faults for utility Y. For utility X, Figure 8.27 shows the distribution of times for faults that started as single-phase faults to involve multiple phases. Faster overcurrent protection should reduce the likelihood of evolving faults. Utility Y tends to have tighter conductor spacings than utility X.

Distribution voltages can sustain very long arcs, but self-clearing faults can occur such as when a conductor breaks and falls to the ground (stretching an arc as it falls). The maximum arc length is important because the longer the arc, the more energy

TABLE 8.4 Summary of Events Longer than 0.5 sec

	Number of Events	
	Utility *X*	Utility *Y*
Faults that stayed single phase	55	15
Single-phase faults that evolved to two phases	22	8
Single-phase faults that evolved to three phases	10	6

is in the arc. For circuits with fault currents on the order of 1000 A and where the transient rise to the open-circuit voltage is about 10 μs, about 50 V may be interrupted per centimeter of arc length (Slepian, 1930). For a line-to-ground voltage of 7200 V, a line-to-ground arc can reach a length of about 12 ft (3.7 m) before it clears. As another approximation, the length that an arc can maintain in resistive circuits is (from (Rizk and Nguyen, 1984) with some reformulation):

$$l = V\sqrt{I}$$

where

l = arc length, in. (1 in. = 2.54 cm)
I = rms current in the previous half cycle, A
V = system rms voltage, kV (line to ground or line to line depending on fault type)

8.5.2 Damage from Arcs

The temperature in the arc can be on the order of 10,000 K. This heat creates hazards from burning and from the pressure wave developed during the fault. The longer

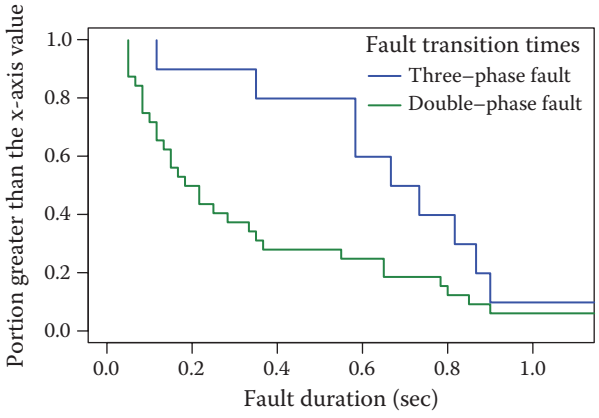


Figure 8.27 Cumulative distribution of transition times to a multiphase fault based on data from utility X. (From EPRI 1018693, *Distribution Arc Flash: Analysis Methods and Arc Characteristics*, Electric Power Research Institute, Palo Alto, CA, 2009. Copyright 2009. Reprinted with permission.)

the arc, the more energy is created. NFPA provides guidelines on safe distances for workers based on arc blasts (NFPA 70E-2000). Several groups have worked to determine the appropriate characteristics of protective clothing (ASTM F1506-94, 1994). Because of the pressure wave, consider hearing protection and fall protection for workers who could be exposed to fault arcs. Arcs can cause fires: pole fires or fires in oil-filled equipment such as transformers.

The pressure wave from an arc in an enclosed substation was the probable cause of a collapse of a substation building (important since many distribution stations are required to be indoors because of environmental considerations). Researchers found during tests that the pressure from a fault arc can be approximated (Drouet and Nadeau, 1979) by

$$A = 1.5\frac{I \cdot t}{l}$$

where

A = pressure, kN/m^2 (1 kN/m^2 = 20.9 lb/ft^2)
I = fault current magnitude, kA
t = duration of the fault, sec
l = distance from the source, m (for $l > 1$ m)

Although many electrical damage characteristics are a function of $\int I^2\,dt$, the pressure wave is primarily a function of $\int I\,dt$ (because the voltage along the arc length is constant and relatively independent of the arc current). Where arcs attach to wires, melting weakens wires and can lead to wire burndown. Most tests have shown that the damage is proportional to $\int I^k\,dt$, where k is near one but varies depending on the conductor type. For burndowns or other situations where the arc burns the conductor, the total length of the arc is unimportant, the small portion of the arc near the attachment point is important. The voltage drop near the attachment point is also very constant and does not vary significantly with current. The damage to conductors is very much like that of an electrical arc cutting torch.

Burndowns are much more likely on covered wire (also called tree wire). The covering restricts the movement of the attachment point of the arc to the conductor. On bare wire, the arc will move because of the heating forces on the arc and the magnetic forces (also called motoring).

On bare wire, burndowns are a consideration only on small conductors. Tests (Lasseter, 1956) have shown that the main cause of failure on small aluminum conductors is that the hot gases from the arc anneal the aluminum, which reduces tensile strength. The testers found little evidence of arc burns on the conductors. Failures can occur midspan or at a pole. Motoring is not fast enough to protect the small wire.

Arcs can damage insulators following flashover along the surface of the insulators. This was the primary reason for the development of arcing horns for transmission-line insulators. Arcing horns encourage a flashover away from the insulator rather than along the surface. Arcs can fail distribution insulators. During fault tests across insulators by Florida Power & Light (Lasseter, 1965), the top of the arc moved along

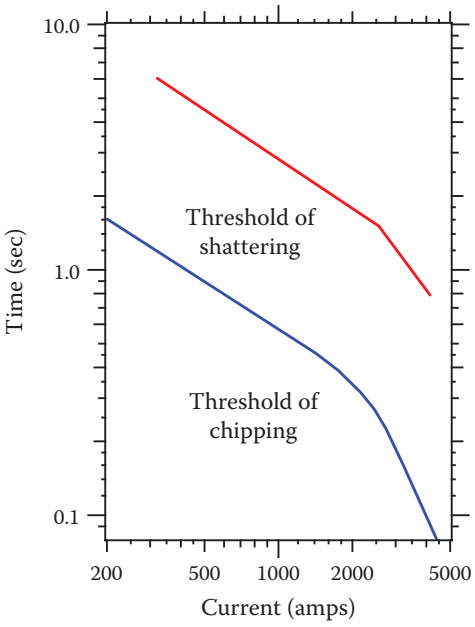


Figure 8.28 Insulator damage characteristics. (Data from Lasseter, J. A., Point way to reduce lightning outages, *Electrical World*, pp. 93–5, October 1965.)

the conductor. The point of failure was at the bottom of the insulator where the arc moved up the pin to the bottom edge of the porcelain. The bottom of the insulator gets very hot and can fail from thermal shock. The threshold of chipping was about 360 C (C = coulombs = A-sec = $\int I\,dt$), and the threshold of shattering was about 1125 C (see Figure 8.28). Adding an aluminum or copper washer (but not a steel washer) on top of the crossarm under the flange of the grounded steel pin reduced insulator shattering. The arc attaches to the washer rather than moving up along the pin, increasing the threshold of chipping by a factor of five. Composite insulators perform better for surface arcs than porcelain insulators (Mazurek et al., 2000). Some composite insulators have an external arc withstand test where $I \cdot t$ shall be 150 kA-cycles (2500 C for 60 Hz) (IEEE Std. 1024-1988).

Stanback (1977) derived bus burn rates for 480-V faults based on fault tests. For copper and aluminum buswork, he proposed the following equations:

Copper bus

$$Y = 0.7230\text{E} - 6 \cdot I_{\text{arc}}^{1.5}$$

Aluminum bus

$$Y = 1.519\text{E} - 6 \cdot I_{\text{arc}}^{1.5}$$

where

Y = burn rate of buswork, in.^{3}/sec (1 in.^{3}/sec = 16.387 cm^3/sec)

I_{arc} = rms arcing fault current, A

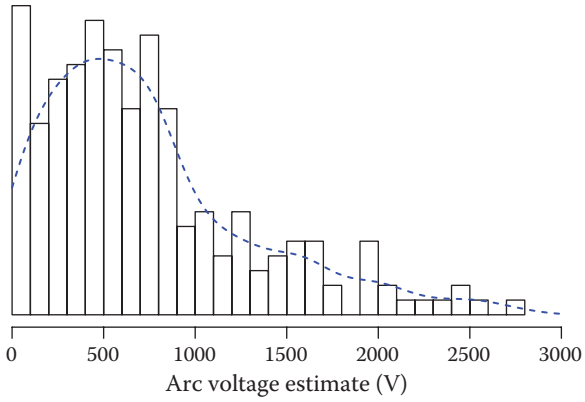


Figure 8.29 Histogram of arc voltages in the DPQ study. (From EPRI 1012438, *Distribution Fault Location: Field Data and Analysis*, Electric Power Research Institute, Palo Alto, CA, 2006. Copyright 2009. Reprinted with permission.)

8.5.3 Arc Voltages

Arc voltages contribute to the power in an arc, so it is an important parameter for arcs in equipment and for arc flash. Arc length and arc voltage are closely related. EPRI's Distribution Power Quality (DPQ) project (EPRI TR-106294-V2, 1996) provides useful data for estimating arc voltages during faults. In most cases, three monitors were installed for each randomly selected feeder, one at the substation and two at randomly selected places along the feeder. I used the downline feeder results for these analyses. Figure 8.29 shows a histogram of arc voltages during single line-to-ground faults in the DPQ study. These were estimated using an algorithm that attempts to eliminate the fundamental-frequency component (because some faults would not necessarily be upstream of the monitor); see EPRI 1018693 (2009) or Short (2011).

Table 8.5 summarizes arc voltages for several utility datasets. Most of the circuits in the DPQ project were mainly overhead. Utility A provided a similar dataset; they were a DPQ participant who kept their monitors in place after the study ended, and

TABLE 8.5 Arc Voltages and Equivalent Arc Lengths from Various Monitoring Datasets

	Arc Voltage, V[a]		Equivalent Arc Length, Inches (1 in = 2.54 cm)	
Data Source	Median	25–75% Range	Median	25–75% Range
EPRI DPQ	594	301–954	15	7.5–24
Utility A (OH)	368	222–630	9	5.5–16
Utility B (OH)	605	235–1058	15	5.8–26
Utility C (UG)	332	204–638		

Notes: The DPQ data and utility A results are from downline feeder measurements; utility B and C results are estimated from substation measurements.

[a]The median arc voltage up to the first 0.2 sec of the event.

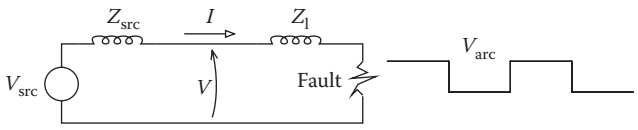


Figure 8.30 Arc voltage estimation. (From EPRI 1012438, *Distribution Fault Location: Field Data and Analysis*, Electric Power Research Institute, Palo Alto, CA, 2006. Copyright 2006. Reprinted with permission.)

the data covered from 1995 until 2008. Utility A has overhead with tight spacings and spacer cables. Utility B data is for mainly overhead faults. Utility C is data for urban underground faults. The arc length estimate for utility C was not included because the arc length relationship to arc voltage is likely to be different in cables and splices than it is in open air. The equivalent arc lengths in Table 8.5 are based on an arc voltage of 40 V/in. (16 V/cm).

Radojevic et al. (2000, 2004, 2005) developed arc voltage estimation as a way to try and determine if a transmission-line fault was temporary or permanent. They assumed that permanent faults would have little arc voltage, and temporary faults have more significant arc voltage. Their approach relies on the approximation that the arc voltage is a square wave (Figure 8.30).

The data for utilities B and C in Table 8.5 is based on a modification of the Radojevic et al. algorithm. With the square-wave assumption, we can estimate arc voltage from the point-by-point monitoring waveforms as follows:

$$V = R \cdot I + L \cdot dI/dt + V_{arc} \cdot \text{sign}(I)$$

This is an overdetermined system. If we use 128 points over one cycle, that gives us 128 equations and three unknowns (R, L, and V_{arc}). It assumes that the arc voltage is a square wave in phase with the line current. Radojevic et al. developed their methodology for transmission lines, but it applies well to distribution circuits. Two enhancements were needed to make the approach of Radojevic et al. work more consistently with monitoring data:

1. The derivative of current (dI/dt) was estimated with smoothing splines. Just using trapezoidal approximation $(i_{k+1}-i_{k-1})/2\Delta t$ resulted in far too much noise that dominated the result.
2. A constrained minimization approach was used to solve the overdetermined system. The error squared was minimized as suggested by Radojevic et al., but the solution parameters (R, L, and V_{arc}) were constrained to be positive using a quadratic programming solution.

8.5.4 Arc Voltages and Fault Type

Hydro Quebec has successfully used arc voltages from a monitoring system to determine fault type. The monitors were developed to locate faults to improve maintenance; these monitors are toward the ends of circuits. Tremblay et al. (2007) and

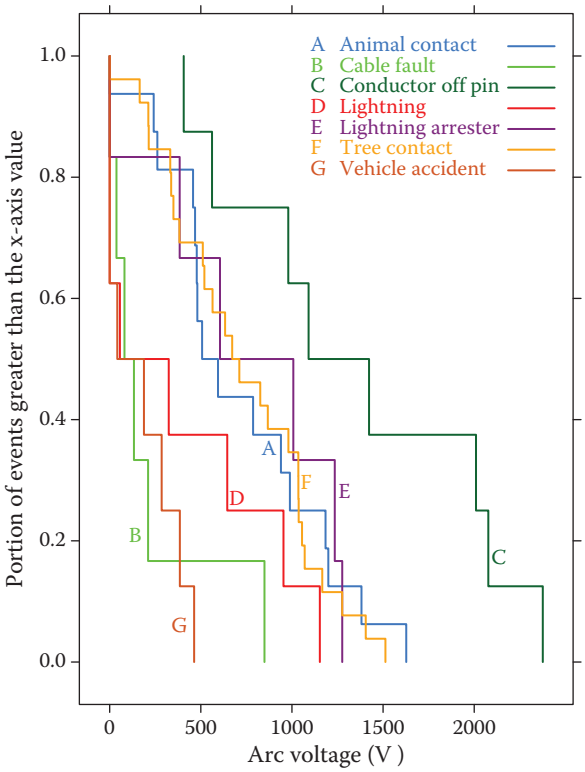


Figure 8.31 Distributions of arc voltage by fault type (utility A). (Adapted from EPRI 1012438, *Distribution Fault Location: Field Data and Analysis*, Electric Power Research Institute, Palo Alto, CA, 2006.)

EPRI 1021999 (2011) show examples of faults that were categorized based on arc voltage. Faults with higher arc voltages correspond to longer arcs, and this information was used several times in conjunction with fault location estimates to identify weak spots and to identify corrective action. Such maintenance included insulator replacement, cutout replacement, and targeted vegetation management. Faults with very low arc voltages are direct conductor-to-conductor contacts.

Figure 8.31 shows cumulative distributions of arc voltage estimates from monitoring data that could be correlated with outage cause. Some causes stand out as having a higher-than-normal or lower-than-normal arc voltage. Cables generally have low arc voltage when faulted. Trees, animals, and conductors off the pin—all are scenarios that can lead to a long arc through the air that tend to have higher arc voltages.

Koch and Christophe (1993) reported on arc voltages found in tests by Hydro Quebec on cable and splice failures. They found low arc voltages on both PILC cables and splices and higher voltages from XLPE cables and premolded splices as shown in Table 8.6. Values for arc voltages for splices are shown for interfacial failures unless noted, meaning that the failure is initiated at the interface where the splice plugs together. Radial failures were initiated by holes directly through the insulation. Radial faults were initiated by boring directly through the insulation. Interfacial failures had

TABLE 8.6 Arc Voltages on Underground Equipment

Equipment	Average Arc Voltage, V
Separable premolded splices, type A	577
Separable premolded splices, type B	1010
Heat shrinkable splices	1530
Heat shrinkable splices; radial faults	807
Nonseparable premolded splices; radial or interfacial	1000
XLPE cables	703
PILC cables	328
PILC splices	491

Source: Data from Koch, B. and Christophe, P., *IEEE Transactions on Power Delivery*, vol. 8, no. 3, pp. 779–88, July 1993.

longer arc paths and tended to have higher arc voltages. They noted that different splices had different failure modes with some breaking open very quickly. Some of their test specimens showed modest dependence on arcing current over the test range of 4 to 16 kA, but most had relatively constant arc voltage, and variability was high.

Estimates of arc voltage in underground equipment showed similar patterns as the Hydro Quebec data. These are estimates from substation monitoring data correlated to the utility's failure records. The arc voltages on the underground primary showed differences between joints, cables, and transformers (Figure 8.32). Failures of cables of different types (PILC, XLPE, and EPR) had similar distributions. Joints had significant differences between solid joints, stop joints (also called transition joints), and paper joints as shown in Figure 8.33. The differences in arc voltage probabilities could be used to aid in locating faults. Events with high arc voltage could signal joint failures, and this could be quantified using probabilities. In addition to arc voltage, other waveform signatures may aid in fault type identification (EPRI 1017842, 2009).

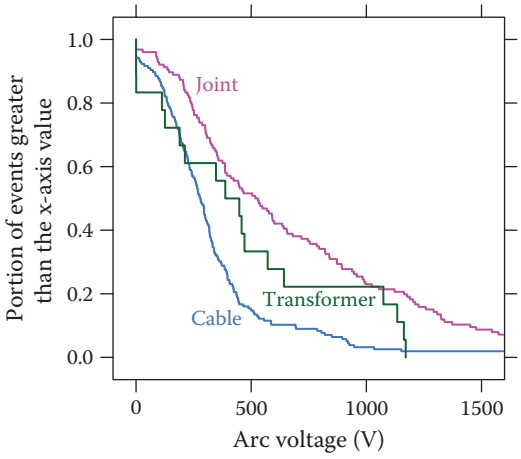


Figure 8.32 Estimates of arc voltage by equipment type (utility C). (Adapted from EPRI 1012438, *Distribution Fault Location: Field Data and Analysis*, Electric Power Research Institute, Palo Alto, CA, 2006.)

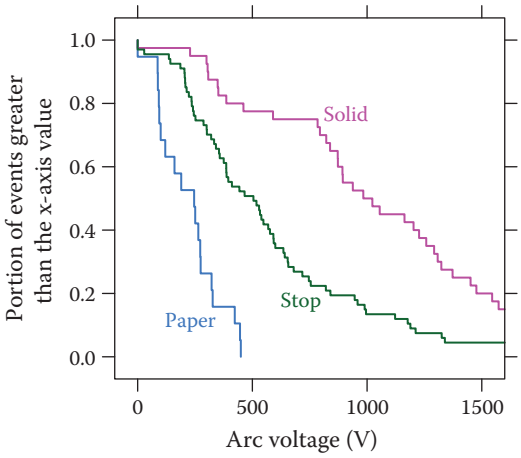


Figure 8.33 Estimates of arc voltage by splice failure type (utility C). (Adapted from EPRI 1012438, *Distribution Fault Location: Field Data and Analysis*, Electric Power Research Institute, Palo Alto, CA, 2006.)

8.6 High-Impedance Faults

When a conductor comes in physical contact with the ground but does not draw enough current to operate typical protective devices, you have a *high-impedance* fault. In the most common scenario, an overhead wire breaks and falls to the ground (a *downed wire*). If the phase wire misses the grounded neutral or another ground as it falls, the circuit path is completed by the high-impedance path provided by the contact surface and the earth.

The return path for a conductor lying on the ground can be a high impedance. The resistance varies depending on the surface of the ground. Table 8.7 shows typical current values measured for conductors on different surfaces (for 15-kV class circuits).

The frequency of high-impedance faults is uncertain. Most utilities responding to an IEEE survey reported that high-impedance faults made up less than 2% of faults while a sizeable number (15% of those surveyed) suggested that between 2% and 5% of distribution faults were not detectable (IEEE Working Group on Distribution Protection, 1995). Even with small numbers, high-impedance faults pose an important safety hazard.

On distribution circuits, high-impedance faults are still an unsolved problem. It is not for lack of effort; considerable research has been done to find ways to detect high-impedance faults, and progress has been made (see IEEE Tutorial Course 90EH0310-3-PWR (1990) for a more in-depth summary). Research has identified many characteristics of high-impedance faults and have tested them for detection purposes. Efforts have been concentrated on detection at the substation based on phase and ground currents. High-impedance faults usually involve arcing, and arcing generally creates the lower odd harmonics. Arcing faults may also contain significant 2- to 10-kHz components. Arcing also bursts in characteristic patterns.

TABLE 8.7 Typical High-Impedance Fault Current Magnitudes

Surface	Current, A
Dry asphalt	0
Concrete (no rebar)	0
Dry sand	0
Wet sand	15
Dry sod	20
Dry grass	25
Wet sod	40
Wet grass	50
Concrete (with rebar)	75

Source: Adapted from IEEE Tutorial Course 90EH0310-3-PWR, Detection of Downed Conductors on Utility Distribution Systems, 1990. Copyright 1990 IEEE. With permission.

High-impedance faults often cause characteristic changes in the load (e.g., a broken conductor will drop the load on that phase). None of these detection methods is perfect, so some detection schemes use more than one method to try to detect high-impedance faults.

We can also detect broken conductors at the ends of radial circuits. Loss of voltage is the simplest method. Communication to an upstream protective device or to a control center is required. A difficulty is that it takes many devices to adequately cover a radial circuit (depending on how many branches occur on the circuit). Also, the "ends" of circuits could change during circuit reconfigurations or sectionalizing due to circuit interruptions. Also, if the loss-of-voltage detector is downstream of a fuse, another detector is needed at the fuse, so we can determine if the fuse operated or the conductor broke.

Practices that help reduce high-impedance faults include

- *Tight construction framings*—If a phase wire breaks, it is more likely to contact a neutral as it falls. (A drawback is that utilities have reported poorer reliability with tighter constructions like the armless design.) A vertical construction is better than a horizontal construction. Single-phase structures are better than three-phase structures.
- *Stronger conductors*—Larger conductors or ACSR instead of all-aluminum conductor are stronger and less likely to break for a given mechanical or arcing condition.
- *Smaller/faster fuses*—Faster fuses are more likely to operate for high-impedance faults. In addition, smaller fuses are likely to clear before arcing damages wires, which could burn down the wires.
- *Tree trimming*—Clearing trees and trimming reduces the number of trees or branches breaking conductors.
- *Fewer reclose attempts*—Each reclose attempt causes more damage at the fault location.
- *Higher primary voltages*—High-impedance faults are much less likely at 34.5 kV and somewhat less likely at 24.94 kV than 15-kV class voltages.

- *Thermal inspections*—Find bad connections.
- *Public education*—Public advertisements warning the public to stay away from downed wires help reduce accidents when high-impedance faults do occur.

Practices to *avoid* include

- *Covered wire*—Burndowns are more likely with covered wire. If a covered wire does contact the ground, it is less likely to show visible signs that it is energized such as arcing or jumping, which would help keep bystanders away.
- *Unfused taps*—Burndowns are more likely with the smaller wire used on lateral taps.
- *Midspan connectors*—Flying taps can cause localized heating and mechanical stress.
- *Rear-lot construction*—Rear-lot construction is not as well maintained as road-side construction, so trees are more likely to break wires. If wires do come down, it is more hazardous since they are coming down in someone's backyard.
- *Neutral on the crossarm*—If a phase wire breaks, it is much less likely to contact the neutral as it falls if the neutral is on the crossarm. Other constructions that may have this same problem are overhead shield wires and spacer cables that do not have an additional neutral below.

Three-wire distribution systems have some advantages and some disadvantages related to high-impedance faults. The main advantage of three-wire systems is that there is no unbalanced load. A sensitive ground relay can be used, which would detect many high-impedance faults. The sensitivity of the ground relay is limited by the line capacitance. The main disadvantage of three-wire systems is that there is no multi-grounded neutral. If a phase conductor breaks, there is a high probability that there will be a high-impedance fault. If there is underbuilt secondary or phone or cable TV under the three-wire system, then a high-impedance fault is less likely because a grounded conductor is below the phases.

Spacer cable has some mechanical strength advantages that could help keep phase wires in the air, and it has fewer faults due to trees. A downside is the covering that makes burndowns more likely. Also, it has a messenger wire that may act as the neutral; if it does not also have an underbuilt neutral, a phase conductor is more likely to fall unimpeded.

Backfeeds from three-phase transformer and capacitor installations can cause dangerous situations. If a wire breaks near a pole, at least half of the time, the load side (downstream side) will lie on the ground. Backfeed to the downed wire can occur through three-phase transformers downstream of the fault. The backfeed can provide enough voltage and current to the downed wire to be dangerous (but there will not be enough current to trip protective devices). Note that a grounded-wye–grounded-wye connection does not eliminate backfeeds. Another backfeed scenario is shown in Figure 8.34 where a three-phase load is fed from a fused tap. A bolted, low-impedance fault on one phase will blow the fuse, but backfeed current may flow through the three-phase connection. Even with a low-impedance fault, the backfeed current can be low enough that neither the remaining tap fuses nor the transformer fuses will operate. The fault can continue to arc until the wire burns down. An ungrounded capacitor bank can also provide a backfeed path.

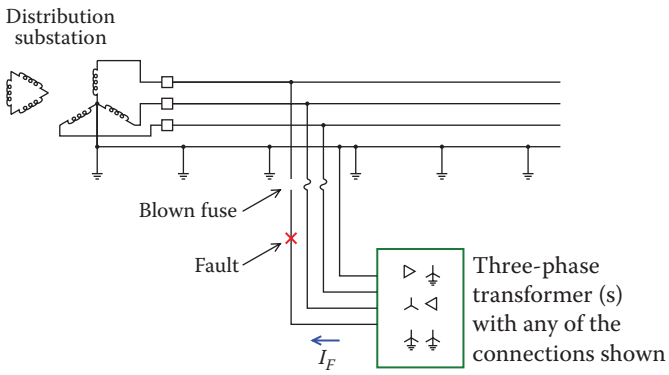


Figure 8.34 Backfeed to a fault downstream of a blown fuse.

Commercial relays that have high-impedance fault detection capabilities are available. One of the main problems with detection of high-impedance faults is false fault detections. If a detection system in the station detects a fault and a whole feeder is tripped for an event that is not really a high-impedance fault, reliability is severely hurt. Before reenergizing, crews patrol the circuit and make sure that there was not a downed conductor. The sensitivity of a device must be traded off against its dependability. If it is too sensitive, many false operations will result. An alternative to tripping is alarming. Operators in control centers may always trip a circuit if it signals a high-impedance fault for fear of discipline if it really was a high-impedance fault and an accident occurred. Each time a high-impedance fault is detected, crews would have to patrol the circuit. If operators have too many false alarms, they may ignore the alarm.

Depew et al. (2006) reported on Pepco's experience covering two years for 280 relays with high-impedance fault detection. In 48 faults recorded by relays and identified by the utility as downed conductors, they found that these relays triggered a high-impedance fault event for 28 events (58% success rate). 16 of the 28 events involved trips of conventional relays followed by reclose events. Their relay settings were biased for security, so they would not excessively flag false events. They only found two instances where the relays flagged high-impedance faults for which there was no documentation of a downed conductor. Depew et al. also found the need for more relay storage and data retention for this type of relay feature because high-impedance faults can persist for many minutes.

A tree branch in contact with a phase conductor also forms a high-impedance fault. This is not as dangerous as a downed wire. Most of the time the circuit operates normally, without danger to the public (see Chapter 14 for more analysis of this situation). A tree branch in contact with a phase conductor can draw enough current to trip a high-impedance fault detector. In a heavily treed area, crews could require many hours to find the location where the tree contact is taking place.

One of the main problems with substation detection is that each feeder usually covers many miles of line. With most faults, lateral fuses provide an effective way to isolate and identify the location of faults within a relatively small area. While it would be nice to have high-impedance fault detection capability on lateral taps, the costs

have been prohibitive. Contrast a station detection scheme (one device) with detectors at taps—tens or hundreds of devices. AMI metering may offer new ways to detect and respond to high-impedance faults, and AMI offers the benefit from being able to identify locations more readily.

Another solution to falling conductors is using guards installed on poles below the phase wires to "catch" phase conductors. The guards are connected to the grounded neutral, so when a phase conductor breaks, a low-impedance fault is created. This would be a significant expense to install system-wide, but it may be suitable for isolated locations where it is critical not to have energized downed conductors (a stretch that runs across a school playground or a span that crosses a major road).

8.7 Equipment Faults

Equipment failures—transformers, capacitors, splices, terminations, insulators, connectors—cause faults. When equipment fails, it is almost always as a short circuit and rarely as an open circuit.

Equipment failures on overhead circuits are usually a small percentage of faults (see Figure 8.1). This is confirmed by another study at Pacific Gas & Electric Co. shown in Table 8.8. These are shown as a percentage of permanent faults. Since equipment faults are almost always permanent faults, the overall percentage of equipment failures is a low percentage of all faults (since most faults are temporary on overhead circuits). On underground circuits, most faults are due to equipment failures.

Distribution transformers are the most common major device, so their failure rate is important. Transformers generally fail at rates of about 0.5% per year. The most common failure mode starts as a breakdown of the turn-to-turn insulation.

Table 8.9 shows equipment failure rates recorded over a 5-year period at PG&E. This data is generic service-time failure rates, which is an estimate to the actual failure rate. Note that this is for California, which has very little lightning and mild weather; other areas may have higher equipment failures. The rate of all permanent faults was 0.11 faults/mi/year for rural circuits (0.071 faults/km/year) and 0.16 faults/mi/year for urban circuits (0.102 faults/km/year). The only component where there was a statistical difference between urban and rural at the 90% confidence level was the difference in failure rates of transformers (the sample size for the rest of the numbers was too small to statistically determine a difference).

TABLE 8.8 Permanent Fault Causes

Source	Rural (%)	Urban (%)
Equipment failures	14.1	18.4
Loss of supply	7.8	9.6
External factors	78.1	72.0

Source: Adapted from Horton, W. F., Golberg, S., and Volkmann, C. A., *IEEE Power Engineering Society Transmission and Distribution Conference*, 1991. Copyright 1991 IEEE. With permission.

TABLE 8.9 Service-Time Overhead Component Failure Rates for PG&E

	Failure Rates per Year	
Component	Rural	Urban
Transformers	0.0271%	0.0614%
Switches	0.126%	0.0775%
Fuses	0.45%	0.374%
Capacitors	1.05%	0.85%
Reclosers	1.50%	1.44%
Voltage regulators	2.88%	n/a
Conductors	1.22/100 mi	1.98/100 mi

Source: Adapted from Horton, W. F., Golberg, S., and Volkmann, C. A., *IEEE Power Engineering Society Transmission and Distribution Conference*, 1991. Copyright 1991 IEEE. With permission.

TABLE 8.10 Overhead Component Failure Rates in the IEEE Gold Book

Component	Failure Rate per Year (%)
Transformers (all)	0.62
Transformers (300 to 10,000 kVA)	0.59
Transformers (>10,000 kVA)	1.53
Switchgear bus (insulated)	0.113[a]
Switchgear bus (bare)	0.192[a]

Source: Adapted from IEEE Std. 493-1997, IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (Gold Book). Copyright 1998 IEEE.

[a]For each circuit breaker and connected switch.

Another source for equipment failure rate data is the IEEE Gold Book (IEEE Std. 493-1997) (Table 8.10). Note that the Gold Book is for industrial facilities. Application and loading practices may be significantly different than typical utility applications. Still, they provide useful comparisons.

8.7.1 Faults in Equipment

Failures in equipment pose special hazards with important safety ramifications. Transformers deserve extra attention because they are so common. One utility has reported one violent distribution transformer failure for every 270 transformers containing an internal fault, and 20% of reenergizations had internal faults, which is one violent failure every 1350 reenergizations (CEA 149 D 491A, 1997). Cuk (2001) estimated that between 2% and 5% of overhead transformers are refused every year (based on analyzing fuse purchases; this number varies with fusing practices). This section discusses failure mechanisms and the consequences of an internal failure.

Transformer insulation degrades over the life of the transformer. Heat drives the degradation of transformer insulation (this is a generality that applies to many other types of insulation as well). Overloading transformers will reduce a transformer's life. Most utilities will overload distribution transformers as it is the best economic way to operate them.

Heat degrades paper insulation at a relatively known rate. ANSI standards give guidelines on loss of life versus temperature. Heating can also cause generation of gas bubbles (Kaufmann and McMillen, 1983). Gas can be created by decomposition of the paper insulation. Prolonged overloading to 175% can cause gas generation. Gas can also be created when heated oil has a pressure drop; the most likely scenario is an overloaded transformer that is cooled quickly (the effect is most significant for overloads above 175%). Rainfall causes the quickest cooling; a loss of load also cools the transformer. The bubbles reduce the dielectric strength of the insulation system. Bubble generation starts when the temperature is near 145°C. Hotspot temperatures exceeding 200°C during overloading can reduce the insulation strength by a factor of two (Kaufmann, 1977). Once the transformer cools off and the bubbles disappear, the insulation recovers most of its initial strength (minus the amount of paper degraded). During overloading, failures can be caused by the power-frequency voltage or a voltage surge (the straw that breaks the camel's back).

Internal faults in equipment such as transformers and capacitors can cause violent damage. Of most concern, explosive failures endanger workers and the public. Figure 8.35 shows a thought-provoking picture of a failure of a recloser. It illustrates how important safety is. Buy quality equipment! Use effective fault protection! Knowing the characteristics of internal failures helps prevent such accidents. We must properly fuse equipment. Fusing should ensure that if equipment does fail internally, it is isolated from the system before it ruptures or ejects any oil.

During the 1970s, considerable work was done to investigate the failure mechanisms, withstand abilities of transformers, and ways to improve protection (Barkan et al., 1976; Goodman and Zupon, 1976; Mahieu, 1975). The voltage along an arc

Figure 8.35 Explosion of a recloser that caused a fatality. (From Dalton Sullivan, Pocahontas (AR) Star Herald. With permission.)

remains relatively constant regardless of the fault current magnitude when under oil just as it does in air. An arc voltage under oil is roughly 215 to 255 V/in. (85 to 100 V/cm) (Goodman and Zupon, 1976; Mahieu, 1975), which is higher than the voltage gradient of arcs in air. The arc voltage is higher because oil cools the arc, which reduces the ionization. Because the arc voltage is constant, the energy in the transformer is a function of $\int I \, dt$.

During a fault under oil, an arc creates a shock wave in the oil that can cause significant dynamic pressures. Also, considerable gas is generated at the rate of roughly 4.3 to 6.1 in.^{3}/kW (70 to 100 cm^3/kW) (Barkan et al., 1976; Goodman and Zupon, 1976). An arc in oil is hot enough to vaporize oil and ionize the gas. The gases created by the arc include roughly 65 to 80% hydrogen and 15 to 25% acetylene with ethylene, methane, and higher-molecular-weight gases. The arc also produces considerable amounts of solids and free carbon. The arc generates combustible gases, but combustion is uncommon because the oxygen level is generally low.

The pressure buildup and failure mode is fairly complicated and depends on the location of the fault. A fault in the windings generally causes less peak pressure on the top of the tank than a free-burning arc in oil even if the energy input is the same. The initial force on the transformer is a large downward force in the oil, but the top usually fails first since that is where the weakest structures are (although the downward force and resulting rebound can cause the transformer to buck violently, which may break the supports). The transformer lid is the weakest structural portion, so with excessive pressure, the lid will be the first place to fail. Another common failure is a bushing ejection. For a given arc energy, larger transformers have less pressure buildup because a larger transformer has a larger air space (a 100-kVA transformer has 3.8 times the air volume as a 10-kVA transformer (Barkan et al., 1976)). Padmounted transformers withstand more pressure buildup than overhead transformers (Benton, 1979). Padmounts have higher volume, and the square shape allows the tank to bulge out, which relieves some of the stress.

Many distribution transformers have pressure release valves. These are not fast enough to appreciably reduce the pressure buildup during high-current faults. The pressure release valves help low-current faults due to interwinding failures. Most failures of distribution transformers start as interwinding faults, either from turn-to-turn or from layer-to-layer. Turn-to-turn faults on the primary winding draw less than load current, so they will not operate the primary fuse. Turn-to-turn faults on the secondary and layer-to-layer faults on the primary draw higher current that may be high enough to operate the primary fuse. Interwinding faults are low-current events where the pressure builds slowly, so the pressure release valves can effectively release the pressure for primary-winding faults, although secondary winding faults may increase pressure faster than the pressure relief valve can dissipate (Lunsford and Tobin, 1997). As an interwinding fault arcs causes damage and melts additional insulation, the fault current will increase; usually the current jumps sharply to the bolted fault condition (not a slow escalation of current).

Overhead completely self-protected transformers (CSPs) and padmounted transformers with under-oil fuses have less withstand capability than conventional transformers. The reason for this is that the under-oil fuse (called a weak-link fuse) provides

another arcing location. When the weak-link fuse melts, an arc forms in place of the melted fuse element. This arc is in addition to whatever arc may exist within the tank that caused the fault in the first place. The arc across the fuse location is generally going to be longer than normal arcs that could occur inside a transformer. The length of an under-oil weak-link fuse is 2 to 3 in. (5.1 to 7.6 cm) for a 15-kV class fuse. Higher-voltage transformers have longer fuses—a 35-kV class fuse has a length of about 5 in. (12.7 cm). Also, the voltage gradient along an arc in a fuse tube under oil is greater than a "free" arc in oil (the fuse tube increases the pressure of the arc, which increases the voltage drop (Barkan et al., 1976)).

Transformers with under-oil arresters have a special vulnerability (Henning et al., 1989). The under-oil arrester provides another possible failure mode, which can lead to very high energy in the transformer if the arrester fails. If the arrester blocks fail, a relatively long arc results. A 10-kV duty-cycle rated arrester has a total block length of about 4.5 in. (11.4 cm). With such a long arc, the energy in the transformer will be very high. Industry tests and ratings do not directly address this issue. To be conservative, consider using a current-limiting fuse upstream of the transformer if the line-to-ground fault current exceeds 1 or 2 kA if under-oil arresters are used.

Stand-alone arresters are another piece of equipment where failure is a concern. If an arrester fails, a long internal arc may cause the arrester to explode, sending pieces of the housing along with pieces of the metal oxide. The move from porcelain-housed arresters to polymer-housed arresters was motivated primarily by the fact that the polymer-housing is less dangerous if the arrester fails. With a porcelain-housed arrester, the thermal shock from the arc can shatter the housing and forcefully expel the "shrapnel." Polymer-housed arresters are safer because the fault arc splits the polymer housing, which relieves the pressure buildup (although if the arc originates inside the blocks, the pressure can expel bits of the metal oxide). Arresters have caused accidents, and they got a bad name when metal-oxide arresters were first introduced because they occasionally failed upon installation.

Distribution arresters may specify a fault current withstand which is governed by IEEE standards (IEEE C62.11-1999). To pass the test, an arrester must withstand an internal failure of the given fault current and all components of the arrester must be confined within the enclosure. The duration of the test is a minimum of 0.1 sec (manufacturers often specify other times as well), which is a typical circuit breaker clearing time when the instantaneous relay element operates. If the available fault current is higher than the rated withstand, then current-limiting fuses should be considered. With polymer-housed arresters, the fault-current withstand is usually sufficient with manufacturers specifying withstand values of 10 to 20 kA for 0.1 sec.

The failure of arresters (especially porcelain-housed arresters) is also a consideration for fusing. If an arrester is downstream of a transformer fuse and the arrester fails, the relatively small transformer fuse will blow. If an arrester is upstream of the transformer fuse, then a larger tap fuse or the substation circuit breaker operates, which allows a much longer duration fault current. Arresters have isolators that disconnect the arresters in case of failure. Isolators do *not* clear fault current. After the fuse or circuit breaker operates, the disconnect provides enough separation to allow the circuit

to reclose successfully. If the next upstream device is a circuit breaker and an instantaneous element is not used, fault currents could be much longer than the tested 0.1 sec, so consider adding a fuse upstream of the arrester on porcelain-housed units.

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You begin to think that trees possibly grow faster toward your power line just out of spite.

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9

Short-Circuit Protection

Contents

9.1 Basics of Distribution Protection 426
9.1.1 Reach 427
9.1.2 Inrush and Cold-Load Pickup 428
9.2 Protection Equipment 430
9.2.1 Circuit Interrupters 430
9.2.2 Circuit Breakers 432
9.2.3 Circuit Breaker Relays 434
9.2.4 Reclosers 437
9.2.5 Expulsion Fuses 438
9.2.5.1 Fuse Cutouts 443
9.2.6 Current-Limiting Fuses 446
9.3 Transformer Fusing 448
9.4 Lateral Tap Fusing and Fuse Coordination 453
9.5 Station Relay and Recloser Settings 454
9.6 Coordinating Devices 456
9.6.1 Expulsion Fuse–Expulsion Fuse Coordination 456
9.6.2 Current-Limiting Fuse Coordination 457
9.6.3 Recloser–Expulsion Fuse Coordination 460
9.6.4 Recloser–Recloser Coordination 461
9.6.5 Coordinating Instantaneous Elements 461
9.7 Locating Sectionalizing Equipment to Optimize Reliability 463
9.8 Fuse Saving versus Fuse Blowing 468
9.8.1 Industry Usage 468
9.8.2 Effects on Momentary and Sustained Interruptions 470
9.8.3 Coordination Limits of Fuse Saving 470
9.8.4 Long-Duration Faults and Damage with Fuse Blowing 472
9.8.5 Long-Duration Voltage Sags with Fuse Blowing 473
9.8.6 Optimal Implementation of Fuse Saving 474
9.8.7 Optimal Implementation of Fuse Blowing 474
9.9 Other Protection Schemes 475
9.9.1 Time Delay on the Instantaneous Element (Fuse Blowing) 475
9.9.2 High–Low Combination Scheme 476
9.9.3 SCADA Control of the Protection Scheme 476
9.9.4 Adaptive Control by Phases 477
9.10 Reclosing Practices 477
9.10.1 Reclose Attempts and Dead Times 478
9.10.2 Immediate Reclose 481

9.10.2.1 Effect on Sensitive Residential Devices 482
9.10.2.2 Delay Necessary to Avoid Retriggering Faults 482
9.10.2.3 Reclose Impacts on Motors 483
9.11 Single-Phase Protective Devices 484
9.11.1 Single-Phase Reclosers with Three-Phase Lockout 486
References 487

Overcurrent protection or short-circuit protection is very important on any electrical power system, and the distribution system is no exception. Circuit breakers and reclosers, expulsion fuses, and current-limiting fuses (CLFs)—these protective devices interrupt fault current, a vital function. Short-circuit protection is the selection of equipment, placement of equipment, selection of settings, and coordination of devices to efficiently isolate and clear faults with as little impact on customers as possible.

Of top priority, good fault protection clears faults quickly to prevent

- *Fires and explosions*
- *Further damage to utility equipment such as transformers and cables*

Secondary goals of protection include practices that help reduce the impact of faults on

- *Reliability* (long-duration interruptions)—In order to reduce the impact on customers, reclosing of circuit breakers and reclosers automatically restores service to customers. Having more protective devices that are properly coordinated assures that the fewest customers possible are interrupted and makes fault-finding easier.
- *Power quality* (voltage sags and momentary interruptions)—Faster tripping reduces the duration of voltage sags. Coordination practices and reclosing practices impact the number and severity of momentary interruptions.

9.1 Basics of Distribution Protection

Circuit interrupters should only operate for faults, not for inrush, not for cold-load pickup, and not for transients. Additionally, protective devices should coordinate to interrupt as few customers as possible.

The philosophies of distribution protection differ from transmission-system protection and industrial protection. In distribution systems, protection is not normally designed to have backup. If a protective device fails to operate, the fault may burn and burn (until an upstream device is manually opened). Of course, protection coverage should overlap, so that if a protective device fails due to an internal short circuit (which is different from failing to open), an upstream device operates for the internal fault in the downstream protector. Backup is not a mandatory design constraint (and is impractical to achieve in all cases).

Most often, we base distribution protection on standardized settings, standardized equipment, and standardized procedures. Standardization makes operating a

distribution company easier if designs are consistent. The engineering effort to do a coordination study on every circuit reduces considerably.

Another characteristic of distribution protection is that it is not always possible to fully coordinate all devices. Take fuses. With high fault currents, it is impossible to coordinate two fuses in series because the high current can melt and open both fuses in approximately the same time. Therefore, close to the substation, fuse coordination is nonexistent. There are several other situations where coordination is not possible. Some low-level faults are very difficult—some would say impossible—to detect. A conductor in contact with the ground may draw very little current. The "high-impedance" fault of most concern (because of danger to the public) is an energized, downed wire.

9.1.1 Reach

A protective device must clear all faults in its protective zone. This "zone" is defined by

- *Reach*—The reach of a protective device is the maximum distance from a protective device to a fault for which the protective device will operate.

Lowering a relay pickup setting or using a smaller fuse increases the reach of the protective device (increasing the device's *sensitivity*). Sensitivity has limits; if the setting or size is too small, the device trips unnecessarily from overloads, from inrush, and from cold-load pickup.

We have several generic or specific methods to determine the reach of a protective device. Commonly, we estimate the minimum fault current for faults along the line and choose the reach of the device as the point where the minimum fault current equals the magnitude where the device will operate. Some common methods of calculating the reach are

- *Percentage of a bolted line-to-ground fault*: The minimum ground fault current is some percentage (usually 25 to 75%) of a bolted fault.
- *Fault resistance*: Assume a maximum value of fault resistance when calculating the current for a single line-to-ground fault. Common values of fault resistance used are 1 to 2, 20, 30, and 40 Ω. Rural Electrification Administration (REA) standards use 40 Ω.

Other options for determining the reach are

- *Point based on a maximum operating time of a device*: Define the reach as the point giving the current necessary to operate a protective device in a given time (with or without assuming any fault impedance). Example: The REA has recommended taking the reach of a fuse as the point where the fuse will just melt for a single line-to-ground fault in 20 sec with a fault resistance of 30 or 40 Ω.
- *Point based on a multiplier of the device setting*: Choose the point where the fault current is some multiple of the device rating or setting. Example: The reach of a fuse is the point where the bolted fault current is six times the fuse rating.

None of these methods are exact. Some faults will always remain undetectable (high-impedance faults). The trick is to try to clear all high-current faults without being overly conservative.

Assuming a high value of fault resistance (20 to 40 Ω) is overly conservative, so avoid it. For a 12.47-kV system (7.2 kV line to ground), the fault current with a 40 Ω fault impedance is less than 180 A (this ignores the system impedance—additional system impedance reduces the calculated current even more). Using typical relay/recloser setting philosophies, which say that the rating of the recloser must be less than half of the minimum fault current, a recloser must be less than 90 A, which effectively limits the load current to an unreasonably low value. In many (even most, for some utilities) situations, this is unworkable. As discussed in Chapter 8, faults with arc impedances greater than 2 Ω are not common, so take the approach that the minimum fault is close to the bolted fault current. On the other hand, high-impedance faults (common during downed conductors) generally draw less than 50 A and have impedances of over 100 Ω. The 40 Ω rule does not guarantee that a protective device will clear high-impedance faults, and in most cases would not improve high-impedance fault detection.

9.1.2 Inrush and Cold-Load Pickup

When an electrical distribution system energizes, components draw a high, short-lived inrush; the largest component magnetizes the magnetic material in distribution transformers (in most cases, it is more accurate to say *remagnetizes* since the core is likely magnetized in a different polarity if the circuit is energized following a short-duration interruption). The transformer inrush characteristics important for protection are

- At a distribution transformer, inrush can reach peak magnitudes of 30 times the transformer's full-load rating.
- Relative to the transformer rating, inrush has higher peak magnitudes for smaller transformers, but the time constant is longer for larger transformers. Of course, on an absolute basis (amperes), a larger transformer draws more inrush.
- Sometimes inrush occurs, and sometimes it does not, depending on the point on the voltage waveform at which the reclosing occurs.
- System impedance limits the peak inrush.

The system impedance relative to the transformer size is an important concept since it limits the peak inrush for larger transformers and larger numbers of transformers. If one distribution transformer is energized by itself, the transformer is small relative to the source impedance, so the peak inrush maximizes. If a tap with several transformers is energized, the equivalent connected transformer is larger relative to the system impedance, so the peak inrush is lower (but the duration is extended). Several transformers energizing at once pull the system voltage down. This reduction in voltage causes less inrush current to be drawn from each transformer. For a whole

feeder, the equivalent transformer is even larger, so less inrush is observed. Some guidelines for estimating inrush are

- *One distribution transformer*—30 times the crest of the full-load current
- *One lateral tap*—12 times the crest of the full-load current of the total connected kVA
- *Feeder*—5 times the connected kVA up to about half of the crest of the system available fault current

At the feeder level, inrush was only reported to cause tripping by 15% of responders to an IEEE survey (IEEE Working Group on Distribution Protection, 1995). When a three-phase circuit is reclosed, the ground relay is most likely to operate since the inrush seen by a ground relay can be as high as the peak inrush on the phases (and it is usually set lower than the phase settings). An instantaneous relay element is most sensitive to inrush, but the instantaneous element is almost always disabled for the first reclose attempt. The ground instantaneous element could operate if a significant single-phase lateral is reconnected.

Transformers are not the only elements that draw inrush; others include resistive lighting and heating elements and motors. Incandescent filaments can draw eight times normal-load current. The time constant for the incandescent filaments is usually very short; the inrush is usually finished after a half cycle. Motor starting peak currents are on the order of six times the motor rating. The duration is longer than transformer inrush with durations typically from 3 to 10 sec.

Cold-load pickup is the extra load following an extended interruption due to loss of the normal diversity between customers. Following an interruption, the water in water heaters cools down and refrigerators warm up. When the power is restored, all appliances that need to catch up energize at once. In cold weather, following an extended interruption, heaters all come on at once (so it is especially bad with high concentrations of resistance heating). In hot weather, houses warm up, so all air conditioners start following an interruption.

Cold-load pickup can be over three times the load prior to the interruption. As diversity is regained, the load slowly drops back to normal. This time constant varies depending on the types of loads and the duration of the interruption. Cold-load pickup is often divided into transformer inrush, which last a few cycles, motor starting and accelerating currents, which last a few seconds, and finally just the load due to loss of diversity, which can last many minutes. Figure 9.1 shows the middle-range time-frame with motor starting and accelerating currents.

It is important to select relay settings and fuse sizes high enough to avoid operations due to cold-load pickup. Even so, cold-load pickup problems are hard to avoid in some situations. A survey of utilities reported 75% having experienced cold-load pickup problems (IEEE Working Group on Distribution Protection, 1995). When a cold-load pickup problem occurs at the substation level, the most common way to reconnect is to sectionalize and pick the load up in smaller pieces. For this reason, cold-load pickup problems are not widespread—after a long interruption, utilities usually sectionalize anyway to get customers back on more quickly. Two other ways

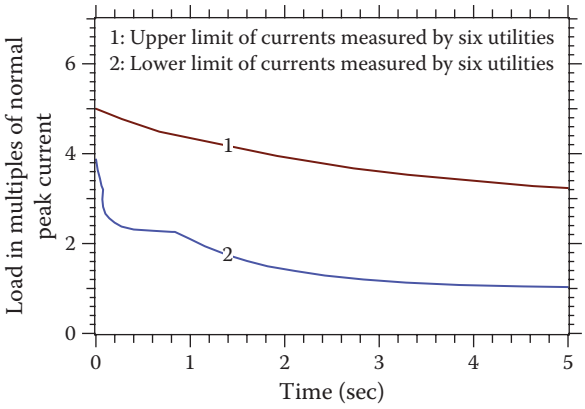


Figure 9.1 Ranges of cold-load pickup current from tests by six utilities. (Data from Smithley, R. S., *Electrical World*, pp. 52–4, June 15, 1959.)

that are sometimes used to energize a circuit are to raise relay settings or even to block tripping (not recommended unless as a very last resort).

In order to pick relays, recloser settings, and fuses, we often plot a cold-load pickup curve on a time–current coordination graph along with the protection equipment characteristics. Points can be taken from the curves in Figure 9.1. It is also common to choose one or two points to represent cold-load pickup. Three hundred percent of full-load current at 5 sec is a common point.

Distribution protective devices tend to have steep time–overcurrent characteristics, meaning that they operate much faster for higher currents. K-link fuses and extremely inverse relays are most commonly used, and these happen to have the steepest characteristics. This is no coincidence; a distribution protective device must operate fast for high currents (most faults) and slow for lower currents. This characteristic gives a protective device a better chance to ride through inrush and cold-load pickup.

9.2 Protection Equipment

9.2.1 Circuit Interrupters

All circuit interrupters—including circuit breakers, fuses, and reclosers—operate on some basic principles. All devices interrupt fault current during a zero-crossing. To do this, the interrupter creates an arc. In a fuse, an arc is created when the fuse element melts, and in a circuit breaker or recloser, an arc is created when the contacts mechanically separate. An arc conducts by ionizing gases, which leads to a relatively low-impedance path.

After the arc is created, the trick is to increase the dielectric strength across the arc so that the arc clears at a current zero. Each half cycle, the ac current momentarily stops as the current is reversing directions. During this period when the current is reversing, the arc is not conducting and is starting to deionize, and in a sense, the

circuit is interrupted (at least temporarily). Just after the arc is interrupted, the voltage across the now-interrupted arc path builds up. This is the *recovery voltage*. If the dielectric strength builds up faster than the recovery voltage, then the circuit stays interrupted. If the recovery voltage builds up faster than the dielectric strength, the arc breaks down again. Several methods used to increase the dielectric strength of the arc are discussed in the following paragraphs. The general methods are

- *Cooling the arc*—The ionization rate decreases with lower temperature.
- *Pressurizing the arc*—Dielectric strength increases with pressure.
- *Stretching the arc*—The ionized-particle density is reduced by stretching the arc stream.
- *Introducing fresh air*—Introducing deionized gas into the arc stream helps the dielectric strength to recover.

An air blast breaker blasts the arc stream into chutes that quickly lengthen and cool the arc. Blowout coils can move the arc by magnetically inducing motion. Compressed air blasts can blow the arc away from the contacts.

The arc in the interrupter has enough resistance to make it very hot. This can wear contact terminals, which have to be replaced after a given number of operations. If the interrupter fails to clear with the contacts open, the heat from the arc builds high pressure that can breach the enclosure, possibly in an explosive manner.

In an oil device, the heat of an arc decomposes the oil and creates gases that are then ionized. This process takes heat and energy out of the arc. To enhance the chances of arc extinction in oil, fresh oil can be forced across the path of the arc. Lengthening the arc also helps improve the dielectric recovery. In an oil circuit breaker, the contact parting time is long enough that there may be several restrikes before the dielectric strength builds up enough to interrupt the circuit.

Vacuum devices work because the dielectric strength increases rapidly at very low pressures (because there are very few gas molecules to ionize). Normally, when approaching atmospheric pressures, the dielectric breakdown of air decreases as pressure decreases, but for very low pressures, the dielectric breakdown goes back up. The pressure in vacuum bottles is 10^{-6} to 10^{-8} torr. A vacuum device only needs a very short separation distance (about 8 to 10 mm for a 15-kV circuit breaker). Interruption is quick since the mechanical travel time is small. The separating contacts draw an arc (it still takes a current zero to clear). Sometimes, vacuum circuit breakers chop the current, causing voltage spikes. The arc is a metal vapor consisting of particles melted from each side. Contact erosion is low, so vacuum devices are low maintenance and have a long life. Restrikes are uncommon.

SF_6 is a gas that is a very good electrical insulator, so it has rapid dielectric recovery. At atmospheric pressures, the dielectric strength is 2.5 times that of air, and at higher pressures, the performance is even better. SF_6 is very stable, does not react with other elements, and has good temperature characteristics. One type of device blows compressed SF_6 across the arc stream to increase the dielectric strength. Another type of SF_6 interrupter used in circuit breakers and reclosers has an arc spinner, which is a setup that uses the magnetic field from a coil to cause the arc to spin rapidly (bringing it in contact with un-ionized gas). SF_6 can be used as the insulating medium as well

as the interrupting medium. SF_6 devices are low maintenance, have short opening times, and most do not have restrikes.

Since interrupters work on the principle of the dielectric strength increasing faster than the recovery voltage, the *X/R* ratio can make a significant difference in the clearing capability of a device. In an inductive circuit, the recovery voltage rises very quickly since the system voltage is near its peak when the current crosses through zero. Asymmetry increases the peak magnitude of the fault current. For this reason, the capability of most interrupters decreases with higher *X/R* ratios. Some interrupting equipment is rated based on a symmetrical current basis while other equipment is based on asymmetrical current. Whether based on a symmetrical or asymmetrical basis, the interrupter has asymmetric interrupting capability.

9.2.2 Circuit Breakers

Circuit breakers are often used in the substation on the bus and on each feeder. Circuit breakers are available with very high interrupting and continuous current ratings. The interrupting medium in circuit breakers can be any of vacuum, oil, air, or SF_6. Oil and vacuum breakers are most common on distribution stations with newer units being mainly vacuum with some SF_6.

Circuit breakers are tripped with external relays. The relays provide the brains to control the opening of the circuit breaker, so the breaker coordinates with other devices. The relays also perform reclosing functions.

Circuit breakers are historically rated as constant-MVA devices. A symmetrical short-circuit rating is specified at the maximum rated voltage (for more ratings information, see ANSI C37.06-1997; IEEE Std. C37.04-1999; IEEE Std. C37.010-1999). Below the maximum rated voltage (down to a specified minimum value), the circuit breaker has more interrupting capability. The minimum value where the circuit breaker is a constant-MVA device is specified by the constant *K*:

$$\text{Symmetrical interrupting capability} = \begin{cases} V_R \cdot I_R & \text{for } \dfrac{V_R}{K} < V \le V_R \\ K \cdot I_R & \text{for } V \le \dfrac{V_R}{K} \end{cases}$$

where

I_R = rated symmetrical rms short-circuit current operating at V_R
V_R = maximum rms line-to-line rated voltage
V = operating voltage (also rms line-to-line)
K = voltage range factor = ratio of the maximum rated voltage to the lower limit in which the circuit breaker is a constant-MVA device. Newer circuit breakers are rated as constant-current devices ($K = 1$)

Consider a 15-kV class breaker application on a 12.47-kV system where the maximum voltage will be assumed to be 13.1 kV (105%). For an ANSI-rated 500-MVA

class breaker with $V_R = 15$ kV, $K = 1.3$, and $I_R = 18$ kA, the symmetrical interrupting capability would be 20.6 kA ($15/13.1 \times 18$). Circuit breakers are often referred to by their MVA class designation (1000-MVA class for example). Typical circuit breaker ratings are shown in Table 9.1.

Circuit breakers must also be derated if the reclose cycle could cause more than two operations and if the operations occur within less than 15 sec. The percent reduction is given by

$$D = d_1(n - 2) + d_1(15 - t_1)/15 + d_1(15 - t_2)/15 + \cdots$$

where

D = total reduction factor, %

$$d_1 = \text{calculating factor, \%} = \begin{cases} 3\% & \text{for } I_R < 18 \text{ kA} \\ \dfrac{I_R}{6} & \text{for } I_R > 18 \text{ kA} \end{cases}$$

n = total number of openings

t_n = nth time interval less than 15 sec

The interrupting rating is then $(100 - D)I_R$. The permissible tripping delay is also a standard. For the given delay period, the circuit breaker must withstand K times the rated short-circuit current between closing and interrupting. A typical delay is 2 sec.

Continuous current ratings are independent of interrupting ratings (although higher continuous ratings usually go along with higher interrupting ratings). Standard continuous ratings include 600, 1200, 2000, and 3000 A (the 600- and 1200-A circuit breakers are most common for distribution substations).

A circuit breaker also has a *momentary* or *close and latch* short-circuit rating (also called the first-cycle capability). During the first cycle of fault current, a circuit breaker must be able to withstand any current up to a multiple of the short-circuit rating. The rms current should not exceed $1.6K \times I_R$ and the peak (crest) current should not exceed $2.7K \times I_R$.

The circuit breaker interrupting time is defined as the interval between energizing the trip circuit and the interruption of all phases. Most distribution circuit breakers are five-cycle breakers. Older breakers interrupt in eight cycles.

TABLE 9.1 15-kV Class Circuit Breaker Short-Circuit Ratings

	500 MVA	750 MVA	1000 MVA
Rated voltage, kV	15	15	15
K, voltage range factor	1.3	1.3	1.3
Short circuit at maximum voltage rating	18	28	37
Maximum symmetrical interrupting, kA	23	36	48
Close and latch rating			
$1.6K \times$ rated short-circuit current, kA (asym)	37	58	77
$2.7K \times$ rated short-circuit current, kA (peak)	62	97	130

Distribution circuit breakers are three-phase devices. When the trip signal is received, all three phases are tripped. All three will not clear simultaneously because the phase current zero crossings are separated. The degree of separation between phases is usually one-half to one cycle.

9.2.3 Circuit Breaker Relays

Several types of relays are used to control distribution circuit breakers. Distribution circuits are almost always protected by overcurrent relays that use inverse time–overcurrent characteristics. An inverse time–current characteristic means that the relay will operate faster with increased current.

The main types of relays are

- *Electromechanical relays*—The induction disk relay has long been the main relay used for distribution overcurrent protection. The relay is like an induction motor with contacts. Current through the CT leads induces flux in the relay magnetic circuit. These flux linkages cause the relay disk to turn. A larger current turns the disk faster. When the disk travels a certain distance, the contacts on the disk meet stationary contacts to complete the relay trip circuit. An instantaneous relay functionality can be provided: a plunger surrounded by a coil or a disk cup design operates quickly if the current is above the relay pickup. Most electromechanical relays are single phase.
- *Static relays*—Analog electronic circuitry (like op-amps) provide the means to perform a time–current characteristic that approximates that of the electromechanical relay.
- *Digital relays*—The most modern relay technology is fully digital based on microprocessor components.

Electromechanical relays have reliably served their function and will continue to be used for many years. The main characteristics that should be noted as it affects coordination are overtravel and reset time. *Overtravel* occurs because of the inertia in the disk. The disk will keep turning for a short distance even after the short circuit is interrupted. A typical overtravel of 0.1 sec is assumed when applying induction relays. An induction disk cannot instantly turn back to the neutral position. This *reset time* should be considered when applying reclosing sequences. It is not desirable to reclose before the relay resets or *ratcheting* to a trip can occur.

Digital relays are slowly replacing electromechanical relays. The main advantages of digital relays are

- *More relay functions*—One relay performs the functions of several electromechanical relays. One relay can provide both instantaneous and time–overcurrent relay protection for three phases, plus the ground, and perform reclosing functions. This can result in considerable space and cost savings. Some backup is lost with this scheme if a relay fails. One option to provide relay backup is to use two digital relays, each with the same settings.

- *New protection schemes*—Advanced protection schemes are possible that provide more sensitive protection and better coordination with other devices. Two good examples for distribution protection are negative-sequence relaying and sequence coordination. Advanced algorithms for high-impedance fault detection are also possible.
- *Other auxiliary functions*—Fault location algorithms, fault recording, and power quality recording functions.

Digital relays have another advantage: internal diagnostics with ability to self-test. With digital technology, the relay is less prone to drift over time from mechanical movements or vibrations. Digital relays also avoid relay overtravel and ratcheting that are constraints with electromechanical relays (though some digital relays do reset like an electromagnetic relay).

Digital relays do have disadvantages. They are a relatively new technology. Computer technology has a poor reputation as far as reliability is concerned. If digital relays were as unreliable as a typical personal computer, we would have many more interruptions and many fires caused by uncleared faults. Given that, most digital relays have proven to be reliable and are gaining more and more acceptance by utilities.

Just as computer technology continues to advance rapidly, digital relays are also advancing. While it is nice to have new features, technical evolution can also mean that relay support becomes more difficult. Each relay within a certain family has to have its own supporting infrastructure for adjusting the relay settings, uploading and downloading data, and testing the relay. Each relay requires a certain amount of crew learning and training. As relays evolve, it becomes more difficult to maintain a variety of digital relays. The physical form and connections of digital relays are not standardized. As a contrast, electromechanical relays change very little and require a relatively stable support infrastructure. Equipment standardization helps minimize the support infrastructure required.

The time–current characteristics are based on the historically dominant manufacturers of relays. Westinghouse relays have a CO family of relays, and the General Electric relays are IAC (see Table 9.2). Most relays (digital and electromechanical) follow the characteristics of the GE or Westinghouse relays. For distribution overcurrent protection, the extremely inverse relays are most often used (CO-11 or IAC-77).

The time–current curves for induction relays can be approximated by the following equation (Benmouyal and Zocholl, 1994):

$$t = TD\left(\frac{A}{M^p - 1} + B\right)$$

where

t = trip time, sec
M = multiple of pickup current ($M > 1$)
TD = time dial setting
A, B, p = curve shaping constants

TABLE 9.2 Relay Designations

	Westinghouse/ABB Designation	General Electric Designation
Moderately inverse	CO-7	
Inverse time	CO-8	IAC-51
Very inverse	CO-9	IAC-53
Extremely inverse	CO-11	IAC-77

With actual induction disk relays, the constants A and B change with the time dial setting, but with digital relays, they stay constant.

Standardized characteristics of relays have been defined by IEEE (IEEE Std. C37.112-1996). This is an attempt to make relay characteristics consistent (since the relay curve can be adjusted to almost anything in a digital relay). The equations for the standardized inverse relay characteristics are shown in Table 9.3. Figure 9.2 compares

TABLE 9.3 IEEE Standardized Relay Curve Equation Constants

	A	B	p
Moderately inverse	0.0515	0.114	0.02
Very inverse	19.61	0.491	2.0
Extremely inverse	28.2	0.1217	2.0

Source: Adapted from IEEE Std. C37.112-1996, *IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays*. Copyright 1997 IEEE. All rights reserved.

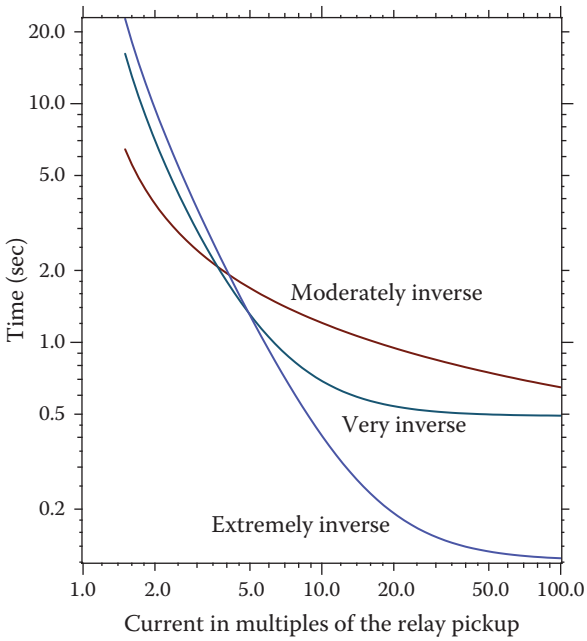


Figure 9.2 Relay curves following the IEEE standardized characteristics for a time dial = 5.

the shapes of these curves. The standard allows relays to have tripping times within 15% of the curves. The standard also specifies the relay reset time for $0 < M < 1$ as

$$t = TD\left(\frac{t_r}{M^2 - 1}\right)$$

where t_r = reset time, sec for $M = 0$.

9.2.4 Reclosers

A recloser is a specialty distribution protective device capable of interrupting fault current and automatically reclosing. An official definition of a recloser is

Automatic circuit recloser—A self-controlled device for automatically interrupting and reclosing an alternating-current circuit, with a predetermined sequence of opening and reclosing followed by resetting, hold closed, or lockout.

Like a circuit breaker, interruption occurs at a natural current zero. The interrupting medium of a recloser is most commonly vacuum or oil. The insulating medium is generally oil, air, a solid dielectric, or SF_6. The recloser control can be electronic, electromechanical (the relay for tripping is electromechanical, and the reclosing control is electronic) or hydraulic. A hydraulic recloser uses springs and hydraulic systems for timing and actuation.

The interrupting rating of a recloser is based on a symmetrical current rating. The interrupting current rating does not change with voltage. There is an exception that some reclosers have a higher interrupting current if operated at a significantly lower voltage than the rating. Smaller reclosers with a 50- to 200-A continuous rating typically have interrupting ratings of 2 to 5 kA (these would normally be feeder reclosers). Larger reclosers that could be used in substations have continuous current ratings as high as 1120 A and interrupting ratings of 6 to 16 kA. Historically, reclosers with series coil types had coil ratings of 25, 35, 50, 70, 100, 140, 200, 280, 400, and 560 A (each rating is approximately 1.4 times higher than the next lower rating).

Reclosers are tested at a specified *X/R* ratio as specified in ANSI/IEEE C37.60-1981. A typical test value is $X/R = 16$. While a lower *X/R* ratio at the point of application does not mean you can increase the rating of a recloser, the recloser must be derated if the *X/R* ratio is larger than that specified.

There are some other differences with recloser ratings versus circuit breaker ratings (Cooper Power Systems, 1994). Reclosers do not have to be derated for multiple operations. Reclosers do not have a separate closing and latching (or first-cycle) rating. The symmetrical current rating is sufficient to handle the asymmetry during the first cycle as long as the circuit *X/R* ratio is lower than the tested value.

Reclosers have many distribution applications. We find reclosers in the substation as feeder interrupters instead of circuit breakers. An IEEE survey found that 51% of station feeder interrupting devices were reclosers (IEEE Working Group on Distribution Protection, 1995). Reclosers are used more in smaller stations and circuit breakers more in larger stations. Three-phase reclosers can be used on the

main feeder to provide necessary protection coverage on longer circuits, along with improved reliability. Overhead units and padmounted units are available. Reclosers are available as single-phase units, so they can be used on single-phase taps instead of fuses. Another common application is in autoloop automation schemes to automatically sectionalize customers after a fault.

Since reclosers are devices built for distribution circuits, some have features that are targeted to distribution circuit needs. Three-phase units are available that can operate each phase independently (so a single-phase fault will only open one phase). Some reclosers have a feature called sequence coordination to enhance coordination between multiple devices.

The time–current characteristics of hydraulic reclosers have letter designations: A, B, and C. The A is a fast curve that is used similarly to an instantaneous relay element, and the B and C curves have extra delay ("delayed" and "extra delayed"). For a hydraulically controlled recloser, the minimum trip threshold is twice the full-load rating of the trip coil of the recloser and is normally not adjustable. On electronically controlled reclosers, the minimum trip threshold is adjustable independently of the rating (analogous to setting the pickup of a time–overcurrent relay).

9.2.5 Expulsion Fuses

Expulsion fuses are the most common protective device on distribution circuits. Fuses are low-cost interrupters that are easily replaced (when in cutouts). Interruption is relatively fast and can occur in a half of a cycle for large currents. An expulsion fuse is a simple concept: a fusible element made of tin or silver melts under high current. Expulsion fuses are most often applied in a fuse cutout. In a fuse tube, after the fuse element melts, an arc remains. The arc, which has considerable energy, causes a rapid pressure buildup. This forces much of the ionized gas out of the bottom of the cutout (see Figure 9.3), which helps to prevent the arc from re-igniting at a current zero. The extreme pressure, the stretching of the arc, and the turbulence help increase the dielectric strength of the air and clear the arc at a current zero. A fuse tube also has an organic fiber liner that melts under the heat of the arc and emits fresh, non-ionized gases. At high currents, the expulsion action predominates, while at lower currents, the deionizing gases increase the dielectric strength the most.

The "expulsion" characteristics should be considered by crews when placing a cutout on a structure. Avoid placement where a blast of hot, ionized gas blown out the bottom of the cutout could cause a flashover on another phase or other energized equipment. Implement and enforce safety procedures whenever a cutout is switched in (because it could be switching into a fault), including eye protection, arc-resistant clothing, and, of course, avoiding the bottom of the cutout.

The *speed ratio* of a fuse quantifies how steep the fuse curve is. The speed ratio is defined differently depending on the size of the fuse (IEEE Std. C37.40-1993):

$$\text{Speed ratio for fuse ratings of 100 A and under} = \frac{\text{Melting current at 0.1 sec}}{\text{Melting current at 300 sec}}$$

Figure 9.3 Example operation of an expulsion fuse during a fault. (Courtesy of the Long Island Power Authority.)

$$\text{Speed ratio for ratings above 100 A} = \frac{\text{Melting current at 0.1 sec}}{\text{Melting current at 600 sec}}$$

Industry standards specify two types of expulsion fuses, the most commonly used fuses. The "K" link is a relatively fast fuse, and the "T" is somewhat slower. K links have a speed ratio of 6 to 8. T links have a speed ratio of 10 to 13. The K link is the most commonly used fuse for transformers and for line taps. The K and T fuse links are standardized well enough that they are interchangeable among manufacturers for most applications.

Two time–current curves are published for expulsion fuses: the minimum melt curve and the maximum total clear curve. The minimum melt time is 90% of the average melt time to account for manufacturing tolerances. The total clearing time is the average melting time plus the arcing time plus manufacturing tolerances. Figure 9.4 shows the two published curves for 50-A K and T fuse links. The manufacturer's minimum melt curves for fuses less than or equal to 100 A normally start at 300 sec, and those over 100 A start at 600 sec.

The time–current characteristics for K and T links are standardized at three points (ANSI C37.42-1989). The minimum and maximum allowed melting current is specified for durations of 0.1 sec, 10 sec, and either 300 sec (for fuses rated 100 A or less) or 600 sec (for larger fuses).

Published fuse curves are for no loading and for an ambient temperature of 25°C. Both loading and ambient temperature change the fuse melting characteristic. Load current causes the most dramatic difference, especially when a fuse is overloaded. Figure 9.5 shows the effect of loading on fuse melting time. Figures 9.6 through 9.9 show time–current curves for K and T links.

For operation outside of this ambient range, the fuse melting time changes. The melting characteristic of tin fuse links changes 3.16% for each 10°C above or below 25°C, so a fuse operating in a 50°C ambient will operate in 92% of the published time

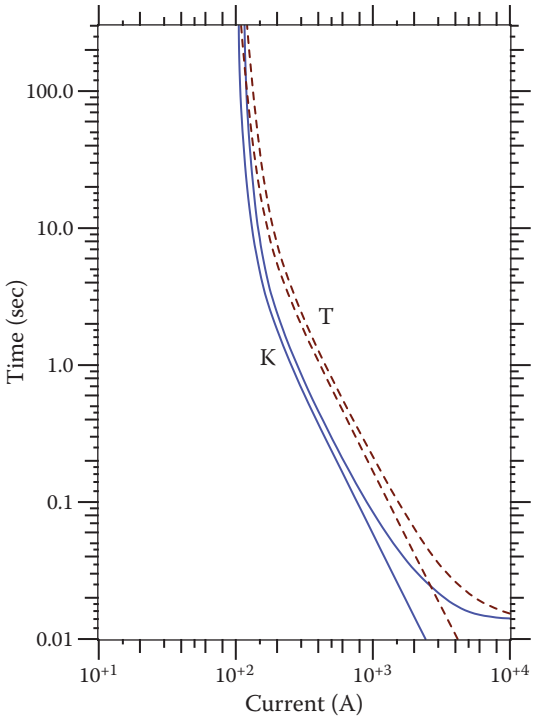


Figure 9.4 Minimum melt and total clearing curves for a T and K link (50 A).

(100% − $\frac{25}{10}$3.16%). Silver links are less sensitive to temperature (0.9% melting change for each 10°C above or below 25°C).

The I^2t of a fuse is often needed to coordinate between fuses. Table 9.4 shows the minimum melt I^2t of K and T links estimated from the time–current curves at 0.01 sec. This number is also useful to estimate melting characteristics for high

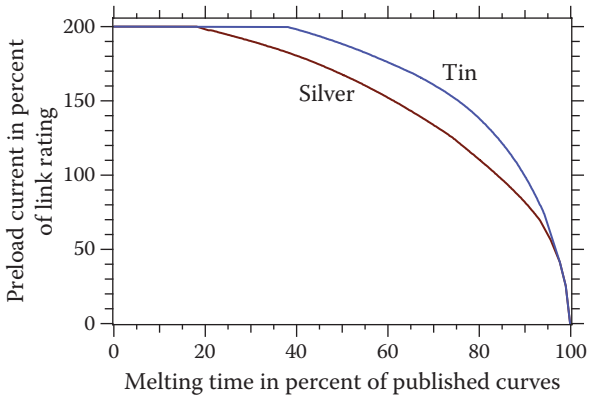


Figure 9.5 Effect of loading on fuse melting time. (Adapted from Cooper Power Systems, *Electrical Distribution—System Protection*, 3rd ed., 1990. With permission from Cooper Industries, Inc.)

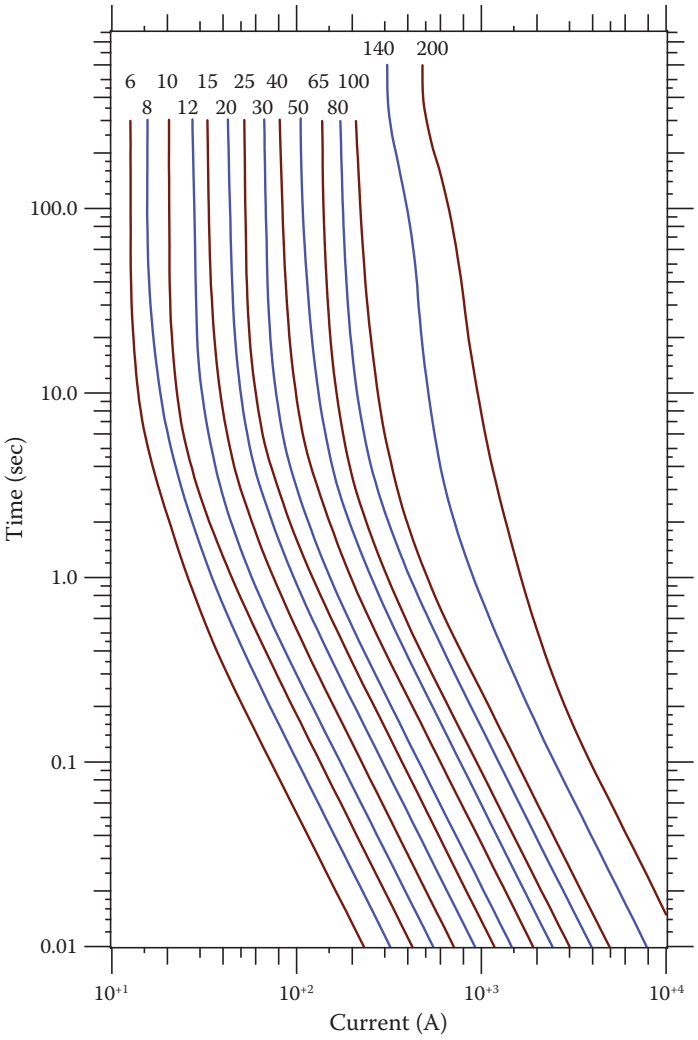


Figure 9.6 Minimum melt curves for K links. (S&C Electric Company silver links.)

currents below the published time–current characteristics, which generally have a minimum time of 0.01 sec.

The 6-, 10-, 15-, 25-, 40-, 65-, 100-, 140-, and 200-A fuses are standard ratings that are referred to as *preferred* fuses. The 8-, 12-, 20-, 30-, 50-, and 80-A fuses are *intermediate* fuses. The designations are provided because two adjacent fuses (for those below 100 A) will not normally coordinate. A 40- and a 30-A fuse will not coordinate, but a 40- and a 25-A fuse will coordinate up to some maximum current. Most utilities pick a standard set of fuses to limit the number of fuses stocked.

K or T links with tin fuse elements can carry 150% of the nominal current rating indefinitely. It is slightly confusing that a 100-A fuse can operate continuously up to 150 A. Overloaded fuses, although they can be safely overloaded, operate significantly

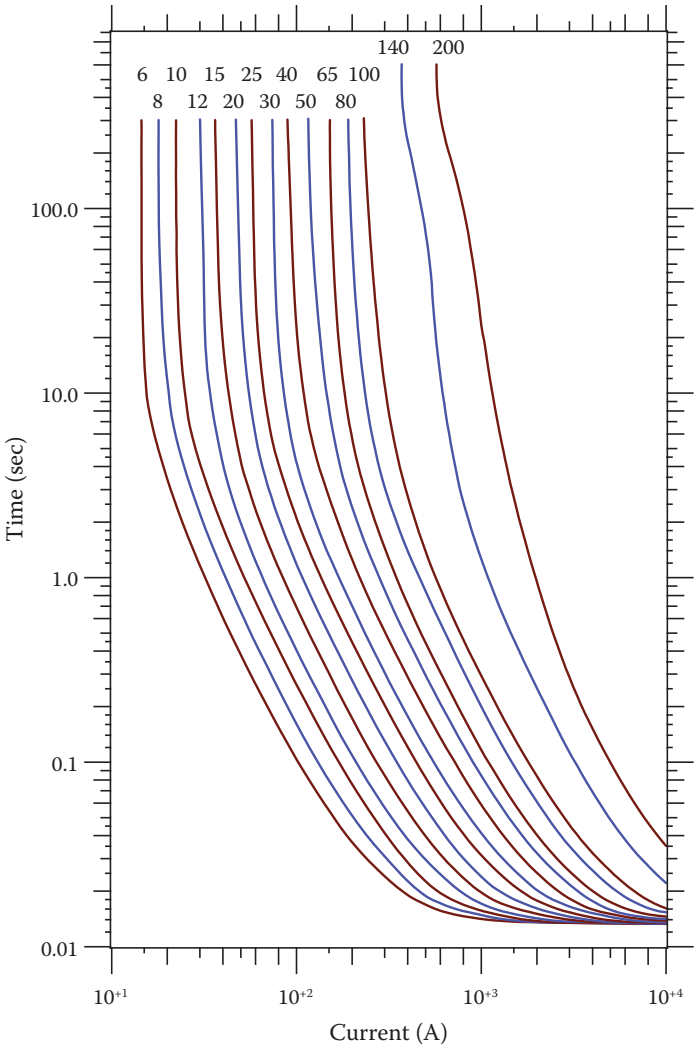


Figure 9.7 Maximum total clear curves for K links. (S&C Electric Company silver links.)

faster when overloaded, which could cause miscoordination. In contrast to tin links, silver links have no continuous overload capability.

Other nonstandard fuses are available from manufacturers for special purposes. One type of specialty fuse is a fuse even slower than a T link that is used to provide better coordination with upstream circuit breakers or reclosers in a fuse-saving scheme. Another notable type of specialty fuse is a *surge-resistant* fuse that responds slowly to fast currents (such as surges) but faster to lower currents. These achieve better protection on transformers for secondary faults and faster operation for internal transformer failures while at the same time reducing nuisance fuse operations due to lightning.

Expulsion fuses under oil are another fuse variation. These "weak-links" are used on CSP (completely self-protected) transformers and some padmounted and vault

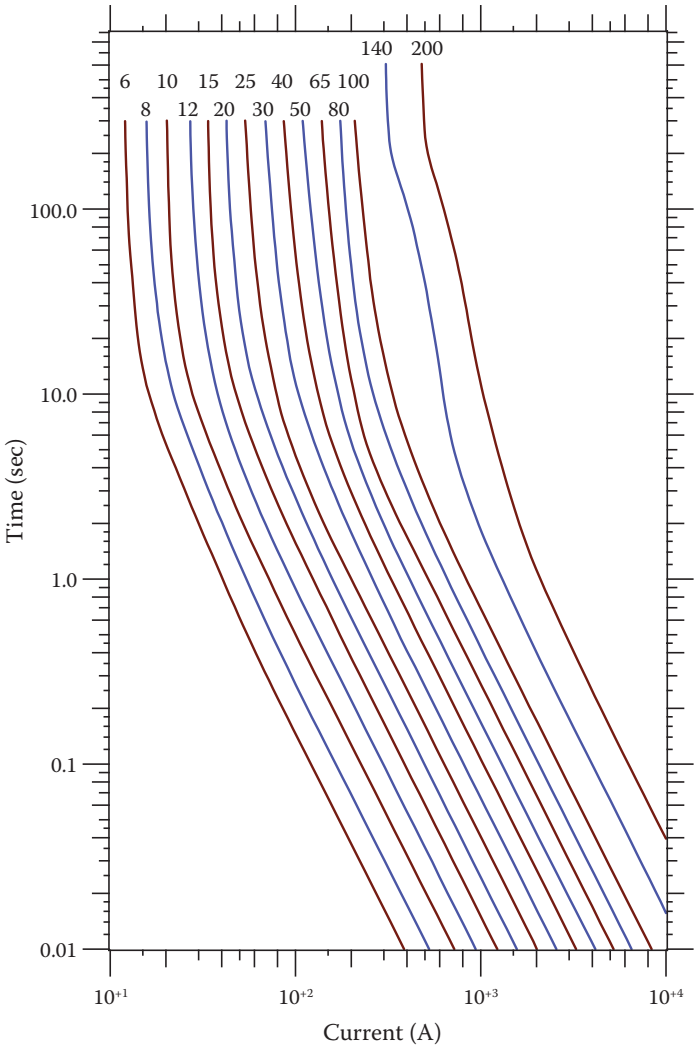


Figure 9.8 Minimum melt curves for T links. (S&C Electric Company silver links.)

transformers. Since they are not easily replaced, they have very high ratings—at least 2.5 times the transformer full-load current and much higher if a secondary circuit breaker is used.

Transformers on underground circuits use a variety of fuses. For padmounted transformers, a common fuse is the replaceable Bay-O-Net-style expulsion fuse. The time–current characteristics of this fuse do not follow one of the industry standard designations.

9.2.5.1 Fuse Cutouts

The cutout is an important part of the fuse interrupter. The cutout determines the maximum interrupting capability, the continuous current capability, the load-break

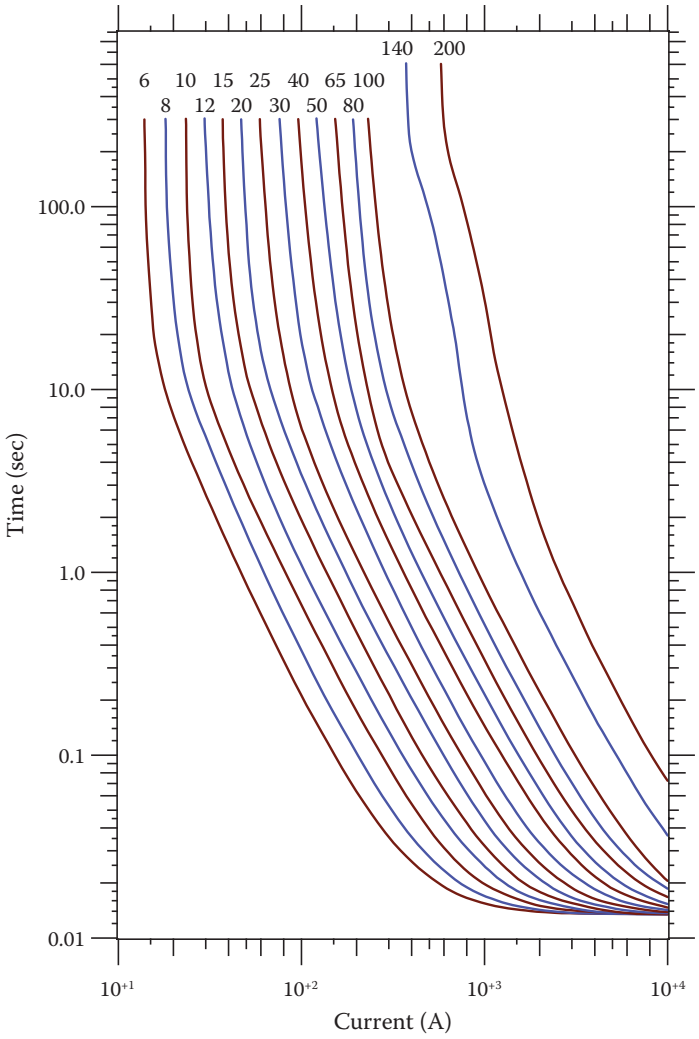


Figure 9.9 Maximum total clear curves for T links. (S&C Electric Company silver links.)

capability, the basic lightning impulse insulation level (BIL), and the maximum voltage. Cutouts are typically available in 100-, 200-, and 300-A continuous ratings (ANSI standard sizes (ANSI C37.42-1989)).

Cutouts are rated on a symmetrical basis. Cutouts are tested at *X/R* ratios of 8 to 12, so if the *X/R* ratio at the application point is higher than the test value, the cutout should be derated. The fuse link holder determines the interrupting capability, not the fuse link.

Most cutouts are of the open variety with a removable fuse holder that is placed in a cutout with a porcelain or polymer bushing support. We also find enclosed cutouts and open-link cutouts. Open links have a fuse link suspended between contacts. Open links have a much lower interrupting capability (1.2 kA symmetrical).

TABLE 9.4 Fuse Minimum-Melt I^2t (A^2-s)

Rating, A	K Links	T Links
6	534	1490
8	1030	2770
10	1790	5190
12	3000	8810
15	5020	15,100
20	8500	24,500
25	13,800	40,200
30	21,200	65,500
40	36,200	107,000
50	58,700	173,000
65	90,000	271,000
80	155,000	425,000
100	243,000	699,000
140	614,000	1,570,000
200	1,490,000	3,960,000

Many cutouts available are full-rated cutouts that can be used on any type of system where the maximum line-to-line voltage is less than the cutout rating. Cutouts are also available that have *slant* voltage ratings, which provide two ratings such as 7.8/15 kV that are meant for application on grounded circuits (IEEE Std. C37.48-1997). One cutout will interrupt any current up to its interrupting rating and up to the lower voltage rating. On a grounded distribution system, in most situations, any cutout can be applied that has the lower slant rating voltage greater than the maximum line-to-ground voltage. On a 12.47Y/7.2-kV grounded distribution system, a 7.8/15-kV cutout could be used. If the system were ungrounded, a full-rated 15-kV cutout must be used. For three-phase grounded circuits, the recovery voltage is the line-to-line voltage for a line-to-line fault rather than the line-to-ground voltage (requiring a higher voltage rating). In this case, the slant-rated cutouts are designed and tested so that two cutouts in series will interrupt a current up to its interrupting rating and up to the higher voltage rating. The two cutouts share the recovery voltage (even considering the differences in the melting times of the two fuses). On grounded systems, there are cases where slant-rated cutouts are "under-rated"—any time that a phase-to-phase fault could happen that would only be cleared by one cutout. This includes constructions where multiple circuits share a pole or cases where cutouts are applied on different poles.

Most cutouts used on distribution systems do not have load-break capability. If the cutout is opened under load, it can draw an arc that will not clear. It is not an uncommon practice for crews to open cutouts under load (if it draws an arc, they slam it back in). Cutouts with load-break capability are available, usually capable of interrupting 100 to 300 A. Cutouts with load-break capability usually use an arc chute. A spring pulls the arc quickly through the arc chute where the arc is stretched, cooled, and interrupted. A load-break tool is available that can open standard cutouts (with no load-break capability of its own) under load up to 600 to 900 A. Utilities also sometimes use solid blades in cutouts instead of fuse holders; then crews can use the cutout as a switch.

9.2.6 Current-Limiting Fuses

CLFs are another interrupter having the unique ability to reduce the magnitude of the fault current. CLFs consist of fusible elements in silicon sand (see Figure 9.10). When fault current melts the fusible elements, the sand melts and creates a narrow tube of glass called a *fulgerite*. The voltage across the arc in the fulgerite increases greatly. The fulgerite constricts the arc. The sand helps cool the arc (which means it takes energy from the arc). The sand does not give off ionizable gas when it melts, and it absorbs electrons, so the arc has very little ionizable air to use as a conductor. Without ionizable air, the arc is choked off, and the arc resistance becomes very high. This causes a back voltage that quickly reduces the current. The increase in resistance also lowers the *X/R* ratio of the circuit, causing a premature current zero. At the current zero, the arc extinguishes. Since the *X/R* ratio is low, the voltage zero and current zero occur very close together, so there will be very little transient recovery voltage (the high arc voltage comes just after the element melts). Because the CLF forces an early current zero, the fuse can clear the short circuit in much less than one half of a cycle.

Current-limiting fuses are noted for their very high fault-clearing capability. CLFs have symmetrical maximum interrupt ratings to 50 kA; contrast that to expulsion fuses, which may have typical maximum interrupt ratings of 3.5 kA in oil and 13 kA in a cutout. CLFs also completely contain the arc during operation and are noiseless with no pressure buildup.

Current-limiting fuses are widely used for the protection of equipment in high fault current areas. Table 9.5 shows the percentages of utilities that use current-limiting fuses. The major reason given for the use of current-limiting fuses is safety, and the second most common reason is high fault currents in excess of expulsion fuse ratings.

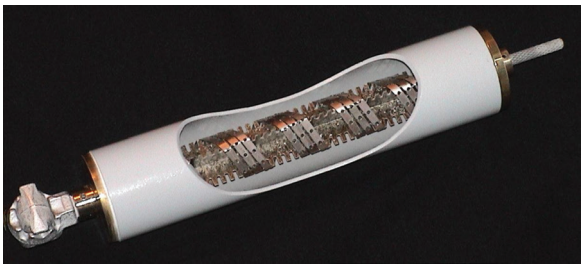


Figure 9.10 Example backup current-limiting fuse. (From Hi-Tech Fuses, Inc. With permission.)

TABLE 9.5 Use of Current-Limiting Fuses as Reported in a 1995 IEEE Survey

	5 kV	15 kV	25 kV	35 kV
General purpose	15%	29%	30%	18%
Backup	15%	38%	43%	30%
On OH line laterals	5%	6%	9%	3%
On UG line laterals	7%	18%	20%	18%

Source: Data from IEEE Working Group on Distribution Protection, *IEEE Transactions on Power Delivery*, vol. 10, no. 1, pp. 176–86, January 1995.

There are three types of CLFs (IEEE Std. C37.40-1993):

- *Backup:* A fuse capable of interrupting all currents from the maximum rated interrupting current down to the rated minimum interrupting current
- *General purpose:* A fuse capable of interrupting all currents from the maximum rated interrupting current down to the current that causes melting of the fusible element in 1 hour
- *Full range:* A fuse capable of interrupting all currents from the rated interrupting current down to the minimum continuous current that causes melting of the fusible element(s), with the fuse applied at the maximum ambient temperature specified by the manufacturer

Current-limiting fuses are very good at clearing high-current faults. They have a much harder time with low-current faults or overloads. For a low-level fault, the fusible element will not melt, but it will become very hot and can melt the fuse hardware, resulting in failure. This is why the most common CLF application is as a backup in series with an expulsion fuse. The expulsion fuse clears low-level faults, and the CLF clears high-current faults. Current-limiting fuses have very steep melting and clearing curves, much steeper than expulsion links. Many CLFs have steeper characteristics than I^2t. At low currents, heat from the notches transfers to the unnotched portion; at high currents, the element melts faster because heat cannot escape from the notched areas fast enough to delay melting.

General-purpose fuses usually use two elements in series—one for the high-current faults and one for the low-current faults. General-purpose fuses could fail for overloads, so restrict their application to situations where overloads are not present or are protected by some other device (such as a secondary circuit breaker on a transformer).

Full-range fuses provide even better low-current capability and can handle overloads and low-level faults without failing (as long as the temperature is within rating).

Current-limiting fuses can be applied in several ways, including

- Backup CLF in series with an expulsion fuse in a cutout
- Full-range CLF in a cutout
- Backup CLF under oil
- Full-range (or general-purpose) fuse under oil
- CLF in a dry-well canister or insulator

The best locations for use on distribution systems are close to the substation. This is where they are most appropriate for limiting damage due to high fault currents and where they are most useful for reducing the magnitude and duration of a voltage sag.

Some of the drawbacks of current-limiting fuses are summarized as

- *Voltage kick*—When a CLF operates, the rapidly changing current causes a voltage spike ($V = Ldi/dt$). Usually, this is not severe enough to cause problems for the fuse or for customer equipment.

- *Limited overload capability*—A backup or general-purpose fuse does not do well for overloads or low-current faults. A full-range fuse performs better but could still have problems with a transient overcurrent that partially melts the fuse.
- *Coordination issues*—A current-limiting fuse may be difficult to coordinate with expulsion fuses or reclosers or other distribution protective devices. CLFs are fast enough that they almost have to be used in a fuse-blowing scheme (fuse saving will not work because the fuse will be faster than the circuit breaker).
- *Cost*—High cost relative to an expulsion fuse.

Current-limiting fuses limit the energy at the location of the fault. This provides safety to workers and the public. Arc damage to life and property occurs in several ways:

- *Pressure wave*—The fault arc pressure wave damages equipment and personnel.
- *Heat*—The fault arc heat burns personnel and can start fires.
- *Pressure buildup in equipment*—An arc in oil causes pressure buildup that can rupture equipment.

All of these effects are related to the arc energy and all are greatly reduced with current-limiting fuses. Distribution transformers are a common application of current-limiting fuses to prevent them from failing violently due to internal failures.

9.3 Transformer Fusing

The primary purpose of a transformer fuse is to disconnect the transformer from the circuit if it fails. Some argue that the fuse should also protect for secondary faults. The fuse cannot effectively protect the transformer against overloads.

Engineers most commonly pick fuse sizes for distribution transformers from a fusing table developed by the utility, transformer manufacturer, or fuse manufacturer. These tables are developed based on criteria for applying a fuse such that the fuse should not have false operations from inrush and cold-load pickup.

One way to pick a fuse is to plot cold-load pickup and inrush points on a time–current coordination graph and pick a fuse with a minimum melt or damage curve that is above the cold-load and inrush points. Most fusing tables are developed this way. A fuse should withstand the cold-load and inrush points given in Table 9.6. The inrush points are almost universal, but the cold-load pickup points are more variable (and they should be since cold-load pickup characteristics change with predominant load types). An example application of the points given in Table 9.6 for a 50-kVA, 7.2-kV single-phase transformer, which has a full-load current of 6.94 A is shown in Figure 9.11. The cold-load pickup and inrush points are plotted along with K links. The minimum melt time and the damage time (75% of the minimum melt time) are shown. Use the damage curve to coordinate. For this example, a 12-A K link would be selected; the 1-sec cold-load pickup point determines the fuse size. Since this point lies between the damage and minimum melt time of the 10 K link, some engineers would pick the 10 K link (not recommended).

TABLE 9.6 Inrush and Cold-Load Pickup Withstand Points for Transformer Fusing

	Full-Load Current Multiplier	Duration (sec)
Cold-load pickup	2	100
	3	10
	6	1
Inrush points	12	0.1
	25	0.01

Source: Data from Amundson, R. H., *IEEE Tutorial Course on Application and Coordination of Reclosers, Sectionalizers, and Fuses*, 1980. Publication 80 EHO157–8-PWR; Cook, C. J. and Niemira, J. K., *IEEE/PES Transmission & Distribution Conference and Exposition*, 1996. Presented at the training session on "Distribution Overcurrent Protection Philosophies."

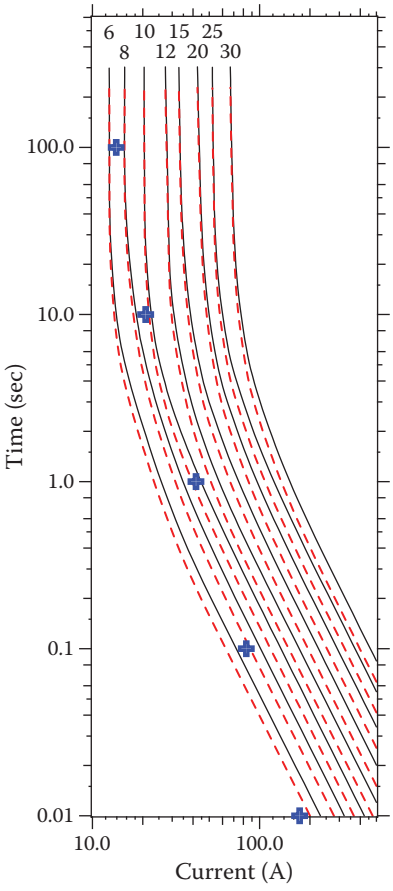


Figure 9.11 Transformer inrush and cold-load pickup points for a single-phase, 50-kVA, 7.2-kV transformer. The minimum-melt curves and damage curves (dotted lines) for K-link fuses are also shown.

Some utilities have major problems from nuisance fuse operations (especially utilities in high-lightning areas). A nuisance operation means that the fuse must be replaced, but the transformer was not permanently damaged. Nuisance fuse operations can be over 1% annually. Some utilities have thousands of nuisance fuse operations per year. A utility in Florida had a region with 57% of total service interruptions due to transformer interruptions, and 63% of the storm-related interruptions required only re-fusing (Plummer et al., 1995). During a storm, multiple transformer fuses can operate on the same circuit. There are differences of opinion as to what is causing the nuisance operations. Some of the possibilities are

- *Inrush*—Transformer inrush may cause fuse operations even though the inrush points are used in the fuse selection criteria. Reclosing sequences during storms can cause multiple inrush events that can heat up the fuse. In addition, voltage sags can cause inrush (any sudden change in the voltage magnitude or phase angle can cause the transformer to draw inrush).
- *Cold-load pickup*—This is the obvious culprit after an extended interruption (many of the nuisance fuse operations have occurred when there is not an extended interruption).
- *Secondary-side transformer faults*—Secondary-side faults that self-clear can cause some nuisance fuse events.
- *Lightning current*—Lightning current itself can melt small fuses. Arrester placement is key here since the lightning current flows to the low-impedance provided by a conducting arrester. If the fuse is upstream of the arrester (which would be the case on a tank-mounted arrester), the lightning surge current flows through the fuse link. If the fuse is downstream, then little current should flow through the fuse.
- *Power-follow current through gapped arresters*—Following operation of a gapped arrester, a few hundred amps of power follow current flows in a gapped silicon carbide arrester until the gap clears (usually just for a half cycle if the gap is in good shape).
- *Transformer saturation from lightning currents*—Lightning can contain multiple strokes and long-duration components that last from 0.1 to 2 sec. These currents can saturate distribution transformers. Following saturation, the transformer becomes a low impedance and draws high current from the system through the fuse (Hamel et al., 1990).
- *Animal faults*—Across transformer bushings or arresters.

Several of these causes may add to the total. Nuisance fuse operations have occurred when circuits were out of service. This means that lightning is the cause since any type of inrush would require the system to be energized. Detroit Edison found that 70 to 80% of fuse operations were due to lightning (Gabrois et al., 1973). Lightning and inrush events are the most likely cause of nuisance fuse operations. Heavily loaded transformers are more susceptible to nuisance fuse operations because of the preheating of the fuse (a heavily loaded transformer is more susceptible to cold-load pickup as well).

Another method of choosing the transformer fuse size that gives "looser" fusing is the ×2 method (Burke, 1996). Choose a fuse size larger than twice the transformer

full-load current. A 50-kVA, 7.2-kV single-phase transformer, which has a full-load current of 6.94 A, should have a fuse bigger than 14 A (the next biggest standard size is a 15-A fuse). This applies for any type of fuse (K, T, or other). The factor of two provides a safety margin so that transformer fuses do not operate for inrush or cold-load pickup, and it helps with lightning.

The *fusing ratio* is the ratio of the fuse minimum melt current to the transformer full-load current (some sources also define a fusing ratio as the ratio of fuse rated current to transformer rated current, which is different from this definition by a factor of two). Tight fusing means the fuse ratio is low. Relatively low fusing ratios have been historically used, which has led to the nuisance fuse problems. The tighter fusing given using the Table 9.6 approach results in fusing ratios of 2 to 4. The looser ×2 method gives a fusing ratio of at least 4 (since the fuse rating is multiplied by two, and the minimum melting current at 300 sec is twice the fuse rating). The fusing ratio for the 50-kVA, 7.2-kV transformer with the 12-K fuse is 3.46, and it is 4.32 with the 15-K fuse.

Another strategy that is especially useful in high-lightning areas: use a standard fuse size for all transformers up to a certain size. This also helps ensure that the wrong fuse is not applied on a given transformer. A standard fuse size of at least 15 T or 20 K results in few nuisance fuse operations (IEEE Std. C62.22-2009). At 12.5 kV, a 20 K fuse should protect a 5-kVA transformer almost as well as it protects a 50-kVA transformer. It may lose some secondary protection relative to a smaller fuse, and a small portion of evolving faults will not be detected as soon, but other than that, there should not be much difference. If fuses get too big, they may start to bump up against tap fuse sizes and limit fuse options for lateral taps.

If looser fusing is used, some argue that overload protection of transformers is lost. Countering that argument, overload protection with fuses is not really possible if the transformer is used for its most economic performance (which means overloading a transformer at peak periods). To avoid nuisance fuse operations from load, we must use a fuse big enough so that thermal overload protection is impossible. It is also argued that most transformer failures start as failures between turns or layers and that a smaller, faster fuse detects this more quickly. Tests have indicated that a smaller fuse might not be much better than a larger fuse at detecting interwinding failures (Lunsford and Tobin, 1997) (pressure-relief valves limit tank pressures very well during this type of failure). All together, the arguments for a smaller fuse are not enough to overcome the concerns with nuisance fuse operations. If overload protection must be used, use a surge-resistant fuse (it has a slower characteristic for high-magnitude, short-duration currents).

A few utilities practice group fusing where a lateral fuse provides protection to all of the transformers on the tap. If the transformer failure rate (including bushing faults) is low enough, then this practice will not degrade the overall frequency of interruptions significantly. One of the major disadvantages of this approach is that an internal transformer failure on a tap may be *very* hard to find. This drives up repair time (so the duration reliability numbers suffer but not necessarily the frequency indices). Also, the beneficial feature of being able to switch the transformer with the fused cutout is lost if group fusing is used.

Widely used, CSP transformers have an internal weak-link fuse; an external fuse is not needed (although they may need an external current-limiting fuse to supplement the weak-link).

Transformer bushing faults often caused by animals can have different impacts depending on fusing practices. A fault across a primary bushing operates an external transformer fuse. If the transformer is a CSP or group fusing is used, the upstream tap fuse operates (so more customers are affected).

Current-limiting fuses are regularly used on transformers in high fault current areas to provide protection against violent transformer failure. NEMA established tests that were later adopted by ANSI (ANSI C57.12.20-1988) for distribution transformers to be able to withstand internal arcs. Transformers with external fuses are subjected to a test where an internal arcing fault with an arc length of 1 in. (2.54 cm) is maintained for 1/2 to 1 cycle. It was thought that 1 in. (2.54 cm) was representative of the length that arcs could typically achieve. The current is 8000 A. Under this fault condition, the transformer must not rupture or expel excessive oil. Note that this test does not include all of the possible failure modes and is no guarantee that a transformer will not fail with lower current. For example, a failure with an arc longer than 1 in. has more energy and ruptures the transformer at a lower level of current.

Table 9.7 shows rupture limits for several types of transformers based on tests for the Canadian Electrical Association. If fault current values exceed those given in this table, consider using current-limiting fuses to reduce the chance of violent failures (the CEA report considers the limits provisional and suggests that more tests are needed). At arc energies within this range, the failure probability is on the order of 15 to 35%. Note that the 2.5-kA limit for pole-mounted transformers is much less than the ANSI test limit of 8 kA. Based on a series of tests with internal 2 in. (5 cm) arcs, Hamel et al. (2003) recommend considering current-limiting fuses for pole-type transformers when the short-circuit current exceeds 1.7 kA.

For transformers with an internal fuse, CSP transformers or padmounted transformers, the arcing test is done to the rating of the fuse, which is generally much lower than 8000 A. Table 9.8 shows the maximum fault current ratings based on the ANSI tests. If the available line-to-ground fault current exceeds these values, then consider current-limiting fuses to reduce the possibility of violent failures. Not all utilities use current-limiting fuses in these situations, and in such instances, internal faults have failed transformers violently, blowing the cover.

TABLE 9.7 Transformer Rupture Limits for Internal Faults

Transformer Type		$I \cdot t$, A-s, or Coulombs	Current Limit for a One Cycle Clearing Time, kA
Pole mounted	1ϕ	41	2.5
Pad mounted	1ϕ	150	9
Pad mounted/subway	3ϕ	180	11
Network with switch compartment	3ϕ	90	5.4
Submersible and vault	1ϕ	41	2.5

Source: Data from CEA 288 D 747, *Application Guide for Distribution Fusing*, Canadian Electrical Association, 1998.

TABLE 9.8 Maximum 1/2- to 1-Cycle Fault Current Rating on Distribution Transformers Based on the Test in ANSI C57.12.20-1988

Transformer	Maximum Tested Symmetrical Current	$\int Idt$ in the ANSI Test
Overhead transformer	8000 A	66.7 A-s
Under-oil expulsion fuse (based on typical fuse ratings)		
Up to 8.3 kV_{LG}	3500 A	29.2 A-s
Up to 14.4 kV_{LG}	2500 A	20.8 A-s
Up to 25 kV_{LG}	1000 A	8.3 A-s

Source: Data from ANSI C57.12.20-1988, *American National Standard Requirements for Overhead-Type Distribution Transformers, 500 kVA and Smaller: High-Voltage, 67 000 Volts and Below; Low-Voltage, 15 000 Volts and Below*, American National Standards Institute.

If a transformer is applied in a location where the available line-to-ground fault current is higher than shown in Table 9.8, use current-limiting fuses.

9.4 Lateral Tap Fusing and Fuse Coordination

Utilities use two main philosophies to apply tap fuses: fusing based on load and standardized fusing schedules. With fusing based on load, we pick a fuse based on some multiplier of peak load current. The fuse should not operate for cold-load pickup or inrush to prevent nuisance operations. As an example, one utility sizes fuses based on 1.5 times the current from the phase with the highest connected kVA. With standardized fuse sizes, a typical strategy is to apply 100 K links at all taps off of the mains (even if a tap only has one 15-kVA transformer). If using second-level fusing, use 65 K links for these and 40 K fuses for the third level. There is no clear winner; each has advantages and disadvantages:

- *Fusing based on load*—This tends to fuse more tightly. High-impedance faults are somewhat more likely to be detected. Nuisance fuse operations are more likely, especially with utilities that tightly fuse laterals. We are more likely to have load growth cause branch loadings to increase to the point of causing nuisance fuse operations. Fusing based on load helps on circuits that have covered wire because a smaller fuse helps protect against conductor burndown (taps that are more heavily loaded usually have a larger wire, which resists burndown).
- *Standardized fuse sizes*—It is simple: we spend less time coordinating fuses, we do not constantly check loadings, and utilities have less inventory. There is also less chance that the wrong fuse is installed at a location. A disadvantage of this approach is that larger fuses than needed are used at many locations, resulting in higher fault damage at the arc location, longer voltage sags, and more stress on in-line equipment.

Coordinating lateral tap fuses is generally straightforward. The fuse must coordinate with the station recloser or circuit breaker relays. Station ground relays

are usually set to coordinate with the largest tap fuse. On the downstream side, a tap fuse should coordinate with the largest transformer fuse. This usually is not a problem.

In addition to sizing a fuse to avoid nuisance operations and coordinating with upstream and downstream protectors, we size fuses to ensure that the fuses provide protection to the line section that they are protecting. The reach of the fuse must exceed the length of the line section. Several methods are used to quantify the reach of a fuse:

- Where the fuse will clear a bolted single line-to-ground fault in 3 sec
- Where the bolted single line-to-ground fault current is six times the fuse rating
- Where the fuse will clear a single line-to-ground fault with a 30 Ω resistance in 5 sec

In most situations, typical fuse sizes provide sufficient reach by any of these methods. The first two methods are the best; the 30 Ω resistance is overly conservative and difficult to apply.

Reliability needs to dictate the number of fuses used. The most common application for line fuses is at tap points. Occasionally, utilities fuse three-phase mains, but a recloser is more commonly used for this purpose. In the southwest United States, in areas with few trees and little lightning, fuses may be rarely used. This is the exception, not the rule. Most utilities fuse most taps off the main line. Some go further and provide several levels of fusing, especially utilities with heavy tree coverage. Returns diminish: too many fuses lead to situations where fuses do not coordinate, and the extra fusing does not increase reliability significantly. Cutouts themselves contribute to causing faults by providing an easy location where animals, trees, and lightning cause faults, especially if they are poorly installed.

9.5 Station Relay and Recloser Settings

The main feeder circuit breaker relays (or recloser) must be set so that the circuit breaker coordinates with downstream devices, coordinates with upstream devices, and does not have trips from inrush or cold-load pickup. Station relays almost always use phase and ground time–overcurrent relays.

Table 9.9 shows typical settings used by several utilities. Many utilities try to use standardized relay settings at all distribution stations. This has the advantage that relays are less likely to be set wrong, and there is less engineering effort in a coordination study. Some other utilities set each relay based on a coordination study.

Differences exist about the meaning of "peak load." Some utilities base it on the maximum design emergency load (which is typically something like 600 A). Others use the designed normal load (typically 400 A). Others may base it on some percentage of the total connected distribution transformer kVA.

Instantaneous relay settings vary more than phase relay settings. Several utilities also either disable or do not use an instantaneous relay setting. The instantaneous relay pickup ranges from one to almost 10 times the phase relay pickup.

TABLE 9.9 Time–Overcurrent and Instantaneous Station Relay Pickup Settings in Amperes on the Primary at Several Utilities

	Phase		Ground		
Utility	TOC	Inst.	TOC	Inst.	Notes
A	720	4000	480	4000	Assumes peak current = 400 A
B	720	1200	360	1200	Full load = 300 to 400 A
C	600	None	300	530	
D	960	1300	480	600	
E	800	None	340	None	
F	960	2880	240	1920	
G	≥2.25 × current rating	Same as TOC	≥0.6 × current rating	Same as TOC	
	600	600	160	160	Typical settings

One reasonable set of base pickup settings is

- *Phase TOC (time–overcurrent) relay*—Use two times the normal designed peak load on the circuit.
- *Ground TOC relay*—Use 0.75 times the normal designed peak load on the circuit.
- *Instantaneous phase and ground relays*—Use two times the TOC relay pickups.

Settings any less than this are prone to false trips from cold-load pickup and inrush.

In addition to avoiding nuisance trips, the relays (or recloser) must provide protection to its line section (to the end of the line or to the next protective device in series). Ensure that the relay has sufficient reach at the minimum operating current of the relay.

For a phase relay, sufficient reach is achieved by ensuring that 75% of the bolted line-to-line fault current at the end of the circuit is greater than the relay's pickup (its minimum operating current). So, if the line-to-line fault current at the end of the circuit is 1000 A, the pickup of the relay should be no more than 750 A. We use the line-to-line fault current because the two types of faults not seen by the ground relay are the three phase and the line to line. Of these, the line-to-line fault has the lower magnitude. The 75% factor provides a safety margin and allows some fault impedance. Another approach is to ensure that the line-to-ground fault current at the end of the circuit is less than the minimum operating current. The line-to-ground fault current is less than the line-to-line fault current, which provides the safety margin.

For a ground relay, ensure that the relay pickup is less than 75% of the line-to-ground fault current at the end of the line or to the next protective device. The ground relay must also coordinate with the largest lateral fuse.

Feeders dedicated to supplying secondary networks, either grid or spot networks, have similar settings as feeders supplying radial loads. Two main differences are

related to loading and the ground relay setting. The pickup settings of station circuit breakers may have to account for higher peak loads. Some utilities have phase relay pickups that are similar to radial circuits, from 600 to 800 A, but some have settings above 900 A with one utility having a 1680-A setting (EPRI 1019937, 2010; Smith, 1999). Also, if feeders are supplying only network load, and all network transformers are connected delta–grounded wye, the unbalanced current seen by the ground relay is small. Utilities can set a low ground relay setting; some have settings ranging from 40 to 80 A (EPRI 1019937, 2010; Smith, 1999). The main limitation on lowering the setting further is that during line-to-ground faults, the unfaulted circuits will back-feed the fault through the zero-sequence capacitance of that circuit. Lower ground-relay settings also help detect turn-to-turn or layer-to-layer faults within the primary windings of network transformers.

9.6 Coordinating Devices

Several details often arise when coordinating specific devices. Normally, we want to ensure that the downstream device clears before the upstream device operates over the range of fault currents available at the downstream device. Time–current characteristics of both devices normally show us how well two devices coordinate. Because of device differences, some combinations require slightly different approaches. We discuss some of the common combinations in the sections that follow.

9.6.1 Expulsion Fuse–Expulsion Fuse Coordination

When coordinating two fuses, the downstream fuse (referred to as the *protecting* fuse) should operate before the upstream fuse (the *protected* fuse). To achieve this goal, ensure that the total clear time of the protecting fuse is less than the damage time of the protected fuse. The damage time is 75% of the minimum melt time. An example for coordinating a 100 K link with a 65 K link is shown in Figure 9.12. Above a certain current, the two fuses do not coordinate; the protected fuse could suffer damage or melt before the protecting fuse can clear. For high fault currents, coordination is impossible because both fuses can open. The example shows that above 2310 A, the total clear curve of the 65 K is above the damage curve of the 100 K link. Utilities live with this common miscoordination. Table 9.10 lists the maximum coordination currents between K links. In cases where fuses do not coordinate, why have the second fuse? The second fuse still has some value; it adds another sectionalizing point (for a fuse in a cutout), and for a downstream fault, it identifies the fault location to a smaller area. Also, the downstream fuse may operate without damaging the upstream fuse. The amount of damage to the upstream fuse depends on the point of the waveform where the fault occurs (the extra 1/2+ cycle waiting for a current zero causes the extra heating to the protected fuse).

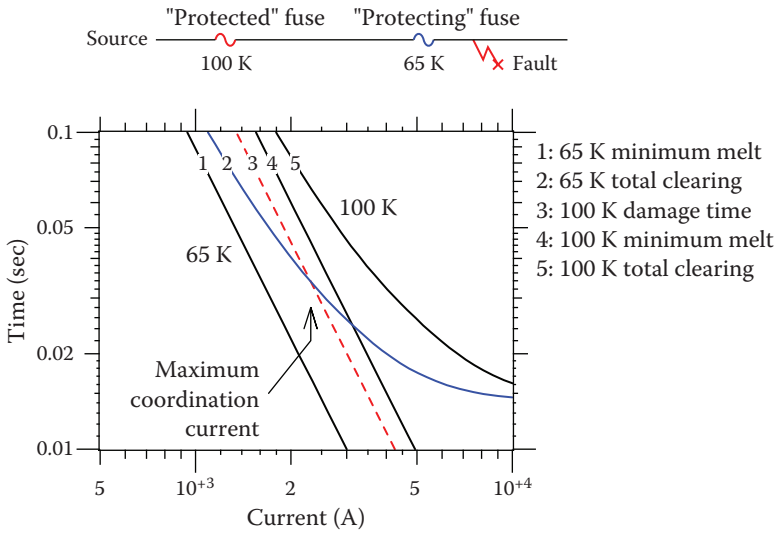


Figure 9.12 Example of fuse coordination between a 100-K (the protected fuse) and a 65-K link (the protecting link).

9.6.2 Current-Limiting Fuse Coordination

Coordinating two CLFs is similar to coordinating two expulsion links. Plot the time–current characteristics, and ensure that the maximum clearing time of the load-side fuse is less than 75% of the minimum melting time of the source-side fuse over the range of fault currents available at the load-side fuse. The 75% factor accounts for

TABLE 9.10 Maximum Fault Currents for Coordination between the Given K Fuse Links

	10 K	12 K	15 K	20 K	25 K	30 K	40 K	50 K	65 K	80 K	100 K	140 K	200 K
6 K	170	310	460	640	840	1060	1410	1800	2230	2930	3670	5890	9190
8 K	20	230	410	610	810	1040	1400	1790	2230	2930	3670	5890	9190
10 K		40	300	550	780	1000	1370	1770	2220	2930	3670	5890	9190
12 K			80	420	690	950	1330	1730	2190	2910	3650	5880	9190
15 K				90	530	840	1250	1670	2120	2870	3640	5870	9190
20 K					100	610	1120	1570	2040	2800	3590	5870	9190
25 K						120	840	1380	1920	2710	3510	5830	9150
30 K							240	1090	1690	2570	3380	5740	9110
40 K								300	1240	2260	3210	5630	9010
50 K									240	1750	2800	5500	8910
65 K										970	2310	5210	8740
80 K											420	4460	8430
100 K												3550	7950
140 K													4210

damage to the source-side fuse. Unlike expulsion links, CLFs can coordinate to very high currents. For coordination at higher currents than are shown on published time–current characteristics (operations faster than 0.01 sec), ensure that the maximum clearing I^2t of the load-side fuse is less than 75% of the minimum-melt I^2t of the source-side fuse. Manufacturers provide both these I^2t values for CLFs.

Coordinating an expulsion link with a current-limiting fuse follows similar principles. Because the melting and clearing characteristics of CLFs are so much steeper than those of expulsion links, coordination is sometimes difficult; the operating characteristic curves are more likely to cross over. A load-side CLF coordinates over a wide range of fault current. For a source-side CLF, the clearing-time limitations of expulsion links (to about 0.8 cycles) prevent coordination at high currents. For currents above this value, either both will operate, or just the CLF will operate.

Backup CLF coordination requires special attention. To ensure that the CLF does not try to operate for currents below its minimum interrupting rating, the intersection of the expulsion fuse's total-clearing curve and the backup fuse's minimum melting curve must be greater than the maximum interrupting rating of the backup fuse. Normally, we select backup CLFs for use with expulsion links based on *matched-melt* coordination. Select a backup CLF that has a maximum melting I^2t below the maximum clear I^2t of the expulsion element. Also, check the time–current curves of the devices. The expulsion link should always clear for fault currents in the low-current operating region, especially below the minimum interrupting current of the CLF.

With matched-melt coordination, the expulsion fuse always operates, including when the backup CLF operates. In overhead applications with an expulsion fuse in a cutout, the dropout of the expulsion fuse provides a visible indication when the fuse(s) operate. Also, the backup fuse is unlikely to have full voltage across it.

The maximum melting I^2t of expulsion links is not provided from curves or data. To estimate this, take the minimum melting I^2t calculated from the minimum-melt curve at 0.0125 sec, and multiply by 1.2 for tin links or 1.1 for silver links. The multiplier allows for conservatism in minimum-melt curves and for manufacturing tolerances.

Somewhat less conservatively, experience has shown that fuses coordinate well if the maximum melt I^2t of the expulsion link does not exceed twice the minimum melt I^2t of the backup fuse (IEEE Std. C37.48-1997). We can tighten up the backup fuse because, under most practical situations, the backup fuse lets through significantly more I^2t than its minimum-melt value.

Manufacturers of backup CLFs normally provide coordination recommendations for their fuses, but review of the coordination approach is sometimes appropriate. Backup fuses often use a "K" nomenclature signifying the K link that it coordinates with. For example, a "25 K" backup link coordinates with a K link rated at 25 A or less. Figure 9.13 shows the time–current curves of a 40 K expulsion link and the curves of one manufacturer's 40 K backup CLF. This graph extends below the normal cutoff time of 0.01 sec to show how the fuses coordinate at high currents. This example shows that the backup fuse does not coordinate using the strict matched-melt criteria (the maximum melting time of the expulsion link is more than the minimum melting time of the backup fuse). The minimum-melt I^2t of the backup fuse is 1.6

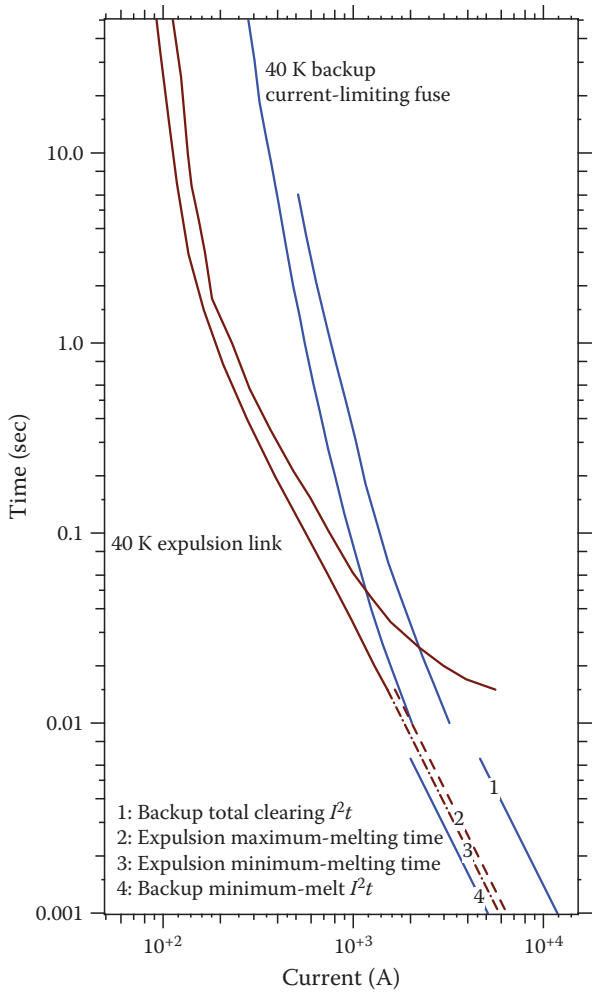


Figure 9.13 Coordination between a 40-K expulsion link and a 40-K backup current-limiting fuse using the relaxed matched-melt criteria.

times the minimum melt I^2t of the backup fuse, so it meets the relaxed matched-melt criteria since this ratio is less than two.

The *time–current curve crossover coordination* allows a smaller backup CLF. As before, the intersection of the expulsion fuse's total-clearing curve and the backup fuse's minimum melting curve must be greater than the maximum interrupting rating of the backup fuse. We do not try to ensure that the backup fuse always melts. We can use a smaller fuse, which reduces the I^2t let through and reduces energy to faults. The backup CLF operates for a wider range of short-circuit currents. With a smaller fuse, the backup fuse can operate before the expulsion link melts for high fault currents. Utilities often use time–current curve crossover coordination for under-oil backup CLFs. In addition to lowering energy to faults, crossover coordination extends the range of CLF protection to larger transformers.

For transformer protection, overload and secondary faults are also considerations for backup CLFs. Secondary faults at the terminals of the transformer should not damage or melt the backup CLF. One way to do this is to ensure that at the total clearing time of the expulsion link with the bolted secondary fault, the backup fuse's minimum melting current is at least 125% of the secondary fault current (Hi-Tech Fuses, 2002). Also, overload should not damage or melt the backup CLF.

9.6.3 Recloser–Expulsion Fuse Coordination

Normally, we want the recloser's fast curve (A curve) to clear before downstream fuses operate. This saves the fuse for temporary faults (we discuss fuse saving in more detail later in this chapter). Select the delayed curve (B, C, …) to be above the clearing time of downstream fuses. A permanent fault downstream of a fuse should blow the fuse, not lockout the recloser.

To open the recloser before the fuse blows, Cooper (1990) recommends adjusting the A curve by multiplying the time by a factor of 1.25 for one fast operation, a factor of 1.35 for two fast operations with a reclosing time greater than or equal to 1 sec, and a factor of 1.8 for two fast operations with a reclosing time from 25 to 30 cycles. For applications with two or more delayed operations, the fast curve coordinates for fault currents up to the point where the adjusted A curve crosses the expulsion fuse's minimum melting curve.

On hydraulically controlled reclosers, the trip-coil rating determines the recloser's "pickup." Beyond that, hydraulically controlled reclosers have limited curve selections and no adjustments. Figure 9.14 shows average clearing curves for a single-phase Cooper 4E hydraulically controlled recloser overlayed on top of two K fuse links. For this example, only a limited range of fuses coordinate for low and high fault currents. Fuses larger than a 65 K have significant overlap in the low-current area, leaving more chance that the recloser could lock out for a fault on a lateral tap. The slower delayed curves, such as the C curve shown, reduce the chance of miscoordination for lower fault currents. For the fast-trip A curve, the 40 K link only coordinates with the fast curve for fault currents up to 360 A; smaller links are worse. Since K links are significantly steeper than these recloser curves, we must expect limited coordination for certain combinations. In this instance, T links coordinate over a wider current range because their time–current characteristics match the slope of the recloser characteristics more accurately. Miscoordination is more problematic in the low-current region. If the recloser locks out for faults downstream of a fuse, more customers are interrupted, and crews have a harder time finding the fault (more area to patrol).

Reclosers with electronic controls and relayed circuit breakers offer more flexibility. We can tailor tripping characteristics to coordinate over a wider range of currents. Three-phase reclosers have a ground-trip element that can increase the sensitivity of the recloser and also coordinate better with downstream fuses.

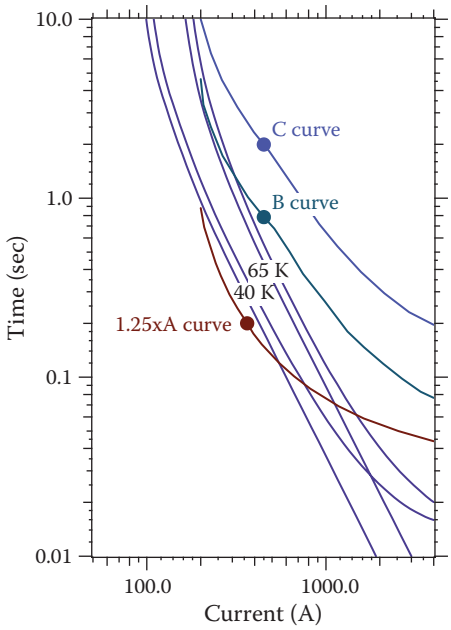


Figure 9.14 Example of coordination between K links and a Cooper 4E single-phase hydraulic recloser with a 100-A trip coil (A, B, and C curves shown).

9.6.4 Recloser–Recloser Coordination

For coordinating two reclosers, the curve separation we need depends on the type of recloser. For hydraulically controlled reclosers that are series coil operated, both operate if there is less than a two-cycle separation; both *may* operate for a separation of 2 to 12 cycles, and both coordinate properly if there are more than 12 cycles of separation. For hydraulically controlled reclosers that use high-voltage solenoid closing (larger reclosers), we need eight cycles of separation for coordination (if it is less than two cycles, both devices operate). This data is for Cooper reclosers (Cooper Power Systems, 1990).

9.6.5 Coordinating Instantaneous Elements

Coordinating instantaneous relay elements or recloser fast curves is difficult. By the nature of an instantaneous element, two in series will both operate if the short-circuit current is above the pickup of both relays.

The most common way to coordinate two instantaneous elements is to raise the pickup of the upstream element. Find a setting where the instantaneous relay will not operate for faults downstream of the second protective device. The upstream relay cannot operate if its pickup is above the available fault current at the location of the downstream element. For this strategy, the instantaneous pickup on the element

must be higher than its time–overcurrent pickup. This rules out hydraulic reclosers, which have the same pickup for the fast (A) curve and the delayed curves (B and C), but is not a concern with electronic reclosers because they have the same flexibility as relayed circuit breakers.

Rather than using an instantaneous relay element, we can perform the "fast trip" function with a time–overcurrent relay with a fast characteristic. Now, we might be able to coordinate the fast curve of a line recloser with the substation circuit breaker or recloser.

As an other way to coordinate two instantaneous elements, use a time delay on the upstream instantaneous element. Choose enough time delay, 6 to 10 cycles, to allow the downstream device to clear before the station device operates.

Even with coordinated fast curves (either using a delay or using a fast TOC curve), nuisance momentary interruptions occur for faults cleared by a downstream line recloser. Consider a station recloser R1 and a downstream line recloser R2 each with one fast curve (A) and two delayed curves (B). If a permanent fault occurs downstream of R2, R2 will first operate on its A curve. If the fast curves of R1 and R2 are coordinated, R1 will not operate. After a delay, R2 recloses. The fault is still there, so R2 operates on its delayed curve (its B curve). Now, R1 *does* operate because it is on its A curve, which operates before R2's B curve. After R1 recloses, R2 should then clear the fault on its B curve, which should operate before R1's B curve. The fault is still cleared properly, but customers upstream of R2 have extra momentary interruptions.

A more advanced form of coordination called *sequence coordination* removes this problem. Sequence coordination is available on electronic reclosers and also on digital relays controlling circuit breakers. With sequence coordination, the station device detects and counts faults—but does not open—for a fault cleared by a downstream protector on the fast trip. If the fault current occurs again (usually because the fault is permanent), the station device switches to the time–overcurrent element because it counted the first as an operation. Using this form of coordination eliminates the momentary interruption for the entire feeder for permanent faults downstream of a feeder recloser. On a relay or recloser that has sequence coordination, if the device senses current above some minimum trip setting and the current does not last long enough to trip based on the device's fast curve, the device advances its control-sequence counter as if the unit had operated on its fast curve. So, when the downstream device moves to its delayed curve, the upstream device with sequence coordination also is operating on its delayed curve. With sequence coordination, for the fast curves, the response curve of the upstream device must still be slower than the clearing curve of the downstream device.

Even if you do not have a device capable of sequence coordination at the substation, you can achieve a similar result by making sure the zone of protection of the upstream device has only a small overlap with the downstream device. Urban circuits often have the entire circuit within the range of the station instantaneous relay, so one can reduce momentary interruptions by changing the setting of the instantaneous relay element at the station, so it would not see way past the downstream line reclosers.

Utilities can also use more advanced features of digital relays to improve reliability. Fault recordings from digital relays can help reveal problems, including

miscoordinations and malfunctioning devices. Fault location algorithms can help crews find faults more quickly; this will speed restoration, especially for mainline lockouts on long circuits.

9.7 Locating Sectionalizing Equipment to Optimize Reliability*

Locating fuses, reclosers, and other sectionalizing devices is an important component of overcurrent protection that affects reliability. Several options are available to use protective devices to improve reliability, including adding devices that can sectionalize and restore circuits faster (automation), using more protective devices (more fuses, more reclosers), reclosing faster, improving coordination, and so on. An advantage of optimizing protection as a way of improving reliability is that many options are low cost—utilities can improve performance by changing relay or recloser settings or applying low-cost fuses more appropriately.

The more fuses we have to isolate faults to smaller chunks of circuitry, the fewer customers we interrupt. Taps are almost universally fused, primarily for reliability. Fuses make cheap fault finders. We want to have a high percentage of a circuit's exposure on fused taps, so when permanent faults occur on those sections, only a small number of customers are interrupted. A number of overlooked scenarios can be improved with better application of fuses: (1) unfused taps on the mainline, (2) transformers without a local fuse, and (3) arresters upstream of fuses.

Many utilities have more taps that are unfused than they realize. If the unfused taps use a smaller conductor size, faults are more likely to burn down such conductors because a circuit breaker will take longer to clear a fault than would a fuse. Because such taps may be on side streets, during patrols, crews may forget to inspect them for damage, increasing the interruption time. So, one way to improve reliability is to make sure that *all* taps are fused. Consider a common example where an unfused tap crosses the street to feed a riser pole. To protect the small, unfused tap, move the fuses from the riser pole to the pole where the circuit taps off of the mainline.

Having a local external fuse to protect a transformer helps improve reliability. If the transformer is a CSP transformer (see Figure 9.15) with an internal fuse, then an animal across a bushing or other bushing failure will force the tap fuse or upstream circuit breaker or recloser to operate, leaving many more customers interrupted, with much more area for crews to patrol. CSPs on the mainline are especially problematic for reliability indices. A local fuse also helps crews more accurately find and identify the source of the problem. The most common fusing equipment for this application is an expulsion fuse in a cutout, but current-limiting fuses are also an option. Because CSPs have lower structural withstand capabilities than conventional transformers, current-limiting fuses are appropriate in many locations to provide protection against violent transformer failure.

* This section has been adapted based on Short and Taylor (2006). Lee Taylor developed Duke Energy's customer-interruptions-saved approach to evaluating sectionalizing.

Figure 9.15 Unfused CSP on a mainline.

Arresters should be placed downstream of fuses if possible. Then, an arrester failure or an animal across the arrester will blow the fuse rather than forcing a mainline protective device operation (interrupting many more customers than if a fuse had operated). If the arrester isolator fails to operate (which can happen), the failure may be extremely hard for the crews to find. A fuse helps localize the failure.

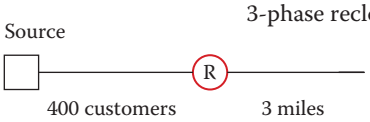
Arresters upstream of fuses can cause further problems. If the arrester fails and the isolator operates, crews may reclose the circuit successfully if they do not find the failed arrester. This leaves the equipment unprotected. Worser yet, the failed arrester body may start to track across the bracket. Eventually, the arrester bracket will flash over causing a hard-to-find permanent fault. With arresters upstream of a fuse, arrester lead lengths will be longer, and the equipment is not protected as well against lightning surges. This can lead to more lightning-caused equipment failures.

Reclosers are another option that can improve reliability and can often be justified for reliability even if they are not needed for reach to protect the entire circuit. Even when reclosers are needed for reach, positioning can often be tweaked to maximize reliability. Single-phase reclosers can provide economical application for certain three-phase line locations and also for longer single-phase taps.

To locate and prioritize sectionalizing projects, we can estimate the number of customer interruptions avoided by the addition of the recloser, fuse, or other sectionalizing device. The main inputs for this calculation are fault rates and circuit lengths. Consider the common but simple example of applying a recloser at the midpoint of a circuit mainline in Figure 9.16a. The recloser protects the customers on the upstream side of the recloser from faults on the mainline downstream of the recloser. To estimate the number of customer interruptions saved, multiply the number of customers

(a) Midpoint recloser

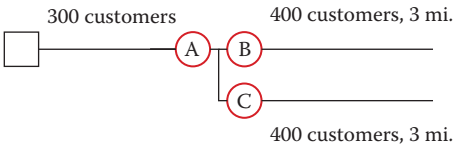
Fault rate = 0.2 faults/mile/year
3-phase recloser installation = $15,000



Customer-interruptions saved
= 400 customers (3 miles) (0.2 faults/mile)
= 240 customer interruptions
Cost per customer interruption saved

$$= \frac{\$15{,}000}{240 \text{ cust. int. saved}} = \$62.5/\text{cust. int. saved}$$

(b) Tee point reclosers



Option A: 300 cust (6 mi) (0.2 faults/mi) = 360 cust. int. saved
Option B or C: 700 cust (3 mi) (0.2 faults/mi) = 420 cust. int. saved
Option C with A already there: 400 cust (3 mi) (0.2 faults/mi)
= 240 cust. int. saved
Option C with B already there: 700 cust (3 mi) (0.2 faults/mi)
= 420 cust. int. saved
Costs per customer interruption saved:
Option A: $15,000/360 = $41.7/cust. int. saved
Option B or C: $15,000/420 = $35.7/cust. int. saved
Option A and C: $30,000/(360 + 240) = $50.0/cust. int. saved
Option B and C: $30,000/(420 + 420) = $35.7/cust. int. saved

Figure 9.16 Recloser examples with customer interruptions saved.

affected (all of those customers upstream of the recloser) by the fault rate times the mainline exposure downstream of the recloser.

If we were finding locations for reclosers, the number of customers saved by each possible recloser location allows us to prioritize possible recloser locations. When comparing different equipment options, the cost effectiveness of each application can be determined by using the ratio of the cost of the installation of the sectionalizing device to the number of customer interruptions saved. Then, select projects with the lowest cost per customer interruption saved.

On radial circuits with a major tee, the tee point is a prime candidate for a sectionalizing device on both branches off of the tee point. Figure 9.16b shows an example comparing recloser options at a tee point, the most number of customer interruptions saved is for reclosers on both branches off of the tee point. The best device (recloser or fuse) and the best location depend on the lengths, customer counts, and customer locations.

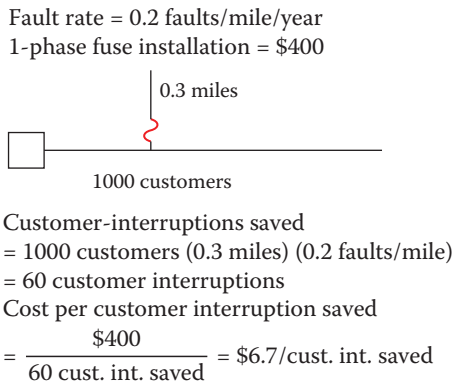


Figure 9.17 Tap fuse example with customer interruptions saved.

Figure 9.17 shows that applying a tap fuse is not surprisingly a very cost-effective way to reduce the number of customer interruptions. For longer taps, we may consider using a single-phase recloser rather than a fuse, and this question calls for a somewhat different analysis approach. One point to keep in mind is that most applications of sectionalizing equipment will not dramatically reduce utility restoration costs; it may take less time to patrol and find the damage, but the largest costs associated with restoration—getting the crews to the site and the repair time—do not change. On overhead circuits, a recloser instead of a fuse will reduce the number of outage events by clearing temporary faults as a momentary interruption rather than having a blown fuse result in a sustained interruption. Consider a 2.5-mi tap with 50 customers. A fuse on that tap might blow (2.5 mi)(0.4 faults/mi/year) = 1 operation per year (assuming a fuse-blowing mode where the fuse operates for both temporary and permanent faults). Having a recloser on the tap may reduce the number of outage events on the tap by a factor of two (one operation every 2 years). If a single-phase recloser installation costs $1500 more than a fuse installation, and each fuse operation costs $800 on average to replace, the recloser will pay for itself in 4 years. In this case, it is easier to estimate the impact by event, rather than using a cost per customer interrupted.

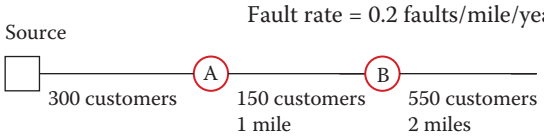
To apply sectionalizing equipment, Duke Energy uses the customer-interruptions-saved approach. They will implement those projects where the cost is less than $50 per customer interruption saved using the cost guidelines in Table 9.11. These estimates are approximate and are intended to give engineers a "feel" for what is justified in sectionalization work. When protecting customers upstream from faults downstream, Duke Energy assumes an annual permanent fault rate on overhead circuits of 0.2 faults/mile (0.32 faults/km) for circuit mainlines and 0.5 faults/mile (0.8 faults/km) for branch lines. Duke also considers a temporary fault rate that will manifest as a sustained interruption unless you use a reclosing device or fuse saving. This temporary fault rate is needed to analyze the impact of a sectionalizing device to protect customers downstream from faults downstream, such as when considering the impact of fuse saving or considering whether a recloser is more appropriate than

TABLE 9.11 Duke Energy Sectionalizing Cost Guidelines

Activity	Approximate Cost
Install one fuse	$200
Install three fuses	$500
Install three single-phase hydraulic reclosers	$7500
Install a three-phase vacuum recloser	$9500
Install a three-phase electronic recloser	$20,000
Relocate a recloser	$3750

a fuse. For either mainlines or branch lines, they assume a temporary fault rate of 0.2 for retrofitted lines (those where transformer locations have been retrofitted with a local fuse along with other upgrades to reduce faults) and 0.8 for unretrofitted lines. To estimate the impact of fuse saving using these temporary fault rates, consider the impact of each fuse downstream of the reclosing device. If the fuse coordinates with the upstream device (meaning the breaker or recloser can open before the fuse blows), then multiply the length of that tap by the temporary fault rate on that tap to arrive at the number of customer-interruptions saved with fuse saving. For a 1/2-mile long tap with 20 customers and a temporary fault rate of 0.8/mile/year, fuse saving will save eight customer interruptions annually on that tap (add up the remaining taps to evaluate the full impact).

Using Duke Energy's numbers, the "value" of each sectionalizing device can be estimated by multiplying the fault rate by the value of each customer interruption ($50) by the exposure, or one can multiply the line exposure and the number of customers affected and then multiply by $10/customer-mile ($50/customer interruption × 0.2 faults per mile). Consider the example in Figure 9.18 when comparing two recloser scenarios. In this case, Duke can justify installing three single-phase reclosers at either location because both locations have a value of $9000, which is less than the installation cost of $7500. Installing reclosers at both locations is not justified as the value of the second recloser location is only $3000. And it is not beneficial to move the reclosers from location B to A (or vice versa) because both have the same number of customer-interruptions saved.



Customer exposure value = (0.2 faults/mi)($50/customer-interruption saved)
= $10/customer-mile

Value of each option:
A only: 300 cust (3 mi) ($10/customer-mile) = $9000
B only: 450 cust (2 mi) ($10/customer-mile) = $9000
A with B already there: 300 cust (1 mi) ($10/customer-mile) = $3000
B with A already there: 150 cust (2 mi) ($10/customer-mile) = $3000

Figure 9.18 Duke Energy sectionalizing example.

To account for the impact on larger customers, Duke Energy considers a major customer (hospitals, prisons, etc.) as multiple customers by assuming 5 kW of peak demand is equivalent to one customer. The equivalent customer count equals the peak demand in kW divided by 5.

Customer groupings are important to consider. Sometimes it makes sense to increase the mainline exposure to protect large customer groupings. For example, if there is a large grouping of customers near the middle of a circuit, putting the recloser just beyond that grouping will improve reliability the most. On circuits with larger groupings of customers near the end will have fewer opportunities for additional sectionalizing equipment unless automated tie-point equipment is used to transfer those customers to another circuit. For long straight radial circuits, one recloser may be beneficial, but having a second recloser may be difficult to justify (although an automated tie recloser may be very beneficial).

For more advanced analysis, modules for reliability evaluations are available for most distribution analysis software, and some offer automatic optimization routines to help apply sectionalizing equipment. Distribution reliability software allows more fine-tuned estimates that can handle different fault rates and account for temporary and permanent faults, possibly account for the coordination between devices, and possibly account for the differences between single-phase and three-phase devices.

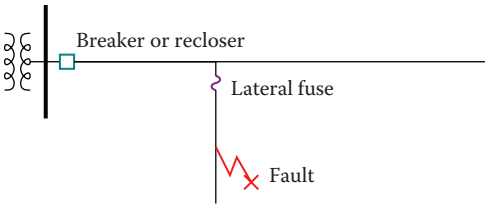
9.8 Fuse Saving versus Fuse Blowing

Fuse saving is a protection scheme where a circuit breaker or recloser is used to operate before a lateral tap fuse. A fuse does not have reclosing capability; a circuit breaker (or recloser) does. Fuse saving is usually implemented with an instantaneous relay on a breaker (or the fast curve on a recloser). The instantaneous trip is disabled after the first fault, so after the breaker recloses, if the fault is still there, the system is time coordinated, so the fuse blows. Because most faults are temporary, fuse saving prevents 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 trip is disabled, and the fuse is always allowed to blow. The fuse-blowing scheme is also called trip saving or breaker saving. Figure 9.19 shows a comparison of the sequence of events of each mode of operation. Fuse saving is primarily directed at reducing sustained interruptions, and fuse blowing is primarily aimed at reducing the number of momentary interruptions.

9.8.1 Industry Usage

Until the late 1980s, fuse saving was almost universally used. As power quality concerns grew, some utilities switched to a fuse-blowing mode. An IEEE survey on distribution protection practices that is done periodically has shown a decrease in the use of fuse saving as shown in Table 9.12.



Fuse saving

Temporary fault

1. The circuit breaker operates on the instantaneous relay trip (before the fuse operates).
2. The breaker recloses.
3. The fault is gone, so no other action is necessary.

Permanent fault

l. The circuit breaker operates on the instantaneous relay trip (before the fuse operates).
2. The breaker recloses.
3. The fault is still there.
4. The instantaneous relay is disabled, so the fuse operates.
5. Crews must be sent out to fix the fault and replace the fuse.

Fuse blowing

Temporary fault

1. The fuse operates.
2. Crews must be sent out to replace the fuse.

Permanent fault

1. The fuse operates.
2. Crews must be sent out to fix the fault and replace the fuse.

Figure 9.19 Comparison of the sequence of events for fuse saving and fuse blowing for a fault on a lateral.

Another survey done by Power Technologies, Inc., in 1996 showed a mixture of practices at utilities as shown in Table 9.13. A few used fuse blowing because they indicated that fuse saving was not successful. Many of the "mixed practices" utilities decided on a case-by-case basis. Many of these normally used fuse saving but switched to fuse blowing if too many power quality complaints were received.

TABLE 9.12 IEEE Survey Results on the Percentage of Utilities That Use Fuse Saving

Survey Year	Percent of Utilities Using Fuse Saving
1988	91
1994	71
2000	66

Data sources: Adapted from IEEE Working Group on Distribution Protection, *IEEE Transactions on Power Delivery*, vol. 3, no. 2, pp. 514–24, April 1988; IEEE Working Group on Distribution Protection, *IEEE Transactions on Power Delivery*, vol. 10, no. 1, pp. 176–86, January 1995; Report to the IEEE working group on system performance, 2002.

TABLE 9.13 1996 Survey on the Usage of Fuse Saving

Use fuse saving	40%
Use a mixture	33%
Use fuse blowing	27%

Source: Adapted from Short, T. A., *EEI Distribution Committee Meeting*, 1999.

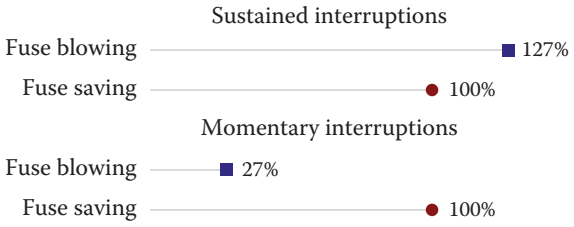


Figure 9.20 Comparison of fuse saving and fuse blowing on a hypothetical circuit. Mains: 10 miles (16.1 km), fault rate = 0.5/mile/year (0.8/km/year), 75% temporary. Taps: 10 miles (16.1 km) total, 20 laterals, fault rate = 2/mile/year (3.2/km/year), 75% temporary. It also assumes that fuse saving is 100% successful.

9.8.2 Effects on Momentary and Sustained Interruptions

The change in the number of momentary interruptions can be estimated 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 mi of mains and 10 mi of laterals, the number of momentaries after switching to fuse blowing would be 1/3 of the number of momentaries with fuse saving (5/(5 + 10) = 1/3). This 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, etc.), the number of momentaries is even less. Note how dramatically we can reduce momentaries by using fuse blowing. No other methods can so easily eliminate 30 to 70% of momentaries. The effect on reliability of going to a fuse-blowing scheme is more difficult to estimate. Fuse blowing increases the number of fuse operations by 40 to 500% (Dugan et al., 1996; Short, 1999; Short and Ammon, 1997). This will increase the average frequency of sustained interruptions by 10 to 60%. Note that there are many variables that can change the ratios. One example is given in Figure 9.20.

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

9.8.3 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 clear quickly relative to circuit breakers, so

where fault currents are high, the fuse blows before the breaker trips. This results in a fuse operation and a momentary interruption for all customers on the circuit. K links, the most common lateral fuses, are fast fuses. Most distribution circuit breakers take five cycles to clear. 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 (about one cycle) plus the five cycles for the breaker. As an illustration, Figure 9.21 shows the limit of coordination of a five-cycle breaker and a 100 K fuse. Fuse saving only coordinates for faults below 1354 A. Smaller fuses have lower current limits. Note that the breaker time is coordinated with the damage time of the fuse.

Tables 9.14 and 9.15 show the limits of coordination of several common lateral fuses for a standard circuit breaker (five cycle) and for a fast breaker/relay combination (three-cycle circuit breaker and one-cycle relay). Also shown are translations of 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 (greater than 100 A) will coordinate for significant portions of the feeder. Smaller fuses used as second- and third-level fuses do not coordinate over the length of most feeders. The situation is even worse at higher voltages. At 24.94 kV, the distances in Tables 9.14 and 9.15 are doubled, so fuse saving is more difficult to achieve at higher voltages. Reclosers are faster than standard five-cycle breakers—the four-cycle total operating time in Table 9.15 is representative of many reclosers.

If smaller K links are used such as 100 and 65 K fuses (the most common lateral fuses), then fuse saving is not going to work very well. In that case, why use it? There is no sense in having a momentary interruption every time a fuse blows (which is what will happen since the circuit breaker is not fast enough to save the fuse).

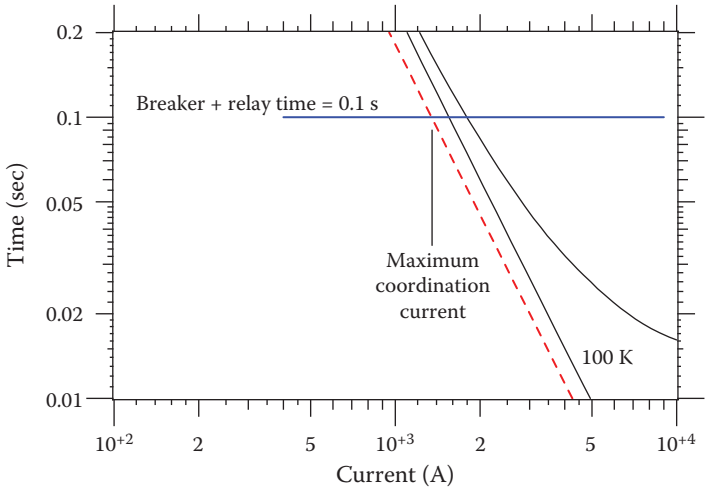


Figure 9.21 Coordination of a 100 K lateral fuse with a five-cycle circuit breaker. Assumptions: 12.47 kV, 500 kcmil, all-aluminum conductors. Ground relay: CO-11, TD = 5, pickup = 300 A.

TABLE 9.14 Maximum Fault Currents and Critical Distances for Fuse-Saving Coordination for Several Common Fuse Links for a Five-Cycle Circuit Breaker and a One-Cycle Relay Time

Fuse	I_c, A	d_c, mi	d_c, km	Fuse	I_c, A	d_c, mi	d_c, km
20 K	254	26.5	42.6	20 T	433	15.5	25.0
25 K	323	20.8	33.5	25 T	552	12.2	19.6
30 K	398	16.9	27.2	30 T	699	9.6	15.5
40 K	520	12.9	20.8	40 T	896	7.5	12.1
50 K	665	10.1	16.3	50 T	1125	6.0	9.7
65 K	816	8.3	13.3	65 T	1428	4.8	7.7
80 K	1078	6.3	10.1	80 T	1790	3.8	6.2
100 K	1354	5.0	8.1	100 T	2277	3.1	4.9
140 K	2162	3.2	5.2	140 T	3447	2.1	3.4
200 K	3401	2.1	3.5	200 T	5436	1.5	2.4

Source: From EPRI 1001665, *Power Quality Improvement Methodology for Wire Companies*, Electric Power Research Institute, Palo Alto, CA, 2003. Copyright © 2003. Reprinted with permission.

Note: I_c = Maximum current where fuse saving works. d_c = Distance from the substation where fuse saving starts to work for 12.47-kV, 500-kcmil overhead line.

9.8.4 Long-Duration Faults and Damage with Fuse Blowing

Fuse blowing has drawbacks: faults on the mains can last a long time. With fuse saving, mainline faults normally clear in 5 to 7 cycles (0.1 sec) on the first shot with the instantaneous element. With fuse blowing, this same fault may last for 0.5 to 1 sec. Much more damage at the fault location occurs during this extra time. Some of the problems that have been identified are

- *Conductor burndowns*—At the fault, the heat from the fault current arc burns the conductor enough to break it, dropping it to the ground.

TABLE 9.15 Maximum Fault Currents and Critical Distances for Fuse-Saving Coordination for Several Common Fuse Links for a Three-Cycle Circuit Breaker and a One-Cycle Relay Time

Fuse	I_c, A	d_c, mi	d_c, km	Fuse	I_c, A	d_c, mi	d_c, km
20 K	332	20.3	32.6	20 T	565	11.9	19.2
25 K	424	15.9	25.5	25 T	723	9.3	15.0
30 K	522	12.9	20.8	30 T	920	7.4	11.8
40 K	682	9.9	15.9	40 T	1175	5.8	9.3
50 K	875	7.7	12.4	50 T	1479	4.6	7.4
65 K	1070	6.3	10.2	65 T	1878	3.7	5.9
80 K	1407	4.8	7.8	80 T	2346	3.0	4.8
100 K	1763	3.9	6.3	100 T	2975	2.4	3.9
140 K	2823	2.5	4.1	140 T	4522	1.7	2.7
200 K	4409	1.7	2.8	200 T	7122	1.3	2.0

Source: From EPRI 1001665, *Power Quality Improvement Methodology for Wire Companies*, Electric Power Research Institute, Palo Alto, CA, 2003. Copyright © 2003. Reprinted with permission.

Note: I_c = Maximum current where fuse saving works. d_c = Distance from the substation where fuse saving starts to work for 12.47-kV, 500-kcmil overhead line.

- *Damage of inline equipment*—The most common problem has been with inline hotline clamps. If the connection is not good, the high-current fault arc across the contact can burn the connection apart.
- *Station transformers*—Extra duty on substation transformers.
- *Evolving faults*—Ground faults are more likely to become two- or three-phase faults.
- *Underbuilt*—Faults on underbuilt distribution are more likely to cause faults on the transmission circuit above due to rising arc gases.

A fault current arc will expand after it is initiated. It has been found that the growth of the arc is generally in the vertical direction, and the growth is primarily a function of time and not of current or voltage (Drouet and Nadeau, 1979, and Chapter 8). The growth of the arc means that a 0.1-sec fault on the instantaneous trip (with fuse saving) is less likely to involve other phases or other circuits than a 0.2 to 1-sec fault on the time-delay trip (with fuse blowing).

9.8.5 Long-Duration Voltage Sags with Fuse Blowing

With fuse blowing, voltage sags last longer, especially for faults on the three-phase mains, which have to be cleared by phase or ground time–overcurrent elements. An example is shown in Figure 9.22 where voltage sag magnitudes and durations are shown for faults at various distances from a substation using fuse blowing. For the same circuit with fuse saving, all of the faults would have cleared in 0.1 sec. For a fault at the substation, the duration triples. For a fault 1 mile (1.6 km) from the substation, the duration quadruples. 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 slower.

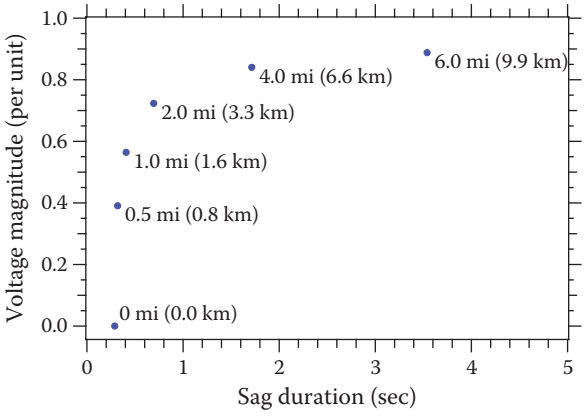


Figure 9.22 Magnitudes and durations of substation bus voltage sags for ground faults applied at the given distance with a fuse-blowing scheme. For the same circuit with fuse saving, all of the faults would clear in 0.1 sec.

9.8.6 Optimal Implementation of Fuse Saving

In order to get a fuse-saving scheme to work, it is necessary to get the substation protective device to open before fuses operate. We can achieve this in several ways:

- *Slow down the fuse*—Use big, slow fuses (such as a 140 or 200 T) near the substation to ensure proper coordination.
- *Faster breakers or reclosers*—If three-cycle circuit breakers are used instead of the normal five-cycle breakers, fuse-saving coordination is more likely. Some reclosers are even faster than three-cycle breakers.
- *Limit fault currents*:
  - Open station bus ties: An open bus tie will reduce the fault current on each feeder and make fuse saving easier. This is the normal operating mode for most utilities.
  - Use a transformer neutral reactor: A neutral reactor reduces the fault current for single-phase faults (all faults on single-phase taps).
  - Use line reactors: This reduces the fault current for all types of faults. This has been an uncommon practice. An added advantage, reactors reduce the impact of voltage sags for faults on adjacent feeders.
  - Specify higher impedance transformers.

We can employ other strategies to limit the impact of momentary interruptions:

- *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).
- *Single-phase reclosers*
- *Immediate reclose*
- *Switch to a fuse-blowing scheme on poor feeders*—For a feeder with many momentaries, disable the instantaneous relay for a time period. Identify poorly performing parts of the circuit during this time. The blown branch fuses provide a convenient fault location method. Once the poor-performing sections are identified and improved, switch the circuit back to fuse saving.

9.8.7 Optimal Implementation of Fuse Blowing

Several strategies can optimize a fuse-blowing scheme:

- *Fast fuses (or CLFs)*—If smaller or faster fuses are used, faults clear faster, so voltage sag durations are shorter. CLFs also limit the magnitude and duration of the sag. Be careful not to fuse too small, or fuses will operate unnecessarily due to loading, inrush, and cold-load pickup. Note that if smaller fuses are used, it is difficult to switch back to a fuse-saving scheme.
- *Covered wire or small wire*—Watch burndowns on circuits with covered wire or small wire that is protected by the station circuit breaker or recloser. If either of these cases exists, use a modified fuse-blowing scheme with a time-delayed instantaneous element (see the next section).

- *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 do not cause permanent interruptions to those customers.
- *More fuses*—Add more second and third level fuses to segment the circuit more.
- *Track lateral operations*—Temporary faults on fused laterals cause sustained interruptions. In order to minimize the impacts on lateral customers, track interruptions by lateral. Identify poorly performing laterals, patrol poor sections, then add tree trimming, animal guards, and so on.

9.9 Other Protection Schemes

9.9.1 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 the instantaneous trip; a definite-time–overcurrent relay also could do the same function) (Engelman, 1990). Faults do not last as long as they would if the relay went to a time–overcurrent element; there is less chance of wire burndowns, and voltage sags are of shorter duration for faults on the mains. A common delay is 0.1 sec.

An example implementation is shown in Figure 9.23 where a 0.1-sec delay is added to the instantaneous. A 100 K fuse link is also shown. For the 100 K link, the scheme is actually a mixture of fuse saving and fuse blowing. For fault currents above roughly 1700 A, it is a fuse-blowing scheme (the fuse clears before the instantaneous relay operates). For currents below 1000 A, the scheme is a fuse-saving scheme (the

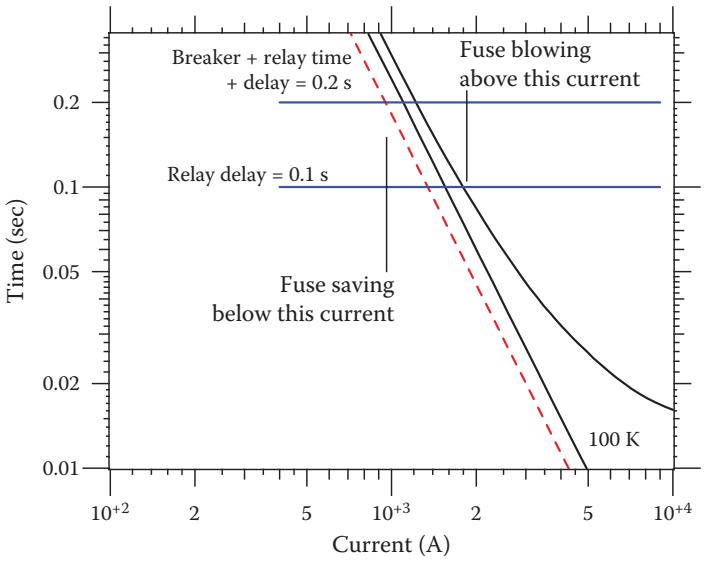


Figure 9.23 Example of a delayed instantaneous element used for fuse blowing.

circuit breaker trips before the fuse is damaged). Between 1000 and 1700 A, one or both devices operate.

Another option sometimes used with this scheme is a high-set instantaneous. The high-set instantaneous has no time delay and is set to clear faults close to the station. This removes the most damaging faults quickly (because they are the most likely to cause damage and cause the most severe voltage sags).

Using a time delay is a better fuse-saving scheme than just removing the instantaneous relay. The disadvantage, and the reason that it is not 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 ease the implementation since they have this time-delay option available.

9.9.2 High–Low Combination Scheme

Another option is to use fuse blowing at the substation and fuse saving at downstream reclosers (Burke, 1996).

- *Substation fuse blowing*—Fault currents are high near the substation, so it is difficult to get fuse saving to work here.
- *Recloser fuse saving*—Fault currents are lower downstream, and reclosers are faster, so fuse saving should work well here.

The high–low scheme is easy to implement. The station instantaneous trip is eliminated. Reclosers are operated with a fast trip (the A curve). Most are already in this mode, so no changes are necessary here.

9.9.3 SCADA Control of the Protection Scheme

Another option is to use SCADA to change back and forth between fuse saving and fuse blowing, getting some of the benefits of both schemes. Fuse blowing is the normal operating mode, but operators could switch to a fuse-saving scheme during storms. This avoids clear-sky momentaries while at the same time improves storm restoration. Several factors make fuse saving better during storms:

- Faults are more likely to be temporary during storms (lightning, wind).
- Customers are more forgiving about momentaries during storms.
- Interruptions due to fuse operations last longer during storms (because crews have many repairs to perform). If fuses are blown due to temporary faults, this increases the number of repair locations. Saving fuses reduces the number of interruptions crews will have to address.

In order for SCADA control of fuse saving to work best, we must design the system for fuse saving to work: larger, slower fuses for laterals close to the substation, faster circuit breakers (or use substation reclosers), or possibly even using grounding reactors in the substation to limit fault currents. Likewise, we must design for fuse

blowing, so avoid using tree wire (or go to delayed instantaneous relaying 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 may 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. Alternatively, the SCADA channel could control the delay on the instantaneous relay element (no delay: fuse saving; with delay: fuse blowing). One SCADA channel could control the fuse-saving/blowing status of all of the distribution feeders in a station. Alternatively, we could control each feeder independently.

9.9.4 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. Tripping quickly reduces the duration of voltage sags for faults on the mains.
- *Single-phase fault*—Use fuse blowing (time delay curves or delayed instantaneous relay).

Adaptive control requires microprocessor-based relays. This is not a common scheme, and the expense and complexity are difficult to justify unless the chosen relay comes with this functionality.

9.10 Reclosing Practices

Automatic reclosing is a universally accepted practice on most overhead distribution feeders. On overhead circuits, 50 to 80% of faults are temporary, so if a circuit breaker or recloser clears a fault and it *recloses*, most of the time the fault is gone, and customers do not lose power for an extended period of time.

On underground circuits, since virtually all faults are permanent, we do not reclose. A circuit might be considered underground if something like 60 to 80% of the circuit is underground. Utility practices vary considerably relative to the exact percentage (IEEE Working Group on Distribution Protection, 1995). A significant number of utilities treat a circuit as underground if as little as 20% is underground while some others put the threshold over 80%.

The first reclose usually happens with a very short delay, either an immediate reclose, which means a 1/3- to 1/2-sec dead time (discussed later) or with a 1- to 5-sec delay. Subsequent reclose attempts follow longer delays. The nomenclature is usually stated as 0–15–30 meaning there are three reclose attempts: the first reclose indicated by the "0" is made after no intentional delay (this is an immediate reclose), the second attempt is made following a 15-sec dead time, and the final attempt is made after a 30-sec dead time. If the fault is still present, the circuit opens and locks open. We also find this specified using circuit breaker terminology as O-0 sec-CO-15 sec-CO-30 sec-CO, where "C" means close and "O" means open. Other common cycles that utilities use are 0–30–60–90 and 5–45.

With reclosers and reclosing relays on circuit breakers, the reclosing sequence is reset after an interval that is normally adjustable. This interval is generally set somewhere in the range of 10 sec to 2 min. Only a few utilities have reported excessive operations without lockout (IEEE Working Group on Distribution Protection, 1995).

9.10.1 Reclose Attempts and Dead Times

Three reclose attempts is most common as shown in Figure 9.24. More reclose attempts give the fault more chance to clear or burn free. Returns diminish; the chance that the third or fourth reclose attempt is successful is usually small. Additional reclose attempts have the following negative impacts on the system:

- *Additional damage at the fault location*—With each reclose into a fault, arcing does additional damage at the fault location. Faults in equipment do more damage. Cable faults are harder to splice, wire burndowns are more likely, and oil-filled equipment is more likely to rupture. Arcs can start fires. Faults (and the damage the arcs cause) can propagate from one phase to other phases.

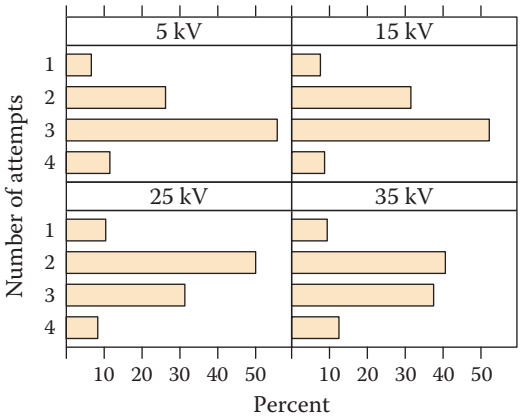


Figure 9.24 IEEE survey results on the number of reclose attempts for each voltage class. (Data from IEEE Working Group on Distribution Protection, *IEEE Transactions on Power Delivery*, vol. 10, no. 1, pp. 176–86, January 1995.)

- *Voltage sags*—With each reclose into a fault, customers on adjacent circuits are hit with another voltage sag. It can be argued that the magnitude and duration of the sag should be about the same, so depending on the type of device, if the customer equipment survived the first sag, it will probably ride through subsequent sags of the same severity. If additional phases become involved in the fault, the voltage sag is more severe.
- *Through-fault damage to transformers*—Each fault subjects transformers to mechanical and thermal stresses. Virginia Power changed their reclosing practices because of excessive transformer failures on their 34.5-kV station transformers due to through faults (Johnston et al., 1978).
- *Through-fault damage to other equipment*—Cables, wires, and especially connectors suffer the thermal and mechanical stresses of the fault.
- *Interrupt ratings of breakers*—Circuit breakers must be derated if the reclose cycle involves more than one reclose attempt within 15 sec. This may be a consideration if fault currents are high and breakers are near their ratings. Reclosers do not have to be derated for a complete four-sequence operation. Extra reclose attempts increase the number of operations, which means more frequent breakers and reclosers maintenance.
- *Ratcheting of overcurrent relays*—An induction relay disk turns in response to fault current. After the fault is over, it takes time for the disk to spin back to the neutral position. If this reset is not completed, and another fault occurs, the disk starts spinning from its existing condition, making the relay operate faster than it should. The most common problem area is miscoordination of a substation feeder relay with a downstream feeder recloser. If a fault occurs downstream of the recloser, the induction relay will spin due to the current (but not operate if it is properly coordinated). Multiple recloses by the recloser could ratchet the station relay enough to falsely trip the relay. The normal solution is to take the ratcheting into account when coordinating the relay and recloser, but in some cases, modification of the reclosing cycle of the recloser is an option. Another option is to use digital relays, which do not ratchet in this manner.

Given these concerns, the trend has been to decrease the number of reclose attempts. We try to balance the loss in reliability against the problems caused by extra reclose attempts. A major question is how often are the extra reclose attempts successful. Table 9.16 shows the success rate for one utility in a high-lightning area. Table 9.17 shows a second utility with similar reclosing practices but quite different reclose success (more lockouts and lower success rates for the first two reclose attempts). Reclose success rates change based on the types of faults most commonly seen in a region. Another data point with a broader distribution of utilities is obtained in the EPRI distribution power quality study. Table 9.18 shows the number of momentary interruptions (reclose attempts) that do not lead to sustained interruptions (lockouts). The key point is that it is relatively uncommon (but not rare) for the third or fourth reclose attempt to be successful.

We may block reclosing in some cases. It is common to block all reclose attempts when workers are doing maintenance on a circuit to provide an extra level of protection (an instantaneous relay element is also commonly enabled in this situation). Another situation is for very high-current faults. A high-set instantaneous relay covering just the first few hundred feet of circuit detects faults on the substation exit

TABLE 9.16 Reclose Success Rates for a Utility in a High-Lightning Area

Reclosure	Success Rate	Cumulative Success
1st shot (immediate)	83.25%	83.25%
2nd shot (15–45 sec)	10.05%	93.30%
3rd shot (120 sec)	1.42%	94.72%
Locked out	5.28%	

Source: Data from Westinghouse Electric Corporation, *Applied Protective Relaying*, 1982.

TABLE 9.17 Reclose Success Rates for One 34.5-kV Utility

Reclosure	Success Rate	Cumulative Success
1st shot (immediate)	25.3%	25.3%
2nd shot (15 sec)	42.1%	67.4%
3rd shot (80 sec)	11.6%	79.0%
Locked out	21.0%	

Source: Johnston, L. et al., *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-97, no. 5, pp. 1876–84, 1978. © 1978 IEEE.

TABLE 9.18 Number of Interruptions per 1 Min Aggregate Period That Do Not Lead to Sustained Interruptions

Number	Percentage
1	87%
2	9%
3	2%
4 or more	2%

Source: Data from EPRI TR-106294-V2, *An Assessment of Distribution System Power Quality: Volume 2: Statistical Summary Report*, Electric Power Research Institute, Palo Alto, CA, 1996.

cables. If it operates, reclosing is disabled. This practice is done to reduce the damage for a failure of one of the station exit cables.

The duration of the open interval—the dead time between reclose attempts—is also a consideration. For a smaller number of reclose attempts, use longer delays to give tree branches and other material more time to clear.

Operator practices must also be considered as part of the reclosing scheme. Not uncommonly, an operator manually recloses the circuit breaker after a feeder lockout (especially during a storm). This sends the breaker or recloser through its whole reclosing cycle along with all of the bad effects (like more equipment damage and more voltage sags) with very little chance of success.

Some engineers and field personnel believe that the purpose of the extra reclose attempts is to *burn* the fault clear. This is dangerous. Faults regularly burn clear on low-voltage systems (less than 480 V), rarely at distribution primary voltages. Faults

can burn clear on primary systems. The most common example is that tree branches or animals can be burned loose. The problem with this concept is that, just as easily, the fault burns the primary conductor, which falls to the ground, causing a high-impedance fault. Fires and equipment damage are also more likely with the "burn clear" philosophy.

To reduce the impacts of subsequent reclose attempts, we could switch back to an instantaneous operation after the first time–overcurrent relay operation. If the fault does not clear after the first time–overcurrent relay operation, it means the fault is not downstream of a fuse (or a recloser). The reason to use a time–overcurrent relay is to coordinate with the fuse. Since the fuse is out of the picture, why not use a faster trip for subsequent reclose attempts? While not commonly done, we could implement this with digital relays. The setting of the "subsequent reclose" instantaneous relay element should be different than the first-shot instantaneous. Set the pickup at the pickup of the time–overcurrent relay. Because of inrush on subsequent attempts, we may use a fast time–overcurrent curve or an instantaneous element with a short delay (something like five cycles).

As an example, if a utility uses a 0–15–30–90 sec reclosing cycle, the system is subjected to five faults if the system goes through its complete cycle. With the instantaneous operation enabled on the first attempt and disabled on subsequent attempts, we have a very high total duration of the fault current. For a CO-11 ground relay with a time-dial of 3, a 2-kA fault clears in roughly 1 sec. For the reclosing cycle to lock out, the system has a total fault time of 4.1 sec (one 0.1-sec fault followed by four 1-sec faults). If the instantaneous operation is enabled for reclose attempts 2 through 4, the total fault duration is 1.4 sec (one 0.1-sec fault followed by a 1-sec fault and three 0.1-sec faults). This greatly reduces the damage done by certain faults.

One scenario that can disrupt this approach is with downstream single-phase hydraulic reclosers on three-phase lines. The problem occurs when a permanent fault spreads from one phase to the other, leaving the line reclosers slightly out of sequence. The substation time–overcurrent relay is finished, but one line recloser is still not quite through its C curve. After the second reclose of the substation breaker, the downstream recloser is still not quite open, and the instantaneous takes the entire circuit out for a fault that is beyond the line reclosers. The evidence can be seen on the sequence-of-events details as the fault is obviously coming from beyond the line recloser. It might appear that the line recloser is malfunctioning (i.e., too slow), but it is actually caused by the evolving fault. So consider this approach if there are no single-phase hydraulic reclosers downstream (on three-phase lines). This is not a concern with fuses or electronic three-phase reclosers.

9.10.2 Immediate Reclose

An immediate reclose (also called an instantaneous or fast reclose) means having no intentional time delay (or a very short time delay) on the first reclose attempt on circuit breakers and reclosers.

From a power quality point of view, a faster reclose is better. Some customers may not notice anything more than a quick blink of the lights. Many residential devices such as the digital clocks on alarm clocks, microwaves, and VCRs can ride through a 1/2-sec interruption where they usually cannot ride through a 5-sec interruption (a first reclose delay used by several utilities).

9.10.2.1 Effect on Sensitive Residential Devices

The most common power quality recorder in the world is the digital clock. Many complaints are due to the "blinking clocks." Using an immediate reclose reduces complaints. Florida Power has reported that a reclosing time of 18 to 20 cycles nearly eliminates complaints (Dugan et al., 1996). Another utility that has successfully used the immediate reclose is Long Island Lighting Company (now Keyspan) (Short and Ammon, 1997). According to an IEEE survey, a time to first reclose of less than 1 sec is the most common practice although the fast reclose practice tends to decline with increasing voltage (see Figure 9.25).

Clocks have a wide range of voltage sensitivity, but most digital clocks will not lose memory for a complete interruption that is less than 0.5 sec. So, an immediate reclose helps residential customers ride through momentary interruptions without resetting many devices. Given the wide variation, some customers are sensitive to a 0.5-sec interruption. Note that the immediate reclose helps with digital clock-type devices whether it be on radio alarm clocks, VCRs, or microwaves. Fast reclosing does not help with most computers or other computer-based equipment, limiting the power quality improvement of using the immediate reclose to residential customers (no help for commercial or industrial customers).

9.10.2.2 Delay Necessary to Avoid Retriggering Faults

Sometimes a delayed reclose is necessary if there is not enough time to clear the fault. A fault arc needs time to cool, or the reclose could retrigger the arc. Whether the arc

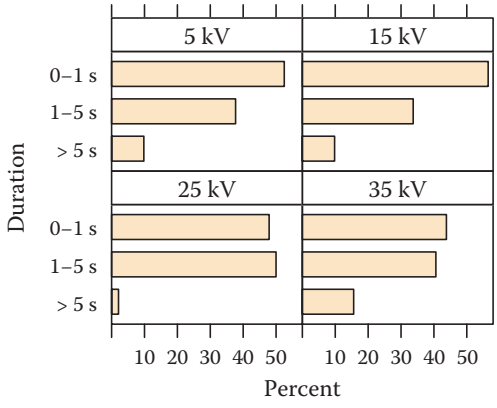


Figure 9.25 IEEE survey results of the intervals used before the first reclose attempt for each voltage class. (Data from IEEE Working Group on Distribution Protection, Distribution line protection practices—Industry survey results, *IEEE Transactions on Power Delivery*, vol. 10, no. 1, pp. 176–86, January 1995.)

strikes again is a function of voltage and structure spacings. A 34.5-kV utility (Vepco) added a delay to the first reclose because the probability of success of the first reclose was much less than normal for distribution circuits (Johnston et al., 1978). The success rate for the first attempt after an instantaneous reclose was 25% which is much less than the 70 to 80% experienced by most utilities. Another item that added to the low success rate of Vepco's 34.5-kV system is that they used a lot of armless design, and the combination of higher voltage and tighter spacings requires a longer time delay for the arc to clear.

With the following equation, we can find the minimum deionization time of an arc based on the line-to-line voltage (Westinghouse Electric Corporation, 1982):

$$t = 10.5 + V/34.5$$

where

t = minimum deionization time, 60-Hz cycles
V = rated line-to-line voltage, kV

The deionization time increases only moderately with voltage. Even for a 34.5-kV system, the deionization time is 11.5 cycles. This equation is a simplification (separation distances are not included) but does show that arcs rapidly deionize. Many high-voltage transmission lines successfully use a fast reclose. The reclose time for distribution circuit breakers and reclosers varies by design. A typical time is 0.4 to 0.6 sec for an immediate reclose (meaning no intentional delay). The fastest devices (newer vacuum or SF_6 devices) may reclose in as little as 11 cycles. This may prove to be too fast for some applications, so consider adding a small delay of 0.1 to 0.4 sec (especially at 25 or 35 kV).

On distribution circuits, other things affect the time to clear a fault besides the deionization of the arc stream. If a temporary fault is caused by a tree limb or animal, time may be needed for the "debris" to fall off the conductors or insulators. Because of this, with an immediate reclose use at least two reclose attempts before lockout. For example, use a 0–15–30 sec cycle (three reclose attempts), or if you wish to use two reclose attempts, use a 0–30 or 0–45 sec cycle (use a long delay before the last reclose attempt).

9.10.2.3 Reclose Impacts on Motors

Industrial customers with large motors have concerns about a fast reclose and damage to motors and their driven equipment. The major problem with reclosing is that the voltage on a motor will not drop instantly to zero when the utility circuit breaker (or recloser) is opened. The motor has residual voltage, where the magnitude and frequency decay with time. When the utility recloses, the utility voltage can be out-of-phase with the motor residual voltage, severely stressing the motor windings and shaft and its driven load. The decay time is a function of the size of the motor and the inertia of the motor and its load.

Motors in the 200 to 2000 hp range typically have open-circuit time constants of 0.5 to 2 sec (Bottrell, 1993). The time constant is the time it takes for the residual voltage to decay to 36.8% of its initial value. Reclose impacts are worse with

- Larger motors.
- Capacitor banks—excitation from the capacitor banks can greatly increase the motor decay time.
- Synchronous motors and generators—much larger time constants makes synchronous machines more vulnerable to damage than induction machines.

On the vast majority of distribution circuits, reclosing impacts will not be a concern because

- Motors on contactors will drop out. Also, larger motors and synchronous motors normally have an undervoltage relay to trip when voltage is lost.
- Most utility feeders do not have individual motor loads larger than 500 hp.
- Even with feeders with large industrial customers, the nonmotor load will be large enough to pull the voltage down to a safe level within the time it takes to do a normal immediate reclose (0.4 to 0.6 sec).

Because of this, we can safely implement an immediate reclose on almost all distribution circuits. One exception is a feeder with an industrial customer that is a majority of the feeder load, and the industrial customer has several large induction or (especially) synchronous motors. Another exception is a feeder with a large rotating distributed generator. In both of these cases, delay the first reclose or, alternatively, use line-side voltage supervision (if voltage is detected downstream of the breaker, reclosing is blocked to prevent an out-of-phase reclosing situation).

9.11 Single-Phase Protective Devices

Many distribution protective devices are single phase or are available in single-phase versions, including reclosers, fuses, and sectionalizers. Single-phase protective devices are used widely on distribution systems; taps are almost universally fused. On long single-phase taps, single-phase reclosers are sometimes used. Most utilities also use fuses for three-phase taps. The utilities that do not fuse three-phase taps most often cite the problem of single-phasing motors of three-phase customers. Some utilities use single-phase reclosers that protect three-phase circuits (even in the substation).

Single-phase protective devices on single-phase laterals are widely used, and the benefits are universally accepted. The fuse provides an inexpensive way of isolating faulted circuit sections. The fuse also aids in finding the fault.

Using single-phase interrupters helps on three-phase circuits—only one phase is interrupted for line-to-ground faults. We can easily estimate the effect on individual customers using the number of phases that are faulted on average as shown in Table 9.19. Overall, using single-phase protective devices cuts the average number of

TABLE 9.19 Effect on Interruptions When Using Single-Phase Protective Devices on Three-Phase Circuits

Fault Type	Percent of Faults	Portion Affected	Weighted Effect
Single phase	70%	33%	23%
Two phase	20%	67%	13%
Three phase	10%	100%	10%
		Total	47%

interruptions in half. This assumes that all customers are single phase and that the customers are evenly split between phases.

Service to three-phase customers downstream of single-phase interrupters generally improves, too. Three-phase customers have many single-phase loads, and the loads on the unfaulted phases are unaffected by the fault. Three-phase devices may also ride through an event caused by a single-phase fault (although motors may heat up because of the voltage unbalance as discussed in the next section). Single-phase protective devices do have some drawbacks. The main concerns are

- Ferroresonance
- Single-phasing of motors
- Backfeeds

Ferroresonance usually occurs during manual switching of single-pole switching devices (where the load is usually an unloaded transformer). It is less common for ferroresonance to occur downstream of a single-phase protective device that is operating due to a fault. The reason for this is that if there is a fault on the opened phase, the fault prevents an overvoltage on the opened phase. Also, any load on the opened section helps prevent ferroresonant overvoltages. Because ferroresonance will be uncommon with single-phase protective devices, it is usually not a major factor in protective device selection. Still, caution is warranted on small three-phase transformers that may be switched unloaded (especially at 24.94 or 34.5 kV).

With single-phase protective devices, backfeeds can create hazards. During a line-to-ground fault where a single-phase device opens, backfeed through a three-phase load can cause voltage on the load side of an opened protective device. Backfeeds can happen with most types of three-phase distribution transformer connections (even with a grounded-wye–grounded-wye connection). The important points to note are that

- The backfeed voltage is enough to be a safety hazard to workers or the public (e.g., in a wire down situation).
- The available backfeed is a stiff enough source to maintain an arc of significant length. The arc can continue causing damage at the fault location during a backfeed condition. It may also be a low-level sparking and sputtering fault.

Based on these points, single-phasing can cause problems from backfeeding. Whether this constrains the use of single-phase protective devices is debatable.

Most utilities do use single-phase protective devices, usually with fuses, on three-phase circuits.

Single phasing can cause problems for three-phase industrial customers due to motor heating and also from unbalance on adjustable-speed drives (Sutherland and Short, 2006). Under single-phasing, motors can overheat and fail. Motors have relatively low impedance to negative-sequence voltage; therefore, a small negative-sequence component of the voltage produces a relatively large negative-sequence current. Consequently, the effect magnifies; a small negative-sequence voltage appears as a significantly larger percentage of unbalanced current than the percentage of unbalanced voltage.

Loss of one or two phases is a large unbalance. For one phase open, the phase-to-phase voltages become 0.57, 1.0, 0.57 for a wye–wye transformer and 0.88, 0.88, 0.33 for a delta–wye transformer. In either case, the negative-sequence voltage is 0.66 per unit. With such high unbalance, a motor overheats quickly. The negative-sequence impedance of a motor is roughly 15%, so for a 66% negative-sequence voltage, the motor draws a negative-sequence current of 440%.

Most utility service agreements with customers state that it is the customer's responsibility to protect their equipment against single phasing. The best way to protect motors is with a phase-loss relay. Nevertheless, some utilities take measures to reduce the possibility of single-phasing customers' motors, and one way to do that is to limit the use of single-phase protective devices. Other utilities are more aggressive in their use of single-phase protective equipment and leave it up to customers to protect their equipment.

9.11.1 Single-Phase Reclosers with Three-Phase Lockout

Many single-phase reclosers and recloser controls come with a controller option for a single-phase trip and three-phase lockout. Three-phase reclosers that can operate each phase independently are also available. For single-phase faults, only the faulted phase opens. For temporary faults, the recloser successfully clears the fault and closes back in, so there will only be a momentary interruption on the faulted phase. If the fault is still present after the final reclose attempt (a permanent fault), the recloser trips all three phases and will not attempt additional reclosing operations.

Problems of single-phasing motors, backfeeds, and ferroresonance disappear. Single-phasing motors and ferroresonance cause heating, and heating usually takes many minutes for damage to occur. Short-duration single-phasing occurring during a typical reclose cycle does not cause enough heat to do damage. If the fault is permanent, all three phases trip and lock out, so there is no long-term single phasing. A three-phase lockout also reduces the chance of backfeed to a downed wire for a prolonged period.

Single-phase reclosers are available that have high-enough continuous and interrupting ratings that utilities can use them in almost all feeder applications and many substation applications.

Another consideration with single-phase reclosers versus three-phase devices is that a ground relay is often not available on single-phase reclosers. A ground relay

provides extra sensitivity for line-to-ground faults. Not having the ground relay is a tradeoff to using single-phase devices. Even if a ground relay is available on a unit with single-phase tripping, if the ground relay operates, it trips all three phases (which defeats the purpose of single-phase tripping).

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If you think a slack span is a period of time that you were unemployed.

If they tell you we are gonna be terminating pot heads, and you think your getting fired.

If your listed as one of the job hazards on the tailboard.

If you think single phase tap is a wrestling move.

You might be a grunt. . .
www.facebook.com/YMBAG

10
Reliability

Contents

10.1 Reliability Indices 492
10.1.1 Customer-Based Indices 492
10.1.2 Load-Based Indices 496
10.2 Variability and Weather 496
10.2.1 Weather Normalization 501
10.3 Variables Affecting Reliability Indices 505
10.3.1 Circuit Exposure and Load Density 505
10.3.2 Supply Configuration 506
10.3.3 Voltage 507
10.3.4 Correlations and Models 507
10.3.5 Long-Term Reliability Trends 513
10.4 Circuit Configurations 514
10.4.1 Modeling Radial Distribution Circuits 514
10.4.2 Parallel Distribution Systems 515
10.5 Sectionalizing and Automation 519
10.6 Reliability Programs 523
10.6.1 Maintenance and Inspections 525
10.6.2 Outage Follow-Ups 527
10.6.3 Problem-Circuit Audits 529
10.6.4 Construction Upgrade Programs 530
10.7 Outage Databases and Targeting 531
10.7.1 Temporal Analysis 531
10.7.2 Outage Codes 533
10.7.3 Cause Codes 538
10.7.3.1 Equipment 540
10.7.3.2 Vegetation 540
10.7.3.3 Unknown 542
10.7.4 Prioritizing Circuits 543
10.7.5 Evaluating Program Performance 547
10.8 Restoration 549
10.9 Interruption Costs 551
References 553

Power outages disrupt more businesses than any other factor (see Figure 10.1). I lose two hours of work on the computer; Jane Doe gets stuck in an elevator; Intel loses a million dollars worth of computer chips; a refinery flames out, stopping production and spewing pollution into the air. End users expect good reliability, and expectations keep rising. Interruptions and voltage sags cause most disruptions. In this chapter,

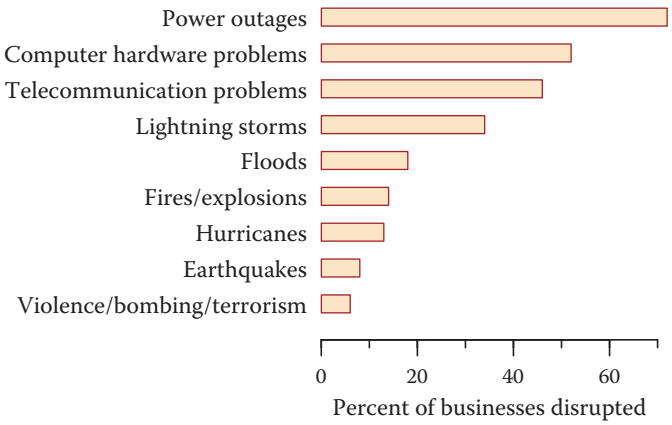

Figure 10.1 Percent of U.S. businesses disrupted by the given problem. (Data from Rodentis, 1999.)

we study "sustained" interruptions, long-duration interruptions generally defined as lasting longer than 1 to 5 min. We investigate momentary interruptions and voltage sags in the next chapter. Reliability statistics, based on long-duration interruptions, are the primary benchmark used by utilities and regulators to identify service quality. Faults on the distribution system cause most long-duration interruptions; a fuse, breaker, recloser, or sectionalizer locks out the faulted section.

Many utilities use reliability indices to track the performance of the utility or a region or a circuit. Regulators require most investor-owned utilities to report their reliability indices. The regulatory trend is moving to performance-based rates where performance is penalized or rewarded based on quantification by reliability indices. Some utilities also pay bonuses to managers or others based in part on indices. Some commercial and industrial customers ask utilities for their reliability indices when locating a facility.

10.1 Reliability Indices

10.1.1 Customer-Based Indices

Utilities most commonly use two indices, SAIFI and SAIDI, to benchmark reliability. These characterize the frequency and duration of interruptions during the reporting period (usually years) (IEEE Std. 1366-2012).

SAIFI (system average interruption frequency index)

$$\text{SAIFI} = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}}$$

Typically, a utility's customers average between one and two sustained interruptions per year. SAIFI is also the average failure rate, which is often labeled λ. Another useful measure is the mean time between failure (MTBF), which is the reciprocal of

the failure rate: MTBF in years = 1/λ. Also useful with SAIFI is customer interruptions (CI), the part that adds to the numerator of SAIFI.

SAIDI (system average interruption duration frequency index)

$$\text{SAIDI} = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customers served}}$$

SAIDI quantifies the average total duration of interruptions. SAIDI is cited in units of hours or minutes per year. Also useful with SAIDI is customer-minutes of interruption (CMI), the part that adds to the numerator of SAIDI.

SAIFI and SAIDI are the most used pair out of many reliability indices, which look like a wash of acronyms—most importantly, *D* for duration and *F* for frequency. Another related index is CAIDI.

CAIDI (customer average interruption duration frequency index)

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customer interruptions}}$$

CAIDI is the "apparent" repair time (from the customers' perspective). It is generally much shorter than the actual repair time because utilities normally sectionalize circuits to reenergize as many customers as possible before crews fix the actual damage.

Also used in many other industries, the availability is quantified as

ASAI (average service availability index)

$$\text{ASAI} = \frac{\text{Customer hours service availability}}{\text{Customer hours service demanded}}$$

We can find ASIFI from SAIDI specified in hours as

$$\text{ASAI} = \frac{8760 - \text{SAIDI}}{8760}$$

(Use 8784 hours/year for a leap year.)

Survey results for SAIFI and SAIDI are shown in Table 10.1. Figure 10.2 shows the distribution of utility indices from the CEA survey. Much of this reliability index data is from Short (2002). Utility indices vary widely because of many differing factors, mainly

- Weather
- Physical environment (mainly the amount of tree coverage)
- Load density
- Distribution voltage
- Age
- Percent underground
- Methods of recording interruptions

TABLE 10.1 Reliability Indices Found by Industry Surveys

	SAIFI, No. of Interruptions/Year			SAIDI, hours of Interruption/Year		
	25%	50%	75%	25%	50%	75%
IEEE Distribution Reliability Working Group (2012)						
No MEDs, 2.5β	0.96	1.16	1.55	1.76	2.38	2.85
Distribution only, no MEDs	0.83	1.05	1.35	1.57	2.12	2.65
All events	1.33	1.64	2.20	3.37	5.17	10.33
NRECA 2011 (Razon, 2013), no MEDs	0.90	1.29	1.88	1.30	2.07	3.17
EEI (1999)						
Excludes storms	0.92	1.32	1.71	1.16	1.74	2.23
With storms	1.11	1.33	2.15	1.36	3.00	4.38
CEA (2001) (with storms)	1.03	1.95	3.16	0.73	2.26	3.28
IP&L Large City Comparison (Indianapolis Power & Light, 2000)	0.72	0.95	1.15	1.02	1.64	2.41

Note: 25%, 50%, and 75% represent the lower quartile, the median, and the upper quartile of utilities surveyed. MED refers to major event days.

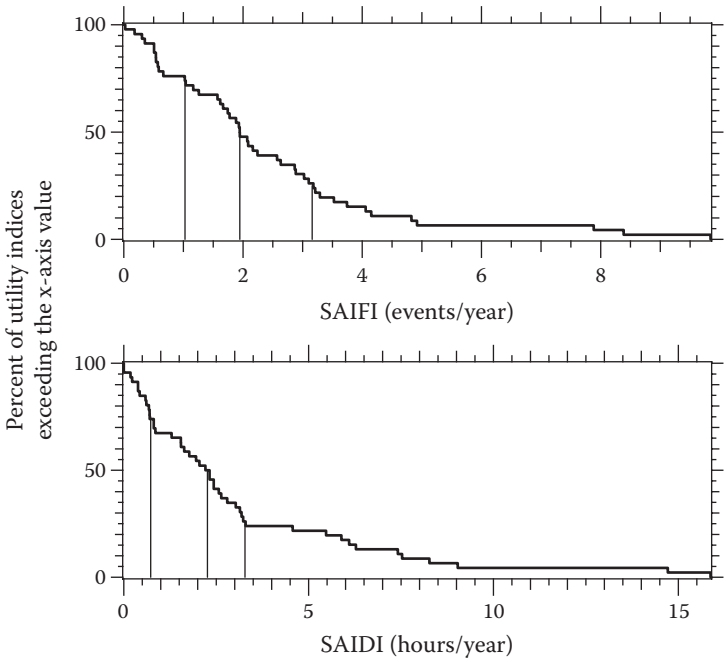

Figure 10.2 Distribution of utility indices in Canada (CEA survey, 36 utilities, two-year average). (Data from CEA, *CEA 2000 Annual Service Continuity Report on Distribution System Performance in Electric Utilities*, Canadian Electrical Association, 2001.)

Within a utility, performance of circuits varies widely for many of the same reasons causing the spread in utility indices: circuits have different lengths necessary to feed different areas of load density, some are older than others, and some areas may have less tree coverage. Figure 10.3 shows the spread of reliability on individual feeders at two utilities for 2 years worth of data. Even though these two utilities are within the same state, SAIFI differs dramatically.

Customer reliability is not normally distributed. A skewed distribution such as the log-normal distribution is more appropriate and has been used in several reliability applications (Brown and Burke, 2000; Christie, 2002). A log-normal distribution is appropriate for data that is bounded on the lower side by zero. The skewed distribution has several ramifications:

- The average is higher than the median. The median is a better representation of the "typical" customer.
- Poor-performing customers and circuits dominate the indices (which are averages).
- Storms and other outliers easily skew the indices.

Realize that SAIFI and SAIDI are weighted performance indices. They stress the performance of the worst-performing circuits and the performance during storms. SAIFI and SAIDI are not necessarily good indicators of the typical performance that customers have.

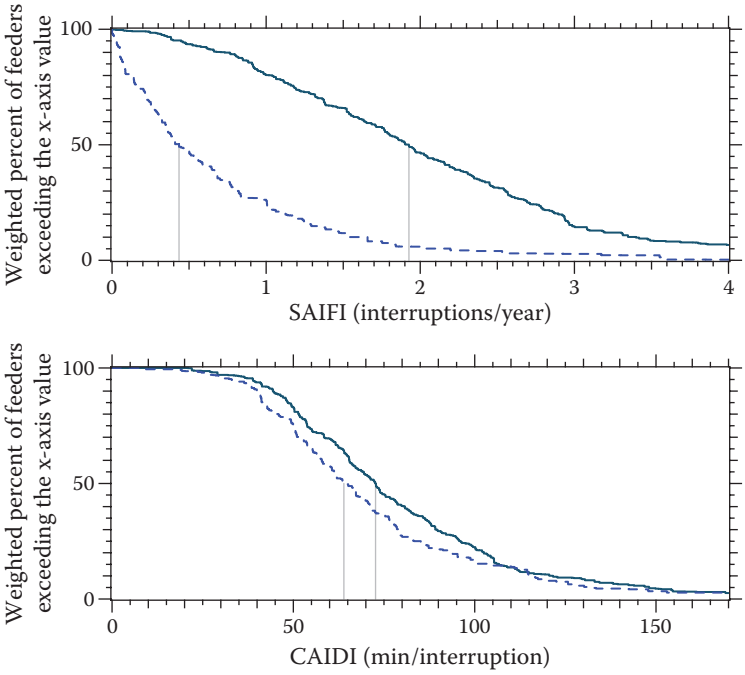

Figure 10.3 Reliability indices by feeder for two utilities. Forced events only—major events, scheduled events, and outside causes (substation or transmission) are excluded. The total SAIFI including all events was 0.79 for Utility A and 3.4 for Utility B.

Another set of indices that are becoming more common are those that track customers with particular levels of reliability. The most common of these is $CEMI_n$ (customers experiencing multiple interruptions) defined as (IEEE 1366-2012)

$$CEMI_n = \frac{\text{Total number of customers that experienced } n \text{ or more sustained interruptions}}{\text{Total number of customers served}}$$

The subscript n is the key threshold. Utilities may track multiple values of $CEMI_n$, for example, $CEMI_3$ or $CEMI_5$. As noted by Brown (2009), improvements aimed at the worst customers may not be accurately accounted for because of the thresholding effect. For example, moving customers from 10 to 6 interruptions does not change $CEMI_5$.

10.1.2 Load-Based Indices

Residential customers dominate SAIFI and SAIDI since these indices treat each customer the same. Even though residential customers make up 80% of a typical utility's customer count, they may only have 40% of the utility's load. To more fairly weight larger customers, load-based indices are available; the equivalent of SAIFI and SAIDI, but scaled by load, are ASIFI and ASIDI:

ASIFI (average system interruption frequency index)

$$\text{ASIFI} = \frac{\text{Connected kVA interrupted}}{\text{Total connected kVA served}}(\text{Average number of interruptions})$$

ASIDI (average system interruption duration index)

$$\text{ASIDI} = \frac{\text{Connected kVA interruption duration}}{\text{Total connected kVA served}}$$

Fewer than 8% of utilities track ASIFI and ASIDI, mainly since they are hard to track (knowing load interrupted is more difficult than knowing number of customers interrupted). Utilities also feel that commercial and industrial customers have enough clout that their problems are given due attention.

10.2 Variability and Weather

Much of the reliability data reported to regulators excludes major storm or major event interruptions. There are pros and cons to excluding storm interruptions. The argument for excluding storms is that storm interruptions significantly alter the duration indices to the extent that restoration performance dominates the index. Further, a utility's performance during storms does not necessarily represent the true performance of the distribution system. Including storms also adds considerable

year-to-year variation in results. On the other hand, from the customer point of view, an interruption is still an interruption. Also, the performance of a distribution system is reflected in the storm performance; for example, if a utility does more tree trimming and puts more circuits underground, their circuits will have fewer interruptions when a storm hits.

If storms are not excluded, the numbers go up as shown in an EEI survey in Figure 10.4. The interruption duration (CAIDI) and the average total interruption time (SAIDI) increase the most if storm data is included. Storms only moderately impact SAIFI. During storms, crew resources are fully used. Downed trees and wires plus traffic makes even getting to faults difficult. Add difficult working conditions, and it is easy to understand the great increase in repair times.

During severe storms, foreign crews, crews from other service territories, and general mayhem add large roadblocks preventing utilities from keeping records needed for tracking indices. Expedience rules—should I get the lights back on or do paperwork?

Utilities use various methods to classify storms. The two common categories are

- *Statistical method*—A common definition is 10% of customers affected within an operating area.
- *Weather-based definition*—Common definitions are "interruptions caused by storms named by the national weather service" and "interruptions caused during storms that lead to a declaration of a state of emergency."

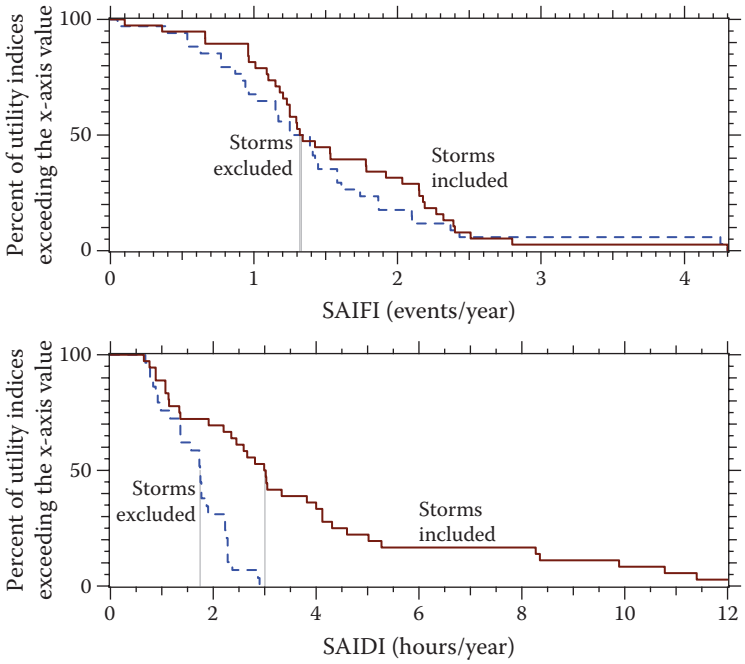

Figure 10.4 Distribution of utility indices with and without excluding storms. (Data from EEI, EEI reliability survey, *Minutes of the 8th Meeting of the Distribution Committee*, March 28–31, 1999.)

Some utilities exclude other interruptions, including those scheduled or those from other parts of the utility system (normally substation or transmission-caused interruptions). Both are done for the same reasons as storm exclusions: neither scheduled interruptions nor transmission-caused interruptions reflect the normal operating performance of the distribution system.

From the customer point of view, major event or no major event, an interruption is still a loss of production or a spoiled inventory or a loss of productivity or a missed football game. For this reason, some regulators hesitate to allow exclusions.

During storm days, the interruption durations increase exponentially. Figure 10.5 shows probability distributions of the daily SAIDI based on data from four utilities. The plot is on a log-normal scale: the x-axis shows SAIDI for each day on a log scale, and the y-axis shows the probability on a normal-distribution scale. On this plot, data with a log-normal distribution comes out as a straight line. Most of the utility data fits a log-normal distribution. But, two of the utilities are even more skewed than a log-normal distribution indicates—at these utilities, storm days have even more customer-minutes interrupted. At one of these utilities, 0.2% of the days contributed 40% of the SAIDI index (over a 7-year period). During the worst year at this utility, 70% of SAIDI for that year happened because of three storms (impacting 5 days total). If we have 1 day with a SAIDI of over 100 min (the value for a whole year at some utilities), it is going to be a long year. Figure 10.6 again emphasizes how skewed the probability distribution of reliability data is. The average is much higher than the median, and the extreme days heavily influence the average.

Because of the inherent subjectivity in defining "Major Events," particularly as they relate to weather-related conditions, the IEEE has established a statistical

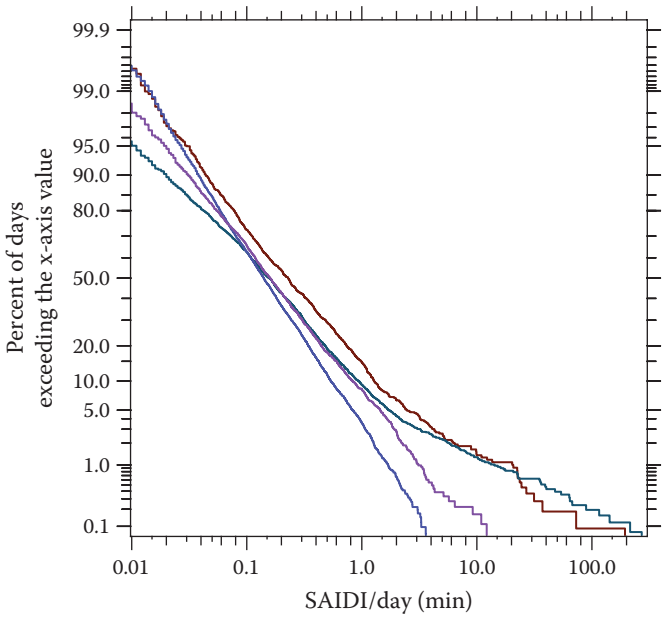

Figure 10.5 SAIDI per day probability distributions for four utilities.

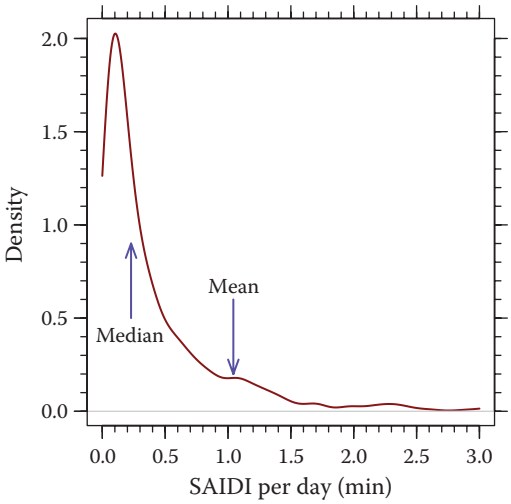

Figure 10.6 SAIDI per day probability density at one utility.

methodology to define such events. The IEEE Working Group on System Design has developed a statistically based definition for "Major Event Day" (MED) classification (IEEE Std. 1366-2012) called the 2.5-beta method. See Christie (2002) for background on the development of this approach. The 2.5-beta method is based on fitting daily SAIDI values to a log-normal distribution then finding the threshold on that distribution (T_{MED}) that is at 2.5 times the log-normal standard deviation (β):

$$T_{\text{MED}} = e^{\alpha+2.5\beta}$$

where

T_{MED} = threshold for daily SAIDI for major-event-day classification
α = average of the natural log of the daily SAIDI values
β = standard deviation of the natural log of the daily SAIDI values

Any days in the next year with a daily SAIDI that exceeds T_{MED} are considered major event days. This method is to be used on the most recent 5 years of data or as much as available. In the historical daily SAIDI data, days with no interruptions are to be excluded; one cannot take the logarithm of zero, and this is one way to account for days with no interruptions. For a perfect fit to a log-normal distribution, a beta of 2.5 corresponds to an average probability of having 2.3 major event days per year. In practice, most utilities will have more than 2.3 major event days using the 2.5-β method. This happens because the distribution of SAIDI days is often more skewed than a log-normal distribution—it has a fatter tail as shown by two of the four examples in Figure 10.5. Note that the calendar day is the fundamental unit of the beta method. A storm may cause interruptions that span more than one calendar day, which can cause odd scenarios of high SAIDI days that do not meet MED criteria.

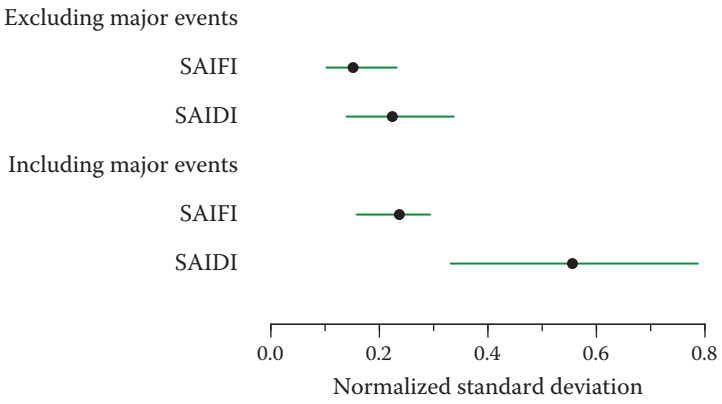

Figure 10.7 Normalized standard deviation of indices. (*Note*: The dot marks the median of the utilities and the bands mark the upper and lower quartiles (75% and 25%)). (From EPRI 1010658, *Distribution Reliability Trends and Correlations*, Electric Power Research Institute, Palo Alto, CA, 2005. Copyright 2005. Reprinted with permission.)

Extremely high SAIDI days—referred to as catastrophic days in IEEE 1366—can skew SAIDI benchmarks if major event days are excluded. This happens because extremely high SAIDI days can skew T_{MED}. For discussions of ways to handle this, see Bouford (2012) and Caswell (2012).

Reliability-based incentives and penalties directly affect a distribution business, so understanding the variability in year-to-year reliability indices is essential for managing the financial risk for a distribution utility.

Figure 10.7 shows the year-to-year variability based on normalized standard deviation of SAIFI and SAIDI for utilities with at least 5 years of reported reliability data (EPRI 1010658, 2005). The data is presented in quartiles and median for the whole population. The figure illustrates that the year-to-year variation in SAIDI is more than the year-to-year variation in SAIFI. This is an important factor in determining dead bands for performance-based rates or for internal goals based on SAIFI and SAIDI. Including major storms (not surprisingly) increases the standard deviation, especially for SAIDI.

The standard deviation is a measure of volatility of a dataset and is often used as a risk assessment parameter. Normalized standard deviation is the standard deviation of a population divided by its mean. Normalized standard deviation allows comparing the variability of two different types of data (e.g., SAIFI and SAIDI).

A standard deviation is most appropriate for a balanced, normal (Gaussian) distribution. Reliability data is often skewed, so some other distribution may be appropriate for analyzing SAIFI and SAIDI data. Lognormal, Weibull, and gamma distributions are often used in reliability analyses to cope with skewed distributions.

With normal data, variations are additive, but with lognormal data, they are multiplicative. Consider an example comparing a normal distribution with a normalized standard deviation of 0.25 to a lognormal distribution with a lognormal standard deviation of 1.4.

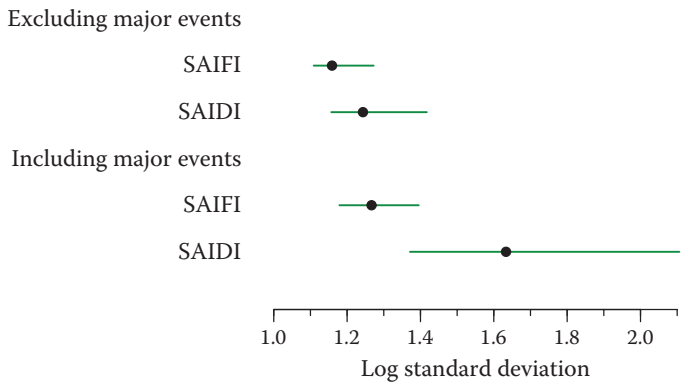

Figure 10.8 Normalized lognormal standard deviation of indices. (*Note*: The dot marks the median of the utilities and the bands mark the upper and lower quartiles (75% and 25%)). (From EPRI 1010658, *Distribution Reliability Trends and Correlations*, Electric Power Research Institute, Palo Alto, CA, 2005. Copyright 2005. Reprinted with permission.)

68.3% of the data lies within one standard deviation (the ranges just differ).

Normal ranges: $1 \pm 0.25 \rightarrow 0.75$ to 1.25
Lognormal ranges: 1 */÷ 1.4 → 1/1.4 to 1*1.4 = 0.71 to 1.4

95.5% of the data lies within two standard deviations

Normal ranges: $1 \pm 2*0.25 \rightarrow 0.5$ to 1.5
Lognormal ranges: $1 */÷ 1.4^2 \rightarrow 1/1.4^2$ to $1*1.4^2 = 0.51$ to 1.96

Figure 10.8 shows the lognormal standard deviation for SAIFI and SAIDI. Higher numbers for the log standard deviation have higher variability. This graph shows the same trends as the normalized standard deviation: SAIDI has more variability than SAIFI, and excluding major events reduces variability.

10.2.1 Weather Normalization

Weather, even if it does not reach the level of "major event," plays a major role in reliability. Weather varies considerably from year to year—these weather variations directly affect reliability indices. Bad lightning years or excessively hot years worsen the indices.

Monitoring by Ontario Hydro Technologies in Ontario, Canada, gives some insight into storm durations and failure rates (CEA 160 D 597, 1998). In a mild to moderate lightning area, 20% of the interruptions occurred during storm periods and 15% in the 24 hours following a storm. The study area had an average of 25 storm days per year and 73 storm hours per year. Therefore, about 35% of outages occur in 7% of the time in a year (and 20% in 0.8% of the time). The study found an interruption rate during storms of 10 to 20 times the nonstorm rate.

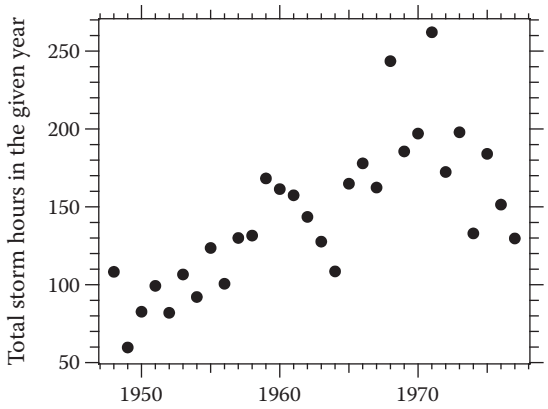

Figure 10.9 Thunderstorm duration by year for Tampa, Florida. (Data from MacGorman, D. R., Maier, M. W., and Rust, W. D., Lightning strike density for the contiguous United States from thunderstorm duration records. Report to the U.S. Nuclear Regulatory Commission, # NUREG/CR-3759, 1984.)

Faults and interruptions have significant year-to-year variation because weather conditions vary significantly. Just as severe storm patterns vary, normal storm frequencies and durations vary. Consider the thunderstorm duration plot in Figure 10.9. Over this 30-year period in Tampa, FL (a very-high-lightning area), some years had less than 80 hours of storms, and a couple of years had more than 240 hours. These are not "severe events," just variations in the normal weather patterns. These storm variations translate into variations in the number of faults and in the reliability indices. Even in areas with lower storm activity, significant variation is possible. Consider these variations if reliability "baselines" are going to be set for performance-based rates. Wind, icing, and temperature extremes all have significant year-to-year variations that directly impact reliability indices. Watch out for a few years of consistent weather; if the data from 1950 to 1955 of Figure 10.9 were used for performance-based rates, we would be in trouble in following years.

The first step in quantifying the effect of weather on interruptions is to track weather statistics along with interruption statistics. Lightning, wind, temperature, and other important weather statistics are available from national weather services as well as private groups, and many statistics have long historical records. Correlations between weather statistics and interruptions can help quantify the variations. Brown et al. (1997) show an example for a feeder in Washington state where wind-dependent failures were analyzed. For this case, they found 0.0065 failures/mi/year/mph of wind speed.

After correlating interruptions with weather data, we can extrapolate how much reliability indices could vary using historical weather data.

An IEEE task force paper (Caswell et al., 2011) has summarized several approaches to normalizing reliability indices to weather variations. One approach to normalizing for weather is to use outage data indications of weather. If a utility uses weather coding for outages, reliability data can be smoothed by excluding outages coded for poor

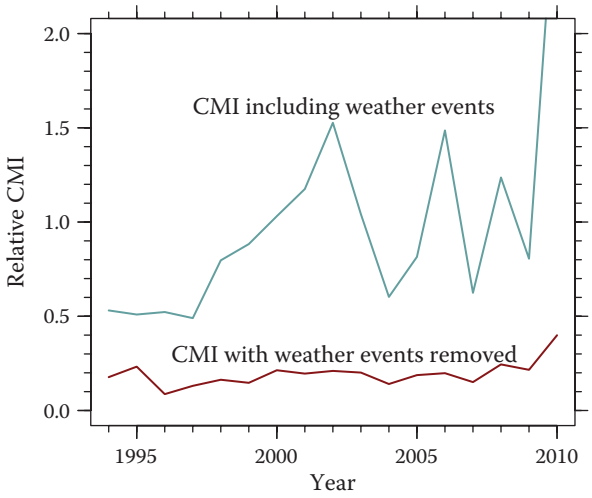

Figure 10.10 Example of normalized CMI with weather causes removed.

weather. Figure 10.10 shows an example for a northeastern U.S. utility that keeps weather codes along with cause codes. With interruptions that have weather codes of significant weather removed, the trend line is much flatter. The data is shown for CMI scaled by the mean yearly value with weather events included.

A modified beta method is another approach that can smooth out variations from weather. Nova Scotia Power Inc. (NSPI) has used a modified beta threshold to further suppress variability (Caswell et al., 2011). The 2.5 beta threshold identifies approximately 2 days annually, and a 2.0 beta threshold identifies on average approximately 6 more days annually. For NSPI, the approach of setting aside the data that exceeds the 2.0 beta threshold eliminated most of the year-to-year variability in the performance statistics, which was the primary objective. The approach also offers the benefits of being nonsubjective, reasonably easy to implement, understandable, and easily communicated.

The use of both 2.5 and 2.0 beta thresholds allows performance data to be stratified for analysis into "base operations," "storm days," and "major event days." Using these thresholds led to good alignment with the levels of storm response under the emergency service restoration plan for NSPI. NSPI averages six "storm" days and two major event days, and these comprise almost all of the days each year on which field crews are operating in one of the emergency service storm response modes.

The IEEE task force evaluated various beta thresholds in a dataset of 49 utilities. From this, the number of days counted for three thresholds is given in Figure 10.11.

If one or more weather parameters significantly correlate with reliability benchmarks, one may attempt to normalize the reliability data to adjust for weather variations. An advantage of directly correlating to weather is that it is possible to judge the performance of the system to weather. If weather parameters are just used to remove the impacts of weather, one might not see the impacts of improvements that become

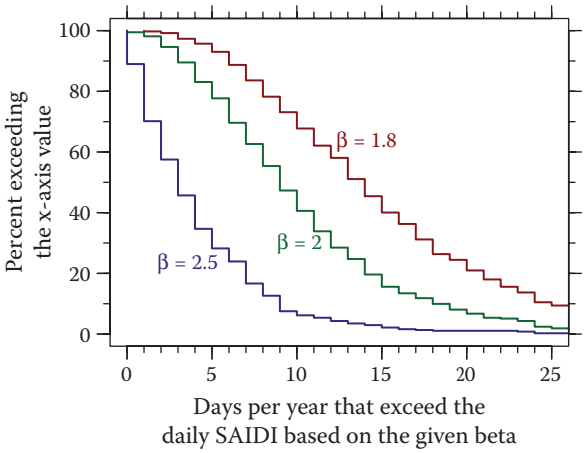

Figure 10.11 Probability distributions of days based on beta thresholds based on IEEE task force data.

prominent during bad weather. For example, a hazard tree-removal program may be most effective under high winds.

Williams (2003) describes a normalization method for Progress Florida for lightning data based on a predicted $SAIFI_W$ and $SAIDI_W$. These normalized parameters are estimated indices based on the given lightning level. They use a linear regression between the monthly correlation between flashes and CI (with animal-caused interruptions removed). For a given month, the CI are predicted from the lightning flash count for that month, and the actual animal-caused interruptions are added. If this predicted value ($SAIDI_W$, for example) is better than the actual value (SAIDI), the system performed better relative to the weather that it is subjected to.

Darveniza et al. (2008) found correlation between daily circuit lockouts and maximum wind gust speed for a utility in south-east Queensland, Australia. The correlation emerges when the maximum gust exceeds 40 km/h. To help normalize to wind, they suggested the concept of a wind severity index (WSI) defined as the sum of the portion of the maximum wind gust that exceeds 40 km/h:

$$\text{WSI} = \sum(\text{mWGSmax} - 40)$$

where mWGSmax is the maximum wind gusts in km/h averaged over a set of monitoring locations.

Zhou et al. (2005, 2006) used regression to study effects of lightning and wind on interruption events on overhead lines.

Using weather data to directly normalize reliability indices is challenging. In moderate- to high-lightning areas, lightning can correlate strongly with reliability, and it is straightforward to use for normalization. Wind has a nonlinear relationship, and correlations are more difficult to obtain.

10.3 Variables Affecting Reliability Indices

10.3.1 Circuit Exposure and Load Density

Longer circuits lead to more interruptions. This is difficult to avoid on normal radial circuits, even though we can somewhat compensate by adding reclosers, fuses, extra switching points, or automation. Most of the change is in SAIFI; the interruption duration (CAIDI) is less dependent on load circuit lengths. Figure 10.12 shows the effect on SAIFI at one utility in the southwest United States.

It is easier to provide higher reliability in urban areas: circuit lengths are shorter, and more reliable distribution systems (such as a grid network) are more economical. The Indianapolis Power & Light survey results shown in Figure 10.13 only

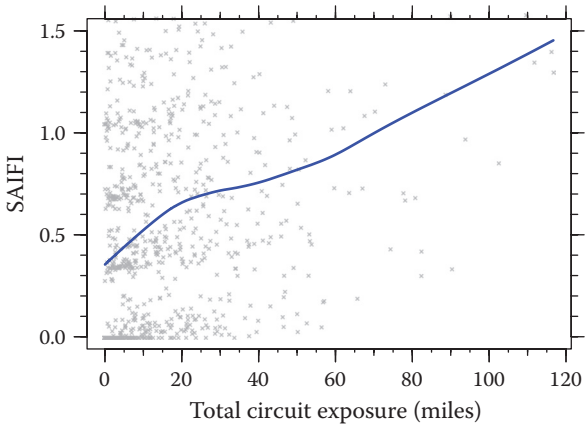

Figure 10.12 Effect of circuit length on SAIFI for one utility in the southwest United States.

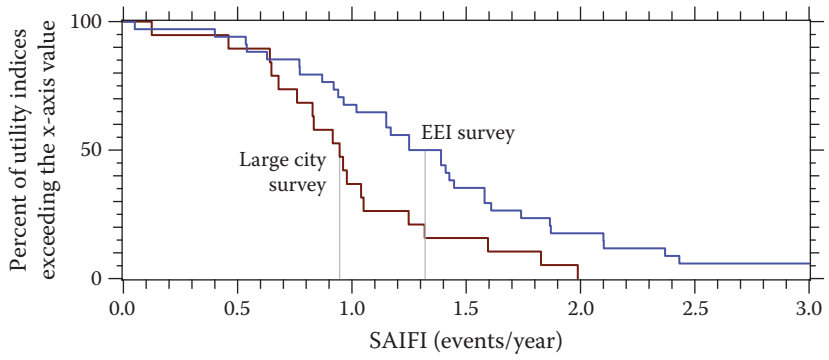

Figure 10.13 Comparison of the Indianapolis Power & Light Large City Survey of SAIFI to the general EEI survey results (with storms excluded). (Data from Indianapolis Power & Light, Comments of Indianapolis Power & Light company to proposed discussion topic, session 7, service quality issues, submission to the Indiana Regulatory Commission, 2000.)

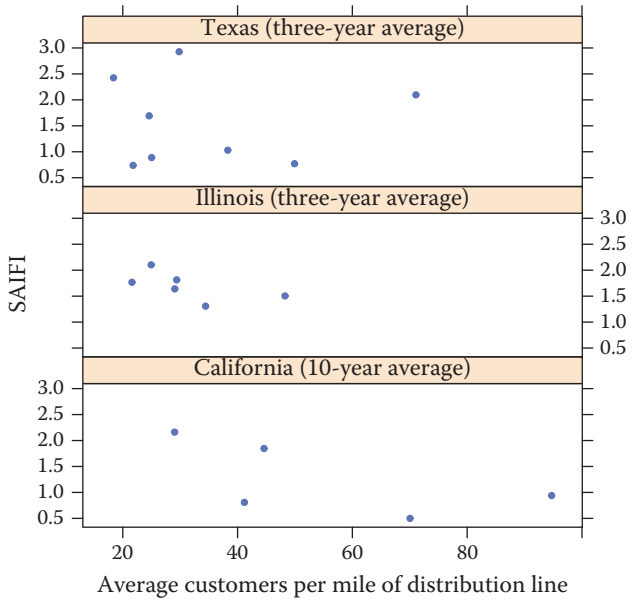

Figure 10.14 Effect of customer density on SAIFI.

included performance of utilities in large cities. As expected, the urban results are better than other general utility surveys. Another comparison is shown in Figure 10.14—in all states, utilities with higher load densities tend to have better SAIFIs.

Figures 10.15 and 10.16 show reliability for different distribution services in several Commonwealth countries. The delineations used for this comparison for Victoria are

- Central business district: used map boundaries
- Urban: greater than 0.48 MVA/mi (0.3 MVA/km)
- Short rural: less than 124 mi (200 km)
- Long rural: greater than 124 mi (200 km)

10.3.2 Supply Configuration

The distribution supply greatly impacts reliability. Long radial circuits provide the poorest service; grid networks provide exceptionally reliable service. Table 10.2 gives estimates of the reliability of several common distribution supply types developed by New York City's Consolidated Edison. Massive redundancy for grid and spot networks leads to fantastic reliability—50 plus years between interruptions. Note that the interruption duration (CAIDI) increases for the more urban configurations. Being underground and dealing with traffic increase the time for repairs.

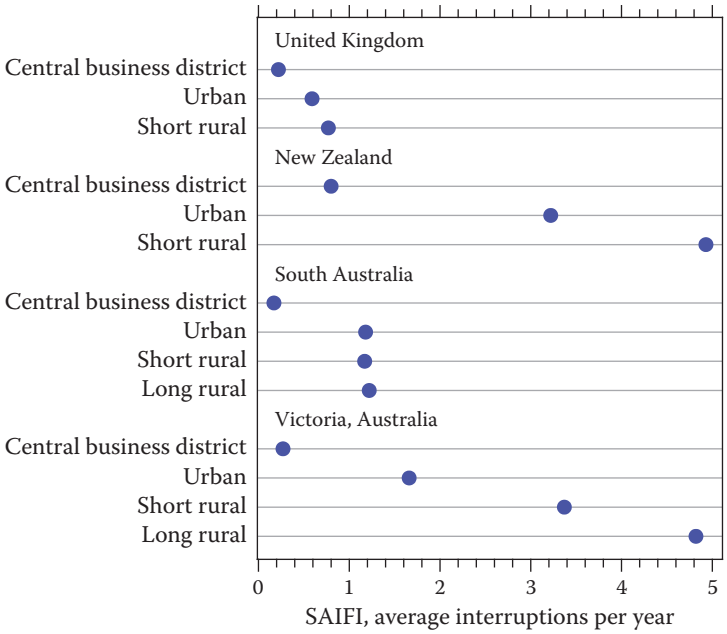

Figure 10.15 Comparison of SAIFI by load density for several former British Empire colonies. (Data from Coulter, R. T., *2001 Electricity Distribution Price Review Reliability Service Standards*, Prepared for the Office of the Regulator-General, Victoria, Australia and Service Standards Working Group, 1999.)

10.3.3 Voltage

Higher primary voltages tend to be more unreliable, mainly because of longer lines. Figure 10.17 shows an example for one utility that is typical of many utilities: higher-voltage circuits have more interruptions.

On higher-voltage primary circuits, we need to make more of an effort to achieve the same reliability as for lower voltage circuits: more reclosers, more sectionalizing switches, more tree trimming, and so forth. With the ability to build much longer lines and serve more customers, it is difficult to overcome the increased exposure. Keeping reliability in mind when planning higher-voltage systems helps. On higher-voltage circuits, wider is better than longer. Burke's analysis (1994) of the service length and width for a generalized feeder shows that for the best reliability, higher-voltage circuits should be longer and wider, not just longer (see Table 10.3). Usually, higher-voltage circuits are just made longer, which leads to poor reliability. Having a long skinny main feeder with short taps off of the mainline results in poor reliability performance.

10.3.4 Correlations and Models

EPRI evaluated a set of utility SAIDI and SAIFI indices to find influential variables and develop regression models based on the most influential variables (EPRI 1010658,

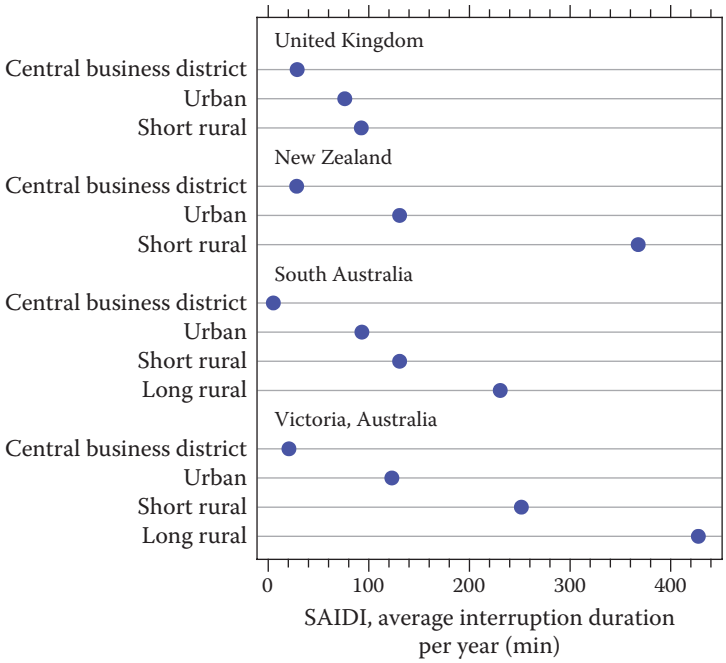

Figure 10.16 Comparison of SAIDI by load density for several former British Empire colonies. (Data from Coulter, R. T., *2001 Electricity Distribution Price Review Reliability Service Standards*, Prepared for the Office of the Regulator-General, Victoria, Australia and Service Standards Working Group, 1999.)

2005). The dataset included 97 operating companies covering 29 states and 13 years with a total of 627 data years in the set. For each operating company, several commonly found variables were used for correlations.

Figure 10.18 shows some of the variables and how they impact SAIFI (major events excluded). Each point in each graph panel shows SAIFI for one year at one utility. Each panel shows plots of a different characteristic (number of customers, overhead

TABLE 10.2 Comparison of the Reliability of Different Distribution Configurations

	SAIFI Interruptions/Year	CAIDI min/Interruption	MAIFI Momentary Interruptions/Year
Simple radial	0.3–1.3	90	5–10
Primary auto-loop	0.4–0.7	65	10–15
Underground residential	0.4–0.7	60	4–8
Primary selective	0.1–0.5	180	4–8
Secondary selective	0.1–0.5	180	2–4
Spot network	0.02–0.1	180	0–1
Grid network	0.005–0.02	135	0

Source: Settembrini, R. C., Fisher, J. R., and Hudak, N. E., Reliability and quality comparisons of electric power distribution systems, *IEEE Power Engineering Society Transmission and Distribution Conference*, 1991. © 1991 IEEE.

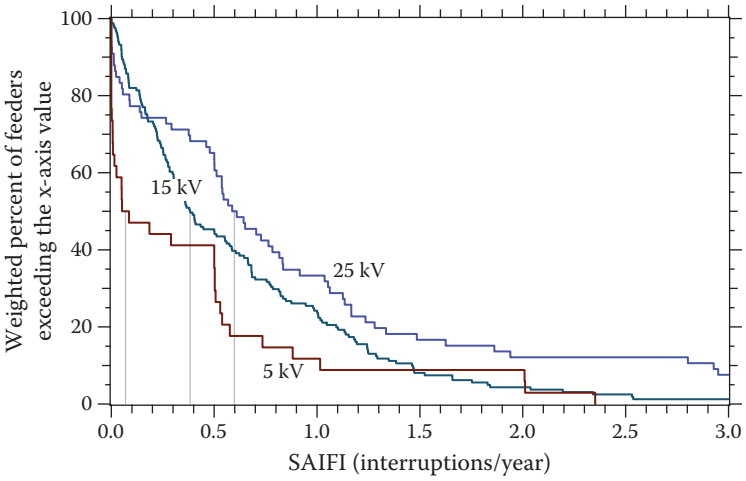

Figure 10.17 Effect of circuit voltage on SAIFI for one utility in the southern United States.

line miles, and so on). Each panel also shows a linear curve fit and a correlation coefficient (r) in the upper left corner. As expected, there is wide dispersion. The strongest correlations are with load density and with the proportion of assets that are overhead. There is surprisingly little correlation with lightning.

Figure 10.19 shows correlations for SAIDI with major events excluded. The correlations tend to follow similar patterns as SAIFI.

Using the most influential variables can be used with statistical regression techniques to try and determine which variables most impact SAIFI and SAIDI. These models are also useful for predicting what range of SAIFI and SAIDI to expect for a utility with certain characteristics.

SAIFI is most strongly influenced by some combination of load density and the division between overhead and underground circuits. The best model for SAIFI with major events excluded was a linear model of the form:

$$\text{SAIFI}_{\text{without major events}} = 1.08 + 7.51\frac{l_{\text{OH}}}{N_{\text{cust}}} - 21.8\frac{l_{\text{UG}}}{N_{\text{cust}}}$$

TABLE 10.3 Mainline Lengths and Lateral Lengths for Optimal Reliability (Assuming a Constant Load Density)

Voltage, kV	Main Feeder Length, mi	Lateral Length, mi	Ratio of Main Feeder to Lateral Tap Length
13.8	1.51	0.95	1.59
23	1.81	1.32	1.37
34.5	2.09	1.71	1.22

Source: Adapted from Burke, J. J., *Power Distribution Engineering: Fundamentals and Applications*, Marcel Dekker, New York, 1994.

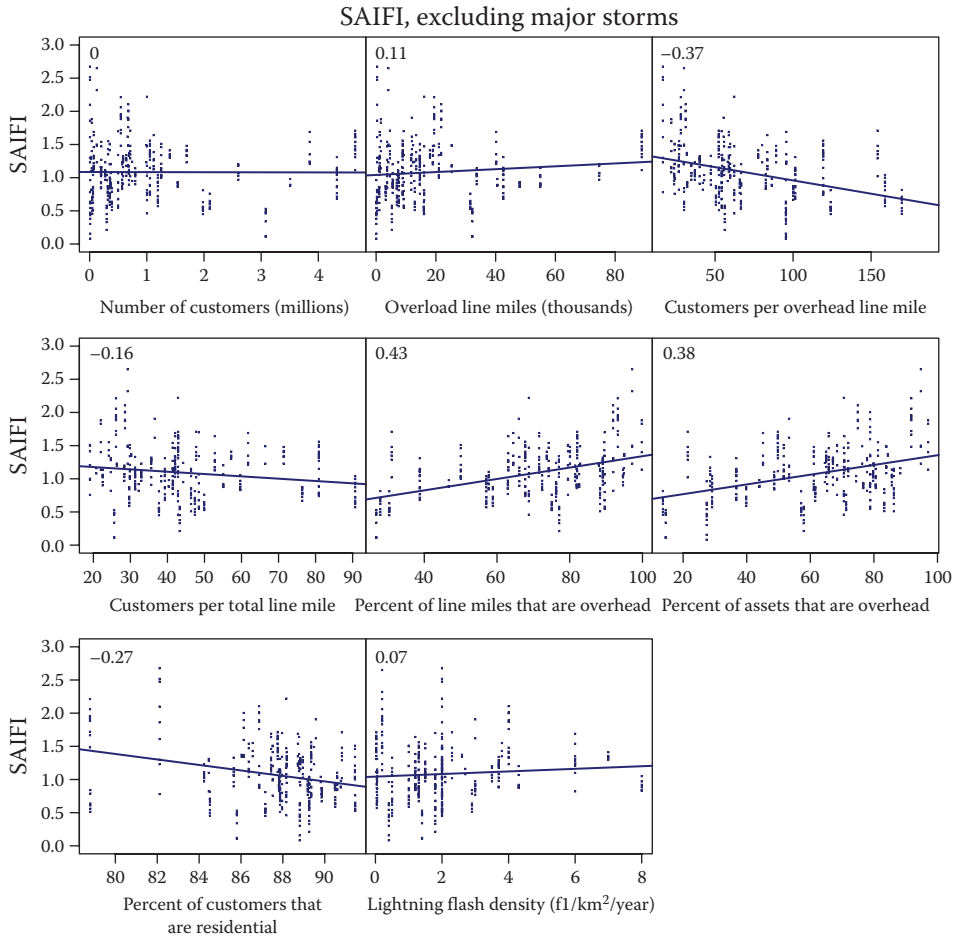

Figure 10.18 Variables impacting SAIFI. (From EPRI 1010658, *Distribution Reliability Trends and Correlations*, Electric Power Research Institute, Palo Alto, CA, 2005. Copyright 2005. Reprinted with permission.)

Lower and upper quartiles = 0.82 and 1.20 per unit

where

l_{OH} = system overhead line miles
l_{UG} = system underground line miles
N_{cust} = number of customers

This model is based on a gamma distribution that skews to the right, like a lognormal distribution. Because of the skew, the lower and upper quartiles are not symmetric around the prediction. This is an important consideration for predictions. This prediction for SAIFI is the expected median for a utility with the given characteristics. In general, we use the median to characterize or compare the effects of parameters. As an indicator, the average or mean misrepresents the typical index. The median represents reliability data better, where, by definition, 50% of utilities have values higher

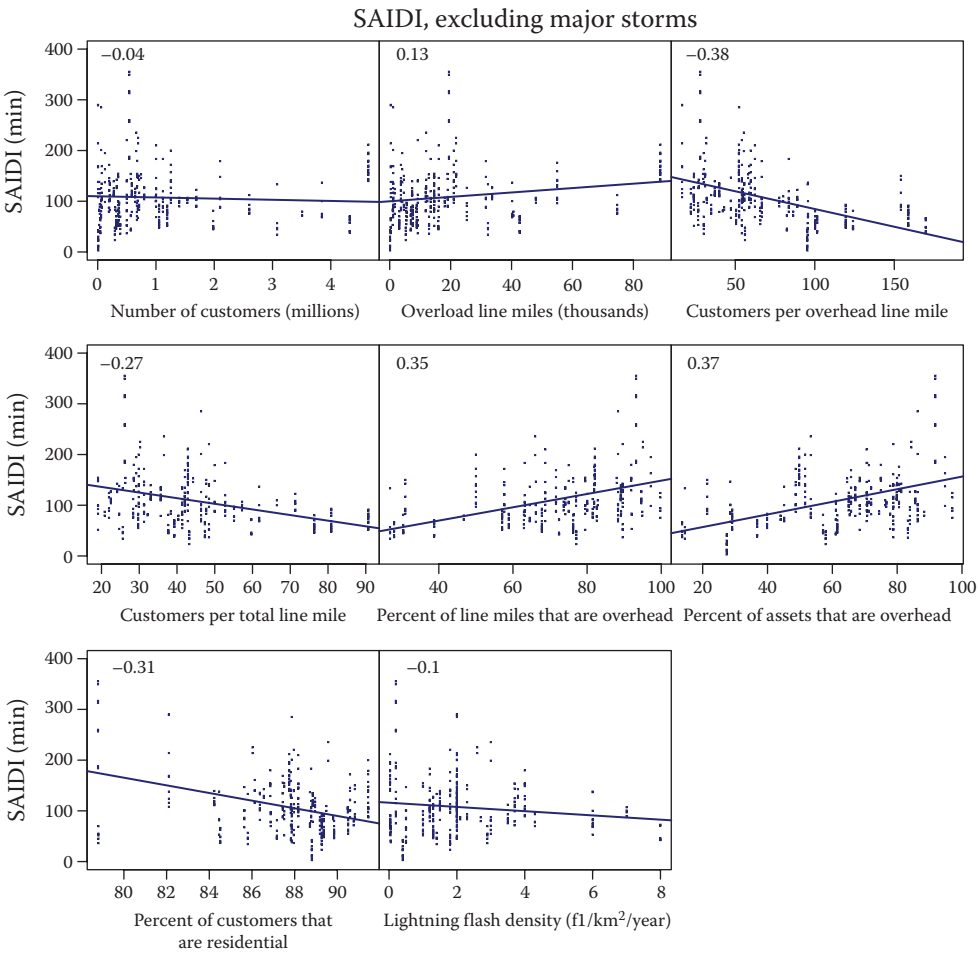

Figure 10.19 Variables impacting SAIDI. (From EPRI 1010658, *Distribution Reliability Trends and Correlations*, Electric Power Research Institute, Palo Alto, CA, 2005. Copyright 2005. Reprinted with permission.)

than the median, and 50% have values lower. With balanced distributions such as the normal distribution, the average equals the median. In a skewed distribution like we see with reliability data, the average is higher than the median. Additionally, poor sites and anomalies such as a severe storm skew the average upward. The upper and lower quartiles (25% and 75%) are also given in per unit. The SAIFI results are only slightly skewed.

Consider the following example on how to interpret this formula. If a fictitious urban utility has 2,000,000 customers, 16,000 overhead line miles, and 36,000 underground line miles, the predicted median SAIFI (major events excluded) is

$$\text{SAIFI}_{\text{without major events}} = 1.08 + 7.51\frac{16{,}000}{2{,}000{,}000} - 21.8\frac{36{,}000}{2{,}000{,}000} = 0.75$$

That means for all utilities with these site characteristics, one would expect that half of the time, the utility median would be above 0.75 and half the time, the site median would be below 0.75. It is really the median of the utility medians. Further, 25% of such utilities would have a median that is less than 0.75*0.82 = 0.62, and 25% of such utilities would have a median that is more than 0.75*1.20 = 0.9. One could also compare how the performance during a given year compared to these quartile boundaries.

Figure 10.20 shows how well this model for SAIFI (without major events) performs with the data used to develop the models. Note the high degree of variability in the predictions—these are not precise estimates, but they do well in predicting observations within a given prediction band. They are most useful in establishing more realistic ranges within which a utility of a given load density and overhead/underground split will be expected to operate.

For SAIFI that includes major events, the best model was of a similar form but with different coefficients:

$$\text{SAIFI}_{\text{with major events}} = 1.37 + 12.7\frac{l_{\text{OH}}}{N_{\text{cust}}} - 33.3\frac{l_{\text{UG}}}{N_{\text{cust}}}$$

Lower and upper quartiles = 0.78 and 1.26 per unit.

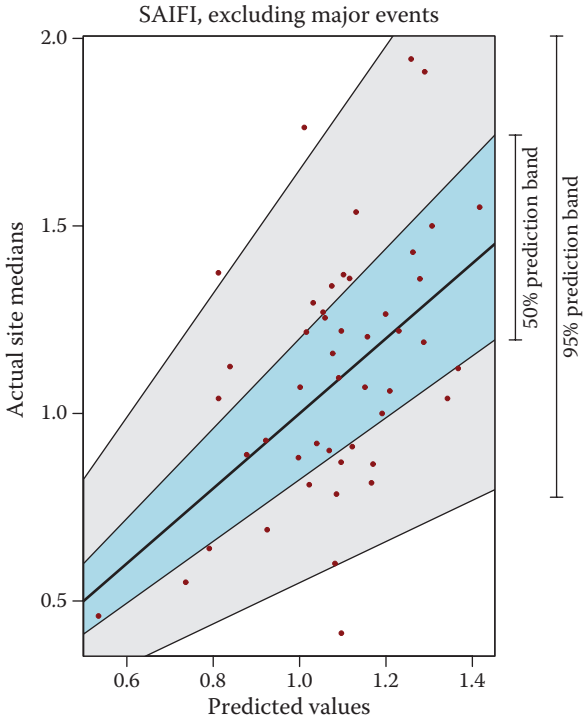

Figure 10.20 Performance of the prediction model for SAIFI. (From EPRI 1010658, *Distribution Reliability Trends and Correlations*, Electric Power Research Institute, Palo Alto, CA, 2005. Copyright 2005. Reprinted with permission.)

The SAIDI models differed somewhat in form from the SAIFI models, even though the most significant variables were still the overhead and underground lengths and number of customers. The best model found for SAIDI with major events excluded is

$$\text{SAIDI}_{\text{without major events}} = 55.2 + 1988\frac{l_{\text{OH}}}{N_{\text{cust}}} \quad \text{(in minutes)}$$

Lower and upper quartiles = 0.74 and 1.32 per unit.

For SAIDI that includes major events, the best model is

$$\text{SAIDI}_{\text{with major events}} = 371 - 0.00269l_{\text{UG}} - 3.34\frac{N_{\text{cust}}}{l_{\text{OH}} + l_{\text{UG}}} \quad \text{(in minutes)}$$

Lower and upper quartiles = 0.49 and 1.79 per unit.

The SAIDI models showed more variability than the SAIFI models as noted by the wider quartile bounds.

Many important variables were not included in this evaluation, including system voltage levels, level of automation, outage management systems (or lack thereof), and tree exposure and tree pruning cycles. Because so many important characteristics are unavailable, it is not possible to have a precise accounting for the impact of all major variables. The best we can do is a first-level assessment based on readily available information.

10.3.5 Long-Term Reliability Trends

Utilities rarely have very long-term data covering decades. The Canadian Electrical Association has tracked reliability data for many years. Figure 10.21 shows SAIDI over a 40-year period for Canada. Significant variation exists from year to year. Part of this is due to the changing nature of the survey (the utility base was not consistent for the whole time period). Much of the variation is due to weather, even though the survey covers a huge geographic area (we expect more variations for smaller geographic areas). The data includes storms. Extreme years stand out. The worst year was 1998, which was dominated by the ice storm that hit Ontario and Quebec. Over 1.6 million customers lost power; Hydro Quebec's SAIDI for the year was almost 42 hours when it is normally less than 4 hours.

Overall, the reliability trend is somewhat worsening. The main factor is probably the gradual move to higher-voltage distribution circuits and suburbanization. These trends lead to longer circuits and more exposure, although better record keeping (outage management systems) may be making SAIDI appear worser relative to earlier approaches because interruptions are recorded more accurately.

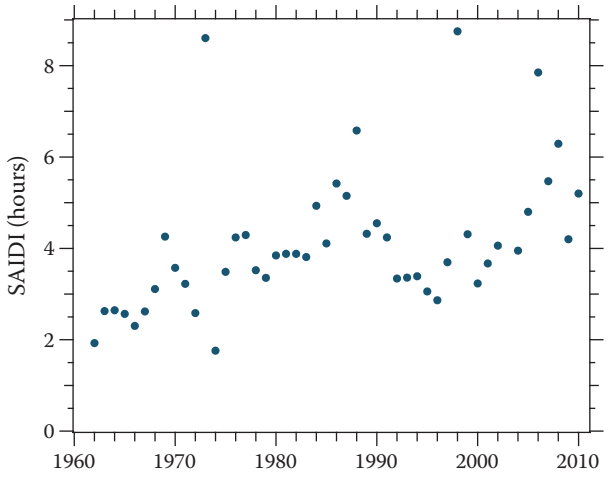

Figure 10.21 Yearly SAIDI for Canada. (Data from Billinton, R., Comprehensive indices for assessing distribution system reliability, *IEEE International Electrical, Electronics Conference and Exposition*, 1981; Billinton, R., 2002. Personal communication; CEA, *CEA 2000 Annual Service Continuity Report on Distribution System Performance in Electric Utilities*, Canadian Electrical Association, 2001; CEA, *Sustainable Electricity Annual Report*, Canadian Electrical Association, 2010.)

10.4 Circuit Configurations

10.4.1 Modeling Radial Distribution Circuits

On purely radial circuits, the customers at the ends of the circuits unavoidably have the poorest reliability. On radial circuits, we can analyze the reliability using series combinations of individual elements. If any series component between the station and the customer fails, the customer loses power.

Series elements can be combined as

$$\lambda_S = \lambda_1 + \lambda_2 + \cdots + \lambda_n$$
$$U_S = U_1 + U_2 + \cdots + U_n = \lambda_1 r_1 + \lambda_2 r_2 + \cdots + \lambda_n r_n$$
$$r_S = \frac{U_S}{\lambda_S}$$

where

λ = failure rate, normally in interruptions per year
U = unavailability (total interruption time), normally in per unit, %, or h or min per year
r = average repair time per failure normally in per unit/year, %/year, or h or min

The subscript S is the total of the series combination, and the subscripts 1,2,. . .,n indicate the parameters of the individual elements.

The failure rate λ is analogous to SAIFI, U is analogous to SAIDI, and r is analogous to CAIDI.

We can use these basic reliability predictions to estimate reliability indices for radial circuits. Calculations quickly become complex if we try to account for sectionalizing or have circuits with parallel elements or backfeeds. Reliability analysis programs are available to model circuits with inputs similar to a load-flow program, except that switch characteristics are included as well as fault and equipment failure rates. Fault rates are the inputs most difficult to estimate accurately. These vary widely based on local conditions and construction practices.

With a given circuit configuration and SAIFI and MAIFI records for the circuit, Brown and Ochoa (1998) provide a way to back-estimate fault rates. For a given circuit configuration, the temporary and permanent fault rates are varied until the reliability prediction for a given circuit matches historical records. Once the failure rates are established, we can more accurately evaluate circuit changes such as automated switches.

10.4.2 Parallel Distribution Systems

To dramatically improve reliability for customers, parallel distribution supplies are needed. We see many forms of redundant distribution systems: auto-looped primary distribution circuits with redundant paths, primary or secondary selective schemes with alternate supplies from two feeders, and spot or grid networks of several supply feeders with secondaries tied together. Analyzing the reliability of these interconnected systems is difficult. Several analytical techniques are available, and some are quite complicated.

With several components in series and parallel, we can find the failure rates and durations by reducing the network using the series or parallel combination of elements.

Parallel elements are combined with

$$\lambda_P = \frac{U_P}{r_p}$$

$$U_P = U_1 \times U_2 \times \cdots \times U_n = \lambda_1 \times \lambda_2 \times \cdots \times \lambda_n \times r_1 \times r_2 \times \cdots \times r_n$$

$$r_P = \frac{1}{1/r_1 + 1/r_2 + \cdots + 1/r_n}$$

for $n = 2$,

$$\lambda_P = \frac{U_P}{r_p} = \lambda_1 U_2 + \lambda_2 U_1 = \lambda_1 \lambda_2 (r_1 + r_2)$$

The subscript P is the total of the parallel combination. Note that the units must be kept the same: λ has units of 1/years, so the repair time, r, must be in units of years. Normally, this means dividing r by 8760 if r is in hours or 525,600 if r is in minutes.

Including parallel elements is more complicated than series elements. The above equations are actually approximations that are valid only if the repair time is much less than the MTBF. This is generally true of distribution reliability applications (and more so for high-reliability applications).

The main problem with the equations representing the parallel combination of elements is that they are wrong for real-life electric supply reliability with multiple sources. A good illustration of this is from the data of the reliability of the utility supply found in a survey published in the *Gold Book* (IEEE Std. 493-1997). The average reliability of single-circuit supplies in the *Gold Book* has the following failure rate and repair time:

$$\lambda = 1.956 \text{ failures/year}$$
$$r = 79 \text{ min}$$

If a system were supplied with two parallel sources with the above failure rate characteristics, one would expect the following failure rates according to the ideal equations:

$$\lambda_p = (1.956)(1.956)(79 + 79)/525600 = 0.00115 \text{ failures/year}$$
$$r_p = 1/(1/79 + 1/79) = 39.5 \text{ min}$$

The actual surveyed reliability of circuits with multiple supplies is

$$\lambda = 0.538 \text{ failures/year}$$
$$r = 22 \text{ min}$$

Another set of data for industrial supplies is shown in Figure 10.22 for the reliability of transmission supplies of Alberta Power. In this case, interruptions were defined as taking place for longer than 1 min. As with the *Gold Book* data, the multicircuit Alberta Power supplies had better reliability than single-circuit supplies, but not by orders of magnitude. Single-circuit supplies had a 5-year average SAIFI of 0.9

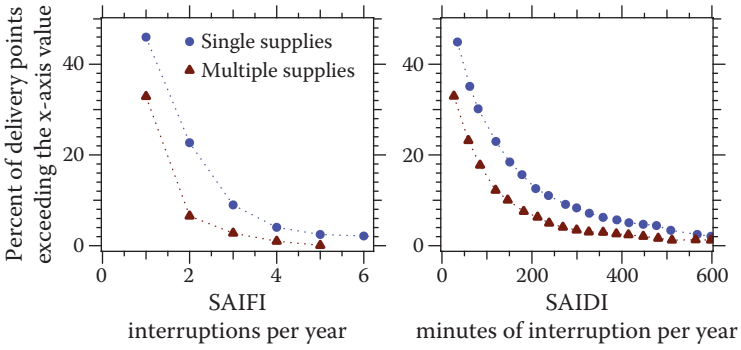

Figure 10.22 Comparison of single and multiple circuits for transmission supply. (Data from Chowdhury, A. A., and Koval, D. O., *IEEE Transactions on Industry Applications*, vol. 32, no. 6, pp. 1440–8, November/December 1996.)

interruptions per year (and SAIDI = 70 min of interruption/year). Multicircuit supplies had a 5-year SAIFI of 0.42 interruptions per year (and SAIDI = 35 min of interruption/year). This information also helps show distribution engineers the number of transmission failures.

The failure rates with multiple circuits are reduced, but they are nowhere near the predicted value that is orders of magnitude lower. The reason the calculations are wrong is that the equations assume that the failures are totally independent. In reality, failures can have dependencies. The major factors are that

- Facilities share common space (utilities run two circuits on one structure)
- Separate supplies contain a common point upstream
- Failures bunch together during storms
- Maintenance must be considered
- Hidden failures can be present

Also, parallel supplies in many cases contain endpoint equipment that is not paralleled, including transformers, buswork, breakers, and cables.

It is possible to analytically model each of these effects. The problem is that much of the necessary input data is unknown, so many "educated" guesses are needed. For example, to analytically handle storm failures, one needs to find a storm failure rate and the duration of storms (both these numbers are hard to come by).

It is common for multiple transmission and distribution circuits to be run on the same structures (and to be in proximity in underground facilities). If a car knocks down a pole with two circuits, both are lost. Lightning often causes multiple interruptions on structures with multiple circuits. There is also common space at the endpoint where the circuits are brought together at the customer. If there is a fire in the basement electrical room of a building with a spot network, the building will lose power.

Cable circuits are susceptible to a different type of outage bunching caused by overload failures. Cables are more sensitive to thermal overloads than are overhead lines. During high load, multiple cables can fail from overloads at the same time (and if one cable fails, the load on the others increases to make up the difference).

If a customer is supplied with two utility feeds off different feeders, the common point may be the distribution substation transformer. If the transformer or subtransmission circuit fails, both distribution feeders are lost simultaneously.

We can model common-mode failures of parallel supplies with the following equations:

$$\lambda_P = \lambda_1\lambda_2(r_1 + r_2) + \lambda_{12}$$

$$r_P = \frac{\lambda_1\lambda_2 r_1 r_2 + \lambda_{12} r_{12}}{\lambda_P}$$

where λ_{12} and r_{12} are the frequency and repair time of the common-mode failures. The effect of common-mode failures is dramatic. If they are 10% of the individual failure rates, the common-mode failures dominate and degrade the parallel-combination failure rate.

One of the main problems is that there is little data on the common-mode failure rate of utility circuits (especially distribution circuits; some data is available for transmission circuits).

Failures requiring long-duration repair times are a special case with significant impacts. If something fails and takes 2 months to repair or replace, the system is much more vulnerable to failures during the maintenance. Long-duration repairs also violate the approximation that the repair time is much less than the MTBF, so the normal parallel and series combination equations are in error.

Also, on systems with redundancy, human nature acts to reduce the redundancy by increasing the repair time. Repairs generally take longer because people do not feel the urgency to make the repair. If sites are without power because of a failure, there are direct, immediate consequences. With redundancy, if a failure in one component occurs, the consequences are indirect (an increase in the likelihood of failure), so repair is not as urgent. If a network primary cable fails, customers are not without power, so crews have less urgency to repair the cable.

Failures due to lightning, wind, and rain occur during storms, and the failure rate during storms is much higher than normal. Since storms are a small portion of the total time, storm interruptions are bunched together, which dramatically raises the possibility of overlapping outages. Billinton and Allan (1984) provide ways to model the effects of storm bunching, and some reliability programs model these effects.

Hidden failures do not immediately show up or show up only when a failure occurs. Some examples might include the following:

- If a customer is served with a primary selective scheme, but the transfer switch is not working, the failure remains hidden until the switch is called upon to operate.
- A five-feeder grid network was originally designed to be able to lose two feeders and still serve the load. Subsequent load growth has reduced the redundancy so that four feeders must be on-line to handle the load. If more than one feeder is lost due to a failure and/or maintenance, the load could have an interruption.

Hidden failures are difficult to track down. In a parallel distribution system, the redundancy can mask failures. Protective equipment and diagnostics equipment that can isolate or identify failures is especially helpful in reducing hidden failures.

Hidden failures are difficult to model because they are obviously hidden. Hidden failures violate the assumption that the repair time is much shorter than the MTBF. This makes it difficult to use the equations listed above for parallel and series connections to analyze hidden failures. Finally, data on hidden failures is very limited.

When designing a redundant distribution system to one or more customers, consider these strategies that help reduce the possibility of overlapping failures:

- *Common space*—Limit sharing of physical space as much as possible. For services with multiple sources—primary or secondary selective schemes—try to use circuits that do not share the same poles or even right of ways. Use circuits that originate out of different distribution substations.
- *Storms*—Using underground equipment helps reduce the possibility of overlapping storm outages (although cables have their own bunched failures from overloads).

- *Maintenance*—Coordinate maintenance as much as possible to limit the loss of redundancy during maintenance. Try to avoid maintenance during stormy weather including heat waves for cables.
- *Testing*—Test switches, protective devices, and other equipment where hidden failures may lurk.
- *Loadings*—Review loadings periodically to ensure that overloads are not reducing designed redundancy.

10.5 Sectionalizing and Automation

Fuses, sectionalizing switches, reclosers, sectionalizers—more, more, more—the more we have, the more we isolate faults to smaller chunks of circuitry, the fewer customers we interrupt.

Taps are almost universally fused, primarily for reliability. Fuses make cheap fault finders. Planners should also try to design to have tap exposure, not too much and not too little. We want to have a high percentage of a circuit's exposure on fused taps, so when permanent faults occur on those sections, only a small number of customers are interrupted.

If taps become too long, use reclosers instead of fuses. Especially for circuits that fan out into two or three main sections (really like having two or three mainlines), reclosers on each of the main sections help improve reliability.

How circuits are protected and coordinated impacts reliability (see Chapter 9). Fuse saving, where the station breaker trips before tap fuses to try to clear temporary faults, helps long-duration interruptions most (but causes more momentary interruptions). Fuse blowing causes more long-duration interruptions because the fuse always blows, even for temporary faults.

Mainline reclosers also help improve reliability. Table 10.4 compares different scenarios for a common feeder with the following assumptions: 5-mi mains, 15 total mi of exposure, 0.3 permanent faults/mi/year, 0.6 temporary faults/mi/year, fused laterals average 0.5 mi, and customers are evenly distributed along the main line and taps. Mainline faults contribute most to SAIFI (1.5 interruptions per year). If the system were not fused at all, it would have 4.5 interruptions per year, pointing out the great benefit of the fuses. Branch-line faults only contribute an average of 0.15 interruptions with fuse saving (assuming fuse saving works right). This is an

TABLE 10.4 Example Reliability Improvement Calculations

	SAIFI	MAIFI
Base case, fuse saving	5(0.3) + 0.5(0.3) = 1.65	5(0.5) + 10(0.9) = 12
Base case, fuse blowing	5(0.3) + 0.5(0.9) = 1.95	5(0.6) = 3
One recloser, fuse blowing	(1.95 + 1.95/2)/2 = 1.46	(3 + 3/2)/2 = 2.25
Three-recloser auto-loop, fuse blowing	1.95/2 = 0.98	(3 + 3/2)/2 = 2.25
Five-recloser auto-loop, fuse blowing	1.95/3 = 0.65	(3 + 2 + 1)/3 = 2

Note: 5-mi mains, 15 total mi of exposure, 0.3 permanent faults/mi/year, 0.6 temporary faults/mi/year, fused laterals average 0.5 mi, customers are evenly distributed along the mainline and taps.

average; some customers on long taps have many more interruptions due to branch-line faults (these are good candidates for reclosers instead of fuses). On a purely radial system, reclosers do not help customers at the end of the line. An auto-loop scheme helps the customers at the ends of the line and significantly improves the feeder reliability indices.

This example only includes distribution primary interruptions. Supply-side interruptions and secondary interruptions should also be added as appropriate.

Sectionalizing switches can significantly improve SAIDI and CAIDI (but not SAIFI, unless the switches are automated). Such switches enable crews to easily re-energize significant numbers of customers well before they fix the actual damage. As Brown's analysis (2009) shows, the biggest gains are with the first few switches. CAIDI for mainline faults reduces in proportion to the difference between the mean time to repair (t_{repair}) and the mean time to switch (t_{switch}). With evenly spaced switches and customers on a radial circuit with no backfeeds, CAIDI reduces with increasing numbers of sectionalizing switches as

$$t_{saved} = \frac{\sum_{i=1}^{n} i}{(n+1)^2}(t_{repair} - t_{switch})$$

where

t_{saved} = reduction in CAIDI, in the same units as t_{repair} and t_{switch}
n = number of sectionalizing switches on the mainline
t_{repair} = time to repair the damage (the original CAIDI)
t_{switch} = time to operate the sectionalizing switch

The new CAIDI equals t_{repair} ⊠ t_{saved}. On a radial circuit, the improvement is not distributed equally; switches do not help customers at the end of the line at all. If a circuit has two evenly spaced sectionalizing circuits, the customers on the last part of the circuit see no improvement, the middle third see improvement for faults on the last third of the circuit, and the third at the front see improvement for faults on the last two-thirds of the circuit.

If the circuit has a backfeed from another circuit, the improvement is equal for all customers, so the overall circuit CAIDI improves. For evenly spaced switches and customers, the reduction is

$$t_{saved} = \frac{n}{n+1}(t_{repair} - t_{switch})$$

Figure 10.23 shows how much sectionalizing switches can reduce CAIDI for the portion due to faults on the main line. The first switches provide the biggest bang for the buck. Beyond five switches, improvement is marginal. For application on real feeders (where the loads are not evenly placed), for biggest gains on radial circuits, place switches just downstream of large blocks of customers. If a circuit has a branch line with many customers, a mainline sectionalizing switch just downstream of the

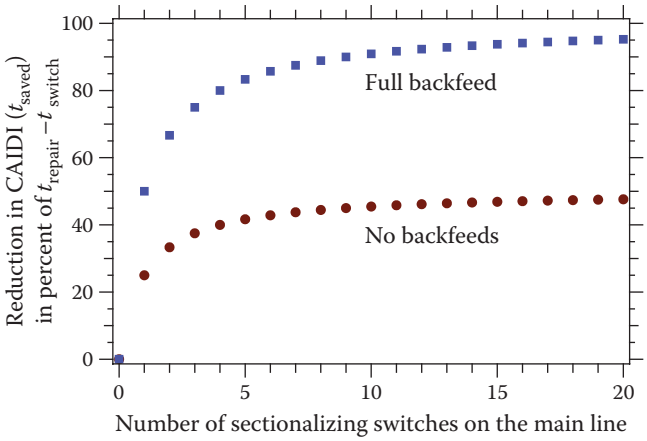

Figure 10.23 Reducing interruption durations with normally closed sectionalizing switches on the mainline.

tap point allows crews to sectionalize that big block of customers for faults downstream of the switch.

The mean time to switch (t_{switch}) includes the time for the crew to get to the circuit, the time they need to find the fault, the time to find and open the appropriate sectionalizing switch, and finally the time to close the tripped breaker or recloser. Typically, t_{switch} is about 1 h. The mean time to repair (t_{repair}) is the time to travel to the circuit, find the fault, repair the damage, and close in the appropriate switching device to reconnect customers. The repair time varies widely—4 h is a good estimate; actual repairs regularly range from 2 to 8 h.

Crews should decide whether to sectionalize based on local conditions. What is damaged? How long will it take to fix? How many customers would sectionalizing bring back? Where are the sectionalizing switches? How long will it take to sectionalize the circuit? Sometimes, crews can start sectionalizing before the fault is found. If crews patrol a circuit section and do not see damage, they can open a sectionalizing switch and reclose the station breaker before they continue looking for the fault downstream.

Automation provides options for improving the reliability of the distribution supply. An auto-loop automated distribution configuration is a popular way to improve reliability on a normally radial circuit. These systems automatically reconfigure a distribution system: we do not need outside intervention or communications. In the three-recloser loop example in Figure 10.24, a normal sequence of operations for a fault upstream of recloser R1 is (1) breaker B1 senses the fault and goes through its normal reclosing cycle and locks open; (2) recloser R1 senses loss of voltage and opens; and (3) recloser R2, the tie recloser, senses loss of voltage on the feeder and closes in. Since R2 can be switching into a fault, normally it is set for one shot; if the fault is there, it trips and stays open.

We can add more reclosers to divide the loop into more sections, but coordination of all of the reclosers is harder. Consider a five-recloser loop (Figure 10.25). Each

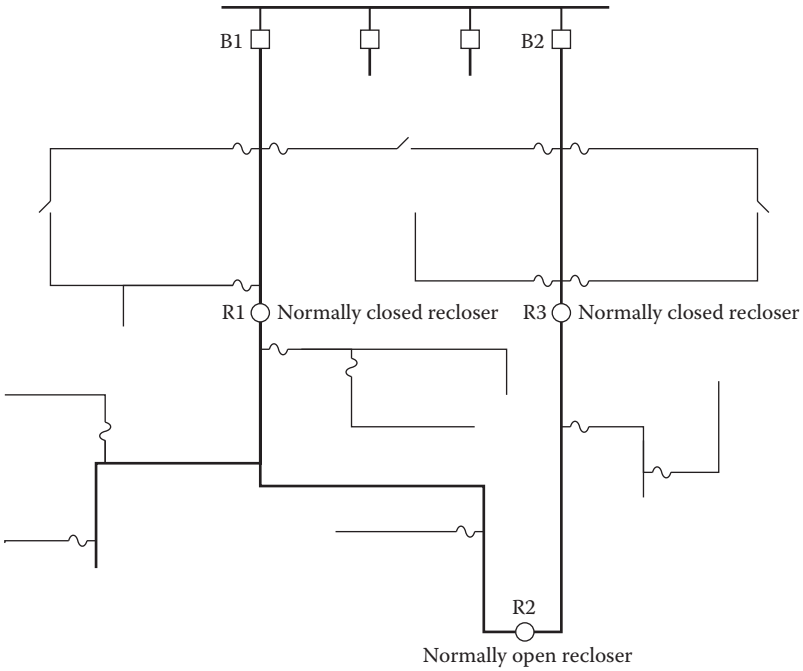

Figure 10.24 Example of an automated distribution feeder.

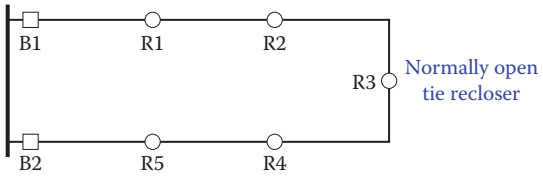

Figure 10.25 Five-recloser automated loop.

feeder has two normally closed reclosers, and there is a normally open tie-point recloser. If feeder #1 is faulted close to the substation, breaker B1 locks out, recloser R1 opens, and the tie recloser closes. Now, we have a long radial circuit with the station breaker in series with four reclosers—that is a lot to try to coordinate. To ease the coordination, some reclosers can lower their tripping characteristics when operating in reverse mode. So, in this example, recloser R2 would drop its pickup setting. R2 sees much lower fault currents than it usually does, and we want it to trip before recloser R3 or R4.

For a fault between B1 and R1, the five-recloser loop responds similarly to a three-recloser loop: (1) breaker B1 locks out, (2) R1 opens on loss of voltage, (3) recloser R2 drops its trip setting, and (4) R3 senses loss of voltage on feeder 1 and closes in. For a fault between R1 and R2, the sequence is more complicated: (1) recloser R1 locks out, (2) recloser R2 drops its trip setting and goes to one shot until lockout, (3) R3 senses loss of voltage on feeder 1 and closes in (and closes in on the fault), and (4) R2

trips in one shot due to its lower setting. In a variation of this scheme, utilities use sectionalizers instead of reclosers at positions R2 and R4. Sectionalizers are easier to coordinate with several devices in series.

Remotely controlled switches are another option for automating a distribution circuit. The preferred communication is radio. Remotely controlled switches are more flexible than auto-loop schemes because it is easier to apply more tie points and we do not have to worry about coordinating protective equipment. Most commonly, operators decide how to reconfigure a circuit.

Even if a circuit is automated, doing another step of sectionalizing within the isolated section can squeeze out better reliability. Brown and Hanson (2001) show that manually sectionalizing after automated switches have operated can reduce SAIDI by several percent. As with other sectionalizing, crews should decide on a case-by-case basis whether to sectionalize.

Auto-loops will not necessarily help with momentary interruptions. Automation turns long-duration interruptions into momentary interruptions. To help with momentary interruptions, consider the following enhancements to automation schemes:

- *Line reclosers*—As part of an automated loop, line reclosers significantly improve momentaries; automated switches do not. Using single-phase reclosers helps interrupt fewer customers.
- *Tap reclosers*—Use reclosers on long lateral taps. Consider single-phase reclosers on three-phase taps. These will interrupt fewer customers.

10.6 Reliability Programs

We have many different methods of improving reliability, including

- *Reduce faults*—tree maintenance, tree wire, animal guards, arresters, circuit patrols
- *Find and repair faults faster*—faulted circuit indicators, outage management system, crew staffing, better cable fault finding
- *Limit the number of customers interrupted*—more fuses, reclosers, sectionalizers
- *Only interrupt customers for permanent faults*—reclosers instead of fuses, fuse saving schemes

Whether we are trying to improve the reliability on one particular circuit or trying to raise the reliability system wide, the main steps are

1. Identify possible projects
2. Estimate the cost of each configuration or option
3. Estimate the improvement in reliability with each option
4. Rank the projects based on a cost–benefit ratio

Prediction of costs is generally straightforward; predicting improvement is not. Some projects are difficult to attach a number to.

An important step in improving reliability is defining what measure to optimize: is it SAIFI, SAIDI, some combination, or something else entirely? The ranked projects

change with the goal. Surveys have shown that the frequency of interruptions is most important to customers (until you get to very long interruptions). Regulators tend to favor duration indicators since they are more of an indicator of utility responsiveness, and excessive cost cutting might first appear as a longer response time to interruptions.

Detailed analysis and ranking of projects can be done on a large scale. Brown et. al. (2001) provide an interesting example of applying reliability modeling to Commonwealth Edison's entire distribution system in Illinois to rank configuration improvements. Normally, large-scale projects require simplification (and often a good bit of guesswork).

Adding reclosers, putting in more fusing points, automating switches—these configuration changes are predictable. Many computer programs will quantify these improvements. Projects aimed at reducing the rates of faults, such as pruning more trees, adding more arresters, installing squirrel guards, are difficult to quantify. Improving fault-finding and repair are also more difficult to quantify. A sensitivity analysis helps when deciding on these projects. In the simplest form, rather than using one performance number, use a low, a best guess, and a high estimate. Pinpointing fault causes also helps frame how much benefit these targeted solutions can have (if there are few lightning-caused faults, additional arresters will provide little benefit).

An obvious approach to reliability improvement is to reduce the number of faults. In addition to long-duration interruptions, this strategy reduces the number of voltage sags and momentary interruptions and makes the system safer for workers and the public.

On-site investigations of specific faults can help reduce subsequent faults. Faults tend to repeat at the same locations and follow patterns. For example, one particular type and brand of connector may have a high failure rate. If these are identified, replacement strategies can be implemented. Another example is animal faults—one particular pole that happens to be a good travel path for squirrels may have a transformer with no animal guards. The same location may have repeated outages. These may be difficult to find at first, but crews can be trained to spot pole structures where faults might be likely.

The best way to reduce faults over time is to "institutionalize" fault-reduction practices. After identifying the most common fault sources, implement programs to address these so performance improves continually. Options for such programs include

- *Design review*—The first step in implementing fault-resistant designs is to start with good designs.
- *Outage follow-ups*—On-site outage reviews can help identify weak points and reduce fault rates. Faults tend to repeat at the same locations and follow patterns. By identifying the location of the fault and any structural deficiencies that contributed to the fault, the deficiencies can be corrected to prevent repeated faults in the future.
- *Construction audits*—Construction audits help reinforce practices to ensure that crews build to the specifications, and audits help educate crews on why things are done and how the designs minimize faults.

- *Problem-circuit audits*—Just as there are pole locations that can have repeated faults, faults can cluster on some circuits. The goals of a problem-circuit audit are (1) to identify the deficiencies that are the most probably sources of faults and (2) to correct deficiencies to avoid repeat fault events.
- *Upgrade and maintenance projects*—Utilities can shore up weak areas by any one of several construction upgrade programs: animal-guard implementations, arrester replacements or new applications, and cable-replacement programs. Maintenance projects include tree clearance, hazard-tree programs, and pole inspection and replacements.

There are no magic programs or devices or quick fixes. Utilities must maintain consistency. For the most part, these are not 1- or 2-year programs. Maintaining fault resistance must be an ongoing process that becomes a core part of utility operations.

Duke Energy pioneered the strategy of identifying and removing sources of faults on the system. By doing this, Duke Energy is able to maintain very respectable reliability numbers despite the fact that its service territory has regular severe weather, and Duke Energy is mainly an overhead utility with predominantly all-radial systems. Since first starting to implement fault reduction programs, Duke has reduced their SAIFI by 20% during a 10-year period.

Because fault sources are most often at equipment poles, consider programs targeted specifically at equipment poles. Duke Energy has many single-phase CSP transformers with an old arrester than can fail at any time, minimal animal protection, and no local fusing. These locations are tied for second place in being the largest contributor of outage minutes on Duke's system. To address this problem area, Duke has a "transformer retrofit" program where a crew will install a local cutout with a surge-resistant fuse, a new lightning arrester, insulated leads, and animal guards. While a crew is set up at a pole, they also insulate uninsulated primary guys and remove pole grounds above the tank level. Duke applies this program on a circuit-by-circuit basis, with each region developing a prioritization plan based on outage database records.

10.6.1 Maintenance and Inspections

For many utilities, the best maintenance is tree maintenance and then more tree maintenance; tree maintenance is by far the largest maintenance expense for these utilities. Beyond tree maintenance, distribution circuit maintenance practices vary widely. Distribution transformers, capacitors, insulators, wires, cables—most distribution equipment—do not need maintenance. Oil-filled switches, reclosers, and regulators need only occasional maintenance.

Most maintenance involves identifying old and failing equipment and targeting it for replacement. Equipment deteriorates over time. Several utilities have increasingly older infrastructure. Equipment fails at varying rates over its lifetime. Typically, it is a "bathtub curve": high failure rates initially during the break-in period (mostly due to manufacturing defects), a period of "normal" failure rates that increases over the equipment's lifetime. Some equipment sees more acceleration in

failure rates than others. Data for distribution equipment is difficult to find. Early plastic cables—high-molecular-weight polyethylene and cross-linked polyethylene—had dramatically increasing failure rates. Duckett and McDonough (1990) found dramatically increasing failure rates with age on Carolina Power & Light's 14.4-kV, 125-kV BIL transformers based on failures recorded from 1984 through 1988. The failure rate shot up when units reached 15 to 20 years old. An earlier study of CP&L's 7.2-kV, 95-kV BIL transformers did not show an increasing failure rate with age, staying at about 0.2 to 0.4% annually (Albrecht and Campbell, 1972). Aged transformers are more susceptible to failure, but we cannot justify replacement based on age; cables are the only equipment that utilities routinely replace solely based on age.

Storms trigger much "maintenance"—storms knock lines and equipment down, and crews put them back up (this is really restoration).

From birth to death, tracking equipment quality and failures helps improve equipment reliability. On most overhead circuits, most failures are external causes, not equipment failures (usually about 10 to 20% are equipment failures). Still, tracking equipment failures and targeting "bad apples" helps improve reliability. Many utilities do not track equipment failures at all. But, some utilities have implemented programs for tracking equipment and their failures. Failures occur in clusters: particular manufacturers, particular models, particular manufacturing years. Whether it is a certain type of connector or a brand of standoff insulator, some equipment has much higher than expected failure rates.

Proper application of equipment also helps, especially not overloading equipment excessively and applying good surge protection.

On underground circuits, equipment failures cause most interruptions. Tracking cable failures (usually by year of installation and type of insulation) and accessory failures and then replacing poor performers helps improve reliability. Monitoring loadings helps identify circuits that may fail thermally.

Quality acceptance testing of new equipment, especially cables, can identify poor equipment before it enters the field. For cables, tests can include microscopic evaluation of slices of cables to identify voids and impurities in samples. A high-pot test can also identify bad batches of cable.

On underground circuits, since workmanship plays a key role in quality of splices, tracking can also help. If a splice fails 6 months after it is installed and if we know who did the splice and who made the splice, we can work to correct the problem, whether it was due to workmanship or poor manufacturing quality.

Utilities use a variety of inspection programs to improve reliability. Of North American utilities surveyed (CEA 290 D 975, 1995), slightly more than half have regular inspection programs, and fewer than 5% have no inspections. Efforts varied widely: 27% spent less than 2% of operations and maintenance budgets on inspections, while 16% of utilities spent 10 to 30% of O&M on inspections.

Some distribution line inspection techniques used are

- *Visual inspections*—Most often, crews find gross problems, especially with drive-bys: severely degraded poles, broken conductor strands, and broken insulators.

Some utilities do regular visual inspections, but more commonly, utilities have crews inspect circuits during other activities or have targeted inspections based on circuit performance. The most effective inspections are those geared toward finding fault sources—these may be subtle; crews need to be trained to identify them.

- *Infrared thermography*—Roughly 40% of utilities surveyed use infrared inspections for overhead and underground circuits. Normally, crews watch a 20°C rise and initiate repair for more than a 30°C rise. Infrared scanning primarily identifies poor connectors. Some utilities surveyed rejected infrared monitoring and did not find it cost effective. Other utilities found significant benefit.
- *Wood pole tests*—Visual inspections can identify severe deterioration. Some utilities use more accurate measures to identify the mechanical strength left in poles. A hammer test, whacking the pole with a sledge, is slightly more sophisticated; a rotted pole sounds different when compared to a solid pole. Sonic testing machines are available that determine density and detect voids.
- *Operation counts*—Most utilities periodically read recloser operation and regulator tap changer counters to identify when they need maintenance.
- *Oil tests*—A few utilities perform oil tests on distribution transformers, reclosers, and/or regulators. While these tests can detect deterioration through the presence of water or dissolved gasses, the expense is difficult to justify for most distribution equipment.

Substation inspections and maintenance are more universally accepted. Most utilities track operation counts or station breakers and regulators, and most also sample and test station transformer oil periodically.

10.6.2 Outage Follow-Ups

On-site outage reviews can help improve outage cause codes, identify weak points, and reduce fault rates. Faults tend to repeat at the same locations and follow patterns (Chow and Taylor, 1995). Consider our example with animal faults and a transformer with no animal guards in an area with many squirrels. The same location may have repeated faults. By identifying the location of fault and any structural deficiencies that contributed to the fault, the deficiencies can be corrected to prevent repeated faults in the future.

The main goals of an outage-review program are

- *Outage database improvement*—Did crews enter the fault code or outage code correctly based on available information? If not, feedback can correct the mistake, and lessons learned can help prevent future mistakes.
- *Training*—Field engineers and operating crews get more "on-the-job training" about specific design and construction deficiencies that lead to faults.
- *Source*—Identify the most probable cause of the fault (tree limb, animal, lightning, etc.)
- *Corrective action*—Construction deficiencies should be corrected to avoid repeat fault events. Corrective action is a prime goal of an outage review.

During an outage review, the main tasks of the reviewer are to review the data at hand and address the following questions:

- What was the most likely location of the fault? What was the flashover path?
- What was the most likely cause of the fault?
- Was the outage code entered correctly?
- Was the faulted circuit adequately covered by protective devices? Was the fault on an unfused tap?
- Did protective devices operate as expected?
- What structural deficiencies contributed to the fault?
- Are the deficiencies likely to lead to additional faults?
- How could the deficiencies be corrected?

Based on addressing these issues, corrective action can be initiated if it is warranted. Corrective action could include rebuilds on one or more structures and could include tree/branch clearance. Corrective action could also include fixing unrepaired damage related to the fault.

The first step is finding the most likely location of the fault that caused the outage. Permanent faults are relatively easy to pinpoint because the crew had to actually fix damage at one or more locations. Temporary faults are harder to pinpoint. If a fuse blows, the area narrows considerably. For areas with repeat fuse operations, careful patrols may identify areas where repeated faults occur. Still, if a tap fuse operates but is refused successfully, the cause may have been a squirrel across a bushing, a tree branch that fell onto then burned off of a line, or wind pushing two conductors together. It often takes a trained eye to determine the cause.

Many outages are classified as "unknown." For some outages, the cause will remain unknown. While the exact cause may remain unknown, information about the outage can help point the way to finding deficiencies. The time of day and the weather during the fault can help suggest a cause. Clear weather may suggest an animal fault, especially if it happens during the daytime. Stormy weather suggests lightning. An outage history for the protective device may reveal patterns. The probable cause can help the outage investigator look for deficiencies that could have led to the cause.

Several options are available to decide which outages to review: all outages that impact over 500 customers (or some other number), all mainline outages, all outages on "problem circuits," all outages on "critical-customer circuits," outages on protective devices with excessive operations over a given time period (pick a threshold based on whether the device is a fuse, recloser, or circuit breaker), or a random portion of all outages. Utilities could also use combinations of these options in forming criteria for outage reviews. Responsibility for outage follow-ups will normally fall to a local field engineer.

In addition to regular outage reviews, a utility may audit a sample of the outage reviews. A "reliability auditor" could visit the outage location with the local field engineer. The main point of such an audit is educate and reinforce consistent approaches to outage follow-ups. If at the time of the audit, the corrective action has been done, the auditor and the local field engineer can review the corrective action to determine if it was done properly. For example, check that animal guards were attached correctly and that sufficient clearances were maintained.

10.6.3 Problem-Circuit Audits

Just as there are pole locations that can have repeated faults, faults can cluster on some circuits. These faults may be from consistently poor construction on a circuit, heavy tree exposure, or a few poor structures with repeated faults. The goals of a problem-circuit audit are

- *Source*—Identify the deficiencies that are the most probably sources of faults.
- *Corrective action*—Correct construction deficiencies to avoid repeat fault events.

Criteria for designating "problem circuits" can come from many options: circuits with critical customers that are having problems, circuits with excessive momentary interruptions, circuits with long-duration interruption problems (high SAIFI or SAIDI), or circuits with excessive customer complaints.

The "problem" should also direct the focus of the audit. If the problem is momentary interruptions, review the section covered by the circuit breaker or recloser that is excessively operating. Pay special attention to animal and lightning susceptibility on the circuit. If the problem is long-duration interruptions, concentrate circuit patrols and reviews on the feeder backbone. Pay special attention to susceptibility to trees; a review of the outage records for the circuit should reveal even more information on where to look for problems.

Some specific items for a repair checklist could include

- Unfused tap lines
- Animal guards missing on any surge arresters or bushings
- Transformers without local, external fuses
- Guy wires without proper insulation
- Pole ground wires run near the primary
- Old arresters
- Heavy tree coverage
- Hazard trees
- Overhanging dead limbs
- Damaged insulators or bushings
- Deteriorated or damaged equipment
- Poor clearances
- Vines on equipment poles
- Midspan conductor faults (poor clearances)
- Wire too small for fault duty, including the neutral (through faults)
- Covered conductors subject to burn downs (arcing faults)

In addition to construction-related issues, a utility should also review the protection schemes on a circuit and review other ways to reduce the impacts of faults (EPRI 1001665, 2003). Are reclosers and other devices coordinated properly? Does the circuit have enough protective devices? Are there any unfused taps? Are all mainline equipment structures protected by a local fuse? Is reclosing done appropriately for that circuit? Are circuit breaker relays set fast enough to protect conductors from burn down?

10.6.4 Construction Upgrade Programs

Outage follow-ups and construction audits along with reviews of outage data help pinpoint the weaknesses in existing construction. Utilities can shore up these weak areas by any one of several construction upgrade programs:

- Animal-guard implementations
- Arrester replacements or new applications
- Tree clearance
- Hazard-tree programs
- Pole inspection and replacements
- Cable-replacement programs

Other options are possible, depending on past construction deficiencies. For example, if a utility has at some point built a number of lines with a shield wire (overhead neutral) that perform poorly, a program might target them for replacement or upgrades. A shield wire design can perform well if it has good insulation and good grounding, but it can also perform poorly if not done right—the grounding downlead can reduce insulation levels and make lightning contacts more likely and can increase the likelihood of animal contacts and contacts from other debris. Then, a shield-wire upgrade program could target these sections for replacement or for insulation upgrades to reduce animal and lightning faults.

Equipment replacement programs also fall under the upgrade category. Many utilities have cable replacement programs. Program policies are done based on the number of failures (the most common approach), cable inspection, customer complaints, or cable testing.

Because fault sources are most often at equipment poles, consider programs targeted specifically at equipment poles. For example, a transformer retrofit program could upgrade all transformer locations to the utility's design specifications. This could include replacement of old arresters with tank-mounted polymer metal-oxide arresters, animal guards on bushings and arresters, covered jumper leads, and elimination of grounded wires above the transformer tank (including grounded guy wires).

It costs much less to upgrade construction when a crew is already set up at a pole. Consider implementing procedures and checklists for the crew to fix problems on the pole *whenever* they are set up for work on a pole. Options to consider in such a program are

- Add animal guards on unprotected bushings or surge arresters.
- Replace old surge arresters.
- Add fiberglass guy insulators to uninsulated guys near the primary.
- Strip out unnecessary grounds above the neutral wire (especially those near primary conductors or jumpers).
- Replace any flashed or damaged equipment.
- Install a local fuse on CSP transformers.

10.7 Outage Databases and Targeting

Tracking outage data for a utility operating region helps identify the most common problems for that service area. These numbers change by region depending on weather, construction practices, load densities, and other factors.

Do not treat all circuits the same. The most important sections are usually not 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-tech commercial customers should warrant different treatment than a rural circuit with fewer, mostly residential and agricultural customers. How this is weighted depends on the utility's philosophy.

On radial distribution circuits, the three-phase mainline is critical. Sustained interruptions on the mains locks out all customers on the circuit until crews repair the damage. Feeders with extra-long mainlines have more interruptions. To reduce the impact of mainline exposure, prune trees and/or inspect and clear hazard trees more often on the mains. Mainline sectionalizing switches help by allowing quick restoration of customers upstream of the fault; automated switches are even better. Another improvement is using normally open tie switches to other feeders, enabling crews to move load to other feeders during sectionalizing.

Lateral taps are another target. We can rank these by historical performance, taking into account their length and number of customers. Some longer laterals are good candidates for single-phase reclosers instead of fuses.

Strategies and programs for improving reliability should be targeted for maximum benefit. Outage databases can help identify problems leading to faults. They can help identify which circuits to target, which areas have the most problems with trees, which areas have the most problems with animals, and so on. Outage databases can also help judge the effectiveness of improvement programs.

10.7.1 Temporal Analysis

Breakdowns by season, by month, by day of the week, and by hour of the day can reveal insights, especially by cause. Figures 10.26 and 10.27 show customer interruptions by cause for breakdowns by month and by hour of the day for one utility's data. Note several trends:

- Animal interruptions increase in late spring and are the lowest in the winter.
- As expected, lightning is highest in the summer. Customer interruptions from "unknown" also has a spike corresponding to the lightning spike, indicating that many of those are from lightning or other thunderstorm-related root cause.
- Overload contributions are highest in the summer.
- The tree contribution is normally highest during the summer, but spikes during the winter indicate susceptibility to occasional big events that impact tree interruptions from ice or snow.
- Equipment failures are consistent but also jump in the summer.

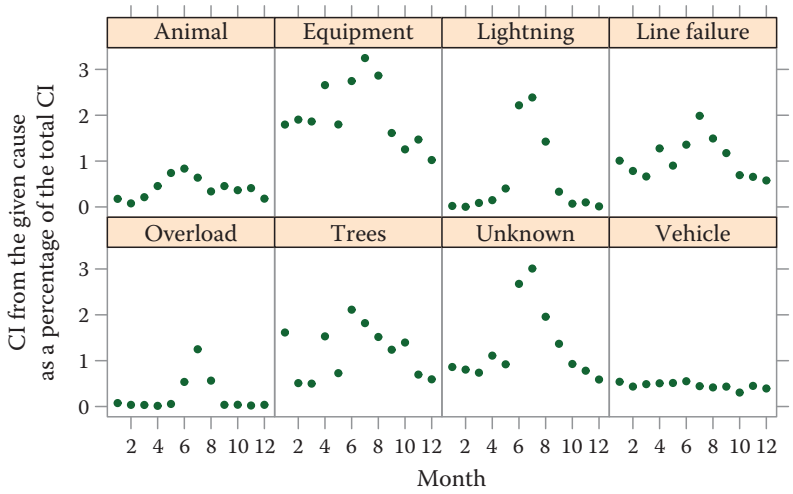

Figure 10.26 Customer interruptions by month. (From EPRI 1013874, *Using Outage Data to Improve Reliability*. Electric Power Research Institute, Palo Alto, CA, 2007. Copyright 2007. Reprinted with permission.)

Day of the week should not impact causes, except for a few that are human caused, like "vehicle." Any significant differences are probably caused by differences in coding on different days. This is a crude check on coding differences.

Hour of the day shows significant differences by cause. Lightning hits in the evening. Animals cause faults in the morning. Unknowns show a late afternoon spike that matches that from lightning as well as the morning spike from animals. That is

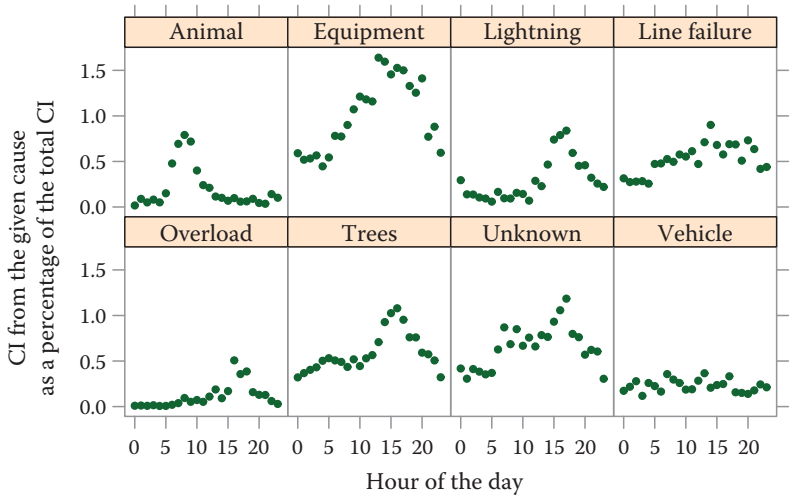

Figure 10.27 Customer interruptions by hour of the day. (From EPRI 1013874, *Using Outage Data to Improve Reliability*, Electric Power Research Institute, Palo Alto, CA, 2007. Copyright 2007. Reprinted with permission.)

good evidence to support the fact that many unknowns can be attributed to thunderstorms or to animals depending on the time of the day and the weather as discussed in Chapter 3. Trees tend to have the same shape as lightning, indicating the importance of weather to tree-caused events. Vehicles are surprisingly constant.

10.7.2 Outage Codes

Tracking and targeting fault types helps identify where to focus improvements. If animals are not causing faults, we do not need additional animal guards. Many utilities tag interruptions with identifying codes. The system-wide database of fault identifications is a treasure of information that we can use to help improve future reliability.

Different fault causes affect different reliability indices. Figure 10.28 shows the impact of several interruption causes on different reliability parameters for Canadian utilities. Relative impacts vary widely; for example, trees had a high repair time but impacted fewer customers.

Without accurate and thorough outage databases, there is no evidence to justify reliability improvement programs. The best strategy is to provide relatively simple database entry codes and remarks fields. Guidelines and training for entering the outage data should be provided. Ensure that the codes are entered accurately by using audits, assessments, and budgetary motivation. Regional budgets for reliability improvement programs are often based on the reliability information extracted from the outage database. Examples of reliability-based budget allocations include underground cable replacement, vegetation maintenance, and "worst circuit" programs. If the correct failure codes are not used in the outage database, then a region may lose money for certain reliability and asset management programs.

All outages contain an element of mystery. The initial coding of outages is based on the best judgment and training of both the "first responder" and the employee who enters the data. However, the initial coding often does not identify the primary root cause. One of the major goals of an outage follow-up process is to identify the primary root cause. Most outages have more than one root cause. The primary root cause is the root cause for which a utility can implement economical corrections within a reasonable period of time. The purpose of codes and coding conventions is to identify the primary root cause of each outage.

Most outage databases provide standard information about the outage such as date, time, customers affected, and other information. For reliability analysis however, the code fields and remarks field provide information that is critical to modern asset management strategies.

Having accurate and precise outage code systems increases the usefulness of outage databases. *Weather* is a common outage cause code, but what does that mean? If a tree knocks down a distribution line during a storm, is that weather? How do you differentiate between lightning and tree-caused outages during a thunderstorm? Another common blunder that crews make is tagging a cause as "cutout" when the cause was really something downstream of the cutout, and the fuse operated to clear

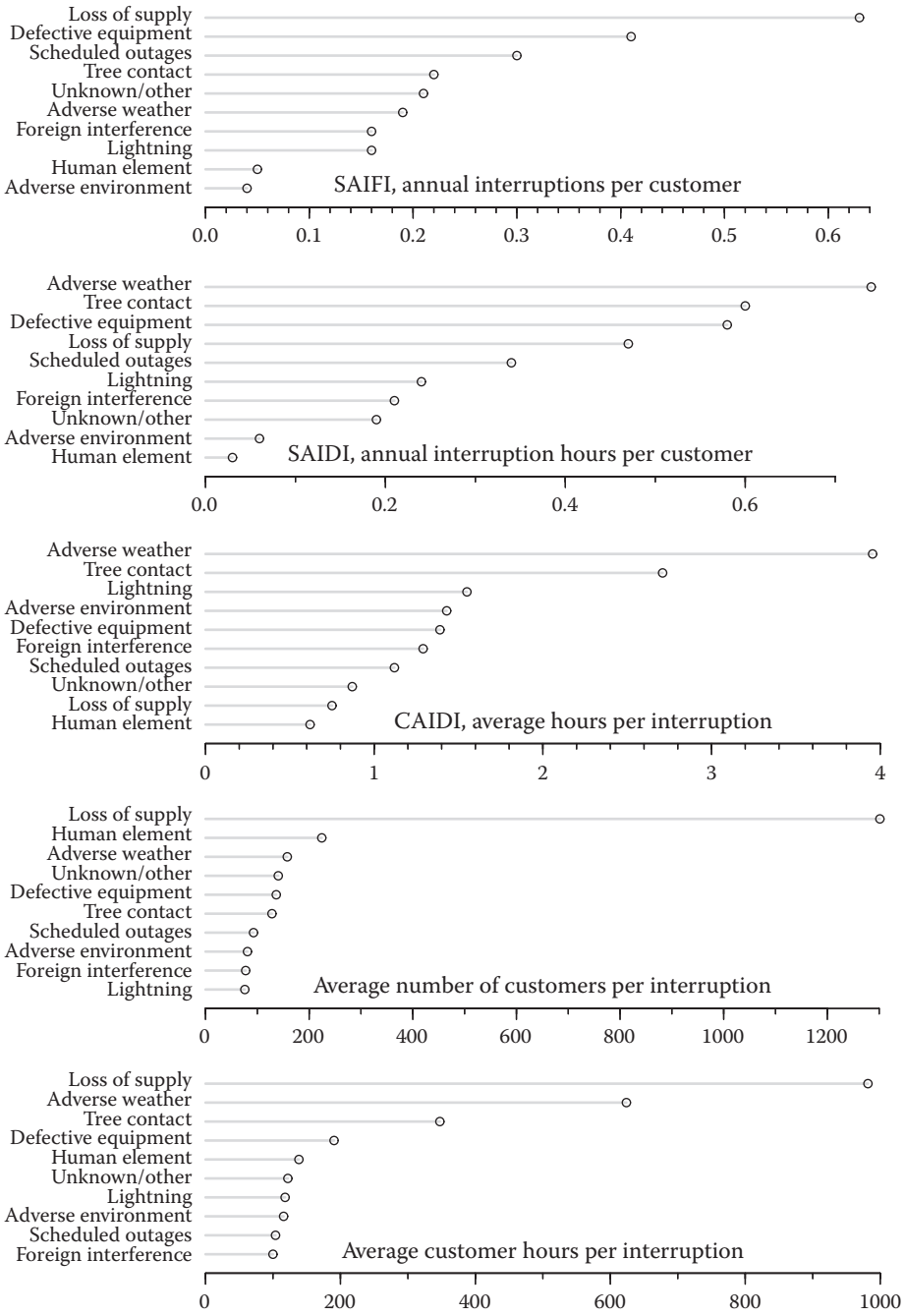

Figure 10.28 Root-cause contributors to different reliability parameters. (Data from CEA, *CEA 2000 Annual Service Continuity Report on Distribution System Performance in Electric Utilities*, Canadian Electrical Association, 2001.)

the fault (the cutout operated properly). As much as possible, good outage code systems should separate the root cause of the outage from the weather, the protective device that operated, and the equipment affected. Use a separate category for weather (and indicate major storm separately). Also, try to have codes that reveal deficiencies: these may include inadequate clearances, deteriorated equipment, missing animal protection, or low insulation.

Duke Energy's system (other utilities use similar systems) provides a good way to characterize an outage by specifying four code fields for an outage: (1) interrupting device, (2) cause or failure mode, (3) equipment code, and (4) weather. These codes, used in combination with each other, are quite accurate in describing what is known about the cause of an outage, or in some cases, what is not known about an outage. In more detail, these codes mean:

1. *Interrupting device*—fuse, line breaker (recloser), station breaker, transformer fuse, and so on.
2. *Cause or failure mode*—animal, tree, unknown, and so on. If the "cause" is not known, or does not fall into a predetermined cause category, then the cause code becomes the failure mode. Often, the failure mode is the only information available. Examples are "burned," "broken," "malfunctioning," and "decayed." Failure modes imply equipment failures, so an equipment code is usually a required entry if using a failure mode. Failure modes represent partial information about the cause, in that the root cause may remain unknown, but certain things about the failure are known. For example, if a station breaker fails to trip, then you may have a specific failure mode called "fail to interrupt." For the equipment code (see below), enter the code for "station breaker." This system is flexible. The same failure mode can be used with other equipment codes to describe other devices that "fail to interrupt." If there is no specific failure mode, then a generic failure mode such as "malfunctioning" or even "broken" can be used.
3. *Equipment code*—For equipment failures, to specify the equipment that failed.
4. *Weather*—It is useful to know if an equipment failure or unknown interrupting device outage occurred during lightning or other stormy weather. Animal outages normally occur in fair weather. By studying combinations of time-of-day, weather, and interruption device activity on a utility, it is often possible to classify unknown outages into likely cause categories. For example, on the Duke Energy system, an unknown outage on a tap fuse on a spring morning in fair weather is highly likely to be an animal outage.

There is often discussion concerning if weather is an outage cause or a contributing factor. From a reliability perspective, the electric distribution system is designed to withstand moderate to bad weather conditions. As a primary root cause, weather that exceeds the design parameters of the system can be considered a primary root cause. However, these weather causes are the exception. Weather situations that may be considered primary root causes include: lightning, wind loading exceeding design parameters (tornadoes), ice loading exceeding design parameters (e.g., 3 in. of ice), or flooding. Even given that, utilities should avoid declaring stormy weather such as wind or lightning as a cause. There may be evidence (burn marks, for example) to show that lightning caused an arrester failure, but if there is not, it is better to code the cause as an equipment failure during a lightning storm. Do not use

weather as an excuse to "explain away" outages. Reliability programs can prevent many outages during stormy weather. Properly funded and executed vegetation management programs can cut down on outages during wind. Properly designed overhead lines and equipment protection can substantially reduce outages during lightning. If the utility is not attempting to make the system more outage resistant during stormy weather, it may be thinking of weather as a cause, rather than a contributing factor.

Engineers often want to specify additional codes such as vintage year (for equipment failures), overhead/underground indicators, how the outage was restored, and others. Most of these codes can be incorporated in the four main codes given above. First responders will likely ignore the rest. For example, underground cable failures have equipment codes that are obviously underground types. Experience on the Duke Energy system has shown that the four codes mentioned above are about the limit that a first responder can accurately handle, even if other codes are requested.

Have a generic comment or remarks section to note specifics that might not be clear from the outage codes. This helps with later analysis and allows for keyword searches to reveal patterns. The remarks field contains vast amounts of information if used liberally. Provide at least 256 characters in the remarks field. Encourage first responders and dispatchers to use the remarks field to describe what happened during the outage. Modern database applications can quickly search and count outages that contain certain keywords or phases within the remarks field. These database applications can also filter out records that contain certain keywords. Here are some examples actually used at Duke Energy (Taylor and Short, 2006).

- There was no code to differentiate between live or dead tree outages in the code system. However, the crews almost always noted in the remarks field if the tree or limbs involved were "dead" or "rotten." This method of counting dead tree outages versus live tree outages was found to be a highly accurate method to determine if the annual hazard-tree survey and removal was effective.
- There was a hypothesis that 3D or smaller transformer fuses were more susceptible to nuisance fuse outages during lightning than 5D or larger transformer fuses. There were a large number of outage records of fuse outages on transformers during lightning, but the fuse size was not a record anyone kept. However, it was discovered that the crew almost always called in the fuse size when they replaced a fuse. The dispatchers put this information in the remarks field. A contextual database search on the remarks field of transformer outages found more than 7000 cases per year where the transformer fuse size was supplied. This sample size was sufficient to allow normalization of 3D and 5D transformer outages against the total population of transformers that would have such fuses. The result of this analysis showed that there was no significant difference in the performance of these two fuses.
- There was a concern that squirrels were causing significant damage to overhead conductors, connectors, and equipment by literally biting and gnawing on various items. The remarks field was searched to find how widespread this behavior was. Duke Energy determined that squirrels will chew and gnaw almost anything, but bare aluminum conductor is their favorite. Also, while widespread, this phenomenon is not a significant reliability problem.

When designing or modifying outage code systems, balance your desire for as much information as possible with the reality that overloading crews with too many options is counterproductive. Stick with clear choices, and do not overwhelm crews with options. Do not use codes that are too generic to provide useful information. Do not use codes that are too complicated for first responders to understand. In either case, you get little useful information. A balance must be maintained between being too generic and too complicated. Here are some additional guidelines for outage coding:

- *Subcodes*—Where appropriate, subcodes provide extra information. As an example, it may make sense to have a code or subcode to denote whether the structure had an animal guard. If that adds too much complexity, have crews enter a generic comment to indicate the structural deficiency (the missing animal guard). Also, for animal outages, crews should only mark it as animal if they find the remains of the animal or other proof.
- *Unknown*—Using unknown as a cause is better than guessing. A wrong cause code can result in resources being directed to the wrong problem.
- *Equipment failures*—Equipment failures are prime candidates for fine-tuning. For example, a subcode could indicate the equipment construction or vintage or even manufacturer. For cables and especially for splices, knowing the manufacturer and vintage can help determine targeted replacement programs. The mode of failure is also an important consideration: Was the equipment broken? Was the failure from decay?

Consider an example outage code for a tree contact during a storm that caused a downed wire that might be tagged as follows:

Interrupting device: Breaker	*Cause*: Vegetation (dead tree)
Equipment: Bare conductor (downed wire)	*Weather*: Wind/rain

This clearly separates the cause (the tree) from the impact on the system (downed wires) and notes the weather conditions during the event. The items in brackets denote subcodes that add useful information; in this case, the subcodes reveal that the tree was dead (points to a better hazard-tree program) and that it caused a downed wire.

An arrester failure found during a lightning storm might be classified as

Interrupting device: Transformer fuse	*Cause*: Equipment failure
Equipment: Arrester (catastrophic)	*Weather*: Lightning storm

In this case, we do not really know the cause of the arrester failure; it was probably lightning, but we do not know for sure. We do not even know for sure that the arrester failed during the storm (the arrester may have failed earlier and was only found when crews arrived at the scene). But because the arrester was obviously failed just downstream of the fuse, and the transformer was still operational, the arrester is very likely to have caused the fault.

Consider a squirrel outage across a bushing:

Interrupting device: Tap fuse	*Cause*: Animal
Equipment: Bushing (no animal guard)	*Weather*: Clear

The use of a subcode for bushing that highlights a common deficiency (no animal guard) helps direct resources to repair the deficiency.

Consider also the way crews provide the information. Using mobile computers allows the most direct data entry, but crews are prone to incorrectly using the software (either not using it or entering the data to process the menus as quickly as possible). Training and straightforward user interfaces can help. The advantage of computer data entry is that the form can adapt to the scenario at hand and fill in data from the outage management system (like outage start time). Having a crew call back outage information to dispatchers allows the dispatchers to query the crew to make sure the codes are entered consistently. Paper data entry sheets can be relatively easy for crews to interpret but limit flexibility for subcodes and options.

Utility culture should also encourage accurate outage codes. Provide a document to show how all outage codes are supposed to be used, and provide training. These guidelines and "code sheets" should be provided to everyone who has anything to do with entering outage codes. At Duke Energy, dispatchers enter outage codes that first responders call in. At the 24-hour center, dispatchers are graded on how accurately the code guidelines are followed. Local reliability engineers or technicians are the "code police." Each day, these employees review all the outage records in their location for the past 24 hours or over the weekend. They make sure that the code guidelines are followed. If there is something missing, unclear, or contradictory about the information in the outage record, the reliability engineer tracks down the information and completes the entry correctly. The "code police" are also assessed quarterly on the accuracy of outage records in their location. Those who police outage data make sure, to the best of their ability, that all outages in their location are reported accurately and completely. Therefore, these individuals should be rewarded for the accurate and complete reporting of outages. To avoid conflicts of interest, these individuals should not have annual outage indices such as SAIFI or SAIDI on their scorecards.

10.7.3 Cause Codes

Outage cause is a primary resource for targeting maintenance and reliability improvement. Distribution interruptions normally happen from inadequate clearances, equipment failures, or trees. Outage causes can identify poorly performing equipment and help focus maintenance or replacement. Many reliability improvement programs directly tie in with outage causes (like animal guards for animal-caused outages). Having a good outage-cause system and using it properly can help better direct these programs.

Utilities vary widely in breakdowns of outage causes. This ranges from a utility that just has several basic cause codes to a utility that has a triple-layer breakdown with multiple levels (cause/subcause/subsubcause). Utilities generally have between 40 and 100 total combinations of causes (EPRI 1013874, 2007).

For systems at most utilities, the cause and subcause would be dropdown boxes that an operator selects. The first-level cause might be vegetation, and the second-level subcause is then restricted to vegetation-type causes, including possibly tree growth,

vines, tree branch failure, or tree trunk failure. Without this restriction, this can lead to some humorous entries like an outage with a cause of "lightning" and a subcause of "squirrel" (that is a fast squirrel) or a "prearranged" "animal" interruption.

As much as possible, good outage code systems should help identify the root cause of the outage. This gets blurred by outage codings used at some utilities. Some particular problems include

- *Weather*—Weather parameters, particularly wind, can be abused as an outage cause. If wind blows tree branches into the line, the problem is that the trees are too close. If wind causes conductor slapping at a slack span, the problem is the conductor spacings and slack on that span. "Major storm" is particularly bad, because that can consist of a large amount of CI and CMI that may be more usefully categorized into more precise failure modes (trees, lightning, conductor slapping, pole failures, and more).
- *Too generic*—Some cause codes are too generic, meaning that they do not provide enough information to act precisely enough. For example a code of "OH equipment failure" by itself is not precise enough to focus on a particular problem (a subcode could fix that, of course).
- *Mixing up purpose*—Some cause systems include the damage done (wire down), weather (wind/rain), and location (primary overhead cable). Some also include the repair action in the cause system.

One way to use outage data to improve reliability is to use the data to help answer questions about certain types of outages. How often do they occur? How many customers are typically impacted? Where do they occur? As an example of this type of data mining, can downed wires be determined from outage data? Are there equipment, damage, or cause fields that explicitly tell when conductors are downed? In EPRI 1013874 (2007), about 40% of the utility datasets had an indicator of downed wires. Some of them differentiated between downed wires from trees and from other causes. For the utilities that did not have a direct indicator, those that entered good comment fields often had an indication of downed wires that way, but comment fields are less reliable as a way to broadly benchmark a type of outage.

The IEEE has a task force on "Interruption Reporting Practices" that is developing guidance for more standardized reporting (see IEEE P1782/D1, 2012; Werner et al., 2006). This draft includes the following 10 standardized cause categories:

- Equipment
- Lightning
- Planned
- Power supply
- Public
- Vegetation
- Weather (other than lightning)
- Wildlife
- Unknown
- Other

Even though they include a "weather" category (which I discourage), the IEEE document stresses that this should include interruptions from weather that exceeded the system design limits and specifically excluded trees and conductor slapping and galloping. These categories are provided for reporting and benchmarking purposes. The utility can of course have more detailed codings for their own purposes. In the next sections, we will look at a few specific cause codes in more detail.

10.7.3.1 Equipment

For several utilities, equipment failures are the number one or number two contributor to SAIFI and SAIDI. Most utilities have equipment cause codes, but some are meshed with other causes that make it difficult to break out. Some utilities have generic categories of equipment failure like "UG equipment failure" and use a subcause field to denote the equipment that failed.

For equipment, we want to know the failure mode. Sometimes, the failure mode is the only information available (we may not know why it failed). Examples include "burned," "broken," "malfunctioning," and "decayed." Failure modes represent partial information about the cause, in that the root cause may remain unknown, but certain things about the failure are known. For example, if a station breaker fails to trip, then you may have a specific failure mode called "fail to interrupt." This could be an equipment code for "station breaker." The same failure mode can be used with other equipment codes to describe other devices that "fail to interrupt." If there is no specific failure mode, then a generic failure mode such as "malfunctioning" or "broken" can be used.

Duke Energy incorporates failure modes as cause codes under the general heading of "deterioration" (Taylor and Short, 2006). Their failure modes include natural deterioration, broken/malfunctioning, decay, melted, burned/catastrophic failure, and more. Failure modes imply equipment failures, so Duke requires an equipment code if using a failure-mode cause. A disadvantage of the Duke model is that their system does not allow easy entry of both a root cause and a failure mode. For example, if an overloaded transformer explodes, it would be nice to know the root cause (overload) and the failure mode (explosion).

Cutouts, fuses, reclosers, and other protective devices are often abused as equipment causes. Dispatchers should question every time if an equipment cause of a cutout is given. Is it really the cutout that failed, or did they just replace a fuse that has blown for some other root cause? Cutouts can certainly have problems, but we need to make sure that the problems are identified appropriately.

10.7.3.2 Vegetation

For many utilities, vegetation interruptions are the number one or number two contributor to SAIFI and SAIDI. Figure 10.29 shows breakdowns for CMI, including storms, for several utilities. Because of the damage done and propensity to occur more during storms, vegetation interruptions have a much larger impact on CMI than on CI.

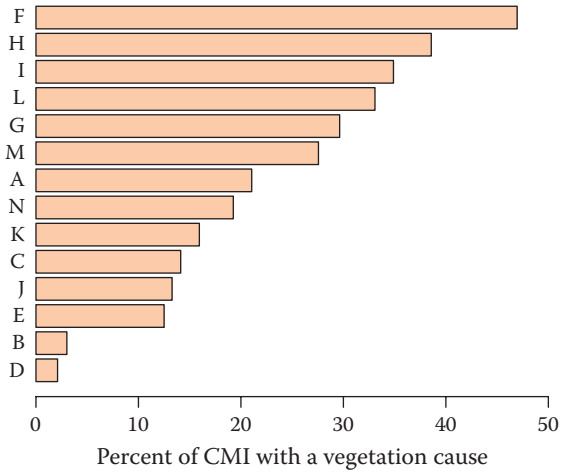

Figure 10.29 Customer-minutes of interruption from vegetation for several utilities. (From EPRI 1013874, *Using Outage Data to Improve Reliability*, Electric Power Research Institute, Palo Alto, CA, 2007. Copyright 2007. Reprinted with permission.)

One of the primary uses of vegetation cause and subcause combinations is to use them to evaluate vegetation maintenance. Are clearances adequate? Are cycle times adequate? How can I focus vegetation management to problem areas? Would an expanded hazard-tree program help? Where should I apply a hazard-tree program? Can I use the data to evaluate a hazard-tree program? Vegetation management is a prime candidate for reliability-centered maintenance—trimming, cutting, and clearing based on reliability. Outage data provides the prime reliability benchmark. As such, with more focus from vegetation outage causes comes the ability to develop more focused vegetation maintenance.

Figure 10.30 shows a breakdown of vegetation CMI by subcode for several utilities. Generally, the data suggests considering these effects when evaluating vegetation maintenance. Low impacts from tree growth indicate that there may be room to lengthen cycle times. Note that the reliability impact is only one factor here. Excessively long tree cycles can make tree maintenance more expensive as trees become entangled with lines.

Most tree impacts are from trees or branches falling into conductors. Although these coding systems do not necessarily show it, many of these are from breakage. A reliability-focused maintenance approach points to programs that can reduce these, like overhang removal and hazard-tree removal.

Some utilities use "preventable" and "nonpreventable" tree categories. That may seem like a noble differentiation, but it is very subjective. How is a troubleshooter supposed to decide if the event was preventable or not? This system is easily abused to the point that it is worthless. Better choices are some combination of "growth/limb/trunk/uprooted" or "inside/outside of right-of-way." Both of these are easier for troubleshooters and line crews to classify based on objective and commonsense criteria, and they suggest what type of program may or may not have impacted the cause.

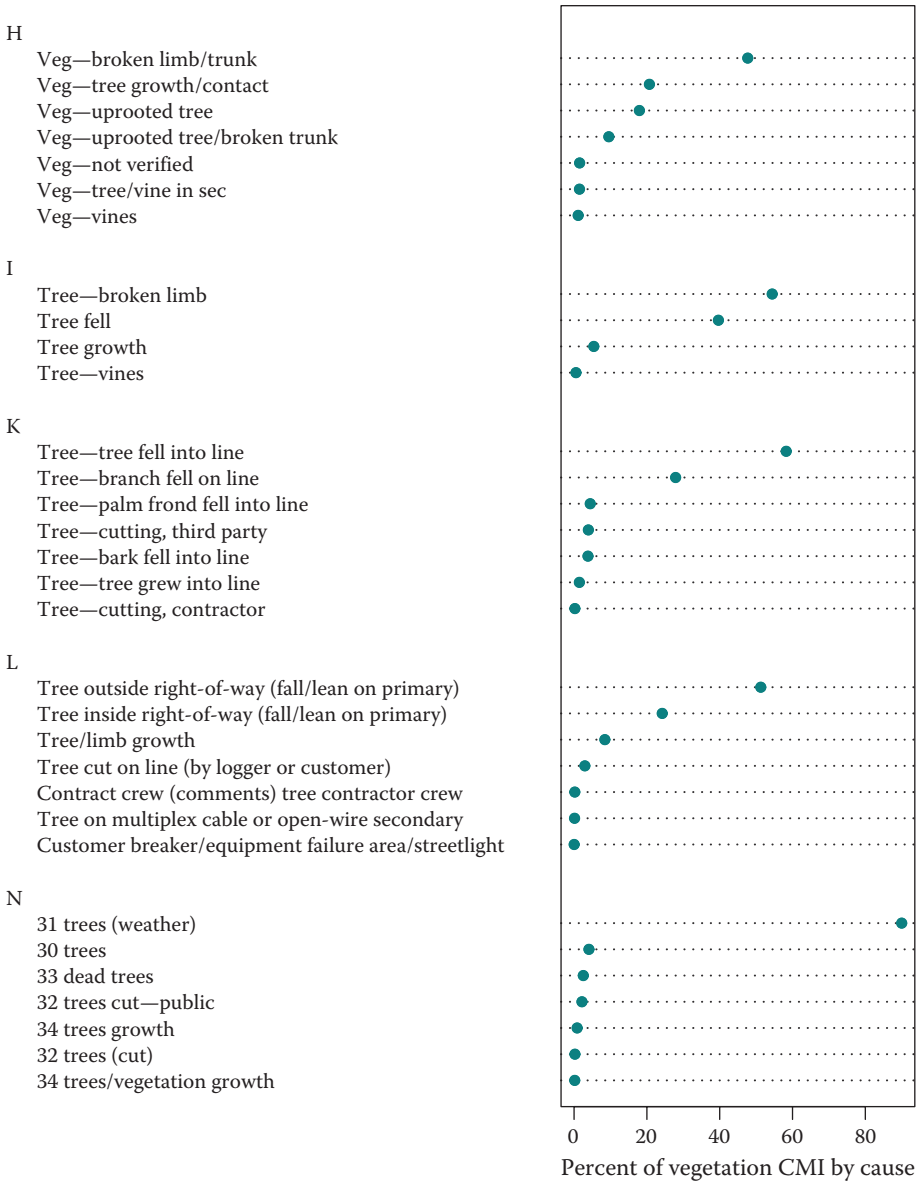

Figure 10.30 Vegetation CMI breakdowns for several utilities. (From EPRI 1013874, *Using Outage Data to Improve Reliability*, Electric Power Research Institute, Palo Alto, CA, 2007. Copyright 2007. Reprinted with permission.)

10.7.3.3 Unknown

Interruption events with no clear cause do happen, both in fair weather or during storms. A fuse may blow, and crews do not find any obvious damage, and successfully replace the fuse. Use of "unknown" is better than guessing, but you do not want field crews or dispatchers using the unknown category as a catch-all to expedite their

work. Unknowns vary from 4% to 20% of CI and from 2% to 15% of CMI (EPRI 1013874, 2007).

Comment fields can help as a check to see if unknowns are really unknown. Even if the final cause is unknown, crews can report what they do know about the event and actions they took to diagnose the interruption and restore service. For example, a comment of "PATROLLED CIRTCUIT BTWN R1 AND RM2 NOTHING FOUND RESTORED TO NORMAL" suggests that it truly is unknown. A comment of "FAILED CABLE IN MH287" suggests a known cause. Some in-between events are suitable, such as a cause of unknown but a comment of "POSSIBLE LIGHTNING" or "140 T refused, possible animal." The troubleshooter may not know the exact cause, but they know something. Outage reviews by dispatchers when closing outage tickets can help ensure that unknowns that become known get filled in appropriately.

Patterns of interruption events have been used to classify "unknown" faults, particularly animal-caused faults and lightning-caused faults. Chow et al. (1993) and Chow and Taylor (1995) developed a classification routine to identify animal-caused faults based on the following outage inputs: circuit ID, weather code, time-of-day of the event, phases affected, and protective device that operated. Animal faults are more likely during fair weather, mornings, where only one phase is affected, and for a transformer or tap fuse. These same classification strategies can be used to estimate how many of the "unknown" interruption events are actually animal-caused faults. Williams (2003) describes an approach on Progress Florida's data using maximum likelihood analysis to assign a portion of unknown events to animal causes and to lightning causes. His analysis used the following outage characteristics: month, hour, device, and weather. Williams successfully used this approach for both unknown and "wind/storm" outages. Of their unknown and storm/wind outages, 58% became assigned to lightning, and 35% became animal-caused.

10.7.4 Prioritizing Circuits

Whether selecting circuits for a worst-performing circuits program or for targeting a reliability program like reclosers, how circuits are prioritized is important. There are different philosophies for prioritizing circuits. Some factors should be kept in mind:

- *Variability*—This is the biggest factor. Whether feeders are prioritized by CI, CMI, SAIFI, or SAIDI, all indices exhibit significant variability. Ranking feeders just based on 1 year of data can give misleading results. Three or more years of data is preferable.
- *Major storms*—Including major storms increases variability, especially for SAIDI.

Figure 10.31 highlights the variability of annual data for a utility with 10 years of data. Even circuits with good performance over a 10-year period can have some bad years. The worse 5% of circuits in any given year are highlighted. The worst 5% are selected as those being in either the worst 5% in SAIFI or SAIDI. This shows that typical or even normally good circuits can show up on the worse 5% list. This data shows

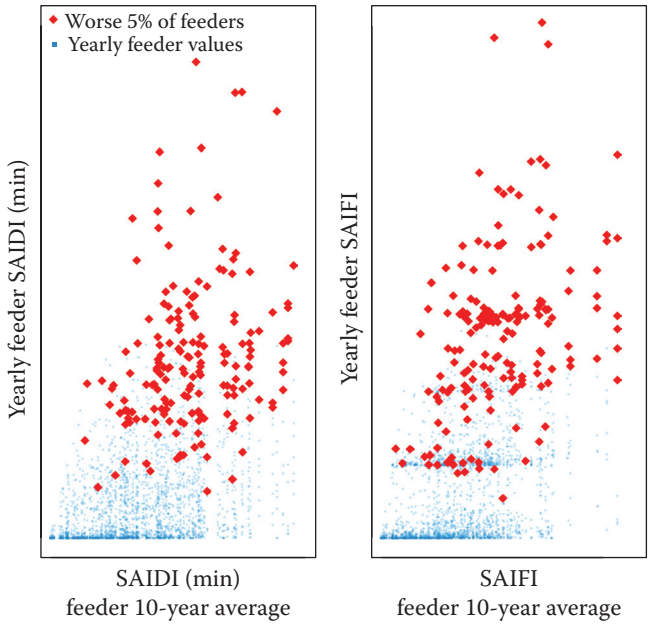

Figure 10.31 Annual worse 5% of circuits highlighted along with all circuits. (From EPRI 1013874, *Using Outage Data to Improve Reliability*, Electric Power Research Institute, Palo Alto, CA, 2007. Copyright 2007. Reprinted with permission.)

that a number of the circuits that appear on the worst 5% list do so just because of an unlucky year. Utilities should not generally spend money on these circuits when other circuits may be more deserving of improvements.

Figure 10.32 shows the portion of circuits "misclassified" based on CI according to different CI thresholds and by different time windows. Misclassifications are defined as circuits that do not have a 14-year average that is below the given threshold. Longer time spans reduce misclassifications. Figure 10.33 shows the portion of circuits "really misclassified" based on the 2% worst circuits. By "really misclassified" it means that circuits that are selected as being in the worst 2% for the given window are not even in the worst 10% based on the 14-year average.

Further, consider these general guidelines for prioritizing circuits:

- *Major storms*—Including storms greatly increases year-to-year variability (especially for SAIDI) and makes it more difficult to accurately prioritize improvements. Exclude major storms when determining the worst circuits and for deciding how much effort to give to a specific feeder.
- *Customer weighting*—Circuits with more customers should have priority when allocating improvement budgets. First, more customers are impacted by the circuit's performance, and second, improving that feeder will help your utility's overall system benchmarks.
- *Almost major events*—Unlucky events can cause a normally good feeder to have a bad year. These can include a storm or storms that did not quite meet the definition of *major*. Review outage records and note the impact of out-of-the-ordinary events.

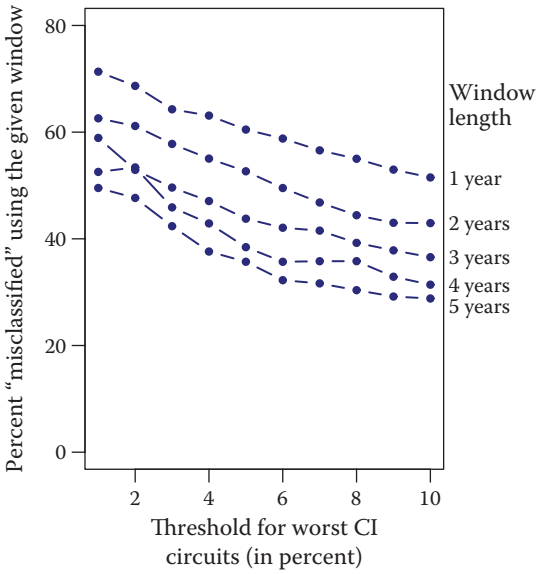

Figure 10.32 Portion "misclassified" based on several windows (CI). (From EPRI 1013874, *Using Outage Data to Improve Reliability*, Electric Power Research Institute, Palo Alto, CA, 2007. Copyright 2007. Reprinted with permission.)

- *Historical records*—Do not rely on just 1 year's performance to decide if a circuit needs improvement. Compare the circuit's performance on a longer time period. If the circuit has performed well over time—compared to similar circuits—then the circuit just had an unlucky year.

See Brown (2004) and Brown et al. (2005) for further evidence on the effects of variability and support of using longer time periods for prioritizing circuits.

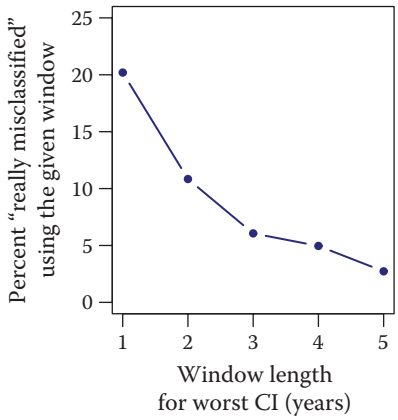

Figure 10.33 Portion of circuits "really misclassified" based on several windows (CI). (From EPRI 1013874, *Using Outage Data to Improve Reliability*, Electric Power Research Institute, Palo Alto, CA, 2007. Copyright 2007. Reprinted with permission.)

Another way to use a longer-term circuit prioritization is to determine the amount of effort to expend on a circuit in a regulatory worst-circuit program. A circuit on the worst-performing list may not need corrective action if

- The circuit has a 10-year historical record that is in the top 50% of circuits
- The circuit's 10-year historical record is within the 75% prediction band of circuits with those characteristics
- Nothing significant has changed on the circuit in question

If you are prioritizing a subset of circuits on which to implement a reliability improvement program, getting statistically valid data can take even longer. For example, if you are examining a hazard-tree program, and vegetation accounts for one-third of outages, then one should expect to need well more than 3 years of data to be reasonably confident of results. Figure 10.34 shows an analysis that is comparable to Figure 10.33 but for tree-caused interruptions only. The number "really misclassified" (again meaning the top 2% of circuits are not even in the top 10% long-term) starts higher, and a somewhat longer window length is needed to achieve the same error. For an even smaller dataset (like lightning-caused interruptions), more time is required.

Beyond outage data, there are other ways to prioritize circuits. On way is to consider the circuit's exposure and customer counts. Much of a circuit's inherent reliability is due to the mainline lengths and customers on those sections.

An alternative to help prioritize circuits is to use a prediction model. Brown (2004) and Brown et al. (2005) describe an approach of using modeling and predictive tools to identify high-risk circuits.

A prediction model can help provide guidance on whether a circuit on the worst-performing list really needs corrective action. The prediction model provides a baseline and range of performance for circuits of a given voltage, length, and other

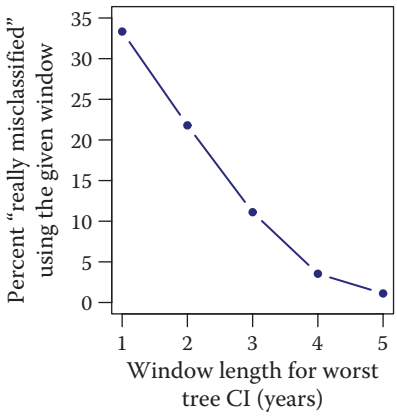

Figure 10.34 Portion of circuits "really misclassified" based on several windows for tree CI. (From EPRI 1013874, *Using Outage Data to Improve Reliability*, Electric Power Research Institute, Palo Alto, CA, 2007. Copyright 2007. Reprinted with permission.)

parameters. The range of performance can be used as an indicator of whether improvement is necessary.

One could use this to decide (as an example) if improvement is necessary if the circuit is historically in the bottom half of performance, and the circuit performs much worse than expected for a circuit with those generic characteristics.

Another approach is to use historical outage data to find fault rates for different circuit types: overhead mains, underground, single-phase taps, and so on. These fault rates can be used in a reliability analysis program to predict reliability indices. This is a useful way to apply reclosers and other sectionalizing programs.

The fault-rate and the prediction approaches do not require long-term historical outage data. They are still based on outage data, just not the limited data for one circuit.

10.7.5 Evaluating Program Performance

To better manage reliability, utilities can use outage data to evaluate reliability improvement programs and maintenance programs. Answers from this analysis can help utilities prioritize programs based on dollars spent per expected CI avoided (helps SAIFI) or based on dollars spent expected CMI avoided (helps SAIDI). Outage data is the primary source of data to estimate the impacts of programs (with CI or CMI), whether it is normal tree maintenance, worst circuit improvement programs, cable replacements, animal guard programs, or recloser or automation programs. We need to evaluate the incremental CI or CMI improvement. Proper evaluation can be difficult. Some factors to consider include

- Compare similar sets. This can include having a control group and an experimental group (where the program is applied).
- Use enough data points to get statistically valid results.
- Try to separate out different effects. For example, if a hazard-tree program is initiated at the same time as recloser installations, how would we separate these effects?

Consider what is referred to in statistical terminology as "regression to the mean," meaning that outliers tend to shift back toward the average; things tend to even out. If you have a worst-circuits program, the 5% or 1% circuits are definitely outliers. Just due to variability, these outliers will tend to shift back to the center (get better). It can be difficult to avoid these problems when making before and after comparisons. This effect is most pronounced for worst-circuits programs where the lowest ranking circuits are picked—obviously—because they have poor SAIFI (or SAIDI or other benchmark). In subsequent years, they will almost always be better, even if you do not do anything to the circuit.

Figures 10.35 and 10.36 summarize an example where the worst 2% of circuits for both CI and CMI are compared to the same benchmarks the year before and the year after. These results are based on the medians and upper and lower quartiles for a set of circuits in an EPRI dataset. As expected according to the principle of regression to the mean, the prior year and the following year tended to be less than the year as

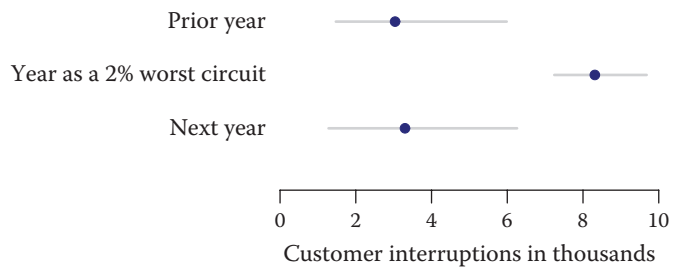

Figure 10.35 Comparison of CI the year before and the year after being one of the worst 2% circuits. The dots mark the site median, and the bands show the range between the upper and middle quartile. (From EPRI 1013874, *Using Outage Data to Improve Reliability*, Electric Power Research Institute, Palo Alto, CA, 2007. Copyright 2007. Reprinted with permission.)

a worst circuit. Note that this analysis includes storms. For both CI and CMI, the medians drop to about one-third. A similar analysis using averages for CI shows that during years as worst circuits, the worst circuits averaged 9070 customer interruptions, and the prior year average was 4120, and the following year average was 4300 customer interruptions. If you do not account for regression to the mean in comparing the worst-circuit year to the next year (or the year after improvements), you might see improvements that are not really there.

Options to avoid regression-to-the-mean problems include

- If worst circuits are selected based on one year's data, compare the set of data one year before the selection year to the year after the improvements were made. For multiyear selection programs, try comparing the years prior to the selection period to a time period after the selection period.
- Instead of comparing a set of circuits before to the same set after improvements are made, compare the worst against a similar set. For example, if you have a worst 1% program, after improvements are made, compare the performance of the worst 1% to the performance of the set of circuits in the range from 1% to 2% (the almost worst set, where no improvements were made).

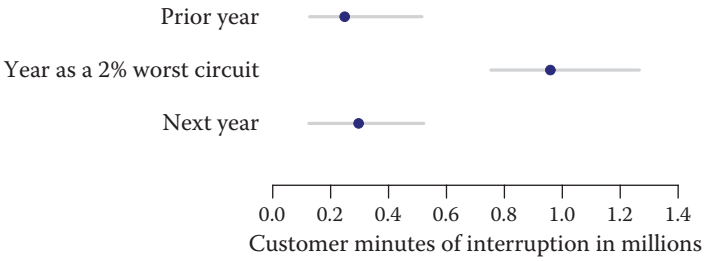

Figure 10.36 Comparison of CMI the year before and the year after being one of the worst 2% circuits. The dots mark the site median, and the bands show the range between the upper and middle quartile. (From EPRI 1013874, *Using Outage Data to Improve Reliability*, Electric Power Research Institute, Palo Alto, CA, 2007. Copyright 2007. Reprinted with permission.)

- Use a true control group. On some random portion of your worst circuits, do nothing. On the rest, make improvements. Now, any performance differences should stand out after improvements are made.

Regression to the mean is most pronounced on worst-circuits programs, but it can factor into many other program evaluations. Any program that is applied based on rankings of recent performance is susceptible to this.

When different effects come into play, several strategies are possible to separate effects. Consider the example of the hazard tree program being applied at the same time as the recloser program. Effects here are mostly straightforward to evaluate. The first step would be to separate out the circuits where one, the other, or both measures were applied. These sets can be compared with each other and also against a control group. Appropriate benchmarks can be used to provide natural segmentation of effects. Outage cause codes can also help. The hazard tree program can be compared with tree CI (SAIFI), tree CMI (SAIDI), or tree faults per mile. The recloser program can be evaluated by looking at impact on customers interrupted per fault on the three-phase mains.

Reclosers, automation programs, and other sectionalizing programs can be evaluated after the fact by recreating event impacts had the sectionalizing not been done. Consider a recloser added to the middle of a circuit. The time period after the recloser was added can be evaluated. For each lockout of that recloser, we can calculate the CI and CMI as if the recloser was not there. The CI and CMI are higher because more customers are interrupted for each event. The incremental difference between CI or CMI with and without is the added benefit of the device. This does not tell the whole story because the restoration time is probably shorter with the recloser lockout than with a whole circuit lockout because there is less circuit to patrol to find the fault. Even given that caveat, this is still a good way to evaluate sectionalizing programs.

10.8 Restoration

Restoration affects SAIDI and CAIDI. Repair times vary considerably as shown in the example in Figure 10.37. Response time degrades quickly during storms as all crew resources are locked up. Even if "major events" are excluded, the responsiveness during bad weather still greatly influences restoration time.

The main way to improve restoration time is to sectionalize the circuit to bring as many customers back in as quickly as possible. Other methods that help reduce the repair time include the following:

- *Prepare*—Use weather information, including lightning detection networks, to track storms. Call out crews before the interruptions hit. Coordinate crews to distribute them as efficiently as possible.
- *Train*—Storm response training and other crew training help improve responsiveness.
- *Locate*—Use faulted circuit indicators and better cable locating equipment; have better system maps available to crews patrolling circuits. Use more fuses—a fuse

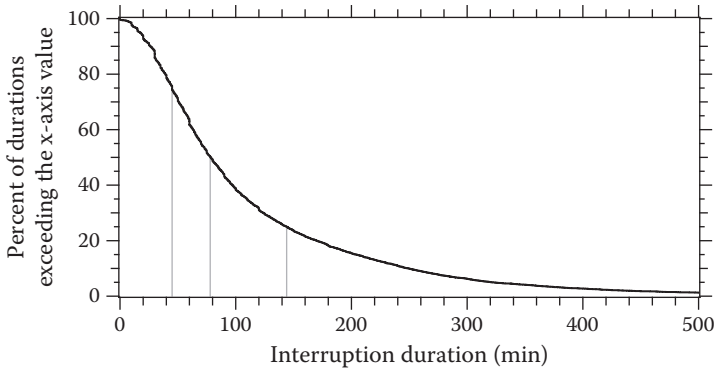

Figure 10.37 Distribution of interruption durations at one utility. (Data from IEEE Working Group on System Design, http://grouper.ieee.org/groups/td/dist/sd/utility2.xls, 2001.)

is a cheap fault locator; with a smaller area downstream of a fuse, less length needs patrolling. Better communication between the call center and crews helps send crews to the right location.

- *Prioritize*—During storms, prioritize efforts based on those that get the most customers back in service quickly. Many of the first efforts will be sectionalizing; next will be efforts to target the repairs affecting most customers (faults on the distribution system mainline). Downed secondary and other failures affecting small numbers of customers have to wait. When prioritizing, safety implications should override reliability concerns; make sure downed wire cases are de-energized before other repairs.
- *Target*—Apply maintenance to address the faults that require long repair times. Tree faults have long repair times, so tree trimming reduces the repair time.

An outage management system helps with restoration and gives utilities information to help improve performance. But, be aware that implementing an outage management system will normally make reliability indices worse—just the indices. The actual effect on customers is not worse; in fact, it should improve as utilities use the outage management system to improve responsiveness. Unfortunately, better record keeping translates into higher reliability indices. Several utilities have reported that SAIFI and SAIDI increase between 20% and 50% after implementing an outage management system. See Bouford and Warren (2006) for one method of quantifying this impact using outage data. McGranaghan et al. (2006) offer another approach. Outage management systems do help improve reliability and efficiency. Responsiveness improves as outage information is relayed more directly to crews. Outage management systems also calculate the reliability indices for utilities and can generate reports that utilities can use to target certain circuits for inspections or tree trimming. In addition to reliability, customer satisfaction improves, as call centers (either automated or people operated) are able to give customers better information on restoration times.

Knowing when most storms tend to occur and when most interruptions occur helps for scheduling crews. Typically, summer months are the busiest. Of course, each area has somewhat different patterns. Figure 10.38 shows SAIDI data from four

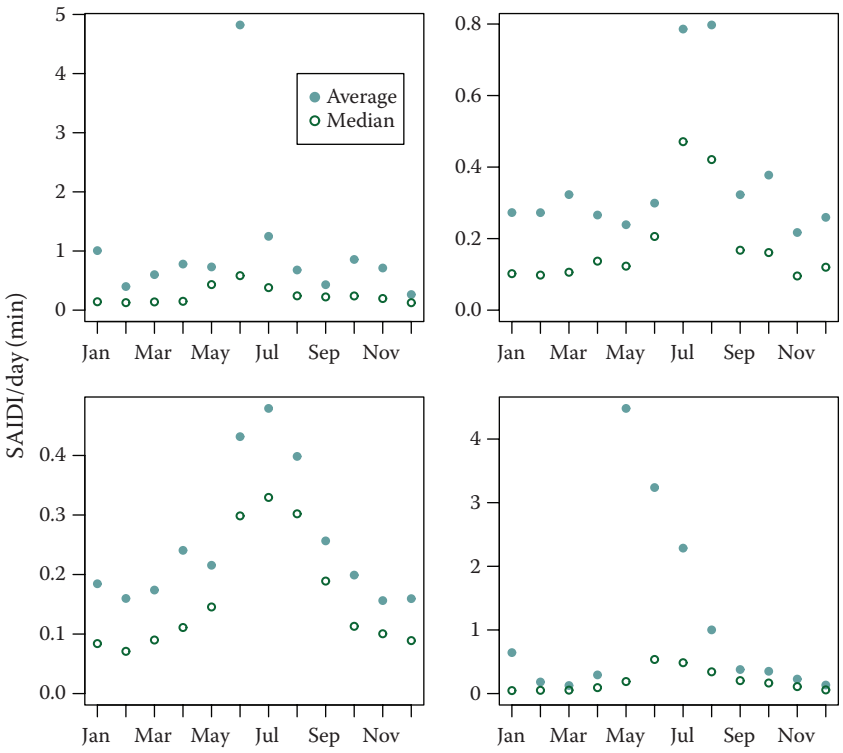

Figure 10.38 SAIDI per day by month of the year for four utilities.

U.S. utilities. Both a median and an average are shown—the median represents a typical day; the average counts toward the yearly index. One or two severe storm days can appreciably raise the average for the given month. Some utilities are hit much more by storms (those with high ratios of average to median).

Safety: Remember safety. Always. Reliability is important, but not worth dying for. Do not push repairs so quickly that crews take shortcuts that might create dangerous situations. Tired crews and rushed crews make more mistakes. Do not work during active lightning storms or other dangerous conditions. Make sure that the right people are doing the job; make sure they use the right tools, take enough breaks, and follow normal safety precautions.

10.9 Interruption Costs

Damaged equipment, overtime pay, lost sales, damage claims from customers—interruptions cost utilities money, plenty of money. An EPRI survey found that an average of 10% of annual distribution costs are for service restoration with ranges at different utilities from 7.6% to 14.8% (EPRI TR-109178, 1998). Restoration averaged $14 per customer and $0.20 per customer minute of interruption. The $14 is per customer, not per customer interrupted, but it is close for a typical SAIFI of 1

TABLE 10.5 Surveyed Utility Restoration Costs in U.S. Dollars

	Average	Range
Per customer	14	12–17
Per customer-minute of interruption	0.2	0.16–0.27
Per mile of overhead circuit	1000	300–1850
Per mile of underground circuit	3100	1700–5500

Source: Data from EPRI TR-109178, *Distribution Cost Structure—Methodology and Generic Data*, Electric Power Research Institute, Palo Alto, CA, 1998.

to 1.5; assuming SAIFI equals 1.4, the average restoration cost is $10 per customer interrupted. Table 10.5 shows the restoration costs scaled by several factors. Not surprisingly, most of the cost is the actual construction to fix the problem as shown in Figure 10.39. Also, labor is the biggest portion of restoration costs, more than 70% in the survey. Note that the costs reported in the survey are costs directly associated with the restoration; lost kWh sales and damage claims are not included.

Costs escalate for major storms that severely damage distribution infrastructure. Table 10.6 shows the Duke Energy company's costs for several major storms. Many of these storms had much higher than normal costs per customer interrupted (as well as very high absolute costs).

Some utilities also consider the costs to customers when planning for reliability. Costs of interruptions for customers vary widely, depending on the type of customer, the size of customer, the duration of the interruption, and the time of day and day of the week. Costs are highest for large commercial and industrial customers—Table 10.7 shows averages of customer costs for large commercial and industrial customers for various interruptions and short-duration events. Costs rise for longer-duration interruptions. Table 10.8 shows surveyed interruption costs for one utility's customers. We have to be careful of surveyed results of reliability surveys; utility customers often will not actually pay for solutions to eliminate the interruptions, even if the solution has a very short payback assuming their claimed costs of losses.

Based on customer costs, the U.S. Department of Energy has developed an Interruption Cost Estimate (ICE) Calculator (US DOE, 2011) based on the work in LBNL-2132E (2009) and Sullivan et al. (2010).

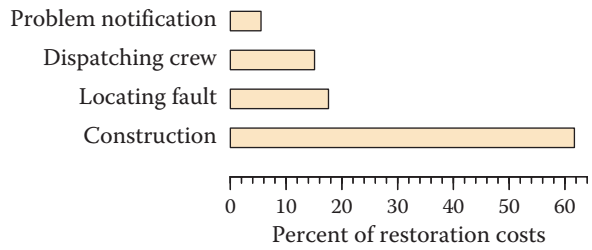

Figure 10.39 Breakdown of utility restoration costs. (Data from EPRI TR-109178, *Distribution Cost Structure—Methodology and Generic Data*, Electric Power Research Institute, Palo Alto, CA, 1998.)

TABLE 10.6 Restoration Costs during a Typical Year and during Major Storms for the Duke Energy Company

Date	Storm Type	Customers Interrupted	Cost, $k	Cost per Customer Interrupted, $
May 1989	Tornadoes	228,341	15,190	67
September 1989	Hurricane Hugo	568,445	64,671	114
March 1993	Wind, ice, and snow	146,436	9176	63
October 1995	Hurricane Opal	116,271	1655	14
January 1996	Western NC snow	88,076	873	10
February 1996	Ice storm	660,000	22,906	35
September 1996	Hurricane Fran	409,935	17,472	43

Source: Data from Keener, R. N., The estimated impact of weather on daily electric utility operations, Social and Economic Impacts of Weather, *Proceedings of a Workshop at the University Corporation for Atmospheric Research*, Boulder, CO, 1997. Available at http://sciencepolicy.colorado.edu/socasp/weather1/keener.html.

TABLE 10.7 Survey of Interruption Costs to 299 Large Commercial and Industrial Customers

	4-h Interruption, No Notice	1-h Interruption, No Notice	1-h Interruption with Notice	Momentary Interruption	Voltage Sag
Production time lost, hours	6.67	2.96	2.26	0.70	0.36
Percent of work stopped	91%	91%	91%	57%	37%
Average total costs	$74,835	$39,459	$22,973	$11,027	$7694
Costs per monthly kWh	0.2981	0.0182	0.0438	0.0506	0.0492

Source: Data from Sullivan, M. J., Vardell, T., and Johnson, M., *IEEE Transactions on Industry Applications*, vol. 33, no. 6, pp. 1448–58, November/December 1997.

TABLE 10.8 Survey of Interruption Costs to Puget Sound Energy Customers

	12-h Interruption	4-h Interruption	1-h Interruption	Momentary Interruption
Commercial and industrial	$5144	$2300	$1008	$109
Residential	$25.95	$12.73	$8.32	$3.64

Source: Adapted from Sullivan, M. and Sheehan, M., Observed changes in residential and commercial customer interruption costs in the pacific northwest between 1989 and 1999, *IEEE Power Engineering Society Summer Meeting*, 2000.

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Selected responses to: Close In Or Patrol?

Our company policy is to try to close and then patrol.

A line fuse is blown. Primary is on the ground. Children are around it. And you want to try it first! You better patrol the line!

I think you should patrol first. We once killed a farmer's cow because primary was down on his fence. Lucky it was just a cow.

Our Company Policy is to Close in on the line on arrival, if the phone center has not recieved any wire down calls. I'm not sure this is a good policy, because Mr and Mrs Customer don't know a powerline from a washline.....I personally would ride the line and then when I was convinced that I have made a good call, close in.....Be CAREFUL.....

www.powerlineman.com

11

Voltage Sags and Momentary Interruptions

Contents

11.1 Location 559
11.2 Momentary Interruptions 561
11.3 Voltage Sags 563
11.3.1 Effect of Phases 568
11.3.2 Load Response 569
11.3.3 Analysis of Voltage Sags 570
11.4 Characterizing Sags and Momentaries 571
11.4.1 Industry Standards 571
11.4.2 Characterization Details 573
11.5 Occurrences of Voltage Sags 574
11.5.1 Site Power Quality Variations 576
11.5.2 Transmission-Level Power Quality 578
11.6 Correlations of Sags and Momentaries 579
11.7 Factors That Influence Sag and Momentary Rates 579
11.7.1 Location 580
11.7.2 Load Density 581
11.7.3 Voltage Class 582
11.7.4 Comparison and Ranking of Factors 582
11.8 Prediction of Quality Indicators Based on Site Characteristics 583
11.9 Equipment Sensitivities 586
11.9.1 Computers and Electronic Power Supplies 586
11.9.2 Industrial Processes and Equipment 590
11.9.2.1 Relays and Contactors 591
11.9.2.2 Adjustable-Speed Drives 593
11.9.2.3 Programmable Logic Controllers 595
11.9.3 Residential Equipment 595
11.9.4 Post-sag Inrush 596
11.10 Solution Options 600
11.10.1 Utility Options for Momentary Interruptions 600
11.10.2 Utility Options for Voltage Sags 600
11.10.2.1 Raising the Nominal Voltage 600
11.10.2.2 Line Reactors 601
11.10.2.3 Neutral Reactors 601
11.10.2.4 Current-Limiting Fuses 603
11.10.3 Utility Options with Nontraditional Equipment 603
11.10.3.1 Fast Transfer Switches 603
11.10.3.2 DVRs and Other Custom-Power Devices 605

11.10.4 Customer/Equipment Solutions 606
11.11 Power Quality Monitoring 607
References 609

The three most significant power quality concerns for most customers are

- Voltage sags
- Momentary interruptions
- Sustained interruptions

Different customers are affected differently. Most residential customers are affected by sustained interruptions and momentary interruptions. For commercial and industrial customers, sags and momentaries are the most common problems. Each circuit is different, and each customer responds differently to power quality disturbances. These three power quality problems are caused by faults on the utility power system, with most of them on the distribution system. Faults can never be completely eliminated, but we have several ways to minimize the impact on customers.

Of course, several other types of power quality (PQ) problems can occur, but these three are the most common; sags and momentary interruptions are addressed in this chapter (other power quality disturbances are discussed in the next chapter).

"The lights are blinking" is the most common customer complaint to utilities. Other common complaints are "flickering," "clocks blinking," or "power out." The first step to improving power quality is identifying the actual problem. Sustained interruptions are the easiest to classify since the power is usually out when the customer calls. The "blinking" is harder to classify:

- Is it momentary interruptions caused by faults on the feeder serving the customer?
- Is it voltage sags caused by faults on lateral taps or adjacent feeders?
- Is it periodic voltage flicker caused by an arc welder or some other fluctuating load on the same circuit?

Some strategies for identifying the problem are

- For commercial or industrial customers, does the customer lose all computers or just some of them? Losing all indicates the problem is momentaries; losing some indicates the problem is sags.
- Is it just the lights flickering? Do any computers or other electronic equipment reboot or reset? If it is just the lights, the problem is likely to be voltage flicker caused by some fluctuating load, which could be in the facility that is having problems.
- If approximate times of events are available from the customer, we can compare these times against the times of utility protective device operations. Of course, to do this, the utility times must be recorded by a SCADA system or a digital relay or recloser controller. If these are available, it is often possible to correlate a customer outage to a utility protective device. If the protective device is a circuit breaker or recloser upstream of the customer, the cause was probably a momentary interruption. If the protective device is on an adjacent circuit or the subtransmission system, the likely cause was a voltage sag.

- A review of the number of operations of the protective devices on the circuit, if these records are kept, can reveal whether the customer is seeing an abnormal number of momentary interruptions or possibly sags from faults on adjacent feeders.
- Does the flickering occur because of changes in the customer load? For example, in a house, does sump-pump starting cause the lights to dim in another room? If so, look for a local problem. A likely candidate—a loose neutral connection—causes a reference shift when load is turned on or off.
- Are other customers on the circuit having problems? If so, then the problem is probably due to momentary interruptions and not just a customer that is very sensitive to sags. Momentary interruptions affect most end users; voltage sags only impact the more sensitive end users.

11.1 Location

Fault location is the primary factor that determines the disturbance severity to customers. Figure 11.1 shows several fault locations and how they impact a specific

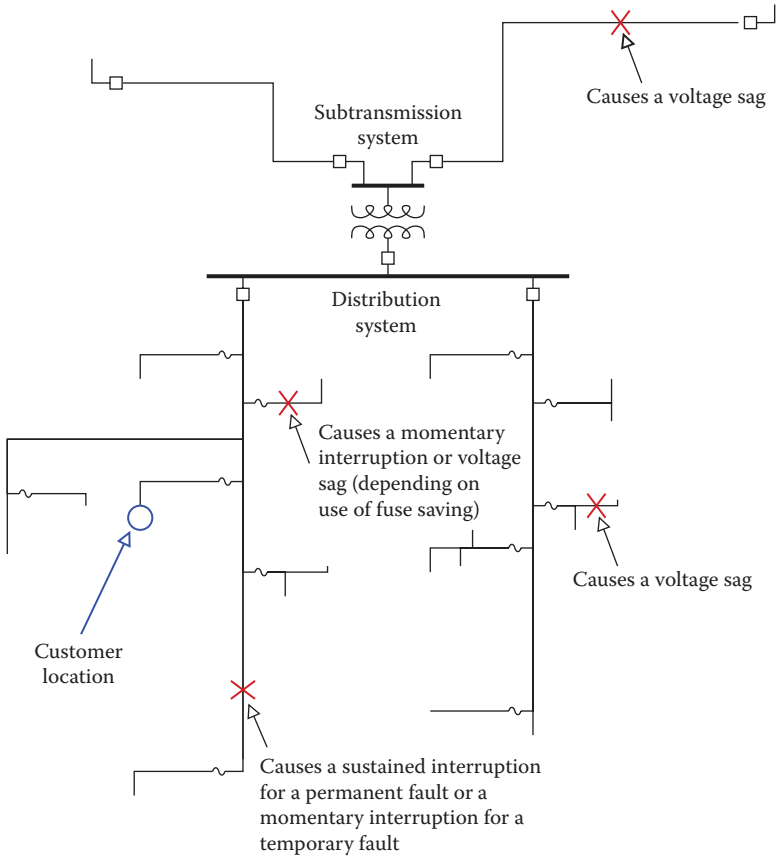

Figure 11.1 Example distribution system showing fault locations and their impact on one customer.

customer differently. A fault on the mains causes an interruption for the customer. If the fault is permanent, the customer has a long-duration interruption, but if the fault is temporary, the interruption is short as the protective device recloses successfully. A fault on a lateral tap causes a voltage sag unless fuse saving is used. With fuse saving, the fault on the tap causes a momentary interruption as the substation breaker or recloser tries to prevent the fuse from blowing.

Faults on adjacent feeders cause voltage sags, the duration of which depends on the clearing time of the protective device. The depth of the sag depends on how close the customer is to the fault and the available fault current. Faults on the transmission system cause sags to all customers off of nearby distribution substations. We can depict all of the possible fault locations by areas of exposure or areas of vulnerability as shown in Figure 11.2. Each exposure area defines the vulnerability for the specific customer. For sags, we have different areas of vulnerability based on the severity of the sag. An outline of the area that causes sags to below 50% is tighter than the area of vulnerability for sags to below 70%. We can use the area of vulnerability curves to help target maintenance and improvements for important sensitive customers.

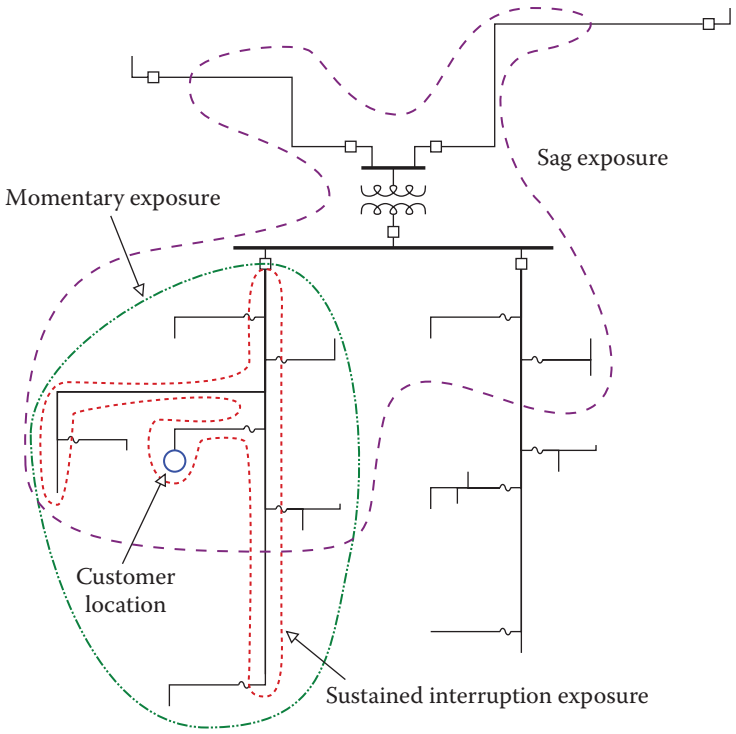

Figure 11.2 Example distribution system showing outlines of circuit exposure that cause a voltage sag, a momentary interruption, and a sustained interruption for one customer location.

11.2 Momentary Interruptions

Momentary interruptions primarily result from reclosers or reclosing circuit breakers attempting to clear temporary faults, first opening and then reclosing after a short delay. The devices are usually on the distribution system, but at some locations, momentary interruptions also occur for faults on the subtransmission system. Terms for short-duration interruptions include *short interruptions*, *momentary interruptions*, *instantaneous interruptions*, and *transient interruptions*, all of which are used with more or less the same meaning. The dividing line for duration between sustained and momentary interruptions is most commonly thought of as 5 min (1 min is also a common definition).

Table 11.1 shows the number of momentary interruptions based on surveys of the reliability index MAIFI. MAIFI is the same as SAIFI, but it is for short-duration rather than long-duration interruptions.

The number of momentary interruptions varies considerably from circuit to circuit and utility to utility. For example, in the EEI survey, the median of the utility averages is 5.4, but MAIFI ranged from 1.4 at the "best" utility to 19.1 at the "worst." Weather is obviously an important factor but so are exposure and utility practices. See Figure 11.3 for distributions of utility survey results.

TABLE 11.1 Surveys of MAIFI

Survey	Median
1995 IEEE (IEEE Std. 1366-2000)	5.42
1998 EEI (EEI, 1999)	5.36
2000 CEA (CEA, 2001)	4.0

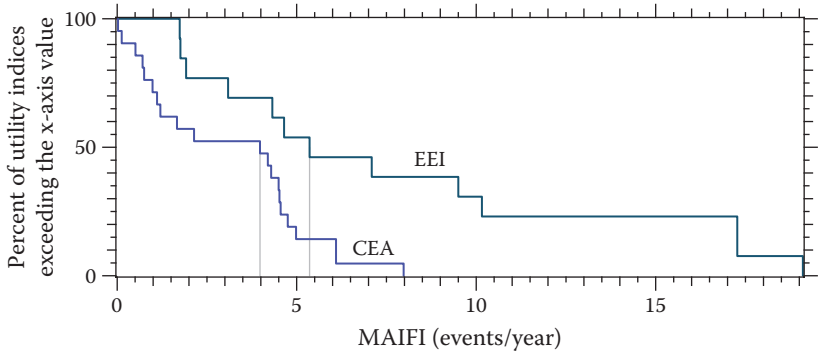

Figure 11.3 Distribution of utility MAIFI indices based on industry surveys by EEI and CEA. (Data from CEA, *CEA 2000 Annual Service Continuity Report on Distribution System Performance in Electric Utilities*, Canadian Electrical Association, 2001; EEI, EEI Reliability survey, *Minutes of the 8th Meeting of the Distribution Committee*, March 28–31, 1999.)

There is a difference between the reliability definition and the power quality definition of a momentary interruption. The reliability definition (IEEE Std. 1366-2012) is

> The brief loss of power delivery to one or more customers caused by the opening and closing operation of an interrupting device. Two circuit breaker or recloser operations (each operation being an open followed by a close) that briefly interrupt service to one or more customers are defined as two momentary interruptions.

In addition, there is a distinction (IEEE Std. 1366-2012) between momentary interruptions and momentary interruption *events*:

> An interruption of duration limited to the period required to restore service by an interrupting device. Such switching operations must be completed within a specified time of five minutes or less. This definition includes all reclosing operations that occur within five minutes of the first interruption. If a recloser or circuit breaker operates two, three, or four times and then holds (within five minutes of the first operation), those momentary interruptions shall be considered one momentary interruption event.

Momentary interruption events and the associated index $MAIFI_E$ (E for event) better represent the impact on customers. Since we expect the first momentary disrupts the device or process, subsequent interruptions are unimportant. Momentary interruptions are most commonly tracked by using breaker and recloser counts, which implies that most counts of the momentaries are based on MAIFI and not $MAIFI_E$. To accurately count $MAIFI_E$, a utility must have a SCADA system or other time-tagging recording equipment.

The power quality definition of a momentary interruption (IEEE Std. 1159-1995) is based on the voltage characteristics rather than the cause:

> A type of *short duration variation*. The complete loss of voltage (<0.1 pu) on one or more phases for a time period between 0.5 cycles and 3 sec.

Several extra events fall under the power quality definition of a momentary interruption. The power quality definition includes both operations of interrupting devices as well as very deep voltage sags. For this book, the reliability definition of a momentary interruption is used. The difference is worth remembering. Momentary interruptions that are tracked by using breaker and recloser counts are different from momentary interruptions recorded by power quality recorders. Table 11.2 shows momentary interruptions as recorded by several power quality studies using the power quality definition and an estimate of the reliability definition where very short events are excluded.

Momentaries can be improved in several ways, including the following:

- *Reduce faults*—tree trimming, tree wire, animal guards, arresters, circuit patrols, and so on
- *Reclose faster*
- *Limit the number of customers interrupted*—single-phase reclosers, extra downstream reclosers, not using fuse saving, and so on.

TABLE 11.2 Average Annual Number of Momentary Interruptions from Monitoring Studies

Study	Power Quality Definition[a] 1 Cycle–10 sec	Reliability Definition[a] 20 Cycles–10 sec
EPRI feeder sites (5-min filter)	6.4	4.5
NPL (5-min filter)	7.9	6.8
CEA primary (no filter)	3.2	1.3
CEA secondary (no filter)	6.5	2.8

Source: Data from Dorr, D. S. et al., *IEEE Transactions on Industry Applications*, vol. 33, no. 6, pp. 1480–7, November 1997.

[a]These are not industry standard definitions, just arbitrary time windows chosen to illustrate that the power quality definition of momentary interruptions has more events than a reliability definition.

11.3 Voltage Sags

Voltage sags cause some of the most common and hard-to-solve power quality problems. Sags can be caused by faults some distance from a customer's location. The same voltage sag affects different customers and different equipment differently. Solutions include improving the ride-through capability of equipment, adding additional protective equipment (such as an uninterruptible power supply (UPS)), or making improvements or changes in the power system.

A voltage sag is defined as an rms reduction in the ac voltage, at the power frequency, for durations from a half cycle to a few seconds (IEEE Std. 1159-1995). Sags are also called *dips* (the preferred European term). Faults in the utility transmission or distribution system cause most sags. Utility system protective devices clear most faults, so the duration of the voltage sag is the clearing time of the protective device.

Voltage sag problems are a contentious issue between customers and utilities. Customers report that the problems are due to events on the power system (true), and that they are the utility's responsibility. The utility responds that the customer has overly sensitive equipment, and the power system can never be designed to be disturbance free. Utilities, customers, and the manufacturers of equipment all share some of the responsibility for voltage sag problems. There are almost no industry standards or regulations to govern these disputes, and most are worked out in negotiations between a customer and the utility.

Terminology is a source of confusion. A 30% voltage sag can be interpreted as the voltage dropping to 70% of nominal or to 30% of nominal. Be more precise and say a "sag *to* X (volts or percent)." There is also some difference between a sag to 60% of nominal and a sag to 60% of the prefault voltage. Since most (but not all) equipment are sensitive to the actual voltage, generally refer to sags based on the percentage of nominal voltage.

Figure 11.4 shows a voltage sag that caused the system voltage to fall to approximately 45% of nominal voltage for 4.5 cycles.

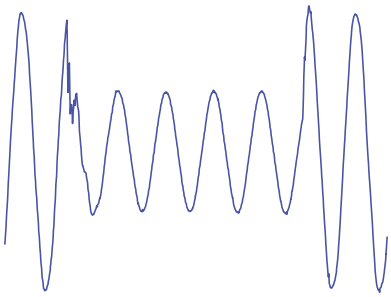

Figure 11.4 Example of voltage sag caused by a fault.

Voltage sags can be improved with several methods on the utility system:

- *Reduce faults*—tree trimming, tree wire, animal guards, arresters, circuit patrols
- *Trip faster*—smaller fuses, instantaneous trip, faster transmission relays
- *Support voltage during faults*—raising the nominal voltage, current-limiting fuses, larger station transformers, line reactors

The voltage during the fault at the substation bus is given by the voltage divider expression in Figure 11.5 based on the source impedance (Z_s), the feeder line impedance (Z_f), and the prefault voltage (V).

The voltage sags deeper for faults electrically closer to the bus (smaller Z_f). Also, as the available fault current decreases (larger Z_s), the sag becomes deeper. The source impedance includes the transformer impedance plus the subtransmission source impedance (often, the subtransmission impedance is small enough to be ignored). The impedances used in the equation depend on the type of fault. For a three-phase fault (giving the most severe voltage sag), use the positive-sequence impedance ($Z_f = Z_{f1}$). For a line-to-ground fault (the least severe voltage sag), use the loop impedance, which is $Z_f = (2Z_{f1} + Z_{f0})/3$. A good approximation is 1 Ω for the substation transformer (which represents a 7- to 8-kA bus fault current) and 1 Ω/mi (0.6 Ω /km) of

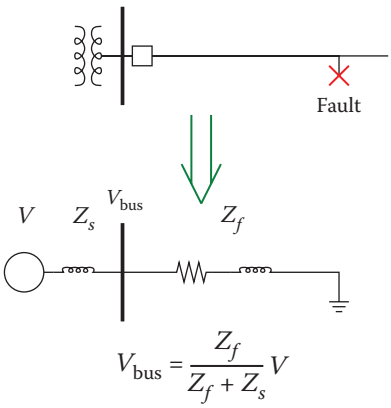

Figure 11.5 Voltage divider equation giving the voltage at the bus for a fault downstream. (This can be the substation bus or another location on the power system.)

overhead line for ground faults. For accuracy, use complex division since the impedances are complex, but for back-of-the-envelope, first-approximation calculations, use the impedance magnitude.

Another way to approximate the voltage divider equation is to use the available short-circuit current at the substation bus and the available short-circuit current at the fault location:

$$V_{\text{bus}} = 1 - \frac{I_f}{I_s}$$

where

V_{bus} = per unit voltage at the substation
I_f = the available fault current on the feeder at the fault location
I_s = the available fault current at the substation bus

Note that this can be used for any type of fault as long as the appropriate fault values are used in the equation. If the angles are ignored, the equation is an approximation (which is usually acceptable). Figure 11.6 shows a profile of the substation bus voltage for faults at the given distance along the line for 12.47, 24.94, and 34.5 kV. The higher-voltage systems have more severe voltage sags for faults at a given distance. The graph also shows that three-phase faults cause more severe sags. Figure 11.7 compares sags on underground and overhead systems.

The effect of feeder faults on voltage sags at the substation bus can be estimated with the following equation:

$$S(V_{\text{sag}}) = n_f \lambda \frac{V_{\text{sag}}}{1 - V_{\text{sag}}} \left(\frac{Z_s}{Z_f} \right)$$

where

S = annual number of sags per year where the voltage sags below V_{sag}
V_{sag} = per unit voltage sag level of interest (in the range of 0 to 1, e.g., 0.7)
n_f = number of feeders off of the bus
λ = feeder mains fault rate per mile (or other unit of distance) per phase, including faults on laterals and including both temporary and permanent faults
Z_f = feeder impedance, Ω/mi (or other unit of distance); usually use $Z_f = (2Z_1 + Z_0)/3$ for ground faults
Z_s = source impedance, Ω

The distribution of voltage sags based on this equation is shown in Figure 11.8 for some common parameters. Several points are noted from this analysis on voltage sags:

- *Exposure*—For 15-kV circuits, we can ignore exposure beyond the first 2 or 3 mi (4 or 5 km) for sags to the bus voltage. The first mile or two is most important as far as circuit improvement, maintenance, or application of current-limiting fuses.

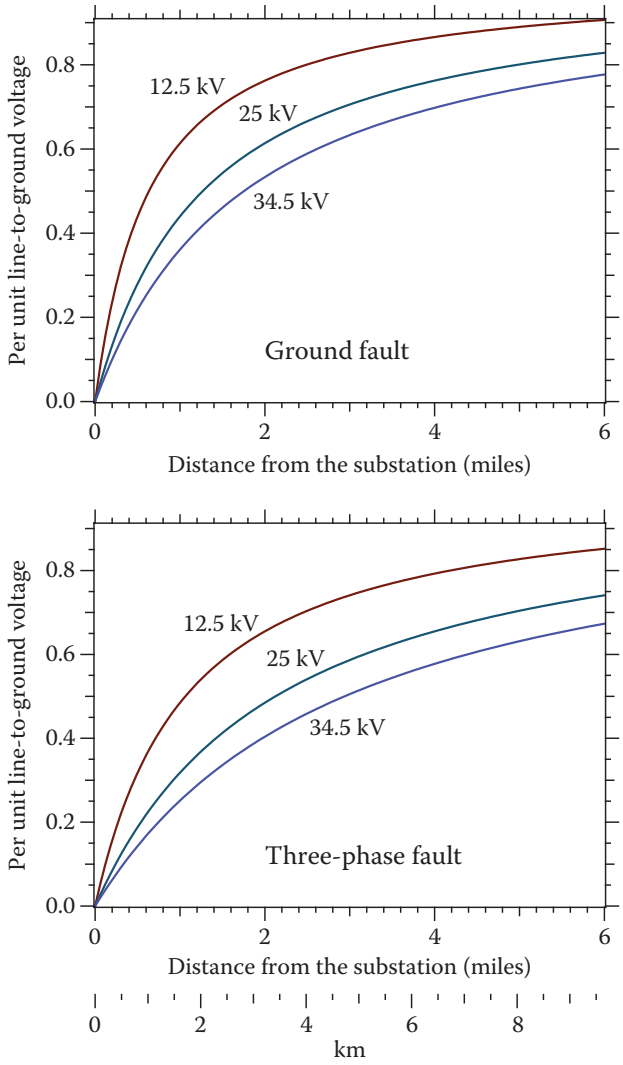

Figure 11.6 Substation voltage profile for faults at the given distance (single-phase and three-phase faults are shown for each voltage—the circuit parameters for the 500-kcmil circuit are the same as those in Figure 8.11).

- *System voltage*—Sags are more severe on higher-voltage distribution systems (especially at 34.5 kV). A fault 4 mi from the substation sags the voltage much more on a 25-kV system than on a 12-kV system because the substation transformer is of a higher impedance relative to the line impedance at higher system voltages. For 24.94 kV, exposure as far as 5 mi from the station is significant.
- *Single versus three-phase faults*—Three-phase faults cause more severe sags than single-line-to-ground faults. Three-phase faults farther away can pull the voltage down.
- *Underground versus overhead*—All-underground circuits have more exposure to sags because cables have lower impedance than overhead lines.

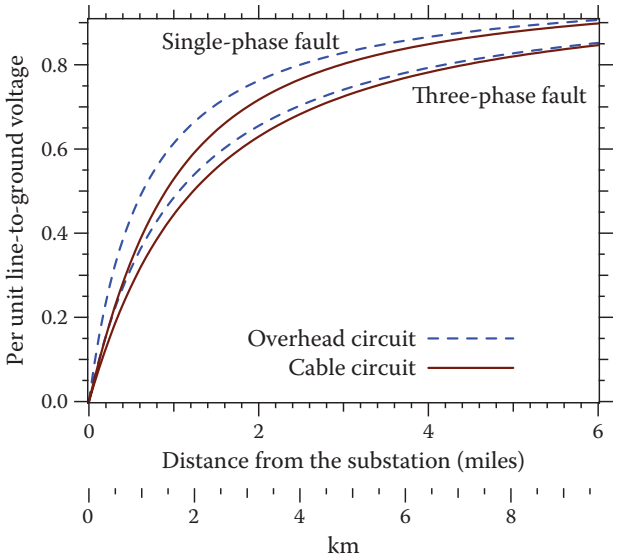

Figure 11.7 Comparison of substation voltage for faults on overhead circuits and cable circuits at the given distance (single-phase and three-phase faults are shown; the circuit parameters are the same as those in Figures 8.11 and 8.12).

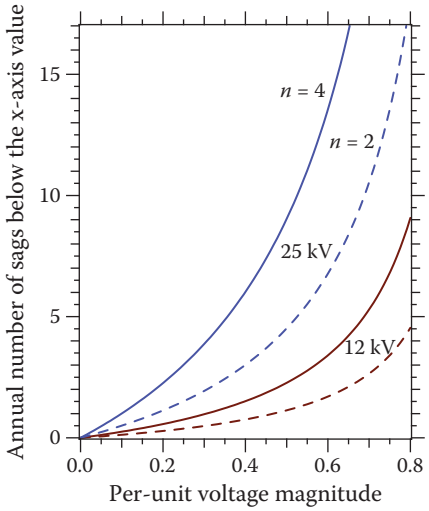

Figure 11.8 Cumulative distribution of substation bus voltage sags per year for the given (25-MVA, 10% transformer, 500-kcmil feeder, $n = 2$ or 4 feeders off of the bus, $\lambda = 1$ faults/phase/mile of mains/year, assumes line-to-ground faults only). (From EPRI 1001665, *Power Quality Improvement Methodology for Wires Companies*, Electric Power Research Institute, Palo Alto, CA, 2003. Copyright 2003. Reprinted with permission.)

- *Number of feeders*—The number of sags on the station bus is directly proportional to the number of feeders off the bus.
- *Transformer impedance*—A lower station transformer impedance (a bigger transformer or lower percent impedance) improves voltage sags.
- *Bus tie*—It does not matter whether a substation bus tie is open or closed. If it is open, a fault only affects half of the feeders. A fault that does occur forces a deeper sag because of a higher effective source impedance. These two effects tend to cancel each other.
- *Voltage regulation*—Raising the nominal voltage improves the voltage seen by customers during a fault. Say that a fault drops the voltage to 0.8 per unit, and the prefault voltage was 1.0 per unit. If the prefault voltage were 1.1 per unit, the voltage during the sag is 0.88 per unit. This is not a big difference, but for equipment sensitive to sags to 0.7 to 0.85 per unit, higher voltages appreciably reduce the number of tripouts.

Customers at the end of a circuit have more severe voltage sags because almost all faults upstream appear as little or no voltage (most actually fit the power quality definition of an interruption, a voltage to below 10%).

11.3.1 Effect of Phases

Three-phase loads are often controlled by single-phase devices (the controls are often the most sensitive element). The effect on three-phase customers depends on how loads are connected and depends on the transformer connection as shown in Table 11.3. In general, if the transformer causes more phases to be affected, the voltage drop is less severe. One situation is not always better than the other. Severity depends on which phases the sensitive devices are located. The type and design of the device and its controls are also factors.

For facility equipment connected *line-to-line*, the wye–wye transformer connection provides the best performance. For facility equipment connected *line-to-ground*, the delta–wye facility transformer is best.

Single-phase sags on distribution systems are more common than two- or three-phase sags. This is expected since most faults on distribution systems are single phase. For example, in EPRI's Distribution Power Quality Study (EPRI TR-106294-V2, 1996), about 64% of voltage sags to below 70% were single phase, while three-phase sags made up 25%, and two-phase sags, 10%. For severe sags below 30% voltage, three-phase events are more common; more than half are three-phase events (see Figure 11.9). This includes momentary interruptions, most of which are three-phase.

TABLE 11.3 Line-to-Ground and Line-to-Line Voltages on the Low-Voltage Side of a Transformer with One Phase on the High-Voltage Side Sagged to Zero

Voltages	Primary Voltages			Voltages Downstream of a Delta–Wye Transformer		
Line-ground	0.00	1.00	1.00	0.58	0.58	1.00
Line-line	0.58	0.58	1.00	0.33	0.88	0.88

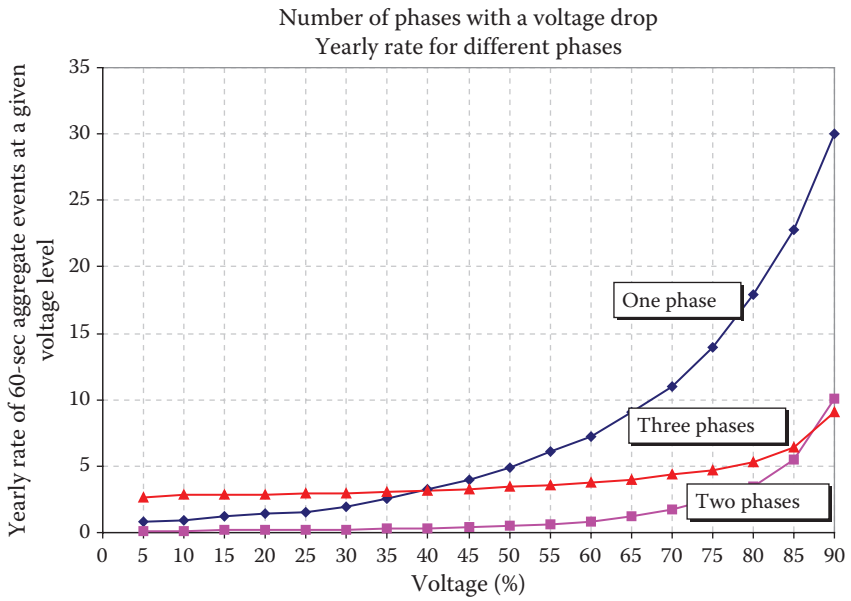

Figure 11.9 Rate of number of phases with a voltage drop in the EPRI DPQ study. (From EPRI TR-106294-V2, *An Assessment of Distribution System Power Quality: Volume 2: Statistical Summary Report*, Electric Power Research Institute, Palo Alto, CA, 1996. Copyright 1996. Reprinted with permission.)

11.3.2 Load Response

During a voltage sag, rotating machinery supports the voltage by feeding current back into the system. Synchronous motors and generators provide the largest boost. Induction motors also provide benefit, but the support decays quickly.

Increasing a motor's inertia is one way to increase the ride through of the motor, which also increases the support to other loads in the facility.

Following a sag, however, the response of loads—particularly motors—may further disturb the voltage. During a sag, motors slow down. After the sag, the motors draw inrush current to speed up. If motors are a large enough portion of the load, this inrush pulls the voltage down, delaying the recovery of voltage. Motors with small slip and those with large inertia draw the most inrush following a sag. These effects are more severe for customers or areas with a large percentage of motor loads and for longer fault clearing times (Bollen, 2000; IEEE Std. 493-1997).

An extreme case of motor inrush sometimes happens with air conditioners. Single-phase air conditioner compressors are prone to stall during voltage sags; during which, the compressor draws locked rotor current, about five or six times normal. Tests by Williams et al. (1992) found that voltages below 60% of nominal for five cycles stalled single-phase air conditioners. Longer-duration sags also stall compressors for less severe sags (in the range of 60 to 70% of nominal). The compressor stays stalled long after the system voltage has returned to normal. It keeps drawing current until thermal overload devices trip the unit, which can take one half of a second. On

the distribution system, this extra current may trip breakers or blow fuses in addition to aggravating the voltage sag.

Adjustable-speed drives (ASDs) and other loads with capacitors (mainly rectifiers) also draw inrush following a voltage sag. During the sag, rectifiers stop drawing current until the dc voltage on the rectifier drops to the sagged voltage. After the sag, the rectifier draws inrush to charge the capacitor. This spikes to several times normal, but the duration is short relative to motor inrush. The inrush may blow fuses or damage sensitive electronics in the rectifier. For severe sags, much of the rectifier-based load trips off, which reduces the inrush.

Normally, we neglect the load response for voltage sag evaluations, but occasionally, we must consider the response of the load, either for its direct impact on voltage sags, or for the impact of the inrush.

11.3.3 Analysis of Voltage Sags

The calculation of the voltage magnitude at various points on a system during a fault at a given location is easily done with any short-circuit program. We make the fairly accurate assumption that the fault impedance is zero. The engineer or computer program finds the duration of the sag using the time–current characteristics of the protective device that should operate along with the fault current through it.

Based on a short-circuit program, the *fault positions method* repeatedly applies faults at various locations and tallies the voltages at specified locations during the faults. The procedures, which may apply thousands of fault locations, result in predictions of the number of voltage sags below a given magnitude at the specified locations. This procedure is well documented in the *Gold Book* (IEEE Std. 493-1997) (see also Conrad et al., 1991).

The faults are applied along each line in a system. The end results are scaled by the fault rate on the line, which can be based on historical results or typical values for the voltage and construction.

We need considerable details for the fault positions analysis, especially a complete system model, including proper zero-sequence impedances and transformer connections (these are left out of many transmission system load-flow models).

Another simpler method for voltage sags is the *method of critical distances* (Bollen, 2000). The approach is to find the farthest distance, the *critical* distance, to a fault that causes a sag of a given magnitude. Pick a sag voltage of interest, 0.7 per unit for example. Find the critical distance for the chosen voltage. Using a feeder map, add up the circuit lengths within the critical distance. Multiply the total exposed length by the fault rate—this is the number of events expected. This method is not as accurate as the fault positions method, but is much simpler: we can calculate the results by hand, and the process of doing the calculations provides insight on the portions of distribution and transmission system that can cause sags to the given customer. We can also target this *area of vulnerability* for inspection or additional maintenance or apply faster protection schemes covering those circuits (to clear faults and sags more quickly).

11.4 Characterizing Sags and Momentaries

11.4.1 Industry Standards

The most commonly cited industry standard for ride through was developed by the Information Technology Industry Council (ITI) (Figure 11.10). The ITI curve updates the CBEMA curve (Computer Business Equipment Manufacturers' Association, which became ITI) and is often referred to as the new CBEMA curve. The ITI curve is not an actual tested standard—computers do not have to be certified to pass some test. The ITI curve is used as a benchmark indicator for comparison of power quality between sites and to track performance over time. Because the ITI curve somewhat represents the ride through of computers, we can single out events below the ITI curve as "suspects," which may trip sensitive equipment.

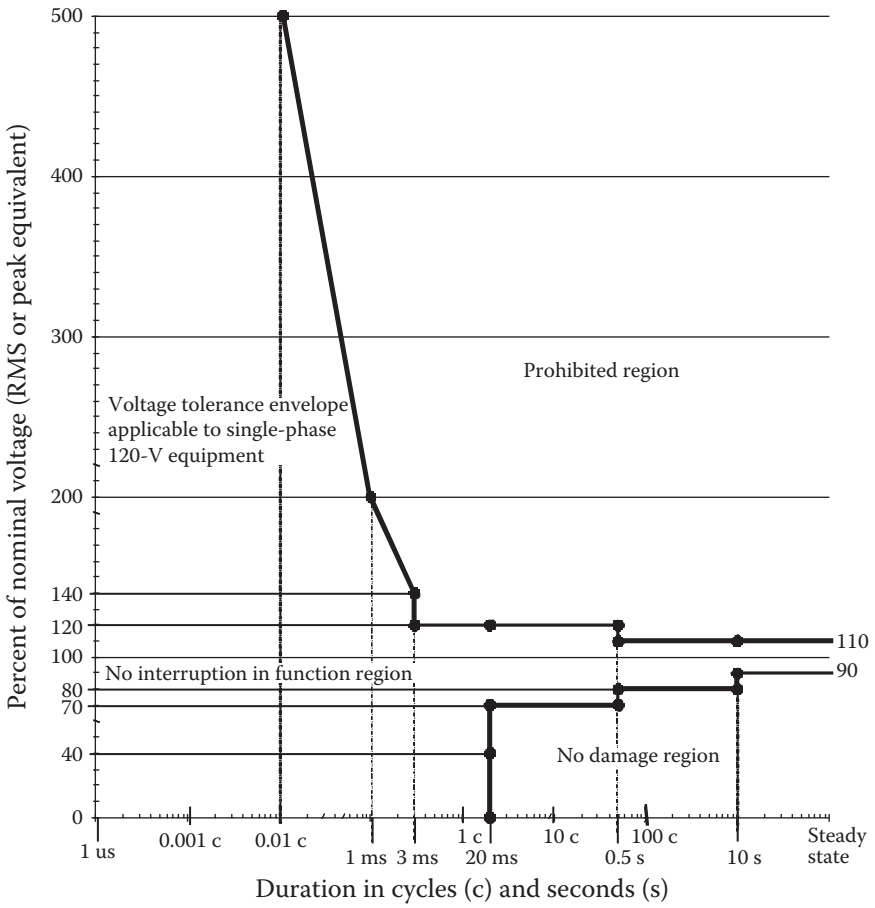

Figure 11.10 ITI curve that shows the typical voltage sensitivity of information technology equipment. (From Information Technology Industry Council (ITI), ITI (CBEMA) curve application note, 2000. Available at http://www.itic.org. With permission.)

Another major equipment standard has been produced by the semiconductor industry (SEMI F47-0200, 1999). The major advance of the SEMI set of standards is that there is an actual test standard for the equipment. To meet the SEMI standard, equipment must pass a series of voltage sag tests (SEMI F42-0600, 1999). The standard defines many factors, including sag generator and other test apparatus requirements, sampling specimens, test procedure, and reporting of test results. The SEMI standard is only for single-phase sags; for three-phase equipment with a neutral, six tests are done: each phase-to-neutral voltage is "sagged," and each phase-to-phase voltage is sagged in turn. For three-phase equipment without a neutral, each phase-to-phase voltage is tested with a sag generator.

The SEMI curve focuses exclusively on voltage sags. In some cases, the SEMI curve is stricter than the ITI curve, and it appears that way when the two curves are graphed together as in Figure 11.11. The SEMI curve has a deeper voltage sag characteristic. The most severe point on the SEMI curve is the 0.2-sec sag for a voltage to 50% of nominal. However, some equipment could meet the SEMI requirement but not pass the ITI curve points. The main types of equipment that fall into this category are relays and contactors. The ITI curve has a 0.02-sec interruption that is enough to disengage many relays and contactors that may survive a 0.2-sec sag to 50% of nominal voltage.

Several power quality indices have been introduced that are similar to the reliability indices (EPRI TP-113781, 1999). Utilities can use these for some of the same purposes as reliability indices: targeting areas for maintenance and circuit upgrades, tracking the performance of regions, and documenting performance to regulators. The most widely used index is SARFI (EPRI TP-113781, 1999; Sabin et al., 1999) defined as

> $SARFI_X$, System Average RMS (Variation) Frequency Index: $SARFI_X$ represents the average number of specified rms variation measurement events that occurred over the assessment period per customer served, where the specified disturbances are those with a magnitude less than X for sags or a magnitude greater than X for swells.

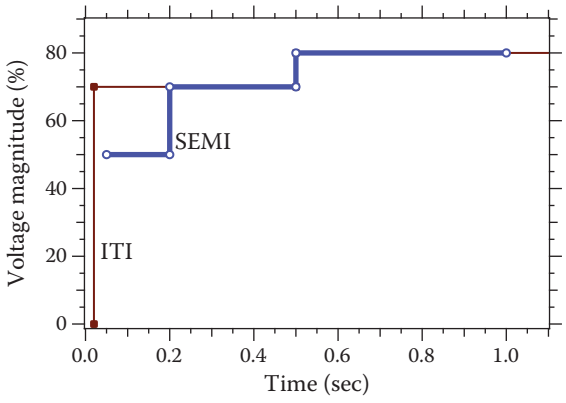

Figure 11.11 SEMI voltage sag ride-through requirement compared against the ITI curve. (SEMI curve from SEMI F47-0200, *Specification for Semiconductor Processing Equipment Voltage Sag Immunity*, Semiconductor Equipment and Materials International, 1999.)

$$\text{SARFI}_X = \frac{\sum N_i}{N_T}$$

where

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

The breakpoints were not chosen arbitrarily. The 90%, 80%, and 70% thresholds are boundaries of the ITI curve, the 50% threshold is a typical breakpoint for motor contactors, and 10% is the dividing line between a sag and an interruption. Two special variations of SARFI have also been defined. $\text{SARFI}_{\text{ITIC}}$ is the number of events below the lower ITI curve. In similar fashion, $\text{SARFI}_{\text{SEMI}}$ is the number of events below the SEMI curve. SARFI can be applied for one monitor (and one customer) or for several monitored locations. It is difficult to extend this concept to make SARFI a system-wide performance indicator like SAIFI—what is straightforward for reliability indices becomes much more complicated for sags because a fault causes different voltages at different locations on the distribution system. It is difficult to find a system-wide average without a vast number of monitors. Approximations must be used to estimate the effects at different customers based on a small number of monitored points.

11.4.2 Characterization Details

Several disturbances often occur within a short time of each other. Commonly, a breaker or recloser goes through several reclosing attempts. The customer sees a sequence of voltage sags. If one of these events causes an end-use disruption, from their point of view, it does not matter if additional events follow within the next few minutes, as the customer is already disturbed. To account for this, we can aggregate events within a rolling time window. Commonly, time windows are 1 and 5 min for calculating SARFI_X or other power quality benchmarks.

Since voltage sags can have different impacts on each phase, how do we account for the differences between a three-phase sag and a single-phase sag? We can tabulate sags in two different ways:

- *Per phase*—Each phase is tracked independently. A three-phase sag counts three times that of a single-phase sag. Single-phase recorders automatically calculate the number of sags per phase.
- *Minimum phase*—A sag event is recorded as the lowest of the three phase voltages. A three-phase sag counts the same as a single-phase sag. SARFI_X uses this approach.

Both approaches are useful depending on the customer and load characteristics. The per-phase method is better for single-phase customers and for customers with three-phase load that is more sensitive to multiple-phase sags. The minimum-phase method is better for facilities where sags on any of the three phases could trip a process. At a three-phase location, the minimum-phase method gives higher numbers of voltage sags.

The line-to-ground and line-to-line voltages may be significantly different during a voltage sag. Ideally, we want to record and benchmark what the critical load sees, but sometimes that is unknown (and, some facilities may have critical loads connected line to line and line to ground). Normally, SARFI is tracked based on how the recorders are connected.

Most voltage sags have a simple shape—the voltage drops in magnitude and stays at a constant value until the fault clears. After that, the voltage returns to its pre-sag value. The rms change is approximately a rectangular wave. The rectangular shape makes classification easy—only a magnitude and a duration are needed. Sometimes, sags do not follow the rectangular shape. If the fault current is not constant, the voltage will not be constant. If the fault evolves from a single line-to-ground fault into a multiple-phase fault, the voltage will change. These types of events are hard to classify, but most of the time, we can ignore them for the purposes of monitoring and collecting statistics at a site. For analysis of specific events that disrupted equipment, review of the rms shape may provide additional meaning beyond just having a magnitude and a duration.

11.5 Occurrences of Voltage Sags

Several power quality monitoring studies have characterized the frequency of voltage sags. The two most widely quoted studies are EPRI's Distribution Power Quality (DPQ) study and the National Power Laboratory's end-use study.

NPL's end-use study recorded power quality at the point of use at residential, commercial, and industrial customers. At 130 sites within the continental U.S. and Canada, single-phase line-to-neutral monitors were connected at standard wall receptacles (Dorr, 1995). The survey resulted in a total of 1200-monitor months of data. Table 11.4 shows the average number of voltage sags that dropped below the given magnitude for longer than the given duration.

EPRI's DPQ project recorded power quality in distribution substations and on distribution feeders, measured on the primary at voltages from 4.16 to 34.5 kV (EPRI TR-106294-V2, 1996; EPRI TR-106294-V3, 1996). It was seen that 277 sites resulted in 5691 monitor-months of data. In most cases three monitors were installed for each randomly selected feeder, one at the substation and two at randomly selected places along the feeder. Table 11.5 shows average numbers of voltage sags for a given magnitude and duration for the DPQ data.

As expected, the number of voltage sags is higher for the end-use NPL study than for the primary-level DPQ study. At the point of use, the nominal voltage is lower, which picks up more voltage sags, especially minor sags. End-use monitoring also picks up events caused internally, mainly voltage sags.

TABLE 11.4 Average Annual Number of Voltage Sags below the Given Magnitude for Longer than the Given Duration from the NPL Data with a 5-Min Filter

	Duration							
Magnitude	1 Cycle	6 Cycles	10 Cycles	20 Cycles	0.5 sec	1 sec	2 sec	10 sec
87%	126.4	56.8	36.4	27.0	23.0	18.1	14.5	5.2
80%	44.8	23.7	17.0	13.9	12.2	10.0	8.0	4.3
70%	23.1	17.3	14.5	12.8	11.5	9.7	7.9	4.3
50%	15.9	14.1	12.9	11.8	10.6	9.4	7.8	4.3
10%	12.2	12.0	11.7	11.0	10.2	9.0	7.5	4.2

Source: Data from Dorr, D. S., et al., *IEEE Transactions on Industry Applications*, vol. 33, no. 6, pp. 1480–7, November 1997.

TABLE 11.5 Average Annual Number of Voltage Sags below the Given Magnitude for Longer than the Given Duration from the EPRI Feeder Data with a 5-Min Filter

	Duration							
Magnitude	1 Cycle	6 Cycles	10 Cycles	20 Cycles	0.5 sec	1 sec	2 sec	10 sec
90%	77.7	31.2	19.7	13.5	10.7	7.4	5.4	1.8
80%	36.3	17.4	12.4	9.3	7.9	6.4	4.9	1.7
70%	23.9	13.1	10.3	8.3	7.2	6.2	4.8	1.7
50%	14.6	9.5	8.4	7.5	6.6	5.9	4.6	1.7
10%	8.1	6.5	6.4	6.2	5.6	5.1	4.0	1.7

Source: Data from Dorr, D. S. et al., *IEEE Transactions on Industry Applications*, vol. 33, no. 6, pp. 1480–7, November 1997.

TABLE 11.6 Annual Number of Power Quality Events (Upper Quartile, Median, and Lower Quartile) for the EPRI DPQ Feeder Sites with a One-Minute Filter

	Duration, sec						
Voltage	0	0.02	0.05	0.1	0.2	0.5	1
0.9	32.8 57.5 104.8	30.8 49.0 95.1	24.4 35.3 65.6	13.6 22.7 38.7	7.6 13.2 24.0	3.3 7.3 14.2	1.4 3.2 8.9
0.8	16.4 31.6 54.1	14.8 26.0 50.1	12.1 20.9 37.9	8.1 15.0 25.1	4.9 9.6 16.9	2.4 5.3 11.0	0.9 2.7 7.5
0.7	10.1 20.5 33.8	8.6 18.8 32.7	8.1 15.3 27.6	5.8 11.3 18.8	4.0 7.8 13.5	1.8 4.5 9.3	0.9 2.5 7.0
0.5	4.7 9.7 19.2	4.5 9.0 17.4	4.2 7.7 14.3	3.5 5.9 11.2	2.3 5.0 9.6	1.4 3.3 7.7	0.8 2.2 5.7
0.3	2.1 4.8 12.8	1.8 4.5 11.0	1.6 4.2 9.5	1.4 3.6 8.6	1.1 3.5 8.3	0.8 2.8 6.6	0.5 1.6 5.1
0.1	0.9 3.2 8.3	0.9 2.9 7.8	0.8 2.8 7.8	0.8 2.7 7.8	0.7 2.7 7.8	0.5 2.2 6.1	0.3 1.6 4.9

Note: A *B* C represent the lower quartile *A*, the median *B*, and the upper quartile *C* of the total number of events below the given magnitude and longer than the given duration (up to 1 min).

Table 11.6 shows cumulative numbers of voltage sags measured at sites during the DPQ study. Table 11.4 and Table 11.5 presented results based on averages—Table 11.6 shows the data based on the median, upper, and lower quartiles. One use of it is to estimate the number of times a year disturbances will affect a device—for example, if a device is sensitive to any event below a voltage of 50% of nominal for longer than

TABLE 11.7 Ratio of Median and Average for DPQ Site Statistics at Feeder Sites

	Median	Average	Ratio of Average to Median
$SARFI_{ITIC}$	21.27	27.86	131%
$SARFI_{SEMI}$	15.28	18.92	124%
$SARFI_{10}$	2.52	5.42	215%

0.1 sec, then Table 11.6 predicts that at half of the sites in the U.S. distribution system, the device misoperates more than 5.9 times per year.

As an indicator, the average misrepresents the typical site power quality. The median represents site data better; here, by definition, 50% of sites have values higher than the median, and 50% have values lower. With balanced distributions such as the normal distribution, the average equals the median. In a skewed distribution, the average is higher than the median. Additionally, poor sites and anomalies such as a severe storm skew the average upward. In the DPQ data, the average is 31 to 115% higher than the median depending on the quality indicator as shown in Table 11.7.

11.5.1 Site Power Quality Variations

EPRI's DPQ project allows us the opportunity to explore how power quality varies at different sites. Completed in 1995, the DPQ project collected data from 24 utility systems at a total of 277 locations on 100 distribution system feeders over a 27-month period. Site and circuit descriptors help us analyze the causes for site variations. Some notable details about the DPQ measurements and our analysis (Short et al., 2003):

- All measurements were on the distribution primary. Of course, most customers connect to the distribution secondary. Normally, this means that a customer's equipment sees more events below a given threshold. Also note that for three-phase customers, a delta–wye transformer distorts the secondary voltages relative to the primary voltages.
- All data was measured at three-phase points on the distribution circuit (single-phase locations were not monitored).
- We present all data based on the worst of the three phases, which is conservative because most faults are single phase. Single-phase customers see fewer sags. In addition, some three-phase equipment is less sensitive to single-phase sags than to three-phase sags.
- Most of the measurements are from phase to ground (the monitors on the ungrounded circuits show phase-to-phase measurements).
- We only used sites with at least 200 days of monitoring.

Power quality varies widely by site. Figure 11.12 shows cumulative distributions of different power quality indices along with statistics and a fit to a log-normal

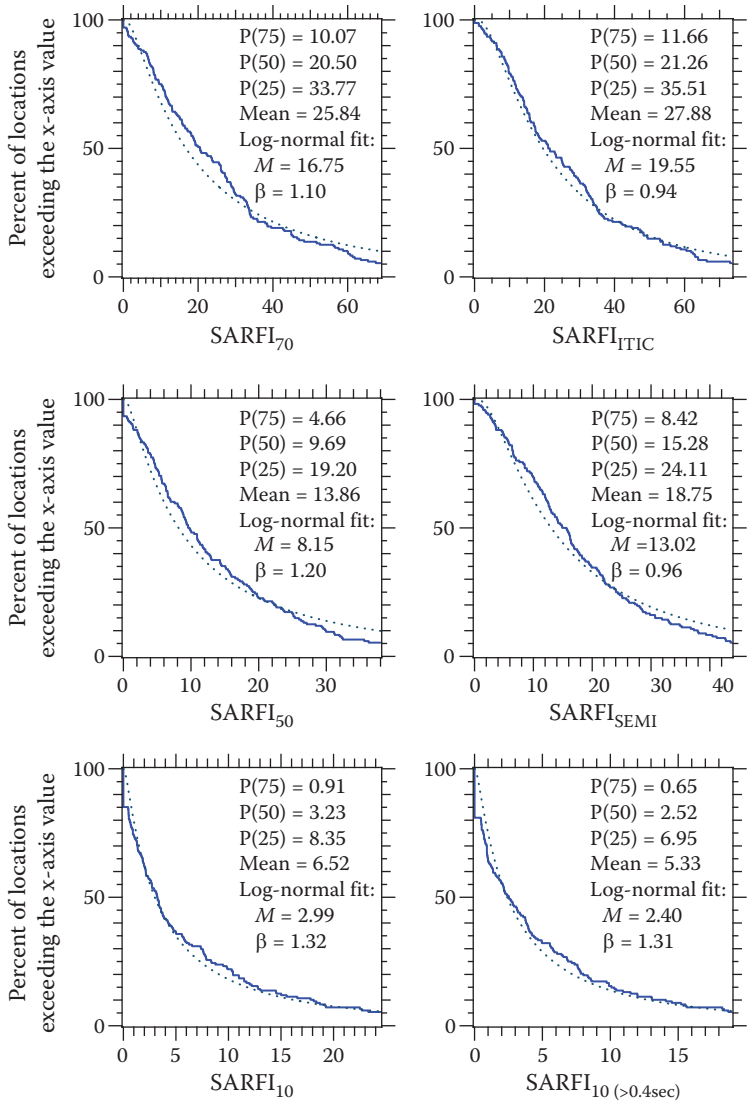

Figure 11.12 Cumulative distributions of DPQ feeder data along with statistics for various indices. SARFI 70, 50, and 10 gives the number of voltage sags below 70%, 50%, and 10%. $SARFI_{ITIC}$ and $SARFI_{SEMI}$ are events below the ITI curve and the SEMI curve, respectively. The dotted line fits a log-normal distribution.

distribution. The left column (SARFI 70, 50, and 10) gives the average annual number of voltage sags below 70, 50, and 10%, which are most applicable for relays, contactors, and other devices that drop out quickly. $SARFI_X$ considers only short-duration rms events, defined as 1/2 cycle to one minute (IEEE Std. 1159-1995). The right column of Figure 11.12 shows data similar to the left column but for criteria that disregards very short events. The ITI curve (Information Technology Industry Council, 2000)

disregards sags less than 0.02 sec, and the SEMI curve (SEMI F47-0200, 1999) disregards sags less than 0.05 sec. The indices that exclude short events are more appropriate for computer power supplies and other devices that ride through short-duration events. $SARFI_{10(>0.4sec)}$ is for momentary interruptions greater than 0.4 sec, which differentiates between deep sags and total loss of voltage due to operation of a breaker or recloser.

The site data is not normally distributed. The site indices are nonnegative, and the distribution skews upward; therefore, we need another distribution, the log-normal, the gamma, or the Weibull. Figure 11.12 includes fits to log-normal distributions. The median (M) of the log-normal distribution equals the mean of the natural log of the values (x_i) raised to e: $M = e^{\text{mean}(\ln(x_i))}$. The log standard deviation is $\beta = \text{sd}[\ln(x_i)]$.

11.5.2 Transmission-Level Power Quality

Large industrial customers, utility's prize customers, are primarily fed with transmission-level service and expect high-quality power. Several semiconductor manufacturing sites provided a basis for developing the SEMI F47 standard for semiconductor tools (Stephens et al., 1999). These sites were primarily served from transmission lines; not all were direct transmission services, but distribution exposure was minimal. While not as extensive as the DPQ study, the monitoring provides good data on the number of events that are primarily from the transmission exposure. Table 11.8 shows summary statistics from the SEMI dataset of 16 sites with 30 total monitor-years of data. Figure 11.13 compares distributions of SEMI data with the DPQ substation data. As expected, the semiconductor manufacturing sites experience fewer events compared to the typical DPQ site. This comparison provides some guidance on the portion of distribution events that are caused on the transmission system. Use caution since these are two independent datasets.

TABLE 11.8 Statistics for Power Quality from the SEMI Monitoring Study, Which Are Primarily Transmission Service

			Median	
	Average	P (75%)	P (50%)	P (25%)
$SARFI_{ITIC}$	4.60	2.05	3.80	5.10
$SARFI_{SEMI}$	2.05	0.00	1.90	3.64
$SARFI_{70}$	4.40	2.05	3.50	5.10
$SARFI_{50}$	0.97	0.00	0.69	1.20
$SARFI_{10}$	0.24	0.00	0.00	0.23

Source: Data from Stephens, M. et al., *Guide for the Design of Semiconductor Equipment to Meet Voltage Sag Immunity Standards*, International SEMATECH, 1999. Technology Transfer #99063760B-TR, available at http://www.sematech.org/public/docubase/document/3760btr.pdf.

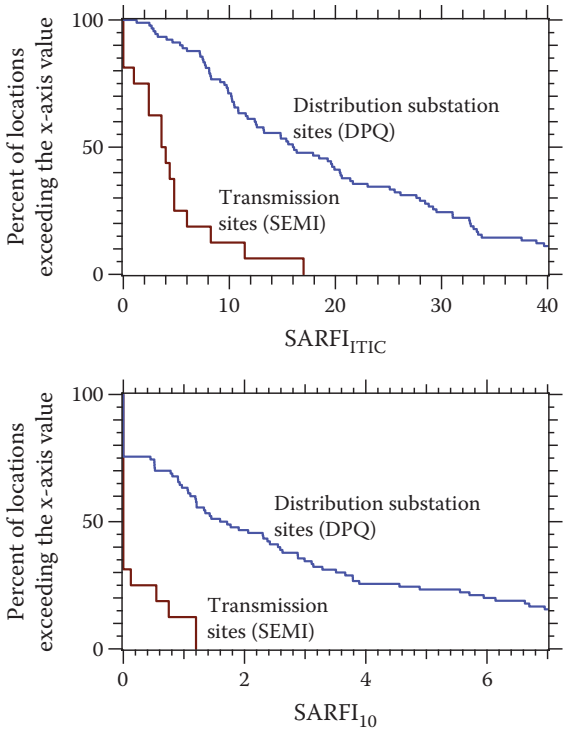

Figure 11.13 Comparison of the 16 SEMI sites with the DPQ substation sites.

11.6 Correlations of Sags and Momentaries

Figure 11.14 shows the number of momentary interruptions at a site plotted against the number of voltage sags. We see that sites with high numbers of momentary interruptions probably also have high numbers of voltage sags. Sites with low numbers of momentary interruptions may have high or low numbers of voltage sags. The correlation coefficient between sags and momentaries for the DPQ sites is 44.8%.

Correlations between deep voltage sags and shallow sags are more pronounced. SARFI$_{90}$ and SARFI$_{50}$ have a 56.9% correlation coefficient. If we break the sites down by load density, the correlation coefficients improve to 90%, 84%, and 74% for urban, suburban, and rural sites.

11.7 Factors That Influence Sag and Momentary Rates

Power system faults cause voltage sags and momentary interruptions. The frequency of faults depends on many factors, including weather, maintenance, and age of equipment. The protection schemes and location of circuit interrupters determine whether a fault causes a voltage sag or an interruption, and the protection system determines

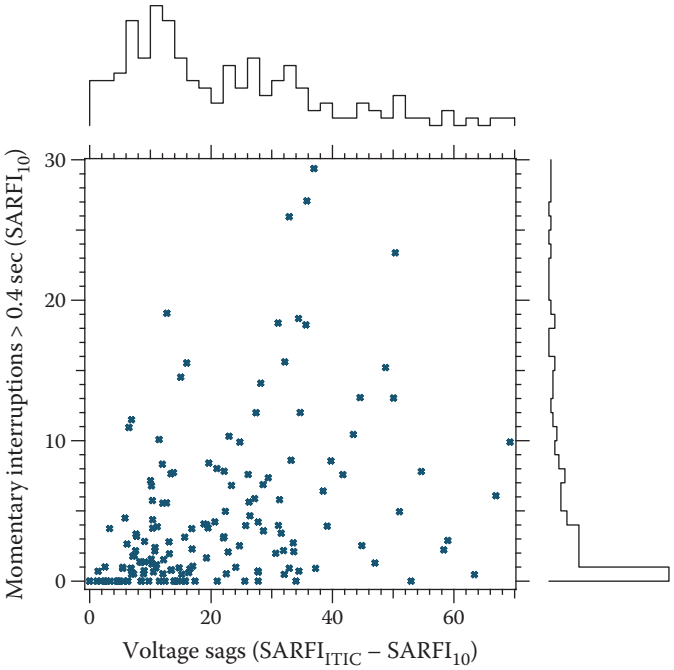

Figure 11.14 Relationship between voltage sags and momentary interruptions (greater than 0.4 sec). Each point gives the average voltage sags and momentary interruptions at a site ($n = 158$).

the event duration. The following sections describe work using EPRI's DPQ data to investigate what factors influence sags and momentaries (Short et al., 2003).

11.7.1 Location

Three monitors were used on each circuit in the DPQ study. One was always at the substation, and two were on the feeder, named "feeder middle" and "feeder end." The feeder sites were randomly picked on the circuits, so the naming is somewhat misleading; "feeder end" does not mean the most distant point from the substation (it just means the most distant of the two monitors randomly placed on the circuit). Since one-third of the monitors are at the substation, the set is biased to "near-substation" customers since most customers are not located near the substation. Although there is some difference between measurement locations, it turns out that it is not drastic. There is surprisingly little difference between the distributions of monitoring locations (see Figure 11.15 for $SARFI_{ITIC}$).

Figure 11.16 shows a more specific comparison of the substation's performance plotted against its two feeder sites. As expected, most feeder sites have more sags than their substation site, especially rural sites. A significant number of feeder sites were better than the substation. Measurement anomalies could produce this (the

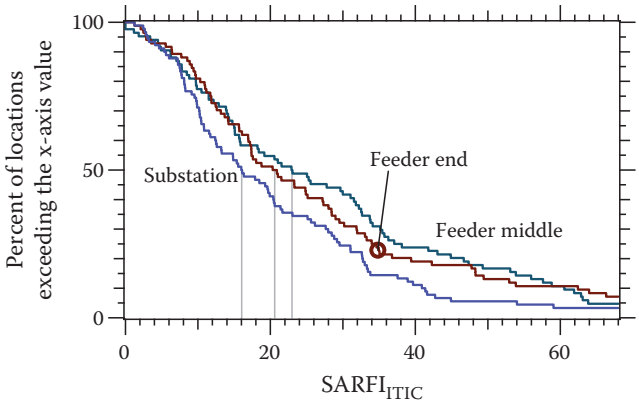

Figure 11.15 Comparison of feeder sites and substation sites in the DPQ data for SARFI$_{ITIC}$.

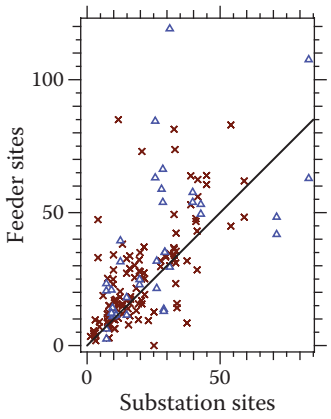

Figure 11.16 SARFI$_{ITIC}$ at substation sites plotted against SARFI$_{ITIC}$ at that substation's feeder sites (triangles indicate rural sites).

substation recorder is down for part of a bad storm season), or it could be real (downstream regulation devices keep the nominal voltage higher or the connected load "pushes" back on the source impedance during bus faults). For most of our analysis, we excluded substation sites, thinking that the feeder sites better represent a random feeder location where customers are fed.

11.7.2 Load Density

Rural sites have more voltage sags and momentary interruptions (see Table 11.9 and Figure 11.17). This is not surprising given the extra lengths of line needed to serve load in low-density areas. Interruptions showed the most dramatic difference.

Why do urban sites not have even more profoundly lower voltage sag rates than suburban and rural sites? After all, urban sites are shorter and mostly underground

TABLE 11.9 Statistics for Momentary Interruptions Longer than 0.4 sec

	P (75%)	Median P (50%)	P (25%)
Rural	2.37	8.56	18.31
Suburban	0.23	2.39	6.71
Urban	0.00	1.37	2.82

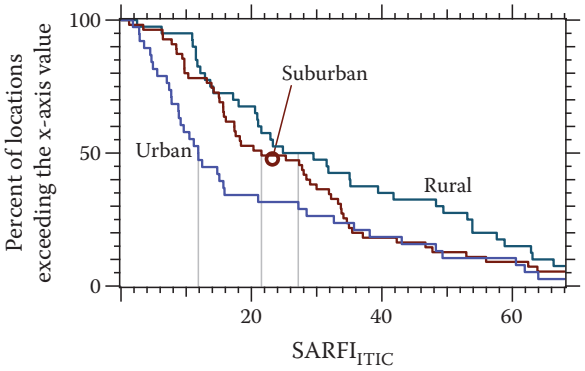

Figure 11.17 Comparison of urban, suburban, and rural sites for SARFI$_{ITIC}$ (feeder sites only).

with fewer faults per mile. The main answer is that urban sites have many more feeders off of a bus. In addition, even though urban circuits are shorter, most of the exposure is close to the substation. So, while many of the faults on rural and suburban circuits are too far away to pull down the substation voltage, almost every fault on an urban circuit causes a significant voltage sag for all customers off of that substation bus.

11.7.3 Voltage Class

Figure 11.18 shows that 5-kV systems have much lower numbers of voltage sags and interruptions. Lower-voltage systems have less feeder exposure, and higher line impedance relative to the station transformer. Fault rates are often lower on 5-kV systems. Somewhat surprisingly, the 25- and 35-kV systems were not worser than the 15-kV systems.

11.7.4 Comparison and Ranking of Factors

We analyzed data available on the DPQ site characteristics to determine what parameters most affected power quality events. Figure 11.19 shows the variations of SARFI$_{ITIC}$ with site characteristics.

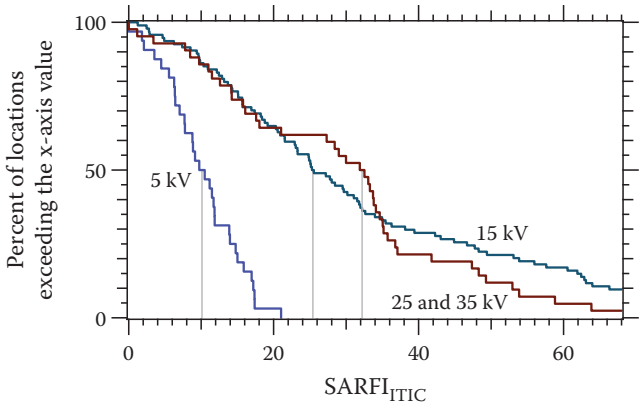

Figure 11.18 Comparison of feeder sites by voltage class in the DPQ data.

The three most significant predictors of excursions below the lower ITI curve are

1. *Circuit exposure*—The total exposure on the circuit including three-phase and single-phase portions is a good predictor of voltage sags. Any fault on the circuit sags the voltage.
2. *Lightning*—Lightning causes many faults on distribution systems, and lightning strongly correlates with voltage sags (based on the 10-year average, 1988–1998, from the U.S. National Lightning Detection Network). In addition, lightning predicts weather patterns—areas with high lightning tend to have more storms and more wind and tree-related faults.
3. *Transformer impedance and number of feeders*—The $n_f \cdot kV^2/MVA_{xfmr}$ term in Figure 11.19 contains the number of feeders off of the transformer bus along with an estimate of the transformer impedance. The transformer impedance is $Z_{\%}kV^2/MVA$, but since the per-unit impedance of station transformers is roughly constant (7 to 10%), we use kV^2/MVA.

This last term requires a bit more explanation. The number of bus sags is directly proportional to n_f, the number of feeders off the bus and to Z_S, the source impedance (a lower station transformer impedance—a bigger transformer or lower percent impedance—improves voltage sags at the station bus). We approximate these two terms as $n_f \cdot kV^2/MVA_{xfmr}$.

Other variables have much less impact on the number of voltage sags than the three main parameters given.

11.8 Prediction of Quality Indicators Based on Site Characteristics

We derive a formula for predicting the number of events for a quality indicator based on a few of the characteristics of the site. If no measurement or historical data is available, this is useful in estimating the utility-side quality.

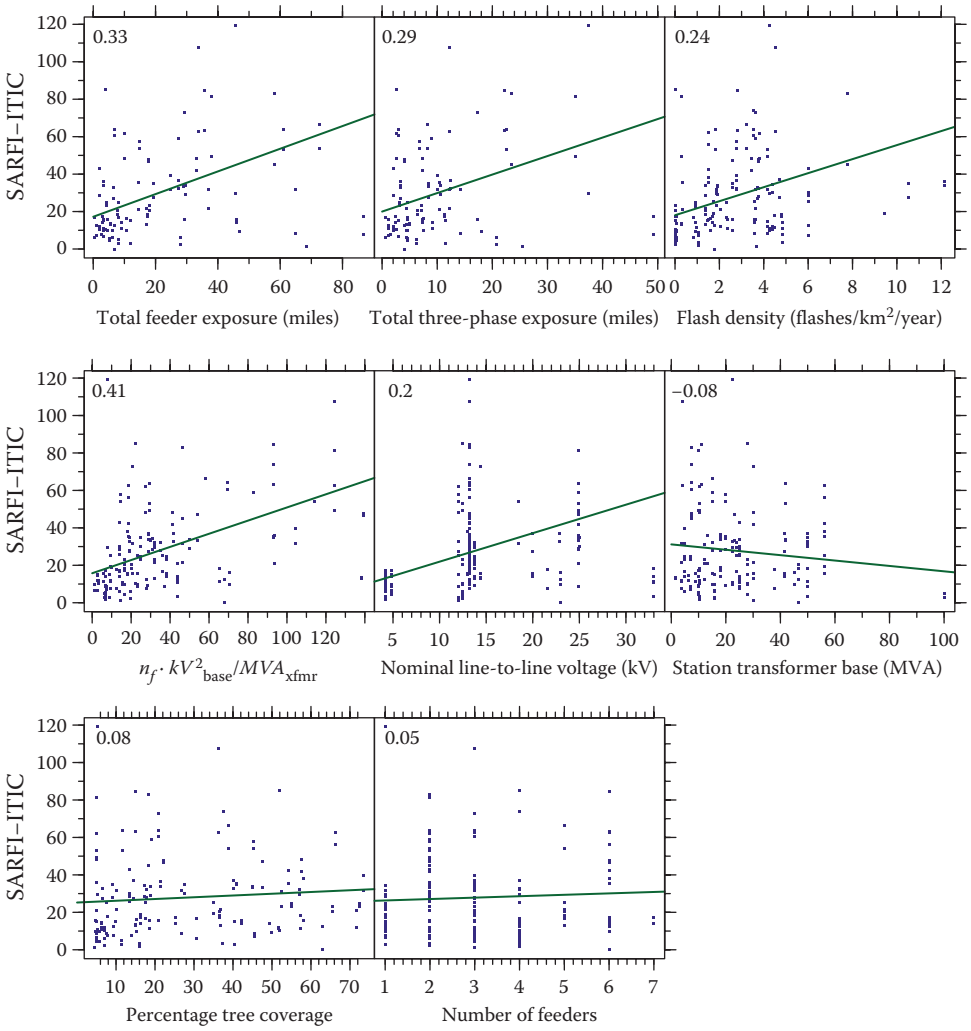

Figure 11.19 Variations in the number of excursions below the lower ITI curve (which are mainly voltage sags) versus various site parameters. The correlation coefficients (r) are given in the upper-left corner of each plot.

Regression techniques are commonly used to find a model prediction formula. A generalized linear model is a least-squares fit to an equation of the following form:

$$y = a_1x_1 + a_2x_2 + \cdots + a_nx_n + \varepsilon$$

The x's are site characteristics (such as base voltage or lightning flash density), and the a's are coefficients fitted to the model. The generalized linear model is somewhat different from a standard linear model; we used a generalization where the distribution of the error ε is assumed to be a gamma distribution rather than a normal distribution in a strictly linear model. A gamma distribution skews to the right, like the log-normal distribution.

A model for estimating $SARFI_{ITIC}$ is

$$N_{ITIC} = 4.74 + 0.293l + 2.47N_g + 0.192\frac{n_f \cdot kV^2}{MVA_{xfmr}} + 8.2 \quad \text{if moderate to heavy tree coverage}$$

where

N_{ITIC} = predicted annual number of events that fall under the lower ITI curve
l = total exposure (including three-phase and single-phase portions) on the circuit, mi (multiply kilometers by 1.609)
N_g = lightning ground flash density, flashes/km²/year
kV = base line-to-line voltage, kV
n_f = total number of feeders off of the substation bus
MVA_{xfmr} = station transformer base rating (open-air rating), MVA

If any of the circuit characteristics are unknown, we could use the following medians from the DPQ data:

l = 14.5 mi (23.4 km)
N_g = 2.57 flashes/km²/year
$\frac{n_f \cdot kV^2}{MVA_{xfmr}} = 25$

All three variable terms in the linear regression are significant to at least 99% (there is less than a 1% chance that the terms of the model do not influence the prediction). The tree coverage term is less certain; there is a 9% chance that the term is not significant. We based the tree coverage term on the University of Maryland's Global Land Cover Facility data from the Advanced Very High Resolution Radiometer (AVHRR). Half of the DPQ sites had more than 19% of the land area covered by trees, which we defined as "moderate to heavy tree cover."

How good is the model? It is decent given all the factors that affect sags and momentary interruptions and inherent variability. Given the variability of power quality events, it is surprising that the model is this good: 34% of the values are within 25% of the prediction, and 60% of the values are within 50% of the prediction. See Figure 11.20 for the prediction scatter.

For an example 12.47-kV case with three feeders, a 25-MVA transformer, a flash density of 4 flashes/km²/year, moderate tree coverage, and a total exposure of 20 mi (32 km), the model predicts 29.8 events per year. For this case, the data shows a prediction interval with a 50% confidence level of between 15.6 and 34.2 events per year (the 90% confidence prediction interval is between 0 and 68.3). The data is so dispersed that the model is not good enough to use for precision estimates (such as in a contract for premium power).

The site characteristics most affecting sags but not included in this model (because no information was available) are (1) subtransmission exposure and characteristics and (2) percentage of the circuit that was underground.

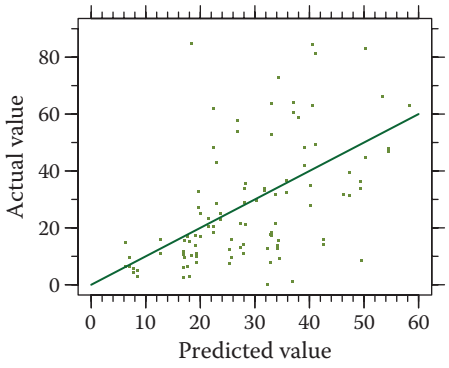

Figure 11.20 Actual values versus predicted values for the model predicting the annual average number of events below the lower ITI curve.

A reasonable model for predicting momentary interruptions is

$$N_{10} = \begin{pmatrix} 5.52 \text{ if rural} \\ 0.29 \text{ if suburban} \\ -1.61 \text{ if urban} \end{pmatrix} + 0.116 l_3 + 0.27 N_g + 1.24 \frac{n_f \cdot kV}{MVA_{\text{xfmr}}}$$

where

N_{10} = the predicted annual number of events with voltage less than 10% of nominal for more than 0.4 sec

l_3 = the three-phase circuit exposure, mi

The parameters differ somewhat from $\text{SARFI}_{\text{ITIC}}$ predictors. Two of the strongest indicators of momentary interruptions are load density and three-phase circuit exposure. Other significant parameters are the lightning activity and a term with voltage, number of feeders, and transformer MVA. The model is not as good as the ITI model, but all parameters have more than a 95% probability of affecting the result. The site characteristic most affecting momentaries that is not included in the model for lack of information is whether fuse saving is used.

11.9 Equipment Sensitivities

11.9.1 Computers and Electronic Power Supplies

Computers and other equipment with electronic power supplies are the most widely found equipment that are sensitive to power quality disturbances. The power supply is typically a switched mode power supply as shown in Figure 11.21. Computers have a wide range of sensitivities. The ride-through capability for interruptions of several computers is summarized in Figure 11.22. Many of the computers had ride through of more than 0.1 sec (0.28 sec was the best of this set of studies), and some could not even ride through a 0.01-sec interruption.

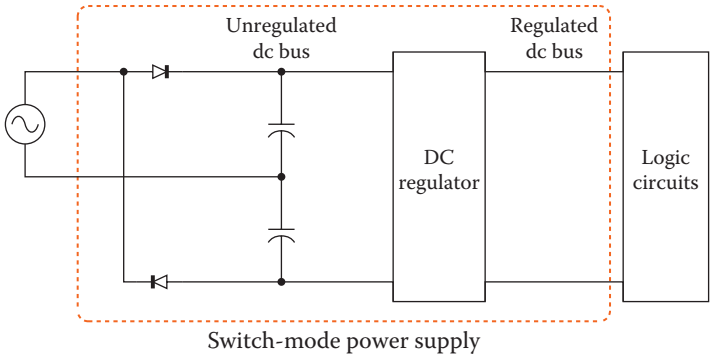

Figure 11.21 Switch-mode power supply used in most computers.

The ride-through capability of computers is close to rectangular. Two points describe the characteristic on a volt–time curve: the interruption ride-through time and the steady-state ride-through point. There is usually a steep transition between the interruption ride-through point and the steady-state ride-through point. Other characteristics of computer ride through are

- There is little difference between the performance when the computer is processing or accessing disk and when the computer is idle.
- The point on the waveform when the disruption occurs does not matter.

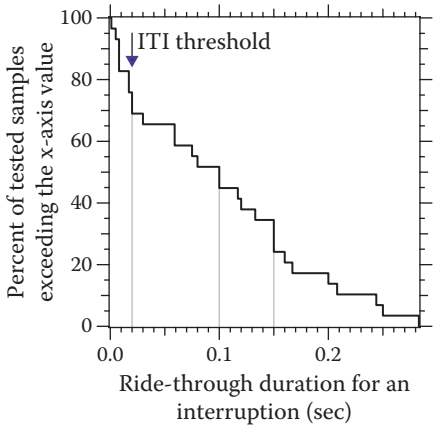

Figure 11.22 Capability of compuers to ride through an interruption ($n = 27$). (Data from Bowes, K. B., Effects of power line disturbances on electronic products, *Power Quality Assurance Magazine*, Premier V, pp. 296–310, 1990; Chong, W. Y., Effects of power quality on personal computer, Masters thesis, University of Queensland, 2000; Courtois, E. L., 2001. Personal communication; Courtois, E. L. and Deslauriers, D., Voltage variations susceptibility of electronic residential equipment, *PQA Conference*, 1997; EPRI PEAC Brief No. 7, *Undervoltage Ride-Through Performance of Off-the-Shelf PersonalComputers*, EPRI PEAC, Knoxville, TN, 1992.)

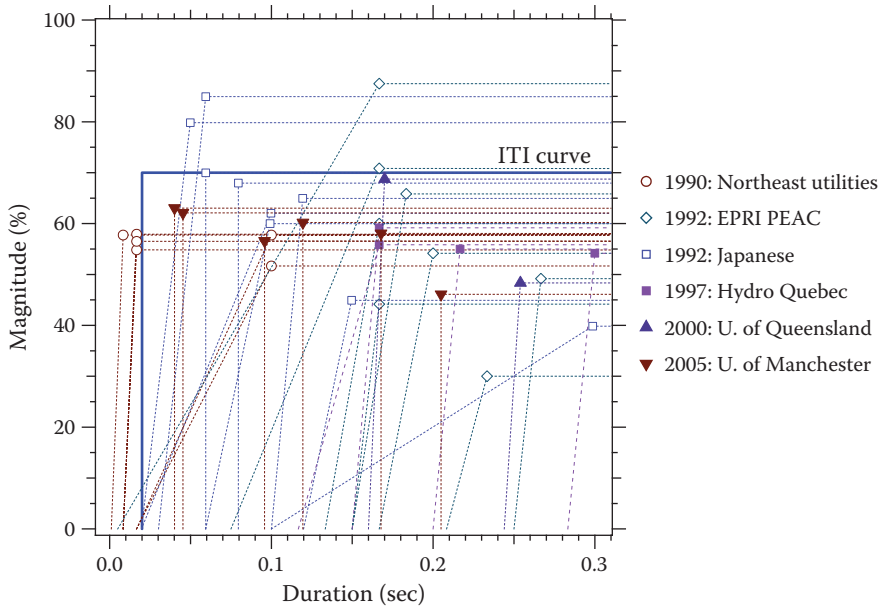

Figure 11.23 Volt–time characteristics of several computers tested in different studies. (Data from Bowes, K. B., Power Quality Assurance Magazine, Premier V, pp. 296–310, 1990; Chong, W. Y., Effects of power quality on personal computer, Masters thesis, University of Queensland, 2000; Courtois, E. L., 2001. Personal communication; Courtois, E. L. and Deslauriers, D., Voltage variations susceptibility of electronic residential equipment, PQA Conference, 1997; Djokic, S. Z., Desmet, J., Vanalme, G., Milanovic, J. V., and Stockman, K., *IEEE Transactions on Power Delivery*, vol. 20, no. 1, pp. 375–83. © (2005a) IEEE; EPRI PEAC Brief No. 7, Undervoltage Ride-Through Performance of Off-the-Shelf PersonalComputers, EPRI PEAC, Knoxville, TN, 1992; Sekine, Y. et al., Present state of momentary voltage dip interferences and the countermeasures in Japan, International Conference on Large Electric Networks (CIGRE), September 1992.)

Figure 11.23 shows volt–time sensitivities of computers from several studies. The most sensitive units, those that violate the ITI curve, were made and tested before the ITI curve was created. That is not much of an excuse as the most sensitive computers also violated the CBEMA curve, which was available to the manufacturers at that time (remember, there is no standard that requires testing computers to meet the ITI/CBEMA curve).

Djokic et al. (2005a) tested six personal computers at a European nominal of 230 V with vintages from 1997 through 2002. The two most sensitive computers had the largest power supplies. These were tested. The authors found no sensitivity to operating system, age, or price. Some computers suffered malfunctions like lockup of read/write operations or blockage of the operating system before shutdown/rebooting.

An important factor regarding the ride-through capability of computers is that it varies significantly depending on the voltage just before the interruption. The energy storage in a switch-mode power supply is from the front-end rectifier capacitors. The energy stored in a capacitor is $1/2CV^2$. Power supplies typically

have two 470-μF capacitors in series, and the voltage across the two capacitors in series is $V_p = 2\sqrt{2} \cdot 120 = 339.4$ V. We can estimate the ride-through capability of a computer as

$$t = \frac{C(V_p^2 + V_d^2)}{4 \times 10^6 P}$$

where

t = ride-through duration for an interruption, sec
P = load on the computer, W
C = capacitance on one half of the bridge rectifier, μF (470 is common)
V_p = peak of the ac voltage, V (339.4 V for 120 V nominal)
V_d = voltage on the unregulated dc bus where the computer will drop out (use half of V_p if unknown or 0 for the maximum ride through)

Since the energy is a function of V^2, a voltage of 90% of nominal means the capacitor stores only 81% of the energy that it would at nominal voltage. Even worse, the computer drops out before all of the energy in the capacitor is used. Figure 11.24 shows the relative ride through as a function of the voltage prior to the interruption, assuming the computer drops out when the unregulated dc bus voltage reaches half of nominal.

The predisturbance voltage affects ride through for any device that has capacitance for energy storage, including most computer power supplies, programmable logic controllers (PLCs), digital clocks, and ASDs. So, either on the utility side or the customer's side, raise voltages to inexpensively increase ride through of devices.

Even more ride-through capability is possible with computers. EPRI PEAC has done tests of a computer power supply modified with extra ride-through capability (EPRI PEAC Brief No. 12, 1993). The enhanced supply, developed by the New England Electric Company, had an extra 4500 μF of capacitors installed in parallel with the existing capacitors, which increased the ride through from 0.175 to 1.8 sec. In the near future, ultracapacitors may supply an even more economical ride-through enhancement.

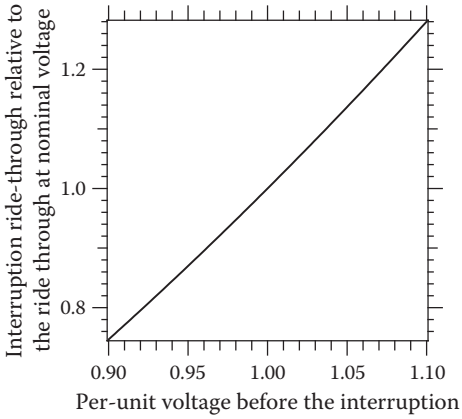

Figure 11.24 Change in the ride-through capability of computers versus the voltage prior to the interruption.

Intelligent power management might also increase ride through. Laptops and most desktops have sophisticated ways of managing power to conserve energy. We could apply similar techniques to short-duration power interruptions. The processor, disk, and other power-hungry equipment could be "quick suspended" during a power interruption to increase the normal 0.05 to 0.2-sec ride-through capability. Just suspending the processor (30 to 50 W typically in fast, hot chips) would extend the ride through considerably. This enhancement requires very little extra hardware; a sensor to measure the incoming ac power or the unregulated dc bus voltage would be needed—no microprocessor-level changes are required.

Industrial dc power supplies share the same characteristics as the computer power supply. Heavily loaded power supplies are more susceptible to voltage sags and interruptions. Use a supply rated at twice the load on the supply to increase ride through.

A power supply with a universal input operates over a wide range of voltages (85–264 V typically), but the ride-through capability changes dramatically with operating voltage. Operation as close to the upper end as possible improves ride through. For this reason, prefer a line-to-line connection (208 V) over a line-to-ground connection (120 V). The low-voltage limit of 85 V is 71% of nominal at 120 V, but we obtain much better ride through when applied at 208 V (now the lower limit is 41% of nominal). The difference in $1/2CV^2$ is dramatic in the two cases. By the same token, if the power supply has alternate settings, use the setting that positions the actual voltage near the high end of the range. Consider a power supply with a 95- to 250-V range designed for Japanese and European loads and a 110- to 270-V range designed for America. The range with an upper limit of 250 V for a 208-V line-to-line connection results in the maximum ride through (McEachern, 2001).

Another option for some industrial supplies and large computer systems is a three-phase power supply instead of a single-phase supply. A three-phase supply is less sensitive to voltage sags. Single-phase sags only slightly depress the dc bus voltage of a three-phase rectifier because the remaining two phases can fully supply the load. Even a two-phase sag is significantly less severe than a three-phase sag.

Linear power supplies have much less ride-through capability than switch-mode power supplies (switch-mode supplies may have 100 times the capacitance). Fortunately, most power supplies are switch-mode supplies (primarily because they are lighter, more efficient, and cost less).

11.9.2 Industrial Processes and Equipment

A variety of industrial equipment is sensitive to voltage sags. Some of the main sensitive equipment used in industrial facilities are

- Programmable logic controllers (PLCs)
- Adjustable-speed drives (ASDs), also called variable-speed drives (VFDs)
- Contactors
- Relays
- Control equipment

TABLE 11.10 Breakdown of Semiconductor-Tool Voltage Sag Sensitivities (n = 33)

Weak Link	Overall Percentage
Emergency off (EMO) circuit: pilot relay (33%), main contactor (14%)	47%
DC power supplies: PC (7%), controller (7%), I/O (5%)	19%
Three-phase power supplies: magnetron (5%), rf (5%), ion (2%)	12%
Vacuum pumps	12%
Turbo pumps	7%
AC adjustable-speed drives	2%

Data source: Stephens, M. et al., *Guide for the Design of Semiconductor Equipment to Meet Voltage Sag Immunity Standards*, International SEMATECH, 1999. Technology Transfer #99063760B-TR, available at http://www.sematech.org/public/docubase/document/3760btr.pdf.

Depending on the process and load, any number of devices can be the weak link. Table 11.10 shows the breakdown of weak links for semiconductor tools serving the semiconductor manufacturing industry.

11.9.2.1 Relays and Contactors

Contactors are electromechanical switches used for a variety of power and control applications. A contactor uses a solenoid to engage when an appropriate voltage is applied. More voltage is required to close the contactor than is required to keep it closed.

Relays and contactors can drop out very quickly. Figure 11.25 shows the ride-through duration for an interruption for several relays and contactors, and Figure 11.26 shows the dropout levels for voltage sags. The devices are somewhat dependent on the point on the wave where the voltage sag starts. Ride through is longest for sags starting at the voltage zero crossing, but unfortunately, faults tend to occur when the

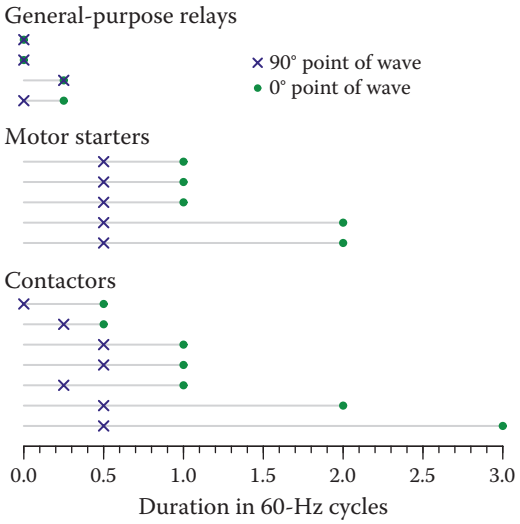

Figure 11.25 Ride-through duration for an interruption to several relays and contactors. (Data from EPRI PEAC Brief No. 44, *The Effects of Point-on-Wave on Low-Voltage Tolerance of Industrial Process Devices*, EPRI PEAC, Knoxville, TN, 1998.)

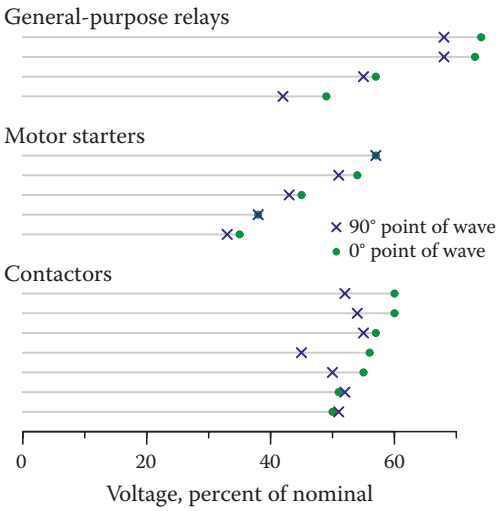

Figure 11.26 Voltage magnitude for dropout of several relays and contactors for a five-cycle voltage sag. (Data from EPRI PEAC Brief No. 44, *The Effects of Point-on-Wave on Low-Voltage Tolerance of Industrial Process Devices*, EPRI PEAC, Knoxville, TN, 1998.)

voltage is near its peak. The fast dropout of contactors limits some of the utility-side solution options—faster relaying, smaller fuses, or 1.5-cycle transfer switches may provide good improvement to computers but offer little help for many relays and contactors. Because they trip very quickly, voltage mainly dominates, not the duration.

The volt–time capability of relays and contactors approximates a rectangular shape. Contactors can have the unusual property that the ride-through capability improves at lower voltages. An example, volt–time ride-through characteristic is shown in Figure 11.27. The reason for this property relates to the fact that current, and not voltage, holds a contactor in. A contactor contains shading rings, which are

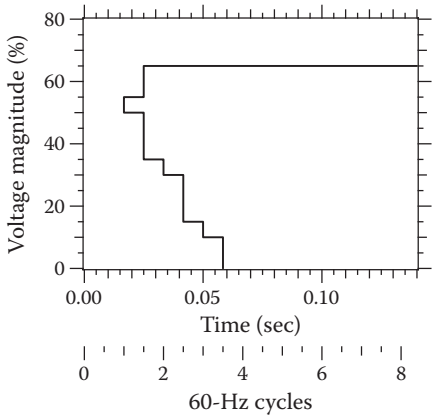

Figure 11.27 Ride-through capability of a NEMA size 1 contactor rated 0 to 50 hp at 480 V. (Data from EPRI PEAC Brief No. 10, *Low-Voltage Ride-Through Performance of AC Contactor Motor Starters*, EPRI PEAC, Knoxville, TN, 1993.)

analogous to damper windings in a rotating machine. A shading ring is a shorted winding around the magnetic core. In response to a voltage transient, the shading ring produces a back emf that opposes the transient. A larger transient (deeper sag) creates more current that holds the contactor in (Collins Jr. and Bridgwood, 1997).

A larger relay generally has more ride through; a contactor usually has more ride through than a relay. Some of the most sensitive relays are small industrial relays with clear plastic cases referred to as *ice-cube* relays.

Several options are available to help hold in contactors and relays (St. Pierre, 1999):

- *Coil hold in*—Use a coil hold-in device. Coil hold-in devices supply current to keep a relay or contactor coil held in during a voltage sag to about 25%.
- *dc*—Rectify the ac voltage and use a dc contactor. A dc contactor generally has a longer ride through than an ac contactor. A capacitor added in parallel with the contactor coil can extend the ride-through time.
- *Time-delay relay*—Add a time-delay relay to the control circuit in parallel with the contactor. If the contactor drops out because of a voltage sag, the time-delay relay keeps the control circuit energized (but the motor still drops out). If the sag finishes before the time-delay setting has elapsed, the contactor pulls back in, and the motor reconnects. This is not the best solution because the motor is disconnected and reconnected. The reconnection draws inrush current, which can itself cause local disruptions, especially if multiple motors are energized together. The high current may trip facility relays and possibly damage motors. Additionally, the disconnection of many motors within a facility removes the voltage support provided by the motors feeding back into the utility system. Furthermore, when the motors reconnect, the inrush creates a voltage sag.
- *Power conditioner*—Apply a constant voltage transformer or other power conditioning device such as a dip-proofing inverter to the control circuit. This provides enough ride through for all but the deepest voltage sags.

11.9.2.2 Adjustable-Speed Drives

ASDs are very common industrial tools used to perform a variety of tasks. Figure 11.28 shows the most common drive topology: the three-phase incoming supply is rectified to dc, and a pulse-width modulation (PWM) inverter converts the dc to a

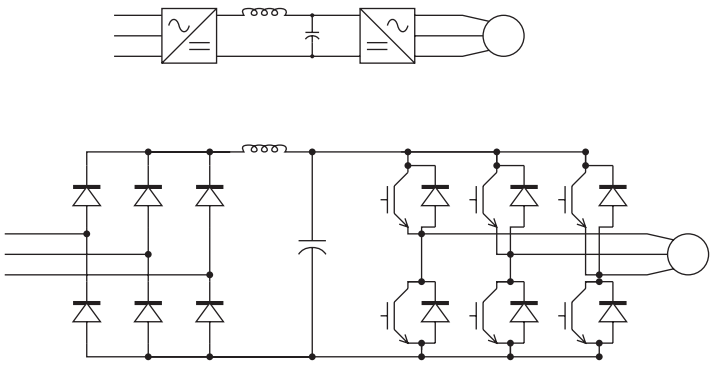

Figure 11.28 Common adjustable-speed drive topology.

variable-frequency three-phase ac voltage that drives an induction motor at variable speeds.

The capacitor on the dc bus provides some energy storage but not much. ASDs are sensitive to voltage sags and almost always drop out for momentary interruptions. A common cause for shutdown is that the dc bus drops too low, and the drive shuts down on an undervoltage trip (normally 70 to 85% of the nominal dc bus voltage). Even if a drive does not actually shut down, the motor may stall and not be able to start without removing the mechanical load. External factors can also cause shutdown: if the drive is wired through a contactor and the contactor trips, the drive shuts down (and the contactor may be more sensitive than the drive) (EPRI PEAC commentary #3, 1998). Also, if PLCs provide stop, start, or other signals, loss of the controller can shut the drive down. Following a voltage sag, the drive can draw large inrush, as much as three or four times the normal current. This can blow fuses or damage the input diodes and trip the drive.

Drives have significant variation. Of small drives tested by EPRI PEAC (Brief No. 9, 1993) at full load, two could ride through five-cycle three-phase sags down to zero volts; another two tripped at about 80% of rating. At half load, three drives survived a five-cycle sag down to zero volts, and the other tripped at 70% of rating. Some of the most sensitive drives are

- *Older drives*—Many older drives power their electronics from the ac system, which makes the controller more sensitive. Modern drives power the controls from the dc bus.
- *Higher-horsepower drives*—The front-end circuit normally uses thyristors instead of diodes in a current-source topology. To prevent commutation failure, the dc undervoltage relay is set more sensitively, often 85 to 90%.
- *dc drives*—A thyristor bridge feeds directly into the dc motor armature. dc drives have no built-in energy, and sags can disturb the timing circuitry for firing the thyristors. Regenerative converters may be very sensitive, especially during regeneration (reverse power flow); a voltage sag can prevent a thyristor from shutting off, which puts a short on the system that will blow a fuse.

ASDs are less sensitive to single-phase sags than three-phase sags because all three phases are rectified (Mansoor et al., 1997). A three-phase sag sags the dc bus voltage down in similar proportions. With a single-phase sag, the two "unsagged" phases can support the drive's dc bus. Whether the drive trips or not depends on how heavily it is loaded and how the undervoltage detection circuitry works. Figure 11.29 shows an example ride-through capability for a 60-kW drive. Djokic et al. (2005b) also found significant differences with the number of phases involved in tests of five drives.

Configuration adjustments can sometimes improve ride through; reducing the undervoltage trip setting significantly improves ride through. Increasing the overcurrent trip setting and setting appropriate restart parameters can also help. Also, some models have firmware upgrades providing additional ride through. Drives with a flying restart feature (the drive can restart while the motor is spinning) are

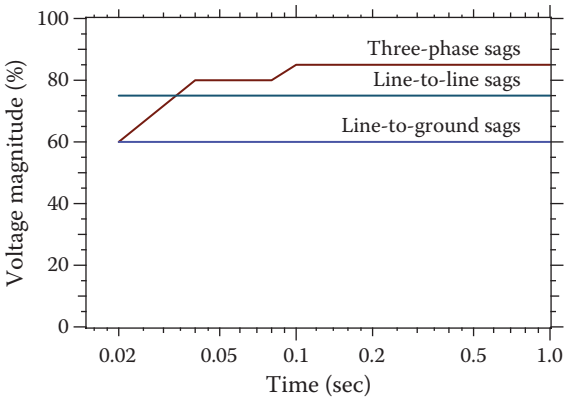

Figure 11.29 Ride-through capability of a 60-kW adjustable-speed drive under different voltage sag conditions. (Data from Abrahams, R. et al., Results of comprehensive testing of a 120 kW CSI variable speed drive at half rating, *PQA Conference*, 1999.)

better for critical loads. A drive with a synchronous flying restart following a sag to 50% voltage for five cycles allowed only a 5% decrease in motor speed and was fully restored in 1/2 sec (a nonsynchronous flying restart is not nearly as good) (EPRI PEAC Brief No. 30, 1995).

11.9.2.3 Programmable Logic Controllers

The performance of PLCs varies widely. A PLC is a hardened electronic controller used to control many types of industrial processes and equipment. PLCs have multiple input and output channels (I/O racks) used to measure and control equipment. A dc power supply powers the cpu and the I/O racks.

In most cases, the PLC power supply is the same as other computer power supplies, a switched-mode power supply usually capable of riding through an interruption of several cycles. The problem is that the power supply is often not the weakest link in the system. A power supply monitoring circuit that senses the input voltage may initiate a shutdown during a voltage sag. PLCs are more sensitive as a result.

Another important concern is that sags or interruptions can not only cause a shutdown of the PLC, a sag can produce faulty outputs on some PLCs. Faulty outputs can cause more havoc with some processes than if the PLC actually shut down. Figure 11.30 shows the sensitivity of several PLCs.

11.9.3 Residential Equipment

The digital clock has been quoted as being "the world's best-selling power quality recorder." The "blinking clocks" are a nuisance for customers and generate many phone calls for utilities. That said, clocks have a wide range of sensitivities, and many actually have very good ride-through capability.

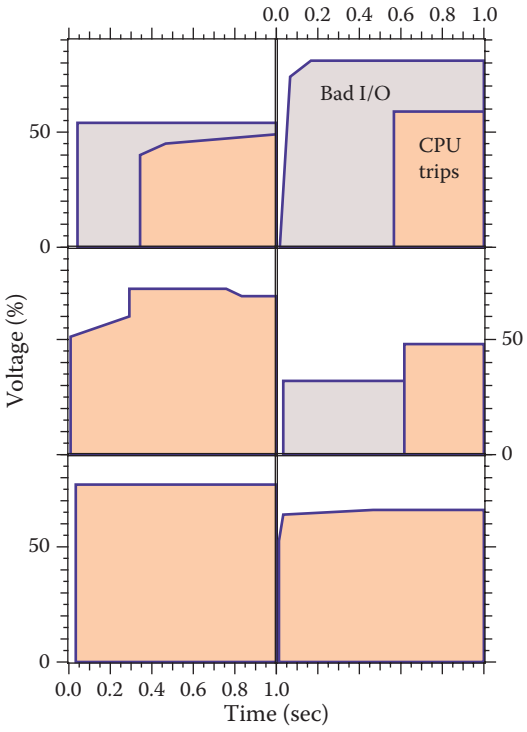

Figure 11.30 Sensitivity of six PLCs. (Adapted from EPRI PEAC Brief No. 39, *Ride-Through Performance of Programmable Logic Controllers*, EPRI PEAC, Knoxville, TN, 1996.)

Figure 11.31 shows ride-through capabilities for several digital clocks tested by EPRI PEAC and Hydro Quebec. There is a wide range of voltage sensitivity, but few of the digital clocks tested (25%) lose memory for a complete interruption that is less than 0.5 sec. The main consideration for distribution circuits is the dead time on the first reclose attempt. This is usually about 0.3 to 5 sec depending on the delay on the reclosing relay. An immediate reclose attempt has a dead time of 0.3–0.5 sec, making it a good option for reducing blinking clocks. Table 11.11 shows the ride through of different residential devices from a study by Northeast Utilities that also shows most devices have good ride through for events less than 0.5 sec.

Figure 11.32 shows the characteristic of several residential devices. Most residential devices have a fairly rectangular volt–time characteristic. Only longer-duration voltage sags affect most residential devices.

11.9.4 Post-Sag Inrush

End-use devices may also suffer damage from inrush following interruptions or severe voltage sags (Bendre et al., 2004). After a deep sag or an interruption, the return of voltage will cause inrush into many devices. In a switch-mode power supply, this inrush will be a sharp current spike (Figure 11.33) as current rushes in to

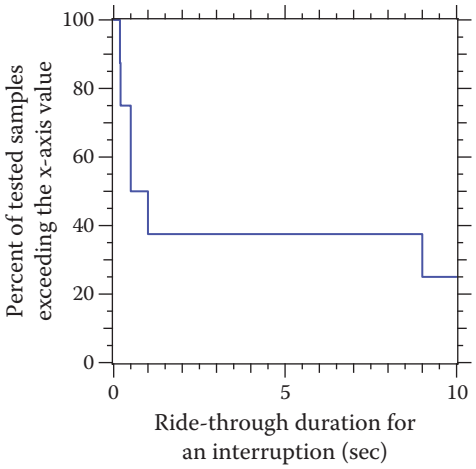

Figure 11.31 Capability of digital clocks to ride through an interruption ($n = 8$). (Data from Courtois, E. L., 2001. Personal communication; Courtois, E. L. and Deslauriers, D., Voltage variations susceptibility of electronic residential equipment, *PQA Conference*, 1997; EPRI PEAC Brief No. 17, *Electronic Digital Clock Performance during Steady-State and Dynamic Power Disturbances*, EPRI PEAC, Knoxville, TN, 1994.)

TABLE 11.11 Percentage of Devices That Were Able to Successfully Ride through a Momentary Interruption of the Given Duration

Device	0.5 sec	2 sec	16.7 sec
Digital clock	70	60	0
Microwave oven	60	0	0
VCR	50	37.5	0
Computer	0	0	0

Source: Bowes, K. B., *Power Quality Assurance Magazine*, Premier V, pp. 296–310, 1990.

charge the power supply's capacitor (see Figure 11.34). This inrush current may damage the fuse in the power supply or even the rectifier diodes. For a power supply, the inrush is worst for a deeper voltage sag and for a longer-duration sag; in both cases, the capacitor discharges more. The inrush also depends on the point of wave at which the voltage recovers with the worst case being a return to normal voltage when the system voltage is at its peak.

The inrush for normal device turn-on is similar, so should not devices normally be designed to withstand this current? Possibly not. Some devices have inrush-limiting circuitry to limit inrush during normal turn-on. This circuitry allows for lower-rated components. This inrush-limiting circuitry only engages during normal turn-on, so it will generally not help for inrush following momentary interruptions or voltage sags.

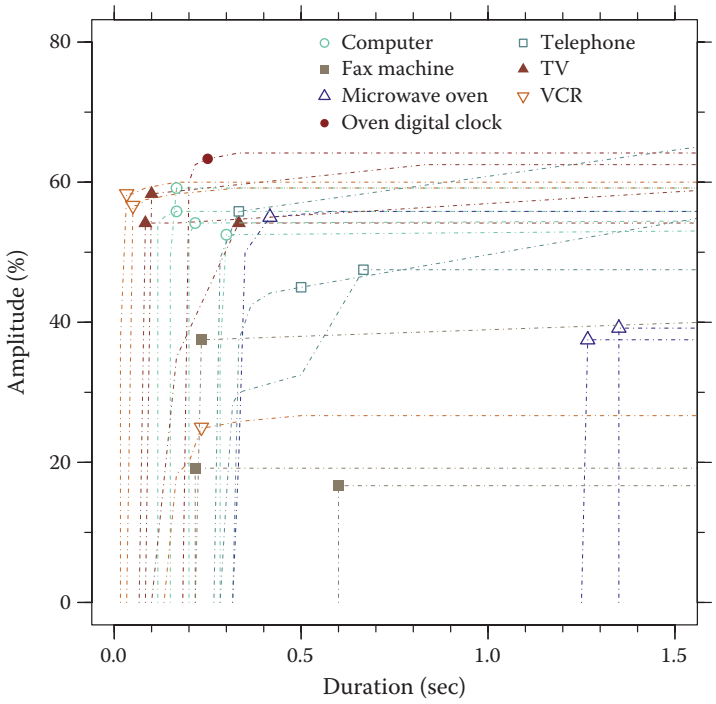

Figure 11.32 Ride-through capability of various residential devices. (Data from Courtois, E. L., 2001. Personal communication; Courtois, E. L. and Deslauriers, D., Voltage variations susceptibility of electronic residential equipment, *PQA Conference*, 1997.)

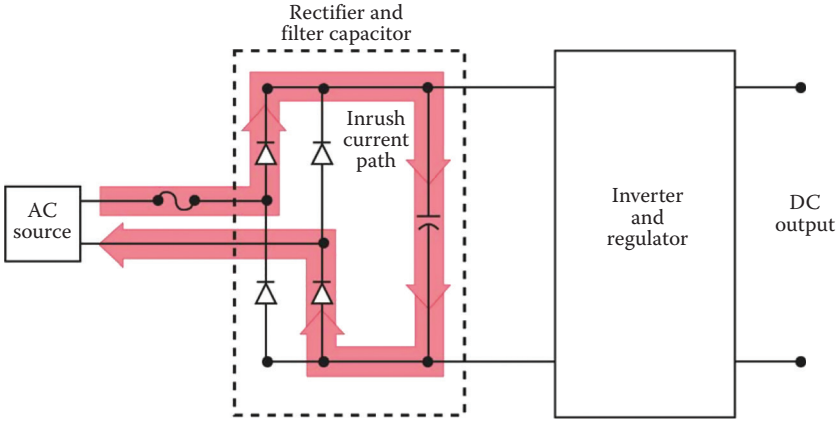

Figure 11.33 Post-sag inrush path through a power supply. (From EPRI 1012451, *The Effects of Post-Sag Inrush on Residential Equipment*, Electric Power Research Institute, Palo Alto, CA, 2006. Copyright 2006. Reprinted with permission.)

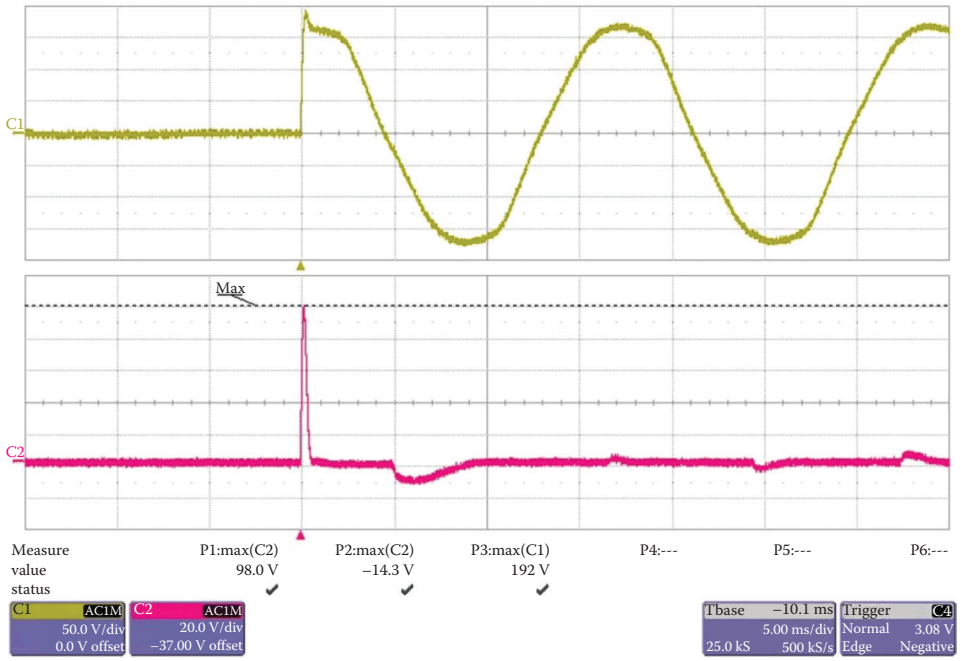

Figure 11.34 Example inrush after an interruption when energized at voltage peak. (From EPRI 1012451, *The Effects of Post-Sag Inrush on Residential Equipment*, Electric Power Research Institute, Palo Alto, CA, 2006. Copyright 2006. Reprinted with permission.)

Because this inrush increases with voltage, temporary or steady-state overvoltages will make damaging inrush more likely. For the case of a permanent line-to-ground fault, a circuit breaker or recloser may close back in on a fault where the neutral shift causes temporary overvoltages on the unfaulted phases. The single-phase load on these unfaulted phases may see an overvoltage upon reclose.

EPRI tested nine residential devices that included PC power supplies, DVD players, and televisions (EPRI 1012451, 2006). Voltage sags that occur frequently with magnitudes to 0.7 to 0.8 per unit did not cause sufficient inrush to be harmful to equipment. The highest inrush occurred for complete interruptions (zero voltage) generally for more than 6 to 10 cycles. The peak inrush exceeded the rating of the supply diode in three of the six samples where this could be determined. No failures occurred with this relatively small sample. One device was subjected to 10,000 worst-case inrush events without failure. EPRI tests showed that a current and voltage surge suppressor (CVSS) can limit this inrush (EPRI 1013876, 2008).

It is unknown how often this inrush causes damage. The inrush following severe sags or momentaries likely contributes to some end-use failures if conditions are just right, particularly if coupled with high steady-state voltage or temporary overvoltages. Djokic et al. (2005a) reported damage to a computer monitor and a computer power supply during voltage sag testing where these inrush currents were observed.

11.10 Solution Options

11.10.1 Utility Options for Momentary Interruptions

We can reduce momentary interruptions in several ways:

- Immediate reclose
- Use of fuse blowing
- Single-phase reclosers
- Extra downstream devices (fuses or reclosers)
- Sequence coordination with downstream devices
- Reduce faults

Reducing faults is a universally good approach to improving power quality. Other approaches target specific disturbances. For momentaries, the single biggest improvement is to use fuse blowing instead of fuse saving (see Chapter 9). Using an immediate reclose, while not reducing the number of momentaries counted, reduces complaints from residential customers. Both these changes for improving momentaries are relatively easy to implement.

Other methods of reducing momentaries involve better application of protection equipment. Extra protection devices that segment the circuit into smaller sections help improve momentary interruptions (and long-duration interruptions). Improving coordination between devices (including the use of sequence coordination to improve coordination between reclosers) helps eliminate some unnecessary blinks. Single-phase reclosers instead of three-phase reclosers or breakers helps reduce the number of phases interrupted for single line-to-ground faults.

11.10.2 Utility Options for Voltage Sags

Utility-side options for reducing voltage sags are limited and are rarely done (at least solely for the purposes of voltage sags). Some of the strategies and equipment that help are

- Use of fuse saving
- Current-limiting fuses
- Smaller lateral fuses
- Faster breakers or reclosers
- Raise the nominal voltage
- Reduce faults

Faster relaying or faster interrupters—any changes in protection schemes that clear faults faster—help reduce the sag's duration. The next few sections address some of the options for reducing the impact of power system faults on the voltage.

11.10.2.1 Raising the Nominal Voltage

Raising the nominal voltage helps the ride through of many types of equipment. Computers, ASDs, and other equipment with capacitors benefit if the voltage is

regulated near the upper end of the ANSI range A, or at least avoid the lower end. On the utility system, we use LTCs, regulators, and switched capacitors. This approach is the opposite of demand-side management programs, which are designed to deliver low voltages in order to reduce peak demand or customer energy usage.

11.10.2.2 Line Reactors

Series line reactors provide electrical separation between feeders off the substation bus. Figure 11.35 shows the effect of line reactors on the station bus voltage for different configurations. Reactors have the added benefit of limiting the fault current. The reactors provide good protection against some voltage sags but do not help with interruptions or sags caused by transmission-level faults. On the faulted feeder, line reactors make the voltage sag worse, but much of the feeder may have very low voltage anyway (downstream of the fault), or the breaker may open and give all of the customers an interruption.

Utilities have used line reactors in this application, mainly at urban stations to reduce high fault currents. Line reactors do not have the best reputation; they are expensive, take up substation space, and increase voltage drop. The reactor must be designed to withstand the fault currents that it will regularly see.

11.10.2.3 Neutral Reactors

Phase reactors effectively isolate feeders and limit the voltage sag, so how about the reactor sometimes used between the substation transformer neutral and ground? The

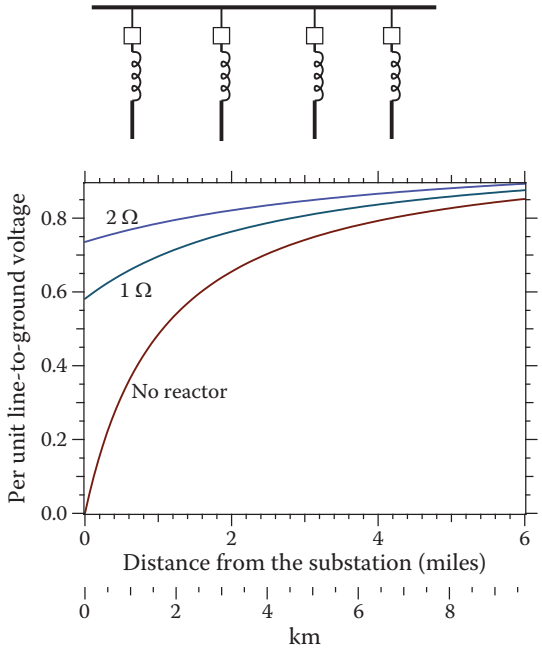

Figure 11.35 Substation bus voltage for a three-phase fault at the given distance for different line reactor configurations (for a 12.5-kV circuit with the same parameters as Figure 8.11).

answer depends on the transformer connection serving the customer and the connection of the load. Neutral reactors generally make voltage sags worse for loads connected line-to-ground on the distribution circuit because

- *Duration*—A neutral reactor lowers the fault current, so tap fuses and time overcurrent relays take slightly longer to operate, increasing the sag duration.
- *Magnitude*—A neutral reactor increases the zero-sequence impedance. The weaker ground source cannot hold up the station line-to-ground voltage as well for a downstream line-to-ground fault.

For line-to-line connected loads, the neutral reactor significantly improves voltages to end-use equipment, because of

- *Neutral shift*—The reactor adds impedance, which shifts the neutral point. This raises the voltage on the unfaulted phases, but supports the line-to-line voltages. (A very large reactor in a high-impedance grounded system would have almost no drop in the line-to-line voltages during a single line-to-ground fault.)

With a single line-to-ground fault, the line-to-line voltage in per unit is (assuming that the circuit resistances are zero for simplification)

$$V = \frac{\sqrt{X_0^2 + X_0 X_1 + X_1^2}}{2X_1 + X_0}$$

The neutral reactor of X ohms adds $3jX$ ohms to the zero-sequence impedance and raises the X_0/X_1 ratio. Table 11.12 and Figure 11.36 show that a modest neutral reactor significantly helps line-to-line loads during line-to-ground faults. Also, with delta–wye distribution transformers, the line-to-ground secondary voltages see equivalent sags as the line-to-line voltage on the primary. The neutral reactor provides benefit only for line-to-ground faults and no help for three-phase or line-to-line faults. A disadvantage of the neutral reactor is that it increases the voltage rise (the swell) on the unfaulted phases (see Chapter 14).

TABLE 11.12 Line-to-Ground and Line-to-Line Voltages on the Low-Voltage Side of a Transformer with One Phase on the High-Voltage Side Sagged to Zero

Voltages	Primary Voltages			Voltages Downstream of a Delta–Wye Transformer		
No Neutral Reactor ($X_0/X_1 = 1$)						
Line-ground	0.00	1.00	1.00	0.58	0.58	1.00
Line-line	0.58	0.58	1.00	0.33	0.88	0.88
Neutral Reactor That Gives $X_0/X_1 = 3$						
Line-ground	0.00	1.25	1.25	0.72	0.72	1.00
Line-line	0.72	0.72	1.00	0.60	0.92	0.92

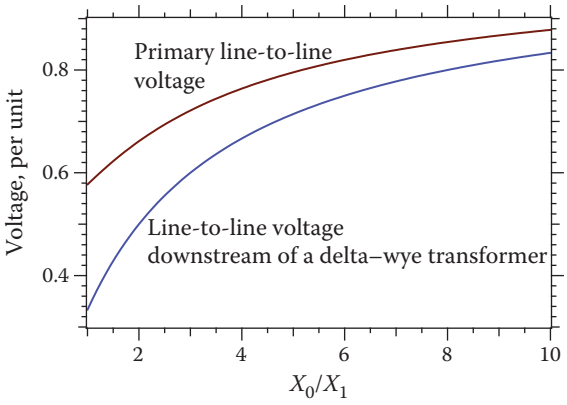

Figure 11.36 Impact of a neutral reactor (higher X_0) on voltage sags.

11.10.2.4 Current-Limiting Fuses

Current-limiting fuses reduce the fault current and force an early zero crossing. In the process, the fuse reduces the severity of the magnitude and reduces the duration. Figure 11.37 shows an example of a fault cleared by a current-limiting fuse. The duration of the sag is very short, and the depth is minimal. These types of results have been verified by other measurements and computer models (Kojovic and Hassler, 1997; Kojovic et al., 1998). Close to the substation is the best location for use, where they are most useful for reducing the magnitude and duration of voltage sags and are most appropriate for limiting damage due to high fault currents.

11.10.3 Utility Options with Nontraditional Equipment

11.10.3.1 Fast Transfer Switches

Medium-voltage static transfer switches are a utility-side option for providing improved power quality and protection from voltage sags and momentary interruptions. Thyristors are used to obtain a 1/2-cycle transfer between two sources. The switches can be configured as preferred/alternate or as a split bus. The normal configuration employs static transfer switches for sensitive customers in a primary selective scheme. After the switch has operated, it may or may not switch back to the original feeder.

We should also consider the impacts on the distribution system. Switching a large load between weak locations on circuits could cause objectionable voltage changes. Possible interaction with other voltage-regulating equipment warrants investigation. This includes other custom-power devices that may be trying to dynamically correct voltage.

Another fast-transfer technology can be used in the same applications as static switches. High-speed mechanical source transfer switches use high-speed vacuum switches and a sophisticated microprocessor-based control to provide

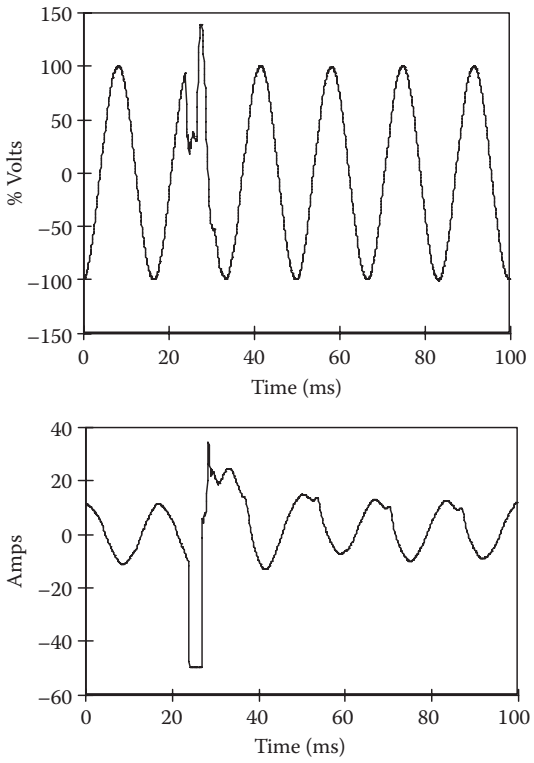

Figure 11.37 Example of a current-limiting fuse operation recorded in the EPRI DPQ study. (From EPRI TR-106294-V3, *An Assessment of Distribution System Power Quality: Volume 3: Library of Distribution System Power Quality Monitoring Case Studies*, Electric Power Research Institute, Palo Alto, CA, 1996. Copyright 1996. Reprinted with permission.)

"break-before-make" transfers in approximately 25 ms or 1.5 cycles. The two sources are not paralleled during the transfer; therefore, the load experiences an interruption of approximately 1.5 cycles. This level of protection may be acceptable for some equipment (but the 1.5-cycle interruption may trip some sensitive equipment). These switches have the advantage of being very efficient (99%), inexpensive (one-fifth to one-tenth the cost of a static switch), and small. Both pole-mounted and padmounted versions are available. For most loads, the fast transfer switch provides significant benefit. Relays and contactors, though, can drop out for a 1.5-cycle interruption.

Normally, fast transfer switches have been applied at individual customers in a primary-selective scheme. The technology could nicely apply to feeder-level application as shown in Figure 11.38. This arrangement provides improved performance for voltage sags, momentary interruptions, and long-duration interruptions for the customers at the end of the circuit (these are customers that usually get the worst power quality).

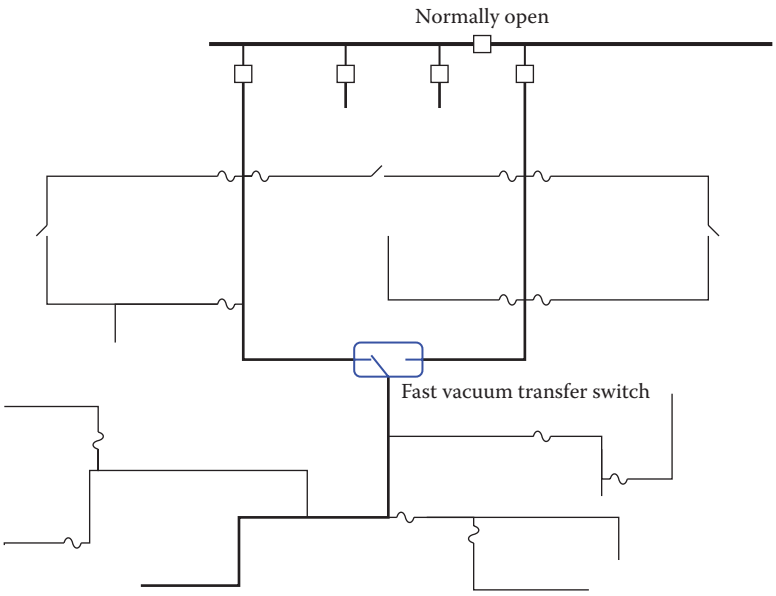

Figure 11.38 Using a fast transfer switch to enhance power quality to a downstream section of circuit. (From EPRI 1007281, *Analysis of Extremely Reliable Power Delivery Systems: A Proposal for Development and Application of Security, Quality, Reliability, and Availability (SQRA) Modeling for Optimizing Power System Configurations for the Digital Economy,* Electric Power Research Institute, Palo Alto, CA, 2002. Copyright 2002. Reprinted with permission.)

11.10.3.2 DVRs and Other Custom-Power Devices

In addition to the static transfer switch, medium-voltage power electronics have enabled a wide variety of utility-level solutions to power-quality problems: series injection devices, static regulators, shunt devices, and medium-voltage UPS systems with a variety of energy storage options. These power-electronics solutions have been coined "custom power." The advantage of utility-side approaches is that the whole facility is supported (we do not have to track down, test, and fix every possible piece of sensitive equipment).

Figure 11.39 shows the configuration of several custom-power configurations. Most provide support during voltage sags. Single-phase sags are more easily corrected (since devices can use energy from the unfaulted phases). For momentary interruptions, some sort of energy storage is necessary such as batteries, ultracapacitors, flywheel, or superconducting coil. A summary of the cost and capability of the most common devices is shown in Table 11.13.

The dynamic-voltage restorer (DVR) is one of the devices most suited for correcting for voltage sags (Woodley et al., 1999). During a voltage sag, the DVR adds voltage through an in-line transformer to offset the missing voltage. A DVR can correct for any sag to 50%, and optional energy storage increases the range of performance.

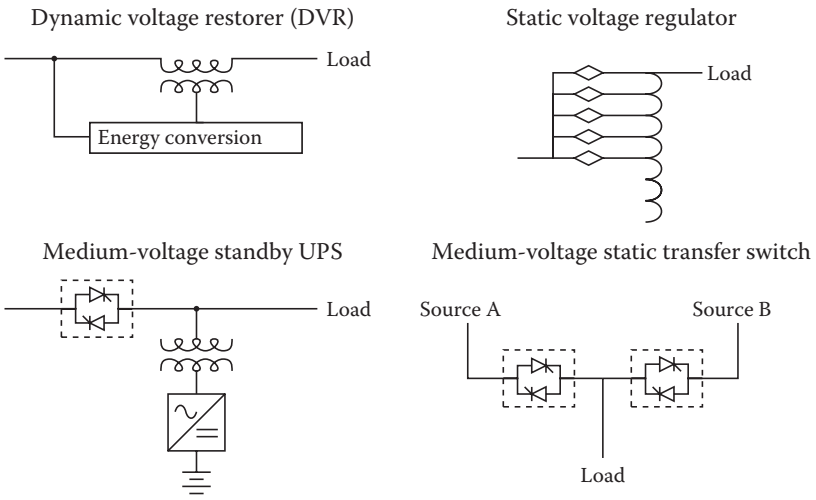

Figure 11.39 Common custom-power devices.

TABLE 11.13 Comparison of Custom-Power Equipment for Correcting Sags and Momentary Interruptions

	Cost, U.S. $	Capability
Static shunt compensation	50–200/kvar	Sags to 70%
Source transfer switch	500–1000/A	
DVR	150–250/kVA	Sags to 50%
Static voltage regulator	80–125/kVA	Sags to 50%
MV UPS	750–1500/kVA	

Source: Adapted from EPRI 1000340, *Guidebook on Custom Power Devices*, EPRI, Palo Alto, CA, 2000.

11.10.4 Customer/Equipment Solutions

The best place to provide solutions for customers is often in the facility. Some of the customer solution options are shown in Table 11.14.

Other tips (McEachern, 2001; Stephens et al., 1999) include

- Wire devices in a phase-to-phase configuration where possible
- Avoid mismatched equipment voltages
- Avoid the use of ac "ice cube" general-purpose relays
- Do not use phase-monitoring relays in interlocking circuits
- Utilize a nonvolatile memory
- Do not overload dc power supplies
- Use a targeted voltage conditioning approach
- Use robust inverter drives

Make sure that computer-controlled equipment can recover from interruptions. This sounds like an obvious solution, but user complaints reveal that a lot of

TABLE 11.14 Comparison of Selected Power Conditioning Equipment

	Sags to 80%	Sags to 50%	Sags to 25%	Below 25%	Outage
Dip-proofing inverter	Solves	Solves	Solves	Solves	To 1 sec
Constant-voltage transformer	Solves	Size[a]	Size[a]	No	No
DySC	Solves	Solves	To 0.33 sec	To 0.26 sec	To 0.15 sec
Uninterruptible power supply	Solves	Solves	Solves	Solves	Solves
Coil hold-in devices	Solves	Solves	Solves	No	No

Source: Data from Stephens, M. et al., *Guide for the Design of Semiconductor Equipment to Meet Voltage Sag Immunity Standards*, International SEMATECH, 1999. Technology Transfer #99063760B-TR, available at http://www.sematech.org/public/docubase/document/3760btr.pdf.

[a]Size = capability depends on the size of the device.

computer-controlled equipment gets completely confused by a disturbance. State machine programming is a promising approach to help make sure that processes recover from disturbances. Another step that helps is to use battery-backed-up memory or a disk to store process step information.

11.11 Power Quality Monitoring

Power quality monitoring helps utilities and their customers diagnose and fix power quality problems. Many locations are suitable for monitoring. The distribution substation is a good place because it can monitor the voltage and currents feeding a large number of customers. For a specific customer having a problem, nothing is better than recording right at or near the sensitive process or piece of equipment. Some suggestions for monitoring are as follows:

- *Voltage and current*—Record both voltage and current, and for three-phase installations, record all three phases plus the ground current. For substation monitoring, currents identify which circuit the fault was on or whether it was caused on the transmission system. With the current, we can estimate the distance to the fault. For facility monitoring, the current shows us if a sag is caused by something internal to the facility or on the utility system. More importantly, the current may show what tripped off within the facility and when it tripped.
- *Triggers*—Do not set the triggers too sensitively. Even with larger onboard memories and disk capabilities, there is usually no reason for highly sensitive settings. The commonly used ±5% is too sensitive. Sensitive triggers create too much data for downloading, storage, and most importantly, for analysis. When recording sags and momentaries, we can safely ignore sags that do not drop below 90%, and a trigger setting of 85% is often appropriate (except for very sensitive loads).
- *Output contacts*—For monitoring at sensitive equipment, record output contacts of any equipment that may indicate its operational status or the process status. Also, be aware that some equipment (like many ASDs and UPSs) keeps an event log that may help track down problems. At the substation, record the output contacts of the pertinent relays to determine which relays tripped.
- *Timing*—Synchronize the monitoring clocks to a GPS time reference to help correlate with other monitoring data or event records. If this is not feasible, establish a protocol

of regularly setting the recorder clocks (and logging the errors to be able to adjust for drift) to keep them close to a time standard. If a process has internal data recording, synchronize those clocks. The same goes for the utility SCADA system—accurate timing increases the certainty with which we can diagnose power quality problems.

- *Trend data*—Record trend data (say 1-min maximum, minimum, and average values) as well as triggered data (sags, swells, etc.). This helps pinpoint problems related to the steady-state voltage. The ride through of some devices depends on the predisturbance voltage.

Fault-recorder-type devices with power quality capability are good for substation application; the large number of channels and ability to monitor relay contacts is very beneficial. Also, many types of devices such as relays, recloser controllers, and customer meters can record power quality disturbances.

A drawback to monitoring is that it requires expert manpower to operate. It takes considerable work to install the monitoring, set up the downloading, and (most significantly) analyze the data. Good power quality software helps by highlighting or paring down the data and creating summary reports. Sometimes, power quality recorders are used in "stealth" mode: they are installed and largely forgotten until there are customer or utility problems.

An important question is, what do we do with all of the data from power quality recorders? Oftentimes, the best answer is nothing, until power quality problems are reported. A good use of the data is benchmarking. Pick an indicator such as $SARFI_{ITIC}$, and collect data from each recording site. We can compare the benchmark on a site-by-site basis to help determine which circuits need more maintenance attention. Further analysis could reveal what practices are better (e.g., circuits with a 3-year tree-trimming cycle could be compared with those having a 5-year trim cycle). Benchmarking can also be used as an advertising tool to try and attract sensitive, high-tech customers.

For high accuracy at a given site, we need long monitoring periods. Events that happen less often require longer monitoring for good accuracy. Table 11.15 shows an approximation by Bollen (2000) based on a Poisson distribution. The length of monitoring needed is at least

$$t = \frac{4}{\mu\varepsilon^2}$$

TABLE 11.15 Monitoring Duration Needed to Achieve the Given Level of Accuracy

Event Frequency	50% Accuracy	10% Accuracy
1 per day	2 weeks	1 year
1 per week	4 months	7 years
1 per month	1 year	30 years
1 per year	16 years	400 years

Source: Bollen, M. H. J., *Understanding Power Quality Problems: Voltage Sags and Interruptions*, IEEE Press, New York, 2000. © 2000 IEEE.

where

ε = accuracy needed, per unit

μ = number of events expected per time period

Treat these as minimum numbers; Bollen's analysis assumes that events randomly appear, while in reality they appear in clusters, during stormy weather or during overloads. This clustering means that even longer monitoring is needed for a given level of accuracy. Another concern is that power systems change over time, which adds further uncertainty to historical monitoring. Bollen also suggests a method of adjusting sag and momentary measurements by the fault rate measured over a longer time period. A better estimate of the actual event rate is

$$\bar{N}_{\text{sags}} = N_{\text{sags}} \frac{\bar{N}_{\text{faults}}}{N_{\text{faults}}}$$

where

N_{sags} and N_{faults} = the number of sags and the number of faults over the recording period

$\bar{N}_{\text{sags}}$ and $\bar{N}_{\text{faults}}$ = the number of sags and the number of faults over a longer period of time

For sites where monitoring cannot meet accuracy needs, prediction methods can help produce an estimate. This requires developing a model of the system and using a stochastic approach to the fault positions analysis method.

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All I know is that when shit hits the fan, management calls us we don't call them.

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12

Other Power Quality Issues

Contents

12.1 Overvoltages and Customer Equipment Failures 613
12.1.1 Voltage Swells and Impact of Temporary Overvoltages 615
12.1.2 Secondary/Facility Grounding 616
12.1.3 Reclose Transients 618
12.2 Switching Surges 620
12.2.1 Voltage Magnification 623
12.2.2 Tripping of Adjustable-Speed Drives 624
12.2.3 Prevention of Capacitor Transients 626
12.3 Harmonics 626
12.3.1 Resonances 632
12.3.2 Telephone Interference 635
12.4 Flicker 638
12.4.1 Flicker Solutions 646
12.4.1.1 Load Changes 646
12.4.1.2 Series Capacitor 647
12.4.1.3 Static Var Compensator 650
12.4.1.4 Other Solutions 651
12.5 Voltage Unbalance 651
References 653

While voltage sags and momentary interruptions cause the most widespread power quality problems, several other power quality disturbances can damage equipment, overheat equipment, disrupt processes, cause data loss, and annoy and upset customers. In this chapter, we explore several of these, including transients, harmonics, voltage flicker, and unbalance.

12.1 Overvoltages and Customer Equipment Failures

Often, customers complain of equipment failures, especially following power interruptions. Is it lightning? Voltage swells during faults? Some sort of switching transient? Sometimes, explanations are obvious, sometimes not. Several events can fail equipment during a fault/interruption, from the disturbance that caused a fault, the voltage sag during the fault, a voltage swell during the fault, or the inrush while the system is recovering. Some possibilities are

- *Overvoltages*—Lightning and other system primary-side overvoltages can enter the facility and damage equipment.

- *Grounding*—Poor facility grounding practices can introduce overvoltages at equipment from fault current.
- *Capacitive coupling*—Reclose operations and other switching transients can create fast-rising voltage on the primary that capacitively couples through the transformer, causing a short pulse on the secondary.
- *Inrush current*—While recovering from a voltage sag or momentary interruption, the inrush current into some electronic equipment can blow fuses or fail semiconductor devices.
- *Unbalanced sags*—Three-phase electronic equipment such as adjustable-speed drives (ASDs) can draw excessive current during a single-phase sag or other unbalanced sag. The current can blow fuses or fail the front-end power electronics.
- *Equipment aging*—Some equipment is prone to failure during turn on, even without a voltage transient. The most obvious example is an incandescent light bulb. Over time, the filament weakens, and the bulb eventually fails, usually when turned on. At turn on, the rapid temperature rise and mechanical stress from the inrush can break the filament.

Lightning can cause severe overvoltages, both on the primary and on the secondary. Damaging surges can enter from strikes to the primary, strikes to the secondary, strikes to the facility, strikes to plumbing, and strikes to cable-television or telephone wires. Poor grounding practices can make lightning-caused failures more likely.

Another source of severe overvoltages is primary or secondary conductors contacting higher voltage lines. Other overvoltages are possible; normally, these are not severe enough to damage most equipment, except for sensitive electronics:

- Voltage swells—Peaks at about 1.3 per unit on most distribution circuits.
- Switching surges—Normally peaks at less than 2 per unit and decays quickly.
- Ferroresonance—Normally peaks at less than 2 per unit.

Just as arresters on distribution lines are sensitive to overvoltages, arresters inside the electronic equipment often are the first thing to fail. The power supply on most computers and other electronics contains small surge arresters (surge suppressors) that can fail quickly while trying to clamp down on overvoltages, especially longer-duration overvoltages. These small suppressors have limited energy absorption capability.

In addition to proper grounding, surge arresters are the primary defense against lightning and other transients. For best protection, use surge protection at the service entrance and surge protection at each sensitive load.

Surge arresters work well against short-duration overvoltages—lightning and switching transients. But arresters have trouble conducting temporary power-frequency overvoltages; they absorb considerable energy trying to clamp the overvoltage and can fail. Small arresters often are the first component to fail in equipment. Using a higher voltage rating helps to give more protection to the surge arrester during temporary overvoltages (e.g., end users should not use arresters with a maximum continuous operating voltage below 150 V). Surge arresters should be coordinated; the large surge arrester at the service entrance should have the lowest protective level of all of the arresters within the facility. Because arresters are so nonlinear, the unit

with the lowest protective level will conduct almost all of the current. So, we want the arrester with the most energy capability to absorb most of the energy.

12.1.1 Voltage Swells and Impact of Temporary Overvoltages

Voltage swells can cause failures of end-use equipment. In the EPRI Distribution Power Quality study (EPRI TR-106294-V2, 1996), an average of 0.5 voltage swells above 125% of nominal occur annually, and 0.3 swells above 135% occur annually.

Residential end-use equipment is insensitive to temporary overvoltages relative to the upper portion of the ITI curve (Bowes, 1991; EPRI 1008540, 2005; EPRI 1010892, 2005). Figure 12.1 shows failure times for several individual devices as a function of voltage based on data from EPRI 1010892 (2005). Each set of points connected by lines generally shows devices of the same model. For overvoltages of around 150% of nominal, surge suppressors that had 130-V metal-oxide surge arresters were the most sensitive device in the EPRI tests. Failure was from thermal fuses in the surge protectors; the metal-oxide arresters were intact and functional. Microwave ovens and digital clocks were the most robust devices against overvoltages. The digital clocks had no surge suppressors, fuses, or other protective electronics, and damage occurred at the power supply transformer. Electronic devices with switch-mode power supplies often had failure of an electrolytic capacitor in the power supply. The incandescent bulbs were also sensitive to overvoltages; all suffered filament failure.

Figure 12.2 shows similar test results by Northeast Utilities (Bowes, 1991). Each of the data points represents an average failure time of *n* samples as noted in the

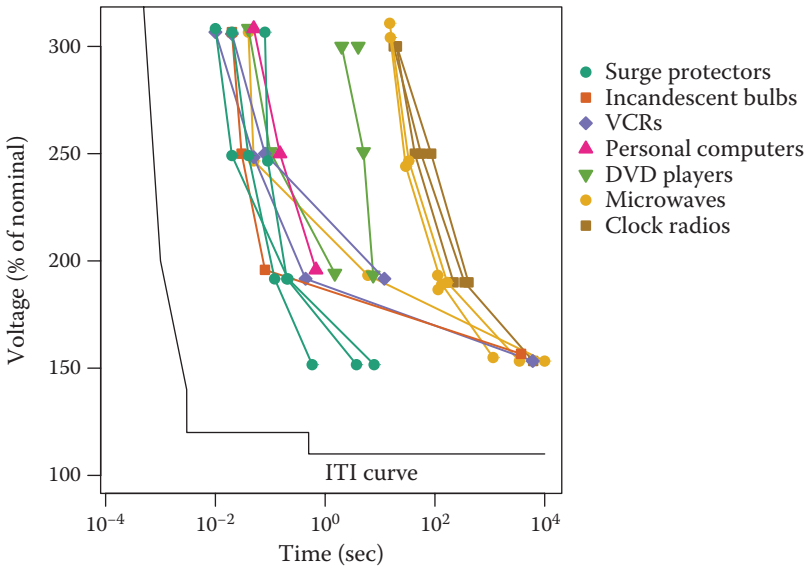

Figure 12.1 Failures of devices from temporary overvoltages. (Data from EPRI 1010892, *Effects of Temporary Overvoltage on Residential Products, Part 2*, Electric Power Research Institute, Palo Alto, CA, 2005.)

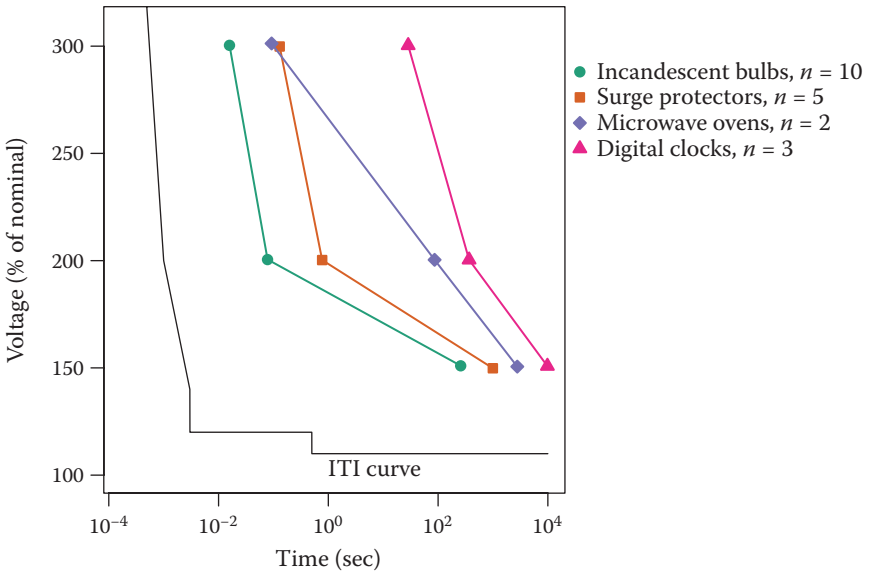

Figure 12.2 Failures of residential devices from temporary overvoltages. (Data from Bowes, K. B., *Power Quality Magazine*, pp. 57–71, September 1991.)

graph legend. The failure modes were similar to the EPRI tests. The most significant difference was in surge suppressors. These tests covered a range of clamping voltage. Bowes reported that several of these failures had package rupture, mild explosions, or combustion. Newer surge suppressors (ANSI/UL 1449, 2010) have protection that helps reduce the chance of dangerous failure modes, but this may make the devices more sensitive to overvoltages.

Le Courtois and Deslauriers (1997) also published failure data from both temporary and long-duration overvoltages. Figure 12.3 shows results from their data that covered digital clocks, televisions, videocassette recorders, microwave ovens, and telephones.

Electronic revenue meters can also fail from temporary overvoltages. In a series of tests on three samples each of six meters each supplied by a different manufacturer, some meter models were more sensitive to overvoltages than others (EPRI 1020089, 2010). Three meter models survived all overvoltage tests up to 240% of nominal for 2 sec. All meters survived overvoltages to 180% for 4 sec, and all but one meter survived overvoltages to 190% for 2 sec. Two meter models had 100% failures for tests to 210% of nominal for 2 sec. In a series of longer-duration tests to 120 sec, these same two meter models had 100% failures for tests to 183% of nominal. In all failures, one or more metal-oxide surge suppressors failed; these units had series-capacitor-type power supplies.

12.1.2 Secondary/Facility Grounding

Grounding problems within a facility can lead to equipment failures or malfunctions. A common problem is ground loops. If the secondary neutral has multiple

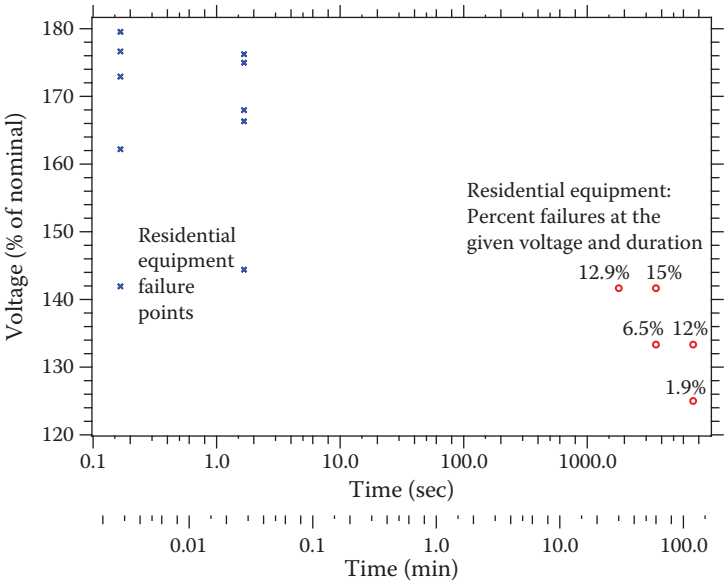

Figure 12.3 Failures of residential devices from temporary and long-duration overvoltages. (Data from Le Courtois, E. and Deslauriers, D., *EPRI PQA Conference*, 1997.)

connections within the facility, external ground currents from lightning or from faults can induce voltages along the neutral. Figure 12.4 shows an example. The neutral voltage shifts can impose overvoltages on sensitive equipment. For more information, see IEEE Std. 1100-1999 or IEEE Std. 142-1991. Single-point grounding of the neutral breaks the loops and reduces noise and possible overvoltages.

Grounding loops between multiple "ports" can create damaging scenarios. Any significant wired connection to equipment counts as a port—power, telephone, cable TV, printer cables, and networking cables. Figure 12.5 shows an example of a television where the cable enters via a different route and has a different ground than its electric service. A fault or lightning strike on the utility side can elevate the potential of the electric-supply ground relative to the television cable ground. Even if both the

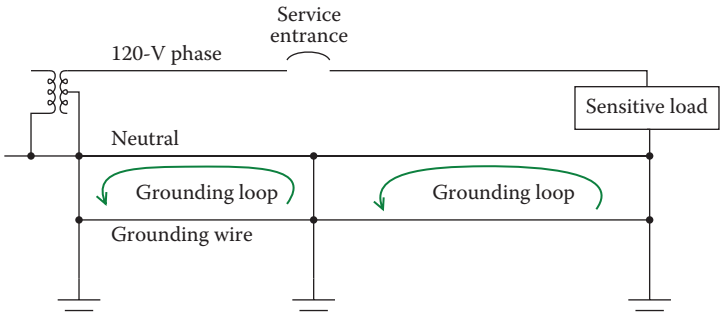

Figure 12.4 Ground loops within a facility.

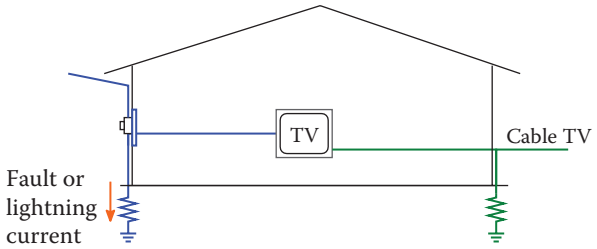

Figure 12.5 Example of a two-port voltage stress at a television between its power source and the cable TV cable.

electric and cable television cables have independent surge protection, surges still create voltage differences between components. To avoid multiple-port difficulties, arrange to have all power and communications enter a building at one location, provide a common ground, and apply surge protection to all ports. To overcome this problem, users can install a "surge reference equalizer" rather than independent surge protection on each port (EPRI PEAC Solution No. 1, 1993). Both the electric supply and the other port (telephone, cable TV, ethernet, etc.) plug into the surge reference equalizer. The equalizer provides surge protection for both incoming ports and a single common grounding connection.

For equipment, overvoltages between the phases and neutral are most important. While it is commonly believed that neutral-to-ground overvoltages cause problems for sensitive electronics, EPRI PEAC found that computers are quite tolerant of neutral-to-ground overvoltages. In tests, neither a continuous 50-V neutral-to-ground voltage nor a 3-kV, 100-kHz ring wave upset the operation of a computer (EPRI PEAC Brief No. 21, 1994).

12.1.3 Reclose Transients

One source of possibly damaging surges is from capacitive coupling through transformers. The very short-duration pulses come from electrostatic coupling through the transformer. Much analysis of this has been done for larger power transformers at generating stations (Abetti et al., 1952). At high frequencies, the transformer acts like a capacitor. A steep surge can pass from the primary to the secondary. How much of the surge gets from the primary to the secondary depends on the capacitances of the transformer and the secondary load—not the transformer turns ratio. A transformer has capacitance from the high-voltage winding to the low-voltage winding (C_1) and capacitance from the secondary winding to ground (C_2). As a first approximation, the voltage on the secondary as a function of the voltage on the primary is a capacitive voltage divider (Greenwood, 1991):

$$V_S = \frac{C_1}{C_1 + C_2} V_P$$

Line energization and capacitor switching and other transients can create surges that pass through the transformer. It does not even have to be an overvoltage on the primary, just a fast rise to the nominal peak—a normal reclose operation—can create a surge on the secondary. When a line is energized near its peak voltage, right when the switch engages, a traveling wave with a very steep front rushes down the line. At a transformer, this front can be steep enough to couple capacitively through to the secondary at voltages much higher than the turns ratio of the transformer. Figure 12.6 shows a 1-μs wide transient to just over 2000 V following a reclose operation.

These capacitively coupled surges are worse with

- Higher-voltage transformations from the primary to the secondary (34.5 kV to 480 V is worse than 12.5 kV to 480 V)
- Loads close to the substation or recloser (the wave front flattens out with distance)
- Minimal resistive load on the secondary

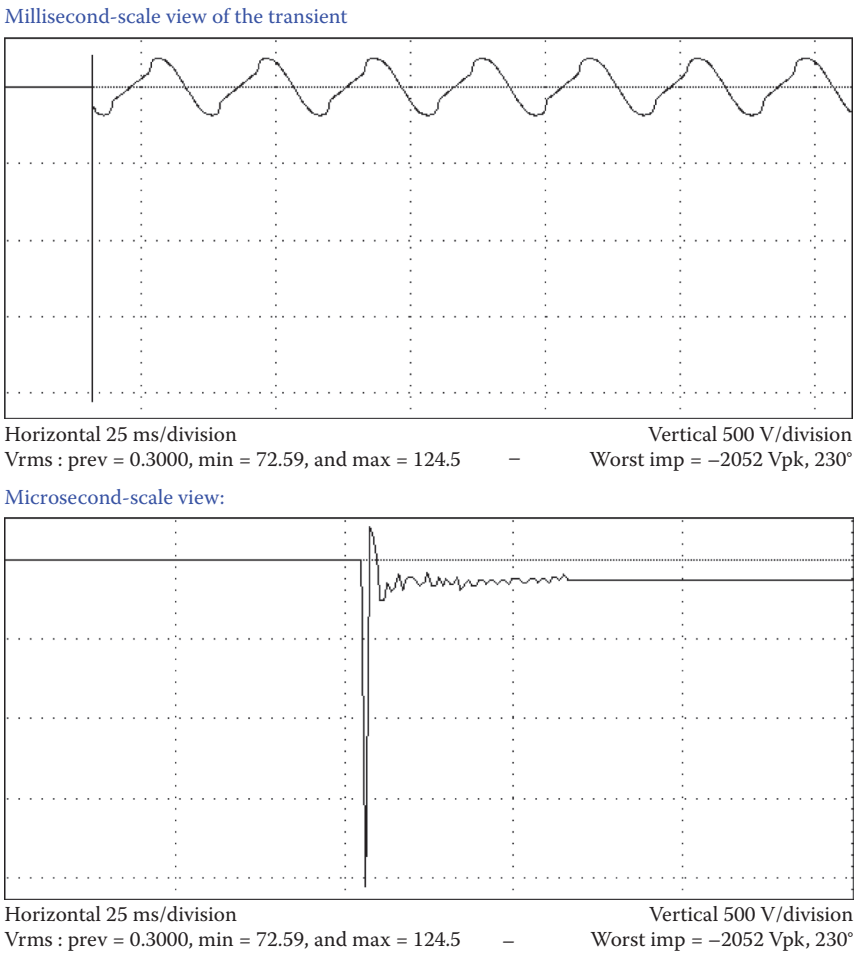

Figure 12.6 Measurements of a transient captured during a circuit reclose. (Recordings courtesy of Francisco Ferrandis Mauriz, Iberdrola Distribucion Electrica.)

We can protect against these surges with

- Line-to-ground capacitor banks in the facility (either power-factor correction or surge capacitors)
- Surge arresters

12.2 Switching Surges

Transients are triggered from capacitor switching, from line energization, and from faults. Capacitor switching transients normally cause the highest peak magnitudes. If a capacitor is switched just when the system voltage is near its peak, the capacitor pulls the system voltage down (as current rushes into the capacitor to charge it up). The system rebounds; the voltage overshoots and oscillates about the fundamental-frequency waveform (theoretically rising to two per unit, but normally less than that). This transient normally decays quickly. The oscillation occurs at the natural resonance frequency between the capacitor bank and the system, usually in hundreds of hertz:

$$f = \frac{1}{2\pi\sqrt{L_S C}} = 60\sqrt{\frac{X_C}{X_L}} = 60\sqrt{\frac{MVA_{sc}}{Mvar}}$$

where

f = frequency, Hz
C = capacitance, F
L_S = system inductance up to the capacitor bank at nominal frequency, H
X_C = line-to-ground impedance of one phase of the capacitor bank at nominal frequency
X_L = system impedance up to the capacitor bank at nominal frequency
MVA_{SC} = three-phase short-circuit MVA at the point where the capacitor is applied
$Mvar$ = three-phase Mvar rating of the capacitor

Capacitor switching transients tend to be more severe when the capacitor is at a weaker point on the system. Other capacitors on the circuit normally help, but if two capacitors are very close together, switching in the second capacitor can create a higher voltage transient.

Normally, switching surges are not particularly severe on distribution systems. The voltages decay quickly, and magnitudes are normally not severe enough to fail line equipment (Figure 12.7 shows a typical example). Switching transients can be large enough to affect sensitive end-use loads, particularly adjustable-speed drives and uninterruptible power supplies. The oscillation frequency is in the hundreds of hertz, low enough for the transient to pass right through distribution transformers and into customers' facilities.

EPRI's DPQ study found regular but mild transient overvoltages, most presumably due to switching operations. Transients measured on the distribution primary above

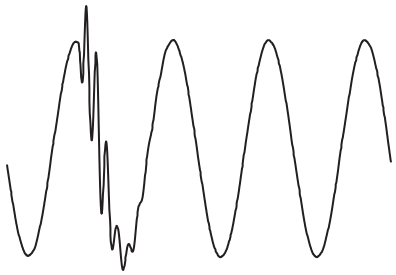

Figure 12.7 Capacitor switching transient. (From EPRI TR-106294-V2, *An Assessment of Distribution System Power Quality. Volume 2: Statistical Summary Report*, Electric Power Research Institute, Palo Alto, CA, 1996. Copyright 1996. Reprinted with permission.)

1.6 per unit are rare, averaging less than two per year (where per unit is relative to the peak of the nominal sinusoidal voltage wave). Figure 12.8 shows the average distribution of transients measured during the study (EPRI TR-106294-V2, 1996). This graph shows occurrences of transients with a peak magnitude between 1.05 and 1.9 per unit with a principal oscillation frequency between 240 and 3000 Hz (excluding transients associated with faults).

During EPRI's DPQ study, most of the transients measured occurred during the morning hours, from 5 a.m. to 10 a.m., when most switched capacitors are coming on line. The wide majority of oscillating transients measured in the study had dominant frequencies between 250 and 800 Hz.

American Electric Power (AEP) staged various switching tests on a 12.47-kV circuit and found that most capacitor switching and line energization transients were

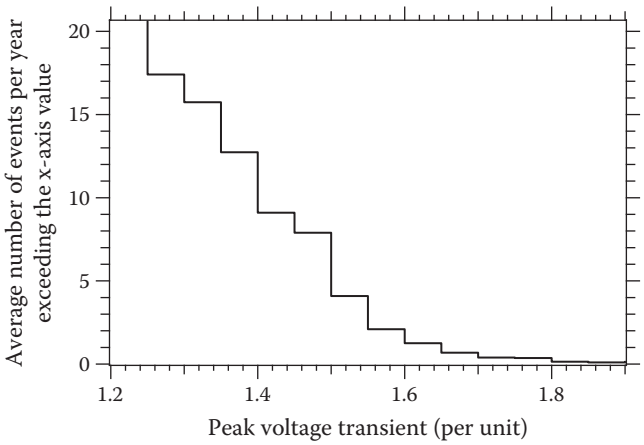

Figure 12.8 Average magnitudes of voltage transients measured on the distribution primary in EPRI's DPQ study. (Data from EPRI TR-106294-V2, *An Assessment of Distribution System Power Quality. Volume 2: Statistical Summary Report*, Electric Power Research Institute, Palo Alto, CA, 1996; Sabin, D. D., Grebe, T. E., and Sundaram, A., *International Conference on Power Systems Transients*, Technical University of Budapest, Budapest, Hungary, 1999b.)

less than two per unit on the primary (Kolcio et al., 1992). In their tests, switching a 450-kvar capacitor bank produced the highest transient, just under 2.3 per unit on closing—vacuum switches produced slightly higher transients than oil switches. Line energizations caused peak primary voltage of just under 1.9 per unit. The transients decayed in less than 5 ms.

Switching transients are normally more problematic on higher voltage distribution circuits, such as 34.5 kV. Several instances of equipment failures have been reported on these higher-voltage systems, usually from switching a large (10 plus Mvar) capacitor bank (Shankland et al., 1990; Troedsson et al., 1983). Capacitors tend to be larger, and sources are weaker. Plus, at higher voltages, primary-level insulation capability is lower on a relative basis compared to lower-voltage systems.

In capacitive circuits, switch *restrike* or *prestrike* generates more severe transients. A restrike can occur when switching a capacitor off; the switch opens at a current zero, trapping the peak voltage on the capacitor (see Figure 12.9). As the system voltage wave decreases from the peak, the voltage across the switch rapidly increases. By the time the system voltage reaches the opposite system peak, the voltage across the switch is 2 per unit (this extra voltage is the main reason that switches have a different rating for breaking capacitive circuits). If the switch restrikes because of this overvoltage, the voltage swings about the new voltage with a peak-to-peak voltage of 4 per unit, forcing the line-to-ground voltage to a peak of 3 per unit (theoretically). The interrupter can clear at another current zero and trap even more voltage on the capacitor, which can cause another more severe restrike; such multiple restrikes can escalate the voltage. Fortunately, such voltage escalation is rare. Restrikes are most likely if the interrupting contacts have not fully separated when the current first interrupts. Restrikes can fail switches and cause higher voltages on the system. Most switching technologies, including vacuum, can restrike under some conditions.

Prestriking occurs when a switch closes into a capacitor. If the gap between a switch's contacts breaks down before the contacts have fully closed, the system voltage charges up the capacitor. Because the contacts are not closed, the switch can

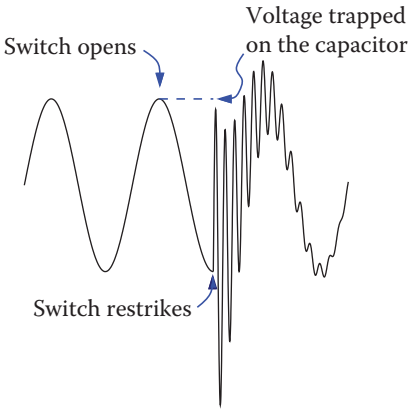

Figure 12.9 Restrike of a capacitor bank.

clear at a current zero, leaving the capacitor charged. We are back to the restriking scenario—when the gap breaks down again, the voltage transient can oscillate around the system voltage at a much higher level. Capacitor switches should not and normally do not regularly restrike or prestrike, and voltages rarely escalate, but some failures can be traced to these switching problems.

Capacitor switching is not the only switching transient that can occur on a distribution circuit. Line energization can cause transients, as can faults. Both of these are normally benign. Walling et al. (1995) tested load-break elbows and switching-compartment disconnects. Such switching results in repeated arc restrikes and prestrikes, but the overvoltages are not particularly severe because the oscillations dampen out without clearing at a transient zero crossing (no escalation of the voltage). With a maximum overvoltage of 2.44 per unit, Walling et al. do not expect consequential effects on underground cable insulation.

12.2.1 Voltage Magnification

Certain circuit resonances can *magnify* capacitor switching transients at locations away from the switched capacitor bank (Schultz et al., 1959). Magnification often increases a transient's peak magnitude by 50%, sometimes even by 100%. Figure 12.10 shows the classic voltage magnification circuit; two sets of resonant circuits interact to amplify the transient that occurs when C_1 is switched. The most severe magnification occurs when

- C_1 is much larger than C_2.
- The series combination of L_1 and C_1 resonates at about the same frequency as L_2 and C_2.
- There is little series or shunt resistance to dampen the transient.

If C_1 is much larger than the series impedance $L_2 + C_2$, switching C_1 in will initiate a transient that oscillates at a frequency of $\omega_1 = 1/\sqrt{L_1 C_1}$. If the downstream pair, L_2 and C_2, happen to have a natural resonant frequency near that of ω_1, oscillation between L_1 and C_1 will pump the natural oscillation between L_2 and C_2, causing higher voltages at V_2.

Consider a 10-Mvar substation capacitor and a 1200-kvar line capacitor on a 12.5-kV circuit with a substation source impedance of 1 Ω at 60 Hz. Under these

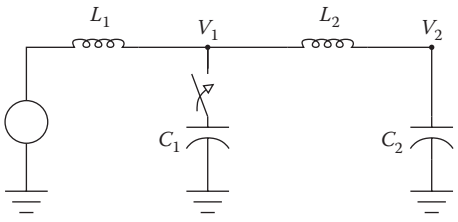

Figure 12.10 Voltage magnification circuit.

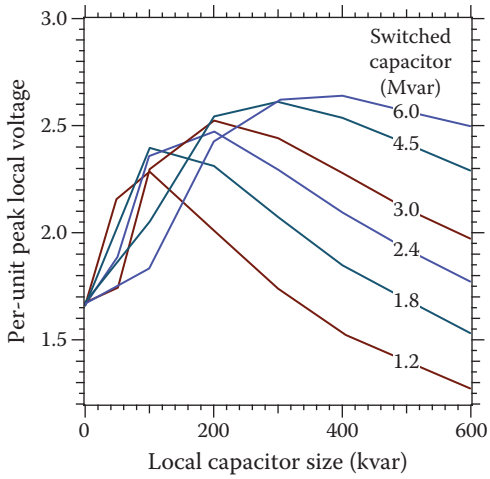

Figure 12.11 Transient magnitude for various sizes of switched distribution feeder capacitors and low-voltage capacitors. (McGranaghan, M. F. et al., *IEEE Transactions on Power Delivery*, vol. 7, no. 2, pp. 862–8, April 1992. © 1992 IEEE.)

conditions, the loop resonances match when X_{L2} is 8.3 Ω, or when the capacitor is about 13 mi from the substation (given typical line impedances). For maximum magnification, the ratio of the inductive impedances equals the inverse of the capacitor kvar ratios ($kvar_1/kvar_2 = X_{L2}/X_{L1}$).

In another common scenario, low-voltage power factor correction capacitors magnify transients from switched utility capacitors (McGranaghan et al., 1992). In this scenario, L_2 is primarily determined by the customer's transformer, and L_1 is determined by the system impedance to the capacitor bank. Their parametric study found that a wide combination of local and switched utility capacitors can magnify transients as shown in Figure 12.11. Larger utility banks are more likely to generate transients that are magnified on the low-voltage side. Resistive load helps dampen these transients; facilities with primarily motor loads have higher transients. Magnified transients can also inject considerably more energy into low-voltage metal-oxide arresters than they are typically rated to handle (especially for switching large utility banks).

Transients from switched capacitor banks on the high side of the substation bus can magnify at distribution capacitors or customer-owned capacitors (Bellei et al., 1996). Again, a wide combination of capacitor ranges can magnify surges.

12.2.2 Tripping of Adjustable-Speed Drives

The main power quality symptoms related to distribution capacitor switching is shutdown of ASDs and other sensitive process equipment. The front-end of an ASD rectifies the incoming line-to-line ac voltages to a dc voltage. The rectifier peak-tracks the

three incoming ac phases, so a switching surge on any phase charges up the dc bus. Because the electronics fed by the dc bus are sensitive to overvoltages, drives normally have sensitive dc bus overvoltage trip settings, typically 1.2 per unit with some as low as 1.17 per unit. It does not take much of a transient to reach 1.2 per unit. At such low sensitivities, the system and customer voltage regulation plays an important role. If the voltage at the drive is at 1.05 per unit when the capacitor switches, the transient does not have to oscillate much to reach 1.17 or 1.2 per unit. These voltages are on the dc bus, which is fed by the line-to-line voltage. The actual line-to-ground transients on the distribution system normally need to be higher than 1.2 per unit to raise the drive dc link voltage to 1.2 per unit (and this depends on the customer transformer connection).

McGranaghan et al. (1991) used transient simulations to analyze several variables impacting the tripping of drives:

- *dc capacitor*—If the drive's rectifier has a dc capacitor, it impacts the drive's sensitivity to switching transients. Drives with larger dc capacitor take longer to charge up, which makes them less likely to trip on overvoltage.
- *Switch closing*—The worst transients are when the capacitor switches all switches at the peak of the waveform.
- *Capacitor size*—Larger capacitor banks cause a more severe transient. For the case McGranaghan et al. (1991) analyzed, capacitor banks less than 1200-kvar banks were less likely to cause drive tripouts (see Figure 12.12).
- *Local power-factor correction capacitors*—If the facility has local capacitors, magnification of the incoming transient makes the drive more likely to trip. End users can avoid this problem by configuring their power-factor correction capacitors as tuned filters (McGranaghan et al., 1992).

Locally, the addition of chokes (series inductors) connected to the input terminals of the ASD reduces the voltage rise on the drive's dc bus. Standard sizes are 1.5%,

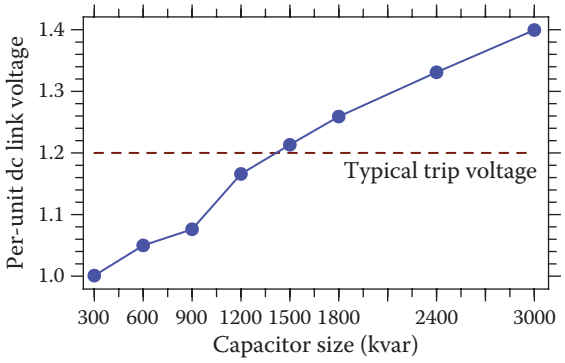

Figure 12.12 DC voltage on an adjustable-speed drive from switching of the given size capacitor bank (with no local power-factor correction capacitors). (McGranaghan, M. F. et al., *IEEE Transactions on Power Delivery*, vol. 6, no. 4, pp. 1623–8, October 1991. © 1991 IEEE.)

3%, and 5% impedance on the drive's kVA rating. A parametric simulation study of transmission-switched capacitors found that a 3% inductor greatly reduced the number of drive trips, but a number of transients can still trip some drives (depending on the size capacitor switched and many other variables) (Bellei et al., 1996).

12.2.3 Prevention of Capacitor Transients

Switched capacitors cause the most severe switching transients. Utility-side solutions to prevent the transient include zero-voltage closing switches or preinsertion resistors or reactors. Zero-voltage closing switches time their closing to minimize transients. Switches with preinsertion resistors place a resistor across the switch gap before fully closing contacts; this reduces the inrush and dampens the transient. Any of these options are available for substation banks, and utilities use them often, especially in areas serving sensitive commercial or industrial customers.

For distribution feeder banks, the zero-crossing switch controllers are the only available option for reducing transients. These controllers time the closing of each switch contact to engage the capacitor at the instant where the system voltage is zero, or very close to zero. An uncharged capacitor closing in at zero volts causes no transient.

The switches time the initiation of the switching so that by the time the switch engages, the system voltage is at zero. Since the capacitor should have no voltage, and it is switched into the system when it has no voltage, the switching does not create a transient. Timing and repeatability are important. One popular 200-A vacuum switch takes 0.015 sec to close and has a repeatability of ±3 degrees (±0.14 ms). Each phase is controlled separately.

Other claimed benefits of zero-crossing switches include increased capacitor and switch life, reduction of induced voltages into the low-voltage control wiring, and reduction of ground transients. Zero-crossing switches also eliminate capacitor inrush, including the much more severe inrush found when switching a capacitor with a nearby capacitor already energized.

12.3 Harmonics

Distortions in voltage and current waveshapes can upset end-use equipment and cause other problems. Harmonics are a particularly common type of distortion that repeats every cycle. Harmonically distorted waves contain components at integer multiples of the base or *fundamental* frequency (60 Hz in North America). Resistive loads such as incandescent lights, capacitors, and motors do not create harmonics—these are passive elements—when applied to 60-Hz voltage; they draw 60-Hz current. Electronic loads, which create much of the harmonics, do not draw sinusoidal currents in response to sinusoidal voltage.

A very common harmonic producer is the power supply for a computer, a switched-mode power supply that rectifies the incoming ac voltage to dc (see Figure 11.21). The

bridge rectifier has diodes that conduct to charge up capacitors on the dc bus. The diodes only conduct when the ac supply voltage is above the dc voltage for just a portion of each half cycle. So, the power supply draws current in short pulses, one each half cycle. Each pulse charges up the capacitor on the power supply. The current is heavily distorted compared to a sine wave, containing the odd harmonics, 3, 5, 7, 9, and so on. The third harmonic may be 80% of the fundamental, and the fifth may be 60% of the fundamental. Figure 12.13 shows examples of the harmonic current drawn by switched-mode power supplies in computers along with other sources of harmonics.

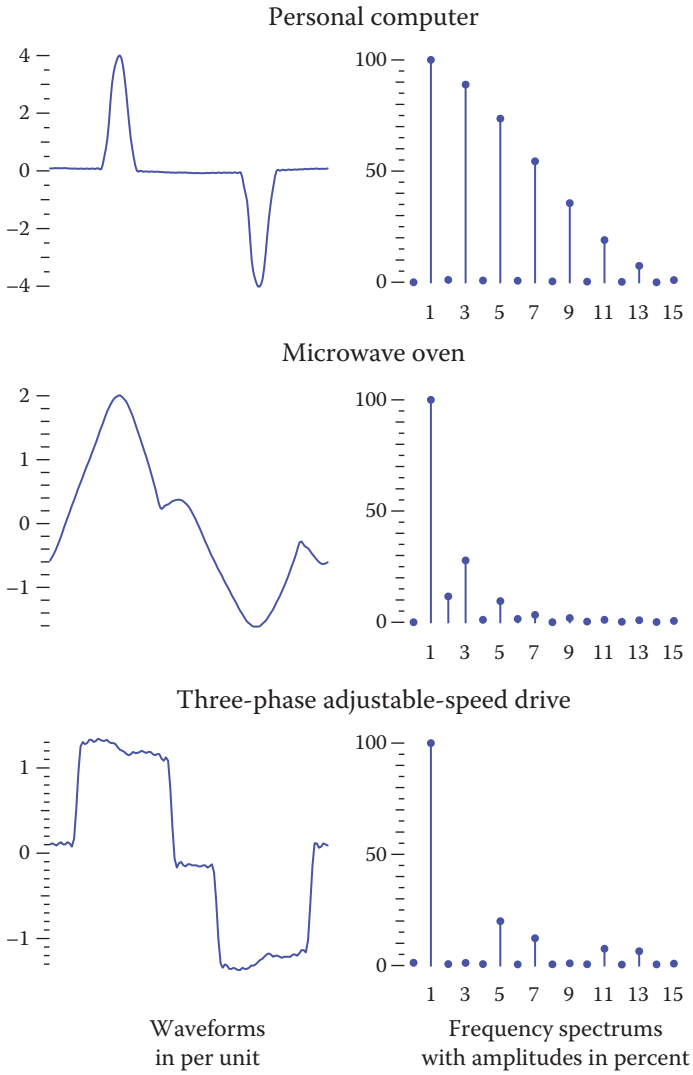

Figure 12.13 Examples of harmonic-current sources. (Data from EPRI PEAC Application #6, *Avoiding Harmonic-Related Overload of Shared-Neutral Conductors*, 1996, various measurements.)

Other very common sources of harmonics are ASDs and other three-phase dc power supplies (see Figure 11.28). These rectify the incoming ac waveshape from each of the three phases. In doing so, drives create current with harmonics of order 5, 7, 11, 13, and so on—all of the odd harmonics except multiples of three. In theory, drives create a fifth harmonic that is one-fifth of the fundamental, a seventh harmonic that is one-seventh of the fundamental, and so forth. Other harmonic-producing loads include arc furnaces, arc welders, fluorescent lights (with magnetic and especially with electronic ballasts), battery chargers, and cycloconverters.

Harmonic currents and harmonic voltages are interrelated. Commonly, nonlinear loads are modeled as ideal current injections ("ideal" meaning they inject the same current regardless of the voltage). An *n*th-harmonic source driving current through an impedance $R + jX$ raises the *n*th voltage to

$$V_n = R \cdot I_n + jn \cdot X \cdot I_n$$

Utility distribution systems are normally stiff enough (low Z) that they can absorb significant current distortions without voltage distortion.

Harmonics have been heavily researched and studied, probably more so than any other power quality problem. Despite the attention, harmonic problems are uncommon on distribution circuits. Most harmonic problems are isolated to industrial facilities; end-use equipment produces harmonics, which cause other problems within the facility.

We can characterize harmonics by the magnitude and phase angle of each individual harmonic. Normally, we specify each harmonic in percent or per unit of the fundamental-frequency magnitude. Another common measure is the *total harmonic distortion*, THD, which is the square-root of the sum of the squares of each individual harmonic. Voltage THD is

$$V_{\text{THD}} = \frac{\sqrt{\sum_{h=2}^{\infty} V_h^2}}{V_1}$$

where V_1 is the rms magnitude of the fundamental component, and V_h is the rms magnitude of component h. The Fourier transform is used to convert one or more waveshape cycles to the frequency domain and V_h values.

IEEE provides a recommended practice for harmonics, IEEE Std. 519-1992, which gives limits for utilities and for end users. Utilities are expected to maintain reasonably distortion-free voltage to customers. For suppliers at 69 kV and below, IEEE voltage limits are 3% on each individual harmonic and 5% on the THD (Table 12.1). Both of these percentages are referenced to the nominal voltage.

Current distortion limits (Table 12.2) were developed with the objective of matching the voltage distortion limits. If users limit their current injections according to the guidelines, the voltage limits will remain under the guidelines imposed on the utility (as long as no major circuit resonance exists). The individual harmonics and the total harmonics (TDD) are referenced to the maximum demand at that point,

TABLE 12.1 Voltage Distortion Limits

	Voltage Distortion Limit
Individual harmonics	3%
Total harmonic distortion (THD)	5%

Source: Adapted from IEEE Std. 519-1992, *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*. Copyright 1993 IEEE.

Note: For a bus limit at the point of common coupling at and below 69 kV. For conditions lasting less than 1 hour, the limits may be exceeded by 50%.

either the 15- or 30-min demand. Harmonic current limits depend on the facility size relative to the utility at the interconnection point. Larger facilities—relative to the strength of the utility at the interconnection point—are more restricted. Likewise, a facility at a stronger point in the system is allowed to inject more than the same facility at a weaker point because the same injection at a weaker point creates more voltage distortion. The ratio I_{sc}/I_L determines which set of limits applies. I_{sc} is the maximum short-circuit current; I_L is the maximum demand for the previous year.

Both the voltage and current limits apply at the *point of common coupling*, the point on the system where another customer can be served. Either side of the distribution transformer can be the point of common coupling, depending on whether the transformer can supply other customers. The point of common coupling is often taken as the metering point.

Harmonics can impact a variety of end-use equipment (IEEE Task Force, 1985, 1993; Rice, 1986). Some of the most common end-use effects are as follows:

- *Transformers*—Current distortion increases transformer losses and heating, enough so that transformers may have to be derated (see IEEE Std. C57.110-1998). Dry-type transformers are particularly sensitive.
- *Motors*—Voltage distortion induces heating on the stator and on the rotor in motors and other rotating machinery. The rotor presents a relatively low impedance to harmonics, like a shorted transformer winding. The effects are similar to motors operating with voltage unbalance, although not quite as severe since the impedance to

TABLE 12.2 Current Distortion Limits for Distribution Systems (120 V through 69 kV)

I_{sc}/I_L	$h < 11$	$11 \le h < 17$	$17 \le h < 23$	$23 \le h < 35$	$34 \le h$	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

Source: Adapted from IEEE Std. 519-1992, *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*. Copyright 1993 IEEE.

Note: Even harmonics are limited to 25% of the odd harmonic limits above. Current distortions that result in a dc offset are not allowed. For conditions lasting less than 1 hour, the limits may be exceeded by 50%.

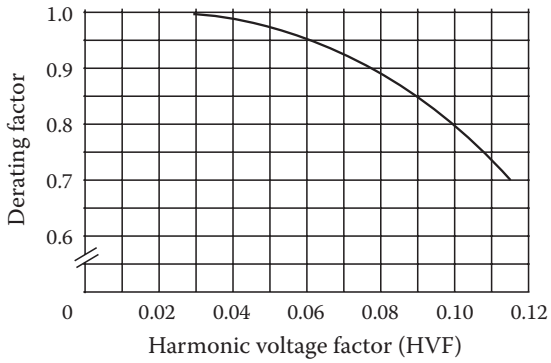

Figure 12.14 Motor derating due to harmonics. NEMA's harmonic voltage factor is slightly different from THD; it includes only the odd harmonics that are not multiples of three. (From NEMA MG-1, *Standard for Motors and Generators*, 1998. With permission.)

the harmonics increases with frequency. Figure 12.14 shows the National Electrical Manufacturers Association's (NEMAs) recommended derating factor for motors running with distorted voltage.

- *Conductors and Cables*—Resistance increases with frequency due to skin effect and proximity effect, particularly on larger conductors. As an example, at the seventh harmonic (420 Hz), a 500-kcmil cable has a resistance that is 2.36 times its dc resistance (Rice, 1986). Neutral conductors in facilities are especially prone to problems; third-harmonic currents from single-phase loads add in the neutral, which can actually increase neutral current above that in the phase conductors (EPRI PEAC Application #6, 1996).
- *Sensitive electronics*—Ironically, some of the main harmonic producers are also sensitive to harmonics. If a UPS detects excessive distortion, it may switch to its batteries; after the batteries run out, the critical load may drop out. Harmonics can impact digital devices that depend on a voltage zero crossing for timing (digital clocks being the simplest example). Excessive harmonics can introduce additional zero crossings that can disrupt controllers.

Most harmonic problems occur in industrial or commercial facilities. Distribution equipment is fairly immune to problems from harmonic voltages or currents. Heating from harmonics is not normally a problem for overhead conductors. Underground cables are more sensitive to heating. Harmonic currents can appreciably increase cable temperatures.

Many harmonic problems relate to heating, in transformers, motors, neutral conductors, or capacitors. Because of the thermal time constants of equipment, heat-related problems occur for sustained levels of harmonics (usually along with heavy power-frequency loading). Heating degrades insulation and leads to premature failure. Higher peak voltages can also cause insulation breakdowns, with capacitors being highly sensitive.

Most distribution circuits have very little distortion, having neither voltage distortion nor current distortion. Figure 12.15 shows average distortion measured during EPRI's DPQ study (EPRI TR-106294-V2, 1996; Sabin et al., 1999a). None of the DPQ

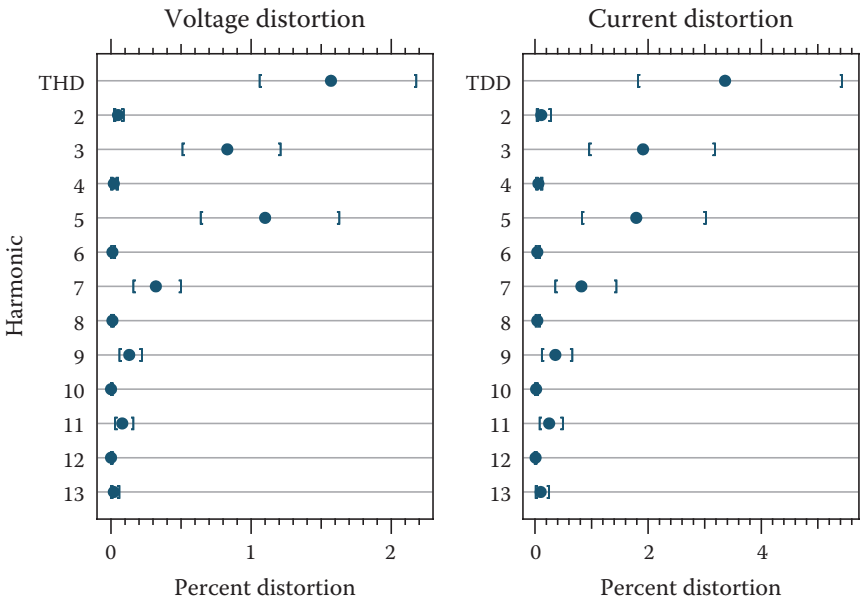

Figure 12.15 Voltage and current distortion measured in EPRI's DPQ study. The dot marks the mean distortion for the given harmonic, and the brackets mark the 5th and 95th percentiles. (Data from EPRI TR-106294-V2, *An Assessment of Distribution System Power Quality. Volume 2: Statistical Summary Report*, Electric Power Research Institute, Palo Alto, CA, 1996; Sabin, D. D., Brooks, D. L., and Sundaram, A., *IEEE Transactions on Power Delivery*, vol. 14, no. 2, pp. 489–96, April 1999a.)

sites had an average voltage THD above the IEEE 519 limit of 5% (the worst couple of sites averaged just under 4.8% THD). And, only 4% of the DPQ sites exceeded this IEEE 519 limit more than 5% of the time. At the DPQ sites, 95% of the time, the voltage THD was less than 2.2%.

Substation sites had slightly lower voltage and current distortions than those recorded at feeder sites: substation average THD = 1.37%; overall average THD = 1.57%. Industrial feeders (defined as having at least 40% of the load coming from industrial loads) showed only slightly higher voltage distortion than the average for all sites.

Other monitoring studies also show fairly low harmonics. Surveys of 76 sites on the Southwestern Electric Power Company's system found that none exceeded a voltage THD of 5% (less than 5% of exceeded 4%; 87% had THD less than 2.5%) (Govindarajan et al., 1991). A few of the sites had current distortion exceeding IEEE 519 standards. In a large survey of locations on the Sierra Pacific Power Company, voltage THD averaged 1.59%, and current THD averaged 5.3% (Etezadi-Amoli and Florence, 1990).

Some work has been done to investigate the impact of new harmonic loads on the harmonic distortion. Compact fluorescent lights with electronic ballasts, heat pumps and air conditioners with ASDs, computers, and electric vehicle battery chargers are some of the loads that could drive up harmonics. Compact fluorescent lights typically have a current THD of almost 140% (EPRI 1017891, 2009; Sharma et al., 2011). Pileggi et al. (1993) predicted that if every home used two or three electronically

ballasted fluorescent lights, voltage distortion may exceed 5%. This is hard to believe, but it does make us consider the impact of future electronic loads. Dwyer et al. (1995) also came to similar conclusions: modest numbers of electronic compact fluorescent lights (50 W per house) can raise the voltage distortion above 5%, especially if feeder capacitors create resonances that amplify the harmonics. It helps that multiple single-phase loads have some phase-angle cancelation; harmonic loads do not necessarily sum linearly (Mansoor et al., 1995). Hofmann (2009) reported on harmonic measurements of network voltage in New York City. Voltage THD increased from an average of 1.59% in 1996–1997 to 1.87% in 2006–2007, and the 99% cumulative probability rose from 2.7% in 1996–1997 to 3.03% in 2006–2007.

In the northeastern United States, Emanuel et al. (1995) predict rising levels of harmonic distortion based on predictions of increased use of ASDs, electronic fluorescent lights, computer loads, and other nonlinear loads. They predict that more nonlinear loads can add as much as 0.3% per year to the voltage THD under the worst-case scenario. A limited number of measurements by the same group of researchers over a 10-year time period found that harmonic voltages have increased at a rate of about 0.1% per year (it takes 10 years for the THD to increase by a percentage point) (Nejdawi et al., 1999).

Penetrations of air conditioners driven by ASDs to 10 to 20% can raise voltage THD levels above 5% (Gorgette et al., 2000; Thallam et al., 1992). In another study, Bohn (1996) predicted that electric-vehicle battery charger penetration levels as low as 5% could increase voltage THD above 5%, especially on weak systems. In both of these cases, investigators found wide differences in equipment designs. Some generate much more harmonics than others. For example, some ASDs with more sophisticated rectifier sections cause much less harmonics than standard rectifiers. As electronic loads grow, utilities must involve themselves in setting guidelines to limit the harmonics introduced by end-use equipment.

Finding the source of harmonics can be tricky—Here are two ways to track down harmonics:

1. *Time variations*—If harmonics are intermittent, correlating the time variations of the voltage or current harmonics with the operation time of facilities or of specific equipment can identify the harmonic producer.
2. *Monitoring with capacitor banks off*—In a radial circuit with no capacitors, harmonic sources inject current that flows back to the power source; following the current leads to the source of the harmonics. If capacitors are present, resonances can mask the true source of harmonics.

12.3.1 Resonances

When harmonics cause problems, capacitors are often a contributing factor. Capacitors can cause resonances that amplify harmonics. Harmonic problems often show up first at capacitor banks, where harmonics cause fuse operations or even capacitor failure. Most problems with severe harmonics are found in industrial facilities where

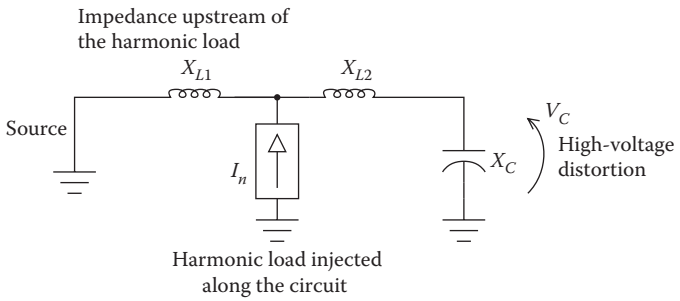

Figure 12.16 Harmonic resonance.

capacitors resonate against the system impedance. Utility resonances are infrequent but sometimes cause problems.

A capacitor on a distribution circuit will resonate against the inductance back to the system source (including the line impedances and transformer impedances). At the resonant frequency, the circuit amplifies harmonics injected into the circuit (see Figure 12.16).

The resonance point between the capacitor and the system for the scenario in Figure 12.16 (this is the same frequency that the system will ring at during a switching surge) is

$$n = \sqrt{\frac{X_C}{X_L}} = \sqrt{\frac{MVA_{sc}}{Mvar}}$$

where

n = order of the harmonic (multiples of the fundamental frequency)
X_C = line-to-ground reactance of one phase of the capacitor bank at nominal frequency
$X_L = X_{L1} + X_{L2}$ = system reactance at nominal frequency
MVA_{SC} = three-phase short-circuit MVA at the point where the capacitor is applied
$Mvar$ = three-phase Mvar rating of the capacitor

If a nonlinear load injects a harmonic frequency equal to the system's resonant point, it can create significant harmonic voltages. Common problem frequencies for resonances are $n = 5$, 7, 11, and 13. Larger capacitors lower the resonant point to where it is more likely to cause problems. For 15-kV class systems, resonances are possible at common capacitor locations for 600- to 1200-kvar banks (see Figure 12.17). For the single-capacitor circuit in Figure 12.16, the voltage distortion at the capacitor is

$$V_C = \frac{X_C X_{L1}}{nX_{L1} + nX_{L2} - \frac{1}{n}X_C} I_n$$

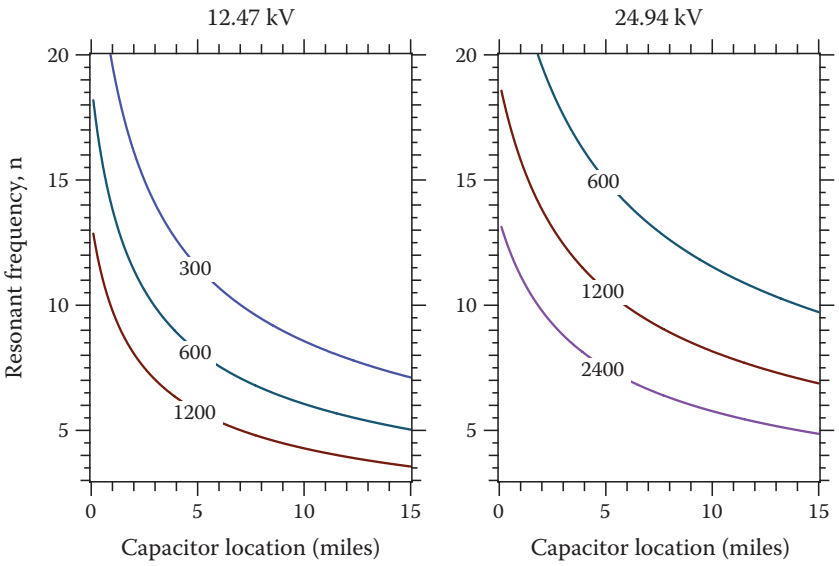

Figure 12.17 Resonant frequency versus capacitor size (in kvar) and location for balanced, positive-sequence resonances (500-kcmil AAC).

where I_n is the nth harmonic current. The worst conditions are when the harmonic source is right at the capacitor or downstream of the capacitor (X_{L2} is small). Harmonics injected further upstream are amplified less. This simplification ignores the resistance of the line and the resistance of the loads. Both reduce the peak magnitude.

Multiple capacitors on a circuit create multiple resonant points that can require more sophisticated analysis. For complicated circuits, especially with capacitor banks, a harmonic analysis program helps identify problems and try out solution options. A harmonic program models multiple harmonic sources at different locations; the solution shows the harmonic current flows and the harmonic voltages. Another tool, the frequency scan—a plot of the impedance at a location versus frequency—helps identify system resonances that appear as peaks in the scan (see Figure 12.18).

Distribution systems rarely need solutions to harmonics because typical voltage distortion levels are so low. When problems arise, specific harmonic producers or specific resonant conditions are often to blame. For offending producers, we can enforce harmonic standards. Where resonances occur, the solutions include

- *Relocate or remove capacitors*—The easiest solution is to disconnect the capacitors that form the resonant circuit. Relocating capacitors or changing their size can also shift the resonant point enough to ease problems.
- *Harmonic filters*—While rarely done, tuned filters, consisting of a capacitor in series with an inductor, absorb harmonics near their tuned frequency. The best location for filters is closest to the harmonic producers. If harmonic producers are distributed, filters located near the center of the line can absorb some of the harmonics. Applying filters requires study to ensure that additional resonances are not created.

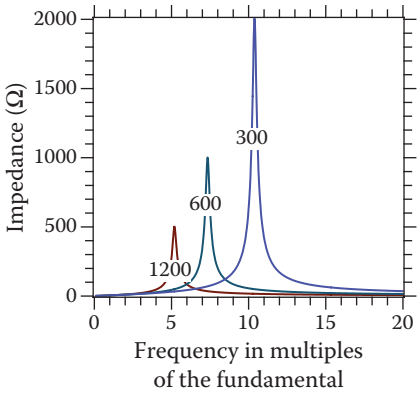

Figure 12.18 Harmonic scans for various size capacitors (shown in kvar) applied on a 12.47-kV circuit 6 miles from the substation.

12.3.2 Telephone Interference

Current flowing through distribution conductors induces voltage along parallel conductors, both power conductors and communication conductors. On low-voltage communication lines, induced voltages can interfere with communication signals, particularly on telephone circuits. Telephone interference is less common than in the past, primarily because telephone companies use more immune circuits with shielded cables or fiber optics. Open-wire communication lines are the most susceptible to interference. Interference depends on the offending current magnitude, the distance between conductors, and the length that the circuits run in parallel.

Harmonics increase the likelihood of telephone interference. Higher frequencies introduce noise that transfers more readily through telephone equipment and is more easily heard. *Telephone influence factors (TIF)* weight harmonics differently, depending on frequency. Figure 12.19 shows TIF weighting factors with frequency. This curve is based on the response of the telephone equipment (mainly the handset) and human

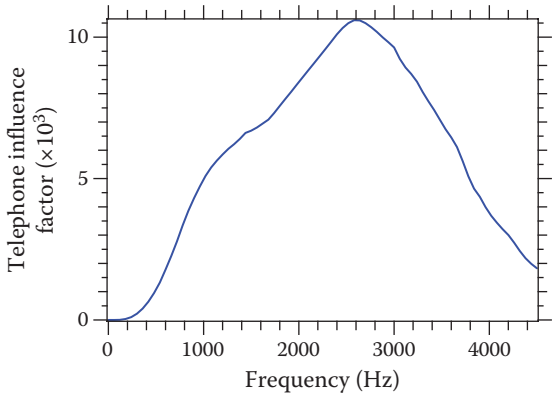

Figure 12.19 Telephone interference factor weights (W_f) with frequency.

perception of different frequencies. The most sensitive frequency is near 2600 Hz ($n = 43$). Lower-order harmonics scaling as far down as the third harmonic can interfere with telephone and other communication circuits. The total TIF for either voltage or current is a weighted factor at each harmonic relative to the total rms current:

$$\text{TIF} = \sqrt{\sum \left(\frac{X_f W_f}{X_t} \right)^2}$$

where

X_t = total rms voltage or current
X_f = single-frequency rms current or voltage at frequency f
W_f = single-frequency TIF weighting at frequency f

TIF is a factor that indicates the harmonic content weighted by frequency; TIF is like THD but scales each harmonic according to its relative interference capability. Because interference depends on current magnitudes as well as harmonic content, interference potential is often described in terms of the product of current and the TIF, $I \cdot T$, where I is the rms current in amperes, and T is the TIF. Table 12.3 shows guidelines for $I \cdot T$ from IEEE 519.

Harmonics in the ground return path are much more likely to interfere with communication circuits. Balanced third and ninth harmonics as well as other multiples of three (the *triplens* or *triples*) are zero-sequence frequencies. These currents generally add in the neutral. Because zero-sequence circuit impedances are higher than positive-sequence impedances, zero-sequence resonances can arise with smaller capacitor banks than for positive-sequence resonances. Figure 12.20 shows capacitor locations that cause zero-sequence resonances that force more current into the ground-return path. Table 12.4 shows locations where capacitors resonate for zero-sequence third harmonics.

While the triplen harmonics are most likely to interfere with communications circuits, other common harmonics such as the fifth or seventh can cause trouble. Although the fifth and seventh harmonics are not naturally zero-sequence currents, if the harmonic components on each of the three phases are unbalanced, the unbalanced portion of harmonics will flow in the ground.

TABLE 12.3 Balanced $I \cdot T$ Guidelines between Overhead Power Circuits and Overhead Telephone Circuits

Classification	$I \cdot T$
Levels most unlikely to cause interference	≤10,000[a]
Levels that might cause interference	10,000–25,000
Levels that probably will cause interference	>25,000

Source: Adapted from IEEE Std. 519-1992, *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.* Copyright 1993 IEEE.

[a]For some areas that use a ground return for either telephone or power circuits, this value may be as low as 1500.

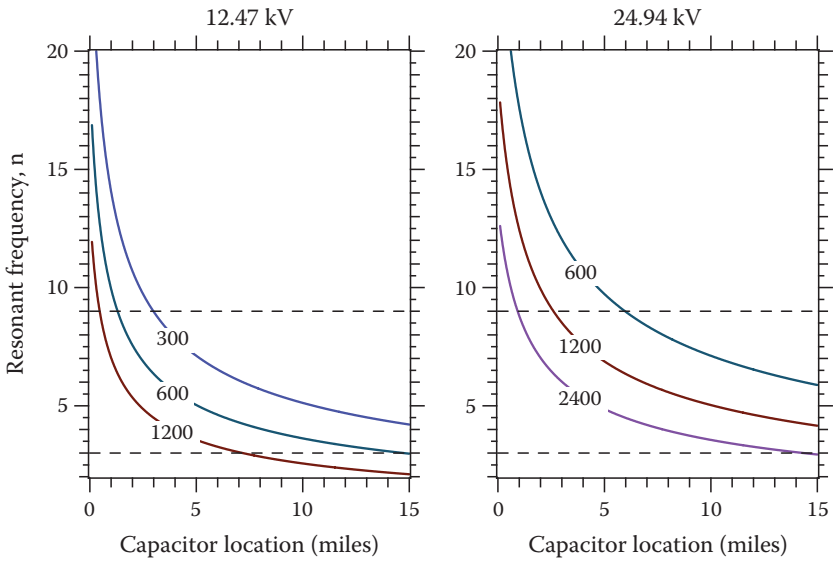

Figure 12.20 Resonant frequency versus capacitor size (in kvar) and location for zero-sequence resonances (500-kcmil AAC, $X_0 = 1.9\ \Omega$/mile).

TABLE 12.4 Capacitor Location in Miles from the Substation Where a Third-Harmonic Zero-Sequence Resonance Occurs for the Given Size Capacitor (for 500-kcmil AAC with $X_0 = 0.3605\ \Omega$/1000 ft)

	System Voltage, kV			
kvar	4.8	12.47	24.94	34.5
600	2.1	14.8	59.8	
900	1.3	9.7	39.6	76.2
1200	1.0	7.2	29.5	56.9
1800		4.7	19.4	37.6
2400			14.4	27.9
4800			6.8	13.4

Telephone interference problems are usually solved by the telephone company in cooperation with the electric utility involved. Solutions are often trial-and-error; harmonic load-flow models can help test out solutions. The normal utility-side solutions are (IEEE Std. 776-1992; IEEE Std. 1137-1991; IEEE Working Group, 1985)

- *Change size*—For problems involving a resonance, increasing or decreasing the size of a bank can shift the resonant point enough to ease interference problems. The easiest solution is to disconnect the bank that is contributing to the problem. This is also a good first step to quantify the role of the capacitor bank in the interference.
- *Balancing*—Balancing harmonic loads between phases reduces the ground return current. In cases of long single-phase runs, we can upgrade the line to a two-phase

line to reduce ground currents. Note that this will not help with the third-harmonic currents.

- *Move the bank*—Moving a capacitor can change a resonant point enough to stop interference problems. On some circuits, one can also move the capacitor away from the telephone circuits having problems.
- *Unground the bank*—A floating-wye connection has no connection to the ground, so the connection blocks zero-sequence harmonic currents. Two-bushing capacitor units are necessary for floating the wye point (unless the utility floats the capacitor tanks and deals with the safety issues that accompany that practice).
- *Add a neutral filter*—While not a common solution, a tuned reactor in the ground path of a wye-connected capacitor bank is invisible to positive and negative sequences, but it changes the zero-sequence resonant frequency of a distribution feeder and often eliminates the resonant problem. As another approach, on a bank close to the harmonic source, one could also tune the filter to drain the offending harmonics (so they do not flow back along the electric/phone lines). Jewell et al. (2000) describe the analysis and development for a filter to mitigate telephone noise.
- *Add a grounding bank*—Grounding banks can change zero-sequence impedances to shift resonances or shift current flows away from parallel utility/communication runs to avoid interference. They also provide a low-impedance path for zero-sequence characteristic currents to flow. A zig-zag bank can be added, or existing floating-wye–delta connections can be converted to grounded wye–delta.

On the communications side, several solutions are possible: conversion to more immune circuits such as fiber optics or shielded conductors. 60-Hz rejection filters, drainage coils between conductor pairs to reduce induced voltages, and neutralizing transformers, which add a voltage opposing the induced voltages. Finally, if the interference can be traced to major harmonic producers, the offending producer can be turned off or harmonics can be filtered at the source.

12.4 Flicker

Light flicker is due to rapidly changing loads that cause fluctuation in the customer's voltage. Even a small change in voltage can cause noticeable lamp flicker. Flicker is an irritation issue. Flicker does not fail equipment; flicker does not disrupt sensitive equipment; flicker does not disrupt processes. Flickering lights or televisions or computer monitors annoy end users.

Annoying lamp flicker occurs when rapid changes in load current cause the power system voltage to fluctuate. Sawmills, irrigation pumps, arc welders, spot welders, elevators, laser printers—all can rapidly change their current draw. In arc furnaces, arcs fluctuate wildly from cycle to cycle, continuously flickering the voltage. When starting, motors draw significant inrush, five or six times their normal current, possibly depressing the voltage for tens of seconds. Some loads such as elevators turn on and off repeatedly. All of these fluctuating load changes can cause flicker.

Susceptibility to flicker depends on the stiffness of the supply system. So, flicker is more common on lower-voltage systems and at the ends of long circuits.

Both magnitude and frequency of fluctuations affect flicker perceptions. People are most sensitive to flicker that changes from 2 to 10 times per second, and flicker is visible up to about 35 Hz. The most common flicker reference curve that has been developed is the GE flicker curve based on tests by General Electric and several utilities around 1930 (General Electric GET-1008 L) and republished in the IEEE Red Book (IEEE Std. 141-1993). (See Walker (1979) for comparison with other flicker curves.) An IEEE survey found that 69% of utilities were using the GE curve (Seebald et al., 1985). The GE curve shows both a "threshold of perception" and a "threshold of irritation" (see Figure 12.21). The GE flicker curve is based on square-wave changes to the supply voltage at the frequencies indicated. Load changes that are more gradual than a stepped square wave result in less noticeable flicker; the eye–brain response is more sensitive to rapid light changes (up to a point). The flicker curve is based on a change in voltage (ΔV) relative to the steady-state voltage (V) (see Figure 12.22). Both ΔV and V are best represented by rms quantities; mixing rms, peak, or peak-to-peak quantities gives errors of 2 or $\sqrt{2}$. The frequency of the changes is also confusing, even for changes that are regular and periodic. The GE flicker curve is based on the number of *dips* per minute or second or hours. Some other curves or criteria are based on the number of *changes* per unit of time (frequency of changes are twice the frequency of dips).

The flicker tendency of different lights varies significantly:

- *Smaller incandescent bulbs*—Smaller filaments cool more quickly, so their light output changes more for a given fluctuation. Higher-voltage bulbs also have smaller filaments, so they flicker less.

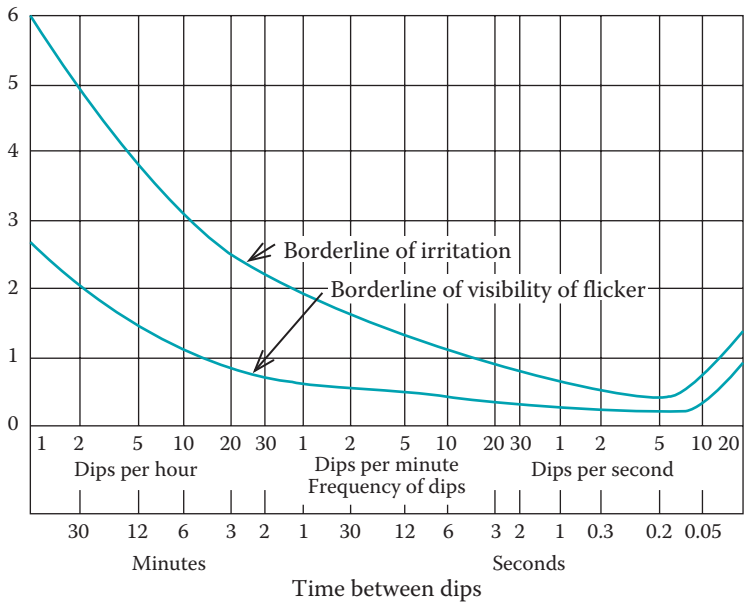

Figure 12.21 GE flicker curve. (IEEE Std. 141-1993, *IEEE Recommended Practice for Electric Power Distribution for Industrial Plants*. © 1994 IEEE.)

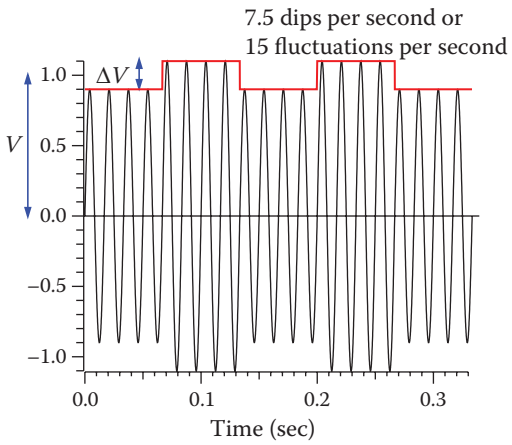

Figure 12.22 Characterizing the magnitude and frequency of voltage changes.

- *Dimmers*—Some electronic dimmers greatly increase voltage flicker, especially at low-light settings (EPRI PEAC Brief No. 25, 1995). Flicker on some dimmed lights is equivalent to the same flicker on undimmed lights with double the voltage fluctuation.
- *Fluorescent lights*—Whether magnetic or electronically ballasted, fluorescent lights normally flicker less for a given voltage input, some by a factor of over five (voltage changes on a fluorescent light need to be five times greater to cause the same level of flicker perception on an incandescent light). This is not always the case though; some fluorescent lights flicker as much as incandescent lights, and there is no general rule to identify whether a fluorescent light is sensitive. Fluorescent light output depends on the point on wave where the phosphors ignites, so peak voltage affects fluorescent lights more than rms-voltage changes.

While lights receive the most attention, voltage fluctuations can also cause televisions and computer monitors to waver.

Because flicker is based on human perception, it is an inexact science. Some people are more sensitive than others. Younger people are more sensitive. Flicker is more noticeable in quiet, low-light settings. In addition, the steady-state voltage during the time of the fluctuation impacts flicker—lower nominal voltages lead to less flicker; a 5% reduction in voltage reduces perceived flicker by 5% (EPRI PEAC Brief No. 36, 1996). Flicker is more noticeable with side vision (peripheral vision) than with straight-ahead vision. The perception process involves the thermal characteristics of the filament and the human eye–brain response.

The European community has derived sophisticated methods of characterizing and analyzing flicker, developing a flickermeter (IEC 868, 1986) and a comprehensive set of standards. The IEEE is moving toward adopting the European flickermeter approach to quantify flicker (Halpin et al.). The flickermeter models the complex lamp–eye–brain interaction to uniformly quantify flicker from a variety of sources, whether the offending load is an arc furnace or repetitive motor starts. The flickermeter measures voltage and produces these outputs:

- *Instantaneous flicker sensation*—This output is in "perception units," a unit-less quantity. One per unit is defined as the threshold of perception for 50% of the population.
- *Short-term flicker indicator* (P_{st})—The short-term flicker indicator is a weighted factor based on probabilities of the instantaneous flicker sensation over a 10-min monitoring period. A $P_{st} = 1$ is the threshold of irritation, the level that the majority of the population finds annoying. P_{st} values as low as 0.7 have been found to be visible under some conditions.
- *Long-term flicker indicator* (P_{lt})—Long-term flicker is based on 2 hours of flicker measurement and combines 12 consecutive P_{st} values (using the cubed root of the sum of the cubes of the 12 P_{st} values).

The flickermeter produces comparable results to the GE flicker curve when the flickermeter has a square-wave input as shown in Figure 12.23. Both the GE curve and the IEC curve (calibrated for 120-V lamps) produce comparable results. A flicker curve analysis is easier for loads that fluctuate periodically in a square-wave fashion. For intermittent or chaotic loads such as welders, a flicker curve is impossible to use. Converting a measured waveform to the frequency domain with a Fourier transform and plotting the results on a flicker curve is imprecise. While the exercise reveals predominant frequencies, the Fourier transform does not mimic the brain's response to flickering light. The flickermeter is much more appropriate for cases where loads fluctuate irregularly.

The P_{st} is an rms quantity that we can treat like a per-unit voltage. If the current draw from the fluctuating load doubles (and the waveshape stays the same), the voltage deviation (ΔV) will double, and P_{st} will double. Just as we can use voltage dividers, we can use impedance dividers to estimate flicker propagation and estimate flicker severity at other locations on a circuit (see Figure 12.24). Flicker decreases as one moves upstream of the fluctuating load on a radial circuit. Customers at or downstream of the fluctuating load experience the worst flicker.

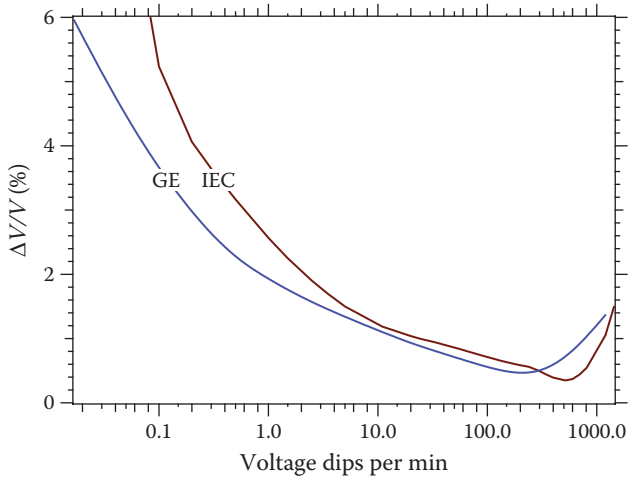

Figure 12.23 GE borderline of irritation curve compared to the voltage change necessary to produce $P_{st} = 1$ from the IEC flickermeter with a square-wave input.

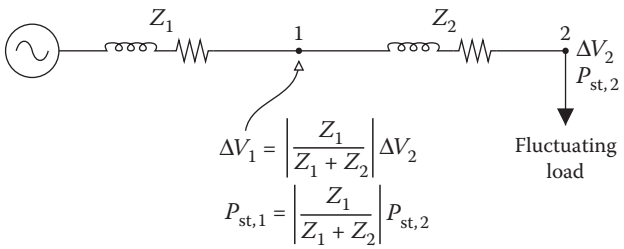

Figure 12.24 Propagation of voltage flicker.

Multiple sources of harmonics can influence flicker differently, depending on the characteristics of the fluctuating loads. Multiple sources combine as

$$P_{st,TOTAL} = \left(\sum P_{st,i}^{m}\right)^{\frac{1}{m}}$$

UIE, the organization that developed many of the European flicker standards (UIEPQ-9715, 1999), suggests the following values of m for combining multiple fluctuating loads (smaller m is more conservative):

m = 4: for arc furnaces operated to avoid simultaneous operations
m = 3: when the risk of simultaneous voltage variations is minimal (most unrelated loads are in this category)
m = 2: simultaneous operation of devices producing random-noise-type fluctuations, such as arc furnaces operating at the same time
m = 1: when there is a high probability of simultaneous operation

The flickermeter can effectively quantify flicker for existing loads; it does not help much for predicting the flicker at new installations. It is possible to model the time variations of fluctuating loads and run a software "flickermeter" on the results. If a similar load exists on the system, another approach is to measure P_{st} at the existing location and scale it by the relative differences between impedances at the existing location and the new location:

$$P_{st,B} = \frac{Z_B}{Z_A} P_{st,A}$$

where

$P_{st,A}$ = the short-term flicker indicator measured at a location with an impedance back to the source of Z_A (the three-phase short-circuit impedance)
$P_{st,B}$ = the short-term flicker indicator for the same fluctuating load moved to a point B, which has a short-circuit impedance of Z_B

A basic screening criteria based on the stiffness of the distribution circuit and the amount of fluctuation also helps determine if flicker could be a problem at new

TABLE 12.5 Thresholds Where Fluctuating Loads Will Not Cause Flicker Problems per IEC 61000-3-7 (1995) and UIEPQ-9715 (1999)

Number of Voltage Changes per Minute, r	$\Delta I/I_{SC}$,%
$r > 200$	0.1
$10 \leq r \leq 200$	0.2
$r < 10$	0.4

installations. The Europeans have adopted a set of criteria depending on the rate of change of the load and the fluctuation relative to the stiffness of the supply (Table 12.5). The change in load (ΔI) is referenced to the short-circuit current at the nearest customer (I_{SC}). At less than 10 changes per minute, with a short-circuit level on the primary of 1000 A, a load could fluctuate by 4 A (as measured on the primary) without causing flicker if the fluctuations are fewer than 10/min. North American limits could be less conservative than this because the lower-voltage North American light bulb is less sensitive to flicker than filaments at higher European voltages (120-V bulbs vs. 230-V bulbs).

Motor starts are a special case of voltage flicker. Most motors start only a few times per day, which is possibly off the flicker curve. While motors may start infrequently, when they do start, the voltage change is sharp, and light change can be deep and easily visible. Motors normally draw five to six times full-load current during starting. Normally, the voltage drops suddenly and then gradually recovers over several seconds as the motor comes up to speed.

Utilities normally have a criteria for motor starts based on the change of voltage and how often the customer starts the motor. Willis (2004) reported that many utilities use a criteria of 3% during motor starting (Table 12.6), but some utilities vary on how they define the percentage (either relative to the nominal voltage, the minimum voltage, or the voltage at the time of the motor start). Also, utilities often limit the size of motors or the starting current allowed by end users, depending on the voltage (see Table 12.7 for one utility's limits).

The source impedance at the customer with the motor (or other fluctuating load) is an important component. As with harmonics, we are most concerned about the

TABLE 12.6 Voltage Flicker Limits at Several Utilities during Motor Starting

Utility	Voltage Criteria
Dense urban area	3%
Urban/suburban	3%
Suburban and rural	3%
Urban and rural	3%
Rural, mountainous	4 V (on a 120-V base)
Rural, mountainous	None

Source: Data from Willis, H. L., *Power Distribution Planning Reference Book*, Marcel Dekker, New York, 2004.

TABLE 12.7 One Utility's Allowable Motor Starting Currents

System	Maximum Allowable Starting Current, A
Single Phase	
120 V	100
208 V	160
240 V	200
Three Phase	
208 V	1554
240 V	1346
480 V	673
2400 V	135

Note: Automatically controlled motors are limited to half of the allowable starting currents in the table.

voltage drop at the point of common coupling, the point where other customers can be tapped off. For customers fed from the same transformer, the point of common coupling is at the transformer. The impedance at the transformer is dominated by the transformer's impedance; the primary-side impedance is normally small. If customers share secondary circuits, also add the impedance of the shared secondary. For larger customers with their own dedicated transformer, the point of common coupling is on the primary. To evaluate the flicker to the customer that has the fluctuating load, consider the secondary and service drop to the meter. Hydro Quebec estimated reference impedances for Canadian residential and industrial facilities (Ba et al., 1997). At the panel, they estimated that 95% of customers have lower impedances than the values in Table 12.8, which we could use as a first approximation for motor starting and other fluctuation limits.

Interharmonics—harmonic distortions that are not integer multiples of the fundamental—can cause voltage flicker (Gunther, 2001). Noninteger harmonics are less common than integer harmonics, so this problem is not particularly widespread. Cycloconverters, arc furnaces, arc welders, and induction furnaces inject interharmonics. Interharmonics also come from loads such as ovens or furnaces with integral cycle control, where the load controls the average voltage by either giving the heater full voltage or no voltage on a cycle-by-cycle basis (60% average voltage could come

TABLE 12.8 Reference Impedances as Seen from the Electrical Panel Board

Location	Impedance, Ω
120-V residential, phase to neutral	$0.19 + j0.062$
240-V residential, phase to return phase	$0.20 + j0.080$
600-V industrial, phase to neutral	$0.58 + j0.107$
600-V industrial, phase to phase	$0.57 + j0.135$

Source: Data from Ba, A. O., Bergeron, R., and Laperriere, A., *CIRED 97*, 1997.

from six cycles on, then four cycles off). Standard six-pulse or 12-pulse power converters do not normally create noninteger harmonics, but a converter can create noninteger harmonics if its electronic switches fire at the wrong time. Misfiring can come from incorrect control settings or a variety of hardware problems. The Wisconsin Electric Power Company had such a problem with a dc arc furnace that caused flicker (Tang et al., 1994).

Two superimposed frequencies beat against each other at this frequency:

$$f = |f_{ih} - f_0|$$

where

f_{ih} = frequency of the interharmonic

f_0 = integer multiple of the fundamental frequency closest to f_{ih}

So, for $n = 3.1$, the beat frequency is $|3.1–3| = 0.1$ per unit, or $|186\text{ Hz}–180\text{ Hz}| = 6$ Hz (see Figure 12.25), right at the most sensitive flicker frequency. Frequencies of n = 1.9, 2.1, 2.9, 3.1, 3.9, and 4.1 per unit each beat at the same frequency: 0.1 per unit. Lower-frequency interharmonics—those near the first through third harmonic—are most likely to cause flicker. The IEC flickermeter detects flicker due to rms changes. Low-frequency interharmonics below the second harmonic change the rms, especially near the fundamental. But interharmonics above the second harmonic only modulate the peak; so at higher-frequency interharmonics, where the rms stays constant, the IEC flickermeter does not detect flicker (even though the fluctuations in the peak can result in noticeable flicker on fluorescent lights).

Incandescent lamps respond to rms voltage. Interharmonics below the second harmonic can cause flicker; higher frequencies do not. Fluorescent lights with electronic ballasts are particularly sensitive to the waveform peak; as the peak fluctuates, light output fluctuates. Electronic ballasts rectify the ac, which tracks the waveform peaks.

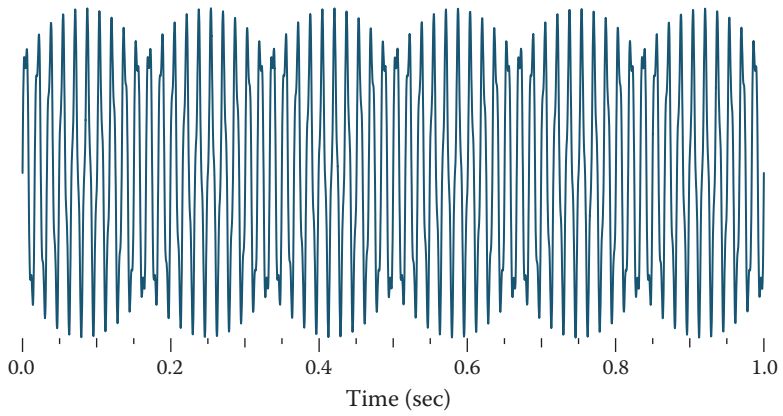

Figure 12.25 A 20% interharmonic frequency of $n = 3.1$ (186 Hz) causing a beat frequency of 6 Hz.

Just as capacitors can amplify integer harmonics, resonances can amplify noninteger harmonics. Solutions to flicker from interharmonics can include some of the solutions to regular flicker discussed in the next section. Also, harmonic solutions are appropriate in some situations, especially removing resonances by resizing or moving capacitors.

12.4.1 Flicker Solutions

12.4.1.1 Load Changes

Often, flicker is most economically solved at the source of the problem, the fluctuating load.

- *Welders*—For single large welders, changing the electrode firing sequence to draw smaller but more frequent current pulses can reduce flicker (EPRI PEAC Case Study No. 1, 1997). For multiple welders, control equipment can add a short delay to some welders to prevent simultaneous firing of several units. Also, on some welders, users can lower the weld "heat" (and current draw) without sacrificing the quality of the weld.
- *Motors*—For motor-starting flicker, one of several reduced-voltage starters will reduce the current draw and voltage deviation during starting. Common ways to reduce the voltage include an autotransformer start, a reactor start, and electronically switching the voltage (like a light dimmer) during starting. Reducing voltage to the motor during starting reduces the current inrush from 5 to 6 times normal current to under 2 per unit in some cases. Electronic motor starters can ramp the current to a preset maximum level. However, reduced-voltage starts also reduce the starting torque, so mechanical load issues can limit how much we can reduce the voltage. For motors susceptible to stalling (such as wood grinders), more careful operations on the mechanical side can reduce flicker (such as controlling the stock fed to the grinder).
- *Resistive heaters*—Heaters with on–off-type controls flicker from repeated on and off cycling. Often, more precise control with less fluctuation is possible by upgrading the heater controls—regulating the voltage to the heating elements or splitting one heater into separately controlled elements.
- *Operational limits*—A simple option requiring no physical changes is to limit operation of offending loads to times when neighboring customers are unlikely to be bothered by flickering lights. Midnight to 6 a.m. is normally safe. Daytime operation might be tolerated. Operation from 6 p.m. to 11 p.m. is most likely to cause complaints. For facilities with multiple fluctuating loads, facilities can stagger operations to limit overlapping operation of multiple units.

Another option is to provide solutions where the customers are complaining. Review the conditions when flicker occurs and what lighting fixtures are flickering. A review of the lighting may reveal especially sensitive light fixtures such as some types of dimmers. These light fixtures can be replaced by fixtures that flicker less. One option is to convert from incandescent to fluorescent lights, which do not flicker as much.

If the facility causing the fluctuations is the only one experiencing the flicker, one solution is to isolate the lighting circuits from the circuits with fluctuating loads. Run

separate circuits to the lighting loads. For single-phase fluctuating loads, put them on one phase and the lighting on the other two phases.

12.4.1.2 Series Capacitor

On distribution lines, much of the voltage drop is due to a circuit's inductance. If we add a capacitor in series with the inductance, the capacitor cancels out a portion of the inductance (see Figure 12.26). Now, the circuit has less total inductance, so fluctuations in load cause less voltage drop. A series capacitor is a passive circuit element. It responds instantaneously and automatically. Series capacitors help with voltage regulation as well as improving voltage flicker.

The best place for a series capacitor depends on where the complaining customers are relative to the offending load. Customers upstream of the series capacitor see no difference in flicker. Voltage improves downstream of the series capacitor. Sizing and placement involves trade-offs. Ideally, we want to size the capacitor such that its impedance equals the circuit impedance to the fluctuating load (smaller series capacitor impedances are more expensive: more kvars, more units in parallel). For placement, a good rule of thumb is electrically half way between the source and the fluctuating load—the point where the voltage drop is half of the total voltage drop due to the fluctuating load. Locations closer to the source reduce flicker for more customers but increase fault duties. An IEEE working group suggests a rule-of-thumb location where the voltage drop is one-third to one-half of the total drop (Miske, 2001).

Series capacitors can superbly compensate flicker from fluctuating inductive loads. For resistive loads, series capacitors provide much less benefit. The voltage drop through the distribution system is approximately $I_R R + I_X X$. Reducing X with a series capacitor helps reduce the $I_X X$ term for fluctuating I_X, but if just I_R fluctuates, series capacitors provide little benefit.

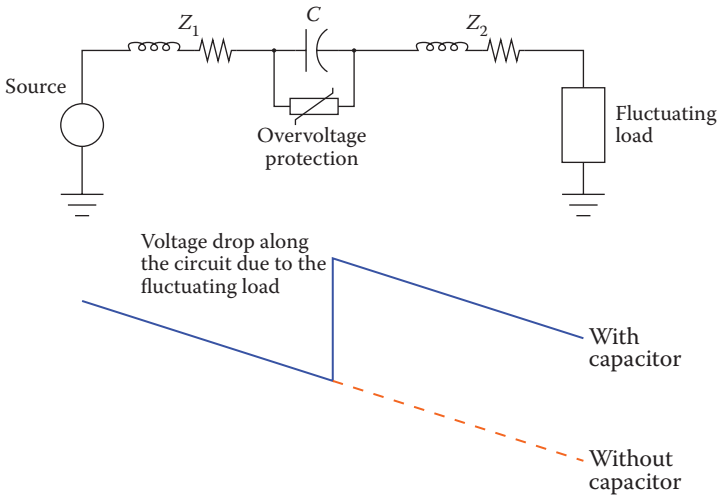

Figure 12.26 Series capacitor.

Electrically, series capacitors elegantly solve voltage flicker; in practice, they are not widely used, mainly because of

- *Reliability of short-circuit protection*—Historically, spark gaps were used to protect the capacitors during downstream faults. Utilities have had many problems with failures.
- *Cost*—Series capacitors are nonstandard and must be custom engineered.
- *Unusual*—Line crews and field engineers find series capacitors strange. For example, if crews switch in a shunt capacitor downstream of a series capacitor, the voltage may go down instead of up. Increased fault currents downstream of the capacitor can make coordination of protective devices more difficult.
- *Ferroresonance*—Series capacitors may also ferroresonate with downstream transformers under the right conditions.

A key design issue is the voltage across the capacitor during faults downstream of the unit. During a fault downstream of the series capacitor, the voltage across the capacitor units is the short-circuit current times the capacitor impedance. Depending on the impedances upstream of the capacitor relative to the capacitor size, the voltage across the series capacitor can exceed the system's nominal voltage. When calculating the available fault current downstream of the capacitor, include the impedance reduction caused by the capacitor. The fault current normally can rise past the capacitor (depending on the amount of capacitance relative to the system impedance and the line *X/R* ratio). The highest fault current can be some distance from the capacitor. Figure 12.27 shows an example on a 12.5-kV system for a series capacitor placed 3 mi from the substation to compensate for a fluctuating load at 8 mi from the substation. The series capacitor significantly alters the fault-current profile, and the fault current impresses significant voltage across the capacitor. Some sort of protection is needed to prevent this.

The increased fault current raises the primary voltage and the customers' voltage during the fault. Figure 12.28 shows a profile of the line voltages for a fault at 4.75 mi for the example shown in Figure 12.27. Under this scenario, the fault current is leading (capacitive), so voltages rise along the line until the series capacitor. These overvoltages are unacceptable, so some overvoltage protection across the capacitor is vital to prevent them. This example has a rather poor choice of location and impedances, but it illustrates how important it is to consider these applications carefully. Reducing the impedance of the capacitor reduces the overvoltages and reduces the fault currents. Lowering the capacitor's impedance to maintain a total line impedance that is always reactive (never capacitive) eliminates the problem of overvoltages. But we still have higher fault currents downstream of the capacitor, and lowering the capacitor's impedance reduces the flicker-prevention capability.

Several protection arrangements have been used to protect capacitors from overvoltages. A spark gap is the simplest device but has been problematic. Duke Power reported that many of the gaps on their units kept arcing and started fires (Morgan et al., 1993). Gap erosion also reduced protection and led to capacitor failures. Lat et al. (1990) used an improved gap that reduced erosion. The most modern units use metal-oxide arresters as protection against overvoltages; several stacks of metal-oxide blocks in parallel are needed to absorb the energy during a fault. Series capacitors

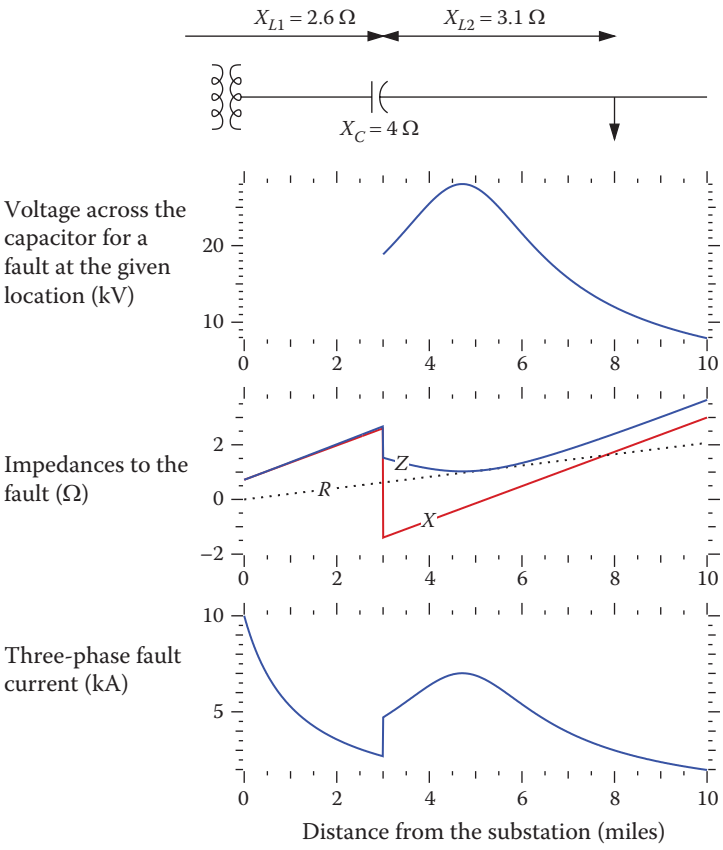

Figure 12.27 Fault-current profile on a 12.5-kV circuit with a series capacitor located 3 miles from the substation (the same line parameters as Figure 8.11, 500-kcmil AAC conductors). The series capacitor has no short-circuit protection.

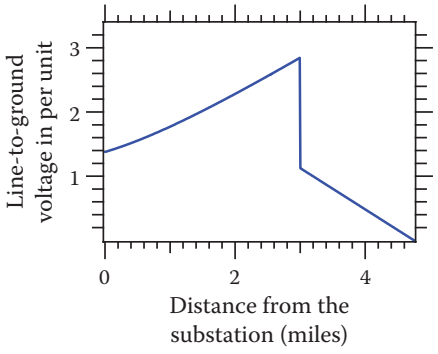

Figure 12.28 Voltages along the circuit for a three-phase fault at 4.75 miles for the application shown in Figure 12.27.

normally have bypass switches to short the unit out if needed. Some designs close the bypass as soon as a fault is detected to reduce the duty on the capacitors and the arresters. Another benefit of using arresters for overvoltage protection is that the arresters short out the capacitors so that the series capacitor does not significantly increase the downstream fault current or cause overvoltages.

Marshall (1997) dealt with the problem of short-circuit protection by designing installations so that they did not need extra protection. This is possible at locations with low fault currents and where we can use a capacitor with a reasonably low voltage rating, especially if we do not try to compensate too aggressively. This is more likely on long rural circuits where the impedances are high, and we want a high capacitive impedance (which means we need less kvar in our series bank). Picking a higher voltage rating for a capacitor unit requires using several more units in parallel. For a given kvar rating, doubling the voltage rating raises the unit's impedance by a factor of four; now, we need four times the kvar for the same impedance.

12.4.1.3 Static Var Compensator

Static var compensators (SVCs) dynamically change their reactance, injecting or absorbing reactive power to regulate the voltage in real time. They are often used at large arc furnaces to control voltage flicker. Utilities sometimes use them to reduce voltage flicker on distribution circuits (Jatskevich et al., 1998; Kemerer and Berkebile, 1998; Wong et al., 1990).

Several styles of var compensators are available:

- *Switched inductor*—A thyristor controls how much reactive power is drawn from the system, depending on where on the voltage waveshape the thyristor turns on. Full vars are drawn if the thyristor turns on when the voltage is at its peak (a full half cycle of current is drawn). Less vars are drawn if the controller waits to turn on the thyristor. Once fired, the thyristor stays on until the current goes through zero and the thyristor shuts off. A drawback to this configuration is that the current blips are not sinusoidal and create harmonics. The inductor may be used in parallel with a shunt capacitor to control vars negatively and positively.
- *Switched capacitors*—In this configuration, several shunt capacitors each have thyristors to control whether the capacitor is connected. The number of capacitor units switched in determines the amount of vars injected. Having more individual blocks of capacitors helps keep the control smooth. The switched capacitors may be paralleled with a fixed inductor to allow the unit to control vars in both directions.
- *STATCOM*—The most advanced reactive power controller, this custom power device has a power electronics interface (normally a pulse-width-modulated inverter using IGBTs or other fast-switching electronics) that injects or absorbs reactive power that is temporarily stored in capacitors on a dc bus. The STATCOM (static compensator) can smoothly vary the reactive power with little harmonics. The STATCOM may be extended to inject or absorb real power with auxiliary energy storage.

None of these devices can instantly counter changes from fluctuating loads; some delay is always present. The delay is normally on the order of one-half to two cycles, depending on the compensator and controller technology.

Reactive power is more efficient than real power at countering voltage changes. Reactive power is more efficient because the equivalent source impedance is normally more reactive than resistive, and the voltage drop is approximately

$$V_{\text{drop}} \approx R \cdot I_R + X \cdot I_X$$

where R and X are the source resistance and reactance, I_R is the resistive component of the load, and I_X is the reactive component of the load.

12.4.1.4 Other Solutions

Other utility-side solutions to flicker include

- *Dedicated circuit*—Running a separate load to the customer with a fluctuating load isolates the flicker to the customer causing the flicker. We can tap the dedicated circuit where the voltage change due to the fluctuating load is tolerable.
- *Reconductoring*—Larger conductors have lower resistance and slightly lower reactance. If the voltage fluctuation is due to changes in the resistive load, larger conductors will help; but if the voltage fluctuation is due to reactive load, larger conductors will not help. Tighter phase spacings reduce the reactance somewhat, but not dramatically. Converting to aerial or underground cable does dramatically reduce the reactance.
- *Upgrading voltage*—On a percentage basis, voltage drop decreases as the square of system voltage. Of course, upgrading the system voltage requires new insulators, arresters, switches, and transformers.

Unfortunately, all of these are normally expensive options. Jenner and Brockhurst (1990) reported success using vacuum-switched shunt capacitor banks to counteract the voltage drop from large motor starts, although the measurements shown still left a significant voltage change.

12.5 Voltage Unbalance

Three-phase end-use equipment expects balanced voltages, each with the same magnitude. If the voltages are not balanced, some equipment can perform poorly, mainly induction motors. Voltage unbalance (or imbalance, an equivalent term used by many) is defined as

$$\text{Percent unbalance} = \frac{\text{Maximum deviation from the average}}{\text{Average of the three phase-to-phase voltages}} \times 100\%$$

Normally, phase-to-phase voltages are used for voltage unbalance rather than phase-to-ground voltages.

ANSI C84.1-1995 states that utilities should limit the maximum voltage unbalance to 3%, measured under no-load conditions. Most distribution systems have modest unbalance, well under the ANSI 3% limit. Field surveys sited by ANSI C84.1 report that only 2% of electric supply systems have unbalance that exceeds 3%.

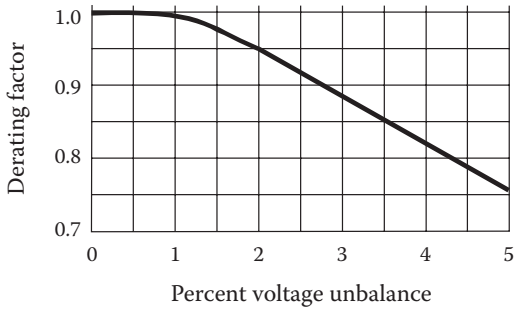

Figure 12.29 Motor derating curve based on voltage unbalance. (From NEMA MG-1, *Standard for Motors and Generators*, 1998. With permission.)

Motors are most efficient with balanced voltages; unbalanced voltage heats motors significantly due to negative-sequence currents. When applied to unbalanced voltages, motors should be derated. Figure 12.29 shows a derating factor that ANSI and NEMA provides for motors.

Motors have relatively low impedance to negative-sequence voltage (approximately equal to the motor's locked rotor impedance); therefore, a small negative-sequence component of the voltage produces a relatively large negative-sequence current. The negative-sequence voltage creates a rotating field that rotates in the opposite direction that the motor is spinning. The rotor is a shorted winding to this counterrotating field.

NEMA standard MG-1 allows a 1% voltage unbalance without derating; operation above 5% unbalance is not recommended (NEMA MG-1, 1998).

Because motors are really influenced by the negative-sequence voltage, another more-precise indicator is the unbalance factor, defined in European standards:

$$\%VUF = \frac{V_2}{V_1} \times 100\%$$

where

V_1 = positive-sequence voltage
V_2 = negative-sequence voltage

The percentage negative-sequence voltage is close to unbalance as defined by NEMA and ANSI using phase-to-phase voltage measurements, with a difference of at most 13% between the two terms (UIEPQ-9715, 1996). The EPRI DPQ study found that 98% of the time, including all sites monitored, the unbalance factor (V_2/V_1) was less than 1.5% with an average just above 0.8% (EPRI TR-106294-V2, 1996). In addition, only 2 out of 277 sites averaged above a 3% unbalance factor.

While negative-sequence voltages impact motors and other line-to-line connected loads the most, zero-sequence unbalance can affect line-to-ground connected three-phase loads. Most sites have little zero-sequence voltage unbalance (although the current unbalance may be significant). The DPQ study found similar levels of V_0/V_1 as V_2/V_1: V_0/V_1 averaged just over 0.8%; only 3 of 277 sites averaged

above 3% zero-sequence voltage. Whereas transformer connections do not change the ratio of V_2/V_1, zero-sequence voltages are blocked by ungrounded transformer connections like the delta–grounded wye.

While motors receive much of the attention, unbalance also affects other loads, particularly electronic loads such as ASDs. With voltage unbalance, ASDs draw significantly unbalanced currents, currents so unbalanced that overload protection circuits can trip (EPRI PEAC Brief No. 28, 1995). An ASD rectifies the three incoming phases. Each phase-to-phase input takes its turn charging up the capacitor on the drive's dc bus; but if one of these three inputs has higher voltage than the others, that phase conducts significantly more current than the other two. Even a 3% voltage unbalance can cause some drives to trip. Voltage unbalance also increases the harmonics that drives create, including the third harmonic, which balanced three-phase drives do not normally produce. Voltage unbalance also increases the ripple on the dc bus voltage.

Some causes of voltage unbalance in the order of most to least likely include

- *Current unbalance*—Voltage unbalance normally comes from excessive current unbalance— more heavily loaded phases have more voltage drop than the lightly loaded phases. Large single-phase laterals are often culprits. Normally, crews can change the phase connections of single-phase laterals to balance the voltages. Also consider the possibility of shifting load to another circuit.
- *Capacitor banks with blown fuses*—Banks with blown fuses inject unbalanced vars, which can severely unbalance voltages.
- *Malfunctioning regulators*—Single-phase line voltage regulators adjust each phase independently. If one phase is stuck or is otherwise working improperly or has inappropriate settings, the regulator will unbalance the voltages. Note that because regulators adjust each phase independently, they normally perform well for improving a circuit's voltage balance.
- *Open-wye–open-delta transformers*—These banks can supply three-phase load from a two-phase supply. But, the connection is prone to causing voltage unbalance to the end user on the transformer. Also, because it injects significant current into the ground, it can contribute to voltage unbalance elsewhere on the circuit.
- *Untransposed circuit*—Transposing distribution circuits is almost unheard of; it is just not needed. Rarely, balanced load can cause unbalanced voltages because the line impedances are unbalanced. As an example, on a flat configuration with an 8-ft crossarm with 336-kcmil ACSR conductors at 12.47 kV, a balanced, unity-power factor current of 100 A through 10 mi of line causes 1% voltage unbalance at the end.

Normally, we can solve unbalanced voltages by correcting the current balance or fixing a problem regulator or capacitor. After that, adding voltage regulators is an option.

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Although they try hard, bless their hearts, consumers that diagnose their own powerline problems tend to miss a thing or two at times.

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13

Lightning Protection

Contents

13.1 Characteristics 662
13.2 Incidence of Lightning 668
13.3 Traveling Waves 669
13.4 Surge Arresters 674
13.4.1 Ratings and Selection 676
13.4.2 Housings 678
13.4.3 Other Technologies 679
13.4.4 Isolators 680
13.4.5 Arrester Reliability and Failures 682
13.5 Equipment Protection 685
13.5.1 Equipment Insulation 685
13.5.2 Protective Margin 686
13.5.3 Secondary-Side Transformer Failures 689
13.6 Underground Equipment Protection 691
13.6.1 Open-Point Arrester 694
13.6.2 Scout Arresters 696
13.6.3 Tapped Cables 697
13.6.4 Other Cable Failure Modes 698
13.7 Line Protection 700
13.7.1 Induced Voltages 700
13.7.2 Insulation 703
13.7.2.1 Practical Considerations 705
13.7.3 Shield Wires 707
13.7.4 Line Protection Arresters 708
13.8 Other Considerations 711
13.8.1 Role of Grounding 711
13.8.2 Burndowns 713
13.8.3 Crossarm and Pole Damage and Bonding 713
13.8.4 Arc Quenching of Wood 714
13.8.5 Protection of Distribution Equipment Controllers and Instrumentation 716
References 720

Protection of power systems from lightning-related damage and faults is crucial to maintaining adequate power quality, reliability, and controlling damage costs to the utility system. In the United States, the most severe lightning activity occurs in the southeast and Gulf coast states. However, lightning is also a major cause of faults and interruptions in areas with just modest lightning activity, such as New England.

There are many facets in the design of lightning protection, including surge arrester sizing and placement, grounding issues, and the selection of appropriate power system equipment and insulation ratings. This chapter focuses on the factors that impact the lightning performance of power distribution systems, providing background on the characteristics of lightning, methods for calculating lightning flashover rates, and guidelines in the application of lightning protection equipment.

In the majority of cases, lightning causes temporary faults on distribution circuits; the lightning arcs externally across the insulation, but neither the lightning nor the fault arc permanently damages any equipment. Normally, less than 20% of lightning strikes cause permanent damage. In Florida (high lightning), EPRI monitoring found permanent damage in 11% of circuit breaker operations that were coincident with lightning (EPRI TR-100218, 1991; Parrish, 1991). Where equipment protection is done poorly, more equipment failures happen. Any failure in transformers, reclosers, cables, or other enclosed equipment causes permanent damage. One lightning flash may cause multiple flashovers and equipment failures. Even if a lightning-caused fault does no damage, a long-duration interruption occurs if the fault blows a fuse.

The protection strategy at most utilities is

1. Use surge arresters to protect transformers, cables, and other equipment susceptible to permanent damage from lightning.
2. Use reclosing circuit breakers or reclosers to reenergize the circuit after a lightning-caused fault.

Lightning causes most damage by directly striking an overhead phase wire and injecting an enormous current surge that creates a very large voltage. The voltage impulse easily breaks down most distribution-class insulation unless it is protected with a surge arrester. Almost all direct lightning strokes cause flashovers. In addition, the lightning current may start a pole fire or burn through conductors. Also, nearby lightning strokes that do not hit the line may couple damaging voltages to the line. These induced voltages may fail equipment or cause flashovers.

Figure 13.1a shows an example of a lightning flash composed of several individual strokes hitting a distribution circuit (the movement of the lightning channel and camera shaking makes it easier to distinguish the individual strokes). Two phases initially flashed over, and the third eventually flashed over (either due to a subsequent stroke or the gases from the initial fault). On three-phase circuits, lightning normally causes two- or three-phase faults. The lightning-caused fault in Figure 13.1a resulted in a downed-wire high-impedance fault that was not cleared by the station protection (the circuit was tripped manually). Taken moments after the lightning flash, Figure 13.1b shows the glow of an arcing downed conductor. In this case, the 60-Hz fault arc, not the original lightning impulse, burned the wires down. Two characteristics made this circuit prone to burndowns: covered wire and relaying that allowed long-duration faults (the instantaneous relay in the substation did not cover this portion of the line). The second bright blob in the lower right of the lightning strike picture is another flashover further down the line on the same circuit. These supplementary flashovers—away from the fault point and on the same circuit—are common,

(a) Lightning strike and flashovers (b) Arcing downed conductor

Figure 13.1 Example of a lightning flash to a 13.2-kV distribution line and the downed wire that resulted. (From Niagara Mohawk Power Corporation. Copyright 1991. Reprinted with permission.)

especially in areas with high ground impedances (the ground potential rise pushes the surge to other locations on the circuit). These pictures were taken by a lightning-activated camera developed by the Niagara Mohawk Power Corporation (now part of National Grid) (Barker and Burns, 1993).

Locations with higher lightning activity have higher fault rates on overhead circuits. Figure 13.2 shows fault rates reported by different utilities against estimated ground flash density (GFD). Utilities in higher-lightning areas have more faults. Not all of these are due to lightning; many are due to wind and other storm-related faults. Lightning is a good indicator of storm activity at a location.

The linear curve fit to the data in Figure 13.2 shows line fault rates per 100 mi per year varying with the GFD, N_g, in flashes/km^2/year as

$$f = 20.6N_g + 43$$

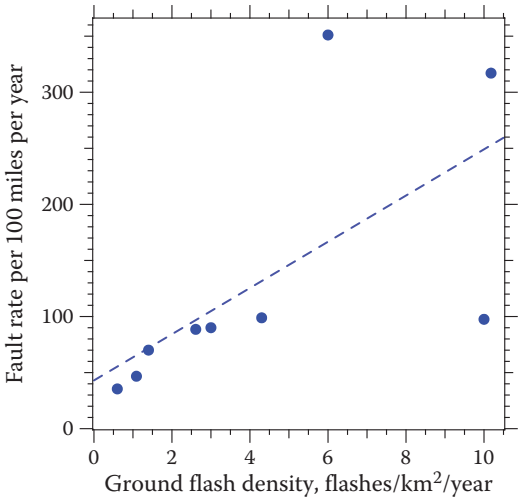


Figure 13.2 Distribution line fault rate versus GFD. (Based on the data in Figure 8.2.)

13.1 Characteristics

Driven by the need to protect transmission and distribution lines and equipment better, the electrical industry performed much of the early research on lightning and electrical breakdowns. Charles P. Steinmetz, Charles F. Wagner, Walter W. Lewis, Karl B. McEachron, Charles L. Fortescue, and Basil F. J. Schonland—the list of early contributors is long—increased our understanding of the physics of lightning and its electrical characteristics.

Lightning is the electric breakdown of air from high electric fields generated when the electric charge separates within a cloud. Lightning may flash within a cloud, from one cloud to another, or from the cloud to the ground. Distribution lines are only affected by cloud-to-ground lightning. In the normal scenario, charge separates within a thundercloud. The upper portion becomes positively charged and the lower portion becomes negatively charged. The ground just underneath the cloud becomes positively charged (being attracted to the negatively charged lower portion of the cloud). The lightning breakdown begins in the lower portion of the cloud. The air breaks down in steps called *stepped* leaders. Each step is about 150 ft (50 m) with pauses of about 50 μsec between steps. The stepped leader may fork and form branches that each progress toward the ground. As the stepped leader progresses closer to the ground (see Figure 13.3), more charge is lowered closer to the ground. More positive charge collects on the earth in response—short upward leaders extend to meet the downward negative stepped leader.

When the downward leader meets the upward leader, a *return stroke* occurs. The negative charge held in the stepped leader rushes into the ground, brilliantly lighting the channel and creating a large pressure wave (thunder). The return stroke propagates up the channel at roughly 20% of the speed of light, releasing charge as it goes. The charge rushing into the ground creates a current of tens of thousands of amperes peaking in

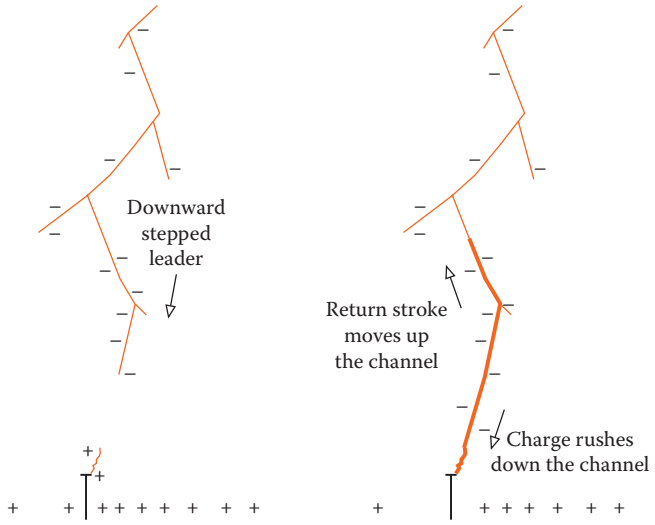


Figure 13.3 Cloud-to-ground lightning.

a few microseconds. The current may extinguish in about 100 μsec, or lower-level continuing current in the range of hundreds of amperes may flow for several milliseconds (about 25% of the time, continuing currents flow following the return stroke).

Subsequent strokes may follow the first stroke. After the current extinguishes and the channel becomes dark, another pocket of charge may work its way down the same path. Fast-moving leaders called dart leaders break down the recently deionized path of the first stroke. Subsequent strokes typically have lower magnitudes of current and charge transferred, but subsequent stroke currents have higher rates of rise. Subsequent strokes have higher return-stroke velocities, often greater than 50% of the speed of light. The first stroke and subsequent strokes make up a lightning *flash*.

While the downward negative flash is the most common, other types of cloud-to-ground lightning occur. About 5 to 10% of cloud-to-ground flashes are positive. Downward positive lightning lowers positive charge from the cloud to the ground. Breakdown starts at a positive portion of the cloud usually near the top of the cloud; a positive downward stepped leader moves downward until it meets an upward negative leader close to the ground. Some positive flashes may have very large peak currents and charge. Positive flashes occur more often during winter storms, especially in some areas. Positive flashes usually have only one stroke. Cloud-to-ground lightning may also start at the ground and rise upward, with an upward stepped leader starting at the ground. These are common on tall objects such as the Empire State Building, but are rare from distribution lines.

Normally, the lightning current injection is considered an ideal current surge (it does not really matter what is struck; the electrical characteristics of the current stay the same). Table 13.1 shows the characteristics of a downward negative current flash. Many of the characteristics fit a log-normal distribution, which is common for the

TABLE 13.1 Lightning Current Parameters for Downward Negative Flashes

	Percent of Cases Less Than Value			
Parameter	5%	50% (*M*)	95%	β
First Strokes				
Peak current (kA)	8	33.3	90	
Model for $I \leq 20$ kA		61.1		1.33
Model for $I > 20$ kA		33.3		0.61
Time to peak (μsec) (virtual front time based on the time from 30% to 90% of the peak = $T_{30-90\%}/0.6$)	1.5	3.83	10	0.553
Steepness, 30–90% (kA/μsec)	2.6	7.2	20	0.921
Tail, time to half the peak (μsec)	30	77.5	200	0.577
Charge, C	1.1	4.65	20	0.882
$\int I^2 dt$ (A^2sec) $\times 10^3$	6	57	546	1.373
Subsequent Strokes				
Peak current (kA)	5.2	12.3	29.2	0.530
Time to peak (μsec) (30–90% virtual front)	0.2	0.67	3.0	
Steepness, 30–90% (kA/μsec)	4.1	20.1	99	0.967
Tail (μsec)	6.5	30.2	140	0.933
Charge, C	0.2	0.938	4	0.882
$\int I^2 dt$ (A^2sec) $\times 10^3$	0.6	5.5	52	1.366
Flash				
Charge, C	1.3	7.5	40	1.02
Flash duration (sec)	0.03	0.2	1	
Number of strokes	1	2–3	9	
Interval between strokes (msec)	6	35	202	1.066

Source: Data from Anderson, R. B. and Eriksson, A. J., *Electra*, vol. 69, pp. 65–102, March 1980a; Anderson, R. B. and Eriksson, A. J., *CIGRE Paper No. 33–06*, 1980b; Berger, K., Anderson, R. B., and Kröninger, H., *Electra*, vol. 41, pp. 23–37, July 1975.

data bounded at zero. The log standard deviation, $\beta = \mathrm{sd}(\ln(x_i))$, is shown for the characteristics that have a log-normal characteristic. The 5th and 95th percentiles are shown based on the log-normal fit. The first stroke peak current data does not fit a log-normal distribution, but Anderson and Eriksson found a good fit using two log-normal parameters, one for low currents and one for high currents. Another common approximation to Berger's data for the probability of the peak magnitude of the first stroke is (EPRI, 1982)

$$P(I_0 \geq i_0) = \frac{1}{1 + (i_0/31)^{2.6}}$$

Table 13.2 shows the characteristics for positive strokes. This data is not as well defined since the dataset is more limited.

TABLE 13.2 Lightning Current Parameters for Downward Positive Flashes

	Percent of Cases Less than Value			
Parameter	5%	50% (*M*)	95%	β
Peak current (kA)	5	35	260	1.21
Time to peak (μsec) (30–90% virtual front)	3	22	140	1.23
Stroke charge, C	2	16	84	1.36
Flash charge, C	18	80	350	0.90

Source: Data from Berger, K., Anderson, R. B., and Kröninger, H., *Electra*, vol. 41, pp. 23–37, July 1975.

Although most stroke and flash characteristics are independent of each other, there are some interdependencies. Cigre (1991) examined correlations between various parameters. Larger first strokes tend to have longer rise times. For first strokes, the equivalent front risetime correlates some with the peak current; the average rate of rise does not. For subsequent strokes, the peak current is independent of the rise time, although the peak current partially correlates with the rate of rise. For both first and subsequent strokes, the peak current correlates to some degree with the maximum rate of rise. The correlations are not particularly strong in any of these cases. Cigre used these interdependencies to find derived distributions that are useful in some stochastic simulations.

More than half of cloud-to-ground lightning flashes are composed of more than one stroke (see Figure 13.4). A quarter of them have at least four strokes. The subsequent strokes usually have less current than first strokes, but the rate of rise of current is higher (important for the inductive voltage rise, *Ldi/dt*, in arrester leads, arrester spacings on lines, and traveling wave issues in cables). Subsequent stroke characteristics are thought to be independent of the first stroke.

A lightning flash may last for more than 1 sec; this impacts line reclosing practices. If a circuit breaker or recloser clears a lightning-caused fault and immediately

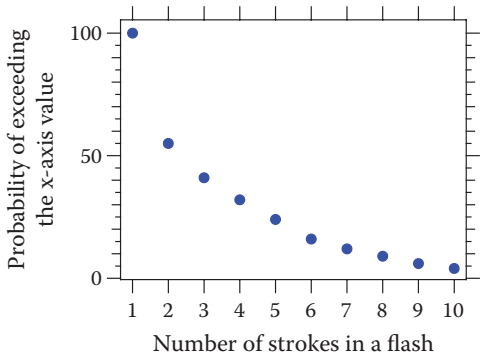


Figure 13.4 Number of strokes in a flash. (Data from Anderson, R. B. and Eriksson, A. J., *Electra,* 69, 65–102, March 1980a; Anderson, R. B. and Eriksson, A. J., *CIGRE Paper No. 33–06*, 1980b.)

TABLE 13.3 Probability of a Successful Reclose following a Lightning-Caused Fault

Duration of the Dead Time before the Reclose (sec)	Probability of a Successful Reclosure (%)
0.3	83
0.4	90
0.5	95

Source: Adapted from Anderson, R. B. and Eriksson, A. J., *Electra*, vol. 69, pp. 65–102, March 1980a.

recloses, a subsequent stroke may flash the line over again (or continuing current in the flash may maintain the fault arc). About 5% of lightning flashes will last beyond a typical immediate reclosing time of 0.5 sec (see Table 13.3). Normally, the extra fault will not cause any more damage; the circuit breaker must open and reclose again. The practical effect of this is to extend a half-second interruption to a 10-sec interruption (or whatever the next delay time is in the reclosing sequence). It does show that it is important to have more than one reclose attempt if an immediate reclose is used.

A good percentage of multiple-stroke flashes have subsequent strokes to different points on the ground (Thottappillil et al., 1992). This implies that GFDs from flash counters and lightning detection networks may underestimate the number of lightning flash ground terminations.

The lightning activity in an area can be measured. Many areas of the world have lightning detection networks that measure the magnetic and/or electric field generated by a lightning stroke, determine if the stroke is from the cloud to the ground, and triangulate the stroke's position. Such systems help utilities prepare for storms; information on storm intensity, direction, and location helps determine the number of crews to call up and where to send them. Maps generated from lightning detection networks of GFD (or N_g) are the primary measure of lightning activity. Figure 13.5 shows a 15-year GFD contour map of the United States from the U.S. National Lightning Detection Network (NLDN), which has been operating before 1990.

Lightning detection networks are also useful for correlating faults with lightning. This data helps with forensics and is even used in real time to direct crews to damage locations. From personal experience with correlating faults with the U.S. NLDN and with camera monitoring studies, the system successfully captures about 90% of strokes. The most important characteristic that allows an accurate correlation of faults and lightning is accurate time tagging of power system event recorders, including power quality recorders, SCADA, or fault recorders (GPS works well). Position accuracy of detection networks is not good enough to determine if strokes hit a line, but it is good enough to narrow the choices of strokes considerably—almost all strokes found by the U.S. NLDN are accurate to within 1 mi (1.6 km), with most of the strokes accurate to 2000 ft (0.5 km).

If direct measurements of ground flash density are unavailable, meteorological records of thunderstorms are available, most commonly, the number of days with

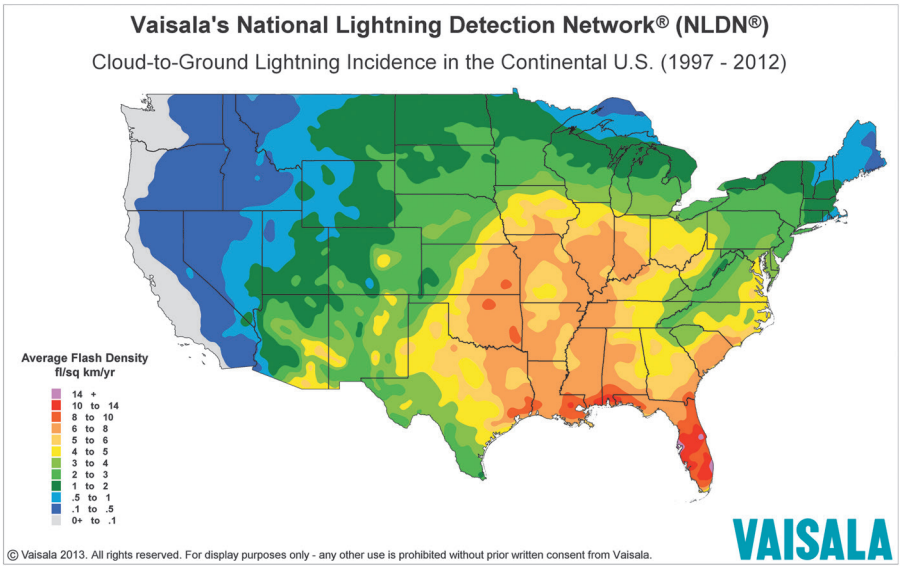


Figure 13.5 Ground flash density from the United States National Lightning Detection System. (Courtesy of VAISALA. With permission.)

thunderstorms (or keraunic level). Thunderstorm days approximately relate to GFD as (Eriksson, 1987)

$$N_g = 0.04T_d^{1.25}$$

Records of the number of thunderstorm hours per year relate to N_g as (MacGorman et al., 1984)

$$N_g = 0.054T_h^{1.1}$$

where T_h is the number of thunderstorm hours per year.

Another crude estimate of the lightning level is from NASA's (National Aeronautics and Space Administration) optical transient detector, which measured worldwide lightning activity for 5 years (Chisholm et al., 1999).

Lightning is highly variable. It takes several hundred lightning flash counts to obtain modest accuracy for an estimate of the average flash density. A smaller geographic area requires more measurement time to arrive at a decent estimate. Similarly, a low-lightning area requires more measurement time to accurately estimate the lightning. Standard deviations for yearly measurements of lightning activity range from 20% to 50% of the mean (IEEE Std. 1410-2010). Figure 13.6 shows the variability of ground flash density in a high-lightning area. Lightning and storms have high variability. Lightning and weather patterns may have cycles that last for many years.

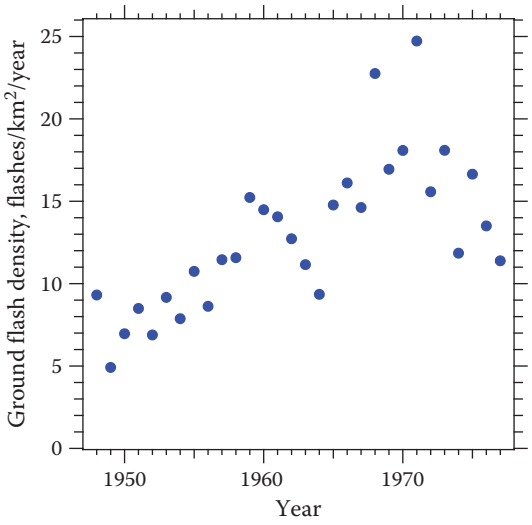


Figure 13.6 Estimated annual GFD for Tampa, Florida based on thunderstorm-hour measurements. (Data from MacGorman, D. R., Maier, M. W., and Rust, W. D., Lightning strike density for the contiguous United States from thunderstorm duration records. Report to the U.S. Nuclear Regulatory Commission, # NUREG/CR-3759, 1984.)

Distribution lines cover small geographic areas, so lightning damage and lightning flashover rates show high variability on a circuit. One year, a circuit may get nailed with damage coming from many storms; the next year, it may have next to nothing.

The variability of lightning and the variability of storms is also important for utility planning regarding regulatory incentives for reliability and for performance guarantees for customers. Just a few years of data usually does not accurately depict the performance of weather-related events for a circuit or even for a whole system.

13.2 Incidence of Lightning

Lightning flashes hit typical-height distribution lines that are in the open at the rate of about 17 flashes/100 circuit mi/year for an area with $N_g = 1$ flash/km^2/year (11 flashes/100 km/year). Flashes to lines vary directly as the ground flash density. Almost all of these flashes to lines cause faults, and some damage equipment. Taller lines attract more flashes. The most accepted model of lightning strikes to power lines in open ground is Eriksson's model, which finds the number of strikes as a function of the line height (Eriksson, 1987):

$$N = N_g \left(\frac{28h^{0.6} + b}{10} \right)$$

where

N = flashes/100 km/year to the line
N_g = ground flash density, flashes/km^2/year
h = height of the conductor (or overhead groundwire) at the tower, m
b = overhead ground wire separation, m

For distribution lines, the b term can be ignored, which gives

$$N = 2.8N_g \cdot h^{0.6}$$

for h in meters and N in flashes/100 km/year, or

$$N = 2.2N_g \cdot h^{0.6}$$

for h in feet and N in flashes/100 mi/year.

For a 30-ft (10-m) line, about 17 flashes/100 mi/year (10.6 flashes/100 km/year) hit a distribution line for $N_g = 1$ flash/km^2/year. The main data point for distribution lines is a South African test line heavily monitored in the 1980s (Eriksson, 1987). The test line had 19 flashes/100 mi/year (12 flashes/100 km/year) normalized for $N_g = 1$ flash/km^2/year for a line height of 28 ft (8.6 m).

The equivalent shadow width or total width that a distribution line attracts lightning is on the order of 360 ft (110 m). This is about 12 times the line height. For many years, a shadow width of four times the line height was used; this model underestimates the number of flashes hitting lines.

More exposed lines—those with no trees nearby or lines on the tops of ridges—attract more flashes. Eriksson's equation is for a line in open ground. Many lines have fewer hits because of shielding from nearby objects (mainly trees, but also buildings and other power lines). For lines in forested areas, the number of strikes is significantly reduced, so this equation should be an upper limit for most lines. Some very exposed lines on hills may have more hits than Eriksson's equation predicts. The number of hits to a line in a shielded area is

$$N_S = N(1 - S_f)$$

where S_f is the shielding factor, which is between 0 and 1. In Florida, shielding factors of around 0.7 were found for circuits out of four substations (Parrish and Kvaltine, 1989). Lines in these areas had moderate-to-heavy shielding by nearby objects.

13.3 Traveling Waves

When lightning injects surge currents into power lines, they move down the conductors as traveling waves. Understanding the nature of traveling waves helps in predicting the voltage and current levels that occur on power systems during lightning

strikes. Surges travel at 99% the speed of light on overhead circuits—about 1000 ft/μsec (300 m/μsec). The inductance L and capacitance C uniformly distributed along the line determine the velocity and the relationship between voltage and current. The velocity in a unit length per second is based on L and C per length unit as

$$v = \frac{1}{\sqrt{LC}}$$

The voltage and current are related by Z, the *surge impedance*

$$V = ZI$$

where Z is a real value, typically 300 to 400 Ω. The distributed inductance and capacitance determines the surge impedance:

$$Z = \sqrt{\frac{L}{C}} = 60 \ln \frac{2h}{r}$$

where
h = average conductor height
r = conductor radius

When surge voltages of like polarity pass over each other, the voltages add as shown in Figure 13.7. The currents subtract; current is charge moving in a direction. The charge of the same polarity flowing in opposite directions cancels.

$$V = V_F + V_B = Z(I_F - I_B)$$
$$I = Z(I_F + I_B)$$

A surge arriving at an open point in the circuit reflects, sending back a voltage wave equal to the incoming wave (see Figure 13.8). The voltage doubles. Think of the incoming wave as a stream of electrons. When these electrons hit the open point, they stop, but the pileup of electrons at the end forces the electrons back in the direction they came from (like charges repel each other). While the voltage doubles, the current cancels to zero as the return wave counters the incoming wave.

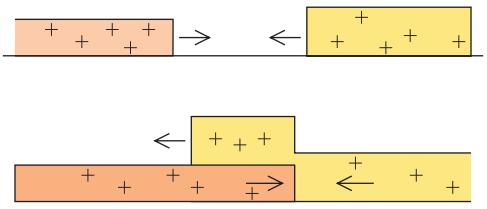


Figure 13.7 Forward and backward traveling waves passing each other.

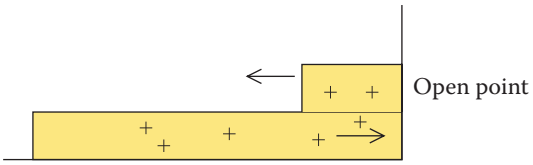


Figure 13.8 Traveling wave reflection at an open point.

Voltage doubling at open points is an important consideration for the protection of distribution insulation. It is a very important consideration when protecting underground cables. It also comes into play when placing arresters to protect a substation.

When a surge hits a short circuit, the voltage drops to zero as we expect. The ground releases an opposing charge that cancels the voltage, creating a reverse wave traveling back toward the source. Now, the current doubles. Two cases are very close to a short circuit: a conducting surge arrester and a fault arc. Both of these act like a short circuit. They generate a voltage-canceling wave.

Line taps, capacitors, open points, and underground taps—any impedance discontinuities—cause reflections. In the general case, the voltage wave reflected from a discontinuity is

$$V_R = aV_I$$

where a is the reflection coefficient:

$$a = \frac{Z_B - Z_A}{Z_B + Z_A}$$

For an open circuit ($Z_B = \infty$), the reflection coefficient, $a = 1$, and for a short circuit ($Z_B = 0$), $a = -1$.

The voltage at the discontinuity is the sum of the incoming wave and the reflected wave:

$$V_T = V_I + V_R = V_I + aV_I = bV_I$$

where b is the refraction coefficient:

$$b = 1 + a = \frac{2Z_B}{Z_B + Z_A}$$

The current waves are found from the voltages as $I_F = V_F/Z$ for forward waves and $I_B = -V_B/Z$ for backward waves. See Figure 13.9.

When a traveling wave hits a split in the line, a portion of the wave goes down each path and another wave reflects back toward the source as shown in Figure 13.10. Use $V_T = bV_I$ to calculate the voltage at the split; just use a new Z_B' as the parallel

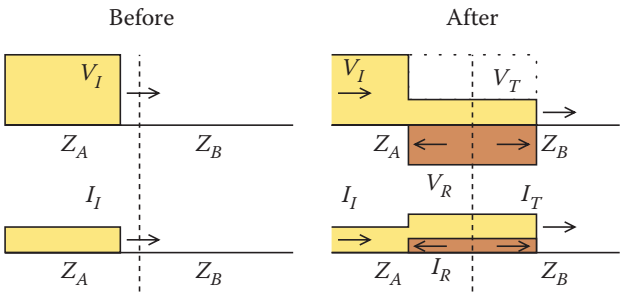


Figure 13.9 Traveling wave reflection at a surge-impedance discontinuity where $Z_B < Z_A$.

combination of Z_B and Z_C; $Z'_B = Z_B||Z_C = Z_BZ_C/(Z_B + Z_C)$. For equal surge impedances ($Z_A = Z_B = Z_C$), the total voltage is 2/3 of the incoming wave.

To a traveling wave, a capacitor initially appears as a very small impedance, almost a short circuit. Then, as the capacitor charges, the effective impedance rises until it becomes an open circuit with the capacitor fully charged. For a traveling wave section terminated in a capacitor, the voltage on the capacitor ramps up to double the voltage as

$$V_T = 2V_I\left(1 - e^{-\frac{t}{ZC}}\right)$$

An inductance initially appears almost as an open circuit. As the inductor allows more current to flow, its impedance drops until it is equivalent to a short circuit. For a traveling wave section terminated in an inductor, the voltage on the inductor initially doubles and then decays down to zero as

$$V_T = 2V_I\, e^{-\frac{Z}{L}t}$$

A cable section attached to an overhead circuit behaves similarly to a capacitor. It is like an open-circuited traveling wave section with a low surge impedance. In fact, a capacitor can be modeled in a traveling wave program such as EMTP as a traveling

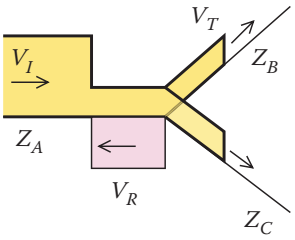


Figure 13.10 Traveling wave reflections at a split.

wave section with a surge impedance of $\Delta t/2C$ and a travel time of $\Delta t/2$, where Δt is small (usually the time step of the simulation) (Dommel, 1986). Likewise, we may model an inductor as a traveling wave section *shorted* at the end with a surge impedance equal to $2L/\Delta t$ and a travel time of $\Delta t/2$.

Corona impacts traveling waves by modifying the surge impedance. When lightning strikes an overhead distribution circuit, tremendous voltages are created. The voltage stress on the conductor surface breaks down the air surrounding the conductor, releasing charge into the air in many small streamers. A high-voltage transmission line may have a corona envelope of several feet (1 m), which increases the capacitance. This decreases the surge impedance and increases coupling to other conductors and slopes off the front of the wave. Normally, distribution line insulation flashes over before significant corona develops, so we can neglect corona in most cases.

Predischarge currents, an effect similar to corona, may also form between conductors. When the voltage between two parallel conductors reaches the flashover strength of air (about 180 kV/ft or 600 kV/m), a sheet of many small streamers containing predischarge currents flows between the conductors. This is a precursor to a complete breakdown. The predischarge current delays the breakdown and relieves voltage stress between the conductors. While the predischarge currents are flowing, the resistance across the gap is 400 Ω/ft or 1310 Ω/m of line section (Wagner, 1964; Wagner and Hileman, 1963, 1964). Normally, on overhead distribution circuits, the weakest insulation is at poles, so in most cases, the circuit flashes over before the circuit enters the predischarge state. Predischarge currents do make midspan flashovers less likely and may help with using arresters to protect lines.

Normally, for modeling lightning in circuits or cables, we can ignore corona and predischarge and use lossless line sections (wire resistance and damping is ignored). This is normally sufficient since only short sections need to be modeled for most situations.

A multiconductor circuit has several modes of propagation; each mode has different velocity and different surge impedance. In most cases, these multiconductor effects are ignored, and we assume that each wave travels on each conductor at 95 to 100% of the speed of light.

For multiconductor circuits, the coupling between circuits is important. The mutual surge impedance determines the voltage on one conductor for a current flowing in another as $V_2 = Z_{12}I_1$. The mutual surge impedance is

$$Z_{ij} = 60 \ln \frac{a_{ij}}{b_{ij}}$$

where

a_{ij} = distance between conductor i and the image conductor j
b_{ij} = distance between conductor i and conductor j

Conductors that are closer together couple more tightly. This generally helps by reducing the voltage stress between the conductors.

13.4 Surge Arresters

Modern surge arresters have metal-oxide blocks, highly nonlinear resistors. Under normal voltages, a metal-oxide surge arrester is almost an open circuit, drawing much less than a milliampere (and the watt losses are on the order of 0.05 W/kV of MCOV rating). Responding to an overvoltage almost instantly, the impedance on the metal-oxide blocks drops to a few ohms or less for severe surges. After the surge is done, the metal oxide immediately returns to its normal high impedance. Metal-oxide blocks are primarily zinc oxide with other materials added. Boundaries separate conductive zinc-oxide grains. These boundaries form semiconductor junctions similar to a semiconducting diode. A metal-oxide block is equivalent to millions of series and parallel combinations of semiconducting diodes. With low voltage across the boundaries, the resistance is very high, but with high voltage, the resistance of the boundaries becomes very low.

Metal-oxide surge arresters overcame many drawbacks of earlier designs. The spark gap was one of the earliest devices used to protect insulation against lightning damage. A spark gap has many of the desirable benefits of a surge arrester; the gap is an open circuit under normal conditions and when it sparks over, the gap is virtually a short circuit. The problem is that after the surge, the gap is still shorted out, so a fuse or circuit breaker must operate. In some parts of the world, notably Europe, spark gaps are still widely used to protect transformers. Spark gaps were improved by adding nonlinear resistors in series. The nonlinear material would clear the power follow current flowing through the spark gap after the surge was done. Gapped arresters with silicon carbide blocks were developed in the 1940s and used for many years. Metal oxide is so nonlinear that a gap is not required. This allows an arrester design, which is simple and highly reliable, with excellent "fast-front" response characteristics. Figure 13.11 shows the voltage–current relationships of a typical metal-oxide

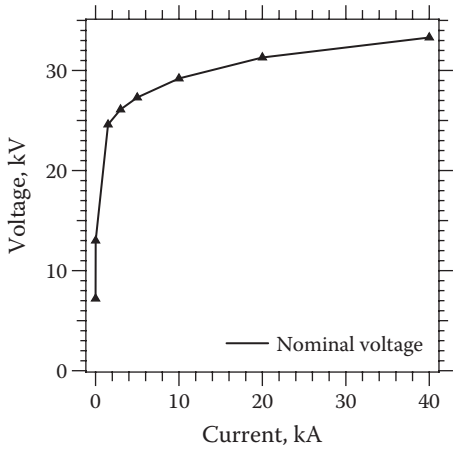


Figure 13.11 Typical characteristics of an 8.4-kV MCOV arrester (typically used on a system with a nominal voltage of 7.2 or 7.62 kV from line to ground).

arrester. At distribution voltages, metal oxide was first used to provide better protection at riser poles feeding underground cables (Burke and Sakshaug, 1981).

Distribution surge arresters are primarily for protection against lightning (not switching surges or other overvoltages). In areas without lightning, they would not be needed. That said, most utilities in low-lightning areas use arresters even if the cost of arresters exceeds the cost of occasional failures. If a utility is hit with a 1-in-40-year storm, it can wipe out a significant portion of unprotected transformers, enough that the utility does not have the inventory to replace them all, and some customers would have very long interruptions.

Arresters must be placed as close as possible to the equipment being protected. This means on the same pole because lightning has such high rates of rise, an arrester one pole span away provides little protection. At the pole structure, the best place for the arrester is right on the equipment tank to minimize the inductance of the arrester leads.

Arresters protect any equipment susceptible to permanent damage from lightning. Figure 13.12 shows examples of arrester applications. Transformers should have arresters. Two-terminal devices such as reclosers, regulators, and vacuum switches should have arresters on both the incoming and outgoing sides. Arresters on reclosers are especially important. When the recloser is open, a surge hitting the open point will double. Commonly, reclosers open to clear lightning-caused faults, and if the

Figure 13.12 Example of arrester applications.

downstream side is not protected, a subsequent lightning stroke that followed the one that caused the fault could fail the open recloser. Cables need special attention to prevent lightning entry and damage. At the equipment with predominantly air flashover paths—insulators, switches, and cutouts—utilities do not normally use arresters.

Most utilities also protect capacitor banks with arresters. Some believe that capacitors protect themselves because capacitors have low impedance to a fast-changing surge. While this is somewhat true, nearby direct lightning flashes may still fail capacitors. About 1.9 C, which is a small first stroke, charges a 400-kvar, 7.2-kV capacitor unit to 95 kV (the BIL for 15-kV equipment).

Several classes of arresters are available for protecting distribution equipment:

- *Riser pole*—Designed for use at a riser pole (the junction between an overhead line and a cable), it has better protective characteristics than heavy-duty arresters (because of voltage doubling, underground protection is more difficult)
- *Heavy duty*—Used in areas with average or above average lightning activity
- *Normal duty*—Higher protective levels and less energy capability. Used in areas with average or below average lightning activity
- *Light duty*—A light-duty arrester is used for protection of underground equipment where most of the lightning current is discharged by another arrester at the junction between an overhead line and the cable

Two protective levels quantify an arrester's performance (IEEE Std. C62.22-2009):

- *Front-of-wave protective level (FOW)*—The crest voltage from a current wave causing the voltage to rise to crest in 0.5 μsec.
- *Lightning impulse protective level (LPL)*—The crest voltage for an 8/20-μsec current injection (8 μsec is the equivalent time to crest based on the time from 10% to 90% of the crest, and 20 μsec is the time between the origin of the 10 to 90% virtual front and the half-value point). These characteristics are produced for current peaks of 1.5, 3, 5, 10, and 20 kA.

Table 13.4 gives the common ranges. Lower protective levels protect equipment better.

13.4.1 Ratings and Selection

The choice of arrester rating depends on the voltage under normal conditions and possible temporary overvoltages (TOVs). Temporary overvoltages during line-to-ground faults on the unfaulted phases are the main concern; therefore, system grounding plays a large role in arrester application.

The most important rating of a metal-oxide arrester is the maximum continuous operating voltage (MCOV). Arresters also have another voltage rating called the duty-cycle rating (this rating is very commonly used to refer to a particular arrester). The duty-cycle rating is about 20% higher than the MCOV rating. Within a given rating class, arresters may have different performance characteristics (such as the discharge voltage and the energy-handling capability). For example, one 8.4-kV MCOV

TABLE 13.4 Common Ranges of Protective Levels

Duty-Cycle Rating (kV rms)	MCOV (kV rms)	FOW Protective Level (kV)			Maximum Discharge Voltage (kV) 8/20 μsec Current Wave		
		5 kA Normal Duty	10 kA Heavy Duty	10 kA Riser Pole	5 kA Normal Duty	10 kA Heavy Duty	10 kA Riser Pole
3	2.55	11.2–17	13.5–17	10.4	10.2–16	9.1–16	8.2
6	5.1	22.3–25.5	26.5–35.3	17.4–18	20.3–24	18.2–25	16.2
9	7.65	33.5–36	26.5–35.3	22.5–36	30–33.5	21.7–31.5	20–24.9
10	8.4	36–37.2	29.4–39.2	26–36	31.5–33.8	24.5–35	22.5–26.6
12	10.2	44.7–50	35.3–50	34.8–37.5	40.6–44	32.1–44	30–32.4
15	12.7	54–58.5	42–59	39–54	50.7–52	35.9–52	33–40.2
18	15.3	63–67	51–68	47–63	58–60.9	43.3–61	40–48
21	17.0	73–80	57–81	52–63.1	64–75	47.8–75	44–56.1
24	19.5	89–92	68–93	63–72.5	81.1–83	57.6–83	53–64.7
27	22.0	94–100.5	77–102	71–81.9	87–91.1	65.1–91	60–72.1
30	24.4	107–180	85–109.5	78–85.1	94.5–99	71.8–99	66–79.5
36	29.0	125	99–136	91–102.8	116	83.7–125	77–96

Source: Adapted from IEEE Std. C62.22-2009, *IEEE Guide for the Application of Metal-Oxide Surge Arresters for Alternating-Current Systems*. Copyright 2009 IEEE.

normal-duty arrester may have a protective level for a 10-kA, 8/20-μsec current injection of 36 kV. A riser-pole arrester of the same rating may have a 27-kV protective level.

Operating voltage is the first criteria for applying arresters. The arrester MCOV rating must be above the normal upper limit on steady-state voltage. Some engineers use the upper (ANSI C84.1-1995) range B, which is slightly less than 6% above nominal. Use 10% above the nominal line-to-ground voltage to be more conservative.

Temporary overvoltages are the second application criteria. An arrester must withstand the overvoltages that occur during line-to-ground faults on the unfaulted phases. The overvoltages are due to a neutral shift. On an ungrounded system, a ground fault shifts the neutral point to the faulted phase. The arresters connected to the unfaulted phases see line-to-line voltage. Four-wire multigrounded systems are grounded but still see some neutral shift. (IEEE C62.92.4-1991) recommends using a 1.35 per unit overvoltage factor for a multigrounded system. Chapter 14 has more information on overvoltages during ground faults.

Arrester TOV capabilities are time dependent; manufacturers publish TOV curves for their arresters (see Figure 13.13). The duration of the overvoltage depends on the relaying and fusing. Normally, this varies, and since arrester applications are not individually engineered, a value is normally assumed.

On four-wire multigrounded systems, the MCOV criteria, not the TOV criteria, determine the arrester application. On ungrounded or impedance-grounded circuits, TOV capability determines the rating.

Riser-pole arresters have less temporary overvoltage capability than normal- or heavy-duty arresters. Riser-pole arresters normally have the same arrester block size

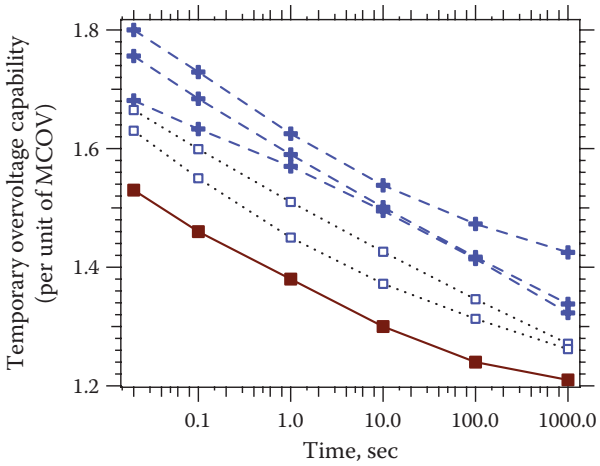


Figure 13.13 TOV capabilities of several different arrester manufacturers and models (dashed lines: heavy-duty arresters, dotted lines: riser-pole arresters, bottom line: lowest TOV capability expected as published in IEEE Std. C62.22-1997).

as heavy-duty arresters; the manufacturer chooses blocks carefully to find those with lower discharge voltages. A lower discharge characteristic means more current and energy for a given temporary overvoltage.

Utilities typically standardize arrester ratings for a given voltage and grounding configuration. Table 13.5 shows some common applications. For the four-wire systems, most of the systems are okay, but try to avoid the tight applications such as the 9-kV duty-cycle arrester at 12.47 kV and the 10-kV duty-cycle arrester at 13.8 kV.

For ungrounded circuits, the voltage on the unfaulted phases rises to the line-to-line voltage. This normally requires an arrester with an MCOV equal to the line-to-line voltage because the fault current is so low on an ungrounded system that single line-to-ground faults are difficult to detect.

13.4.2 Housings

Polymer materials such as silicone or EPR compounds are used for arrester housings. Porcelain housings are available, and all arresters up until the 1980s were porcelain housed. The main advantage of a polymer over porcelain is a safer failure mode. An internal fault in a porcelain arrester can explode the housing and expel porcelain such as shrapnel. The polymer housing will split from the pressures of an internal fault. Arc energies may still crack apart and eject portions of the blocks, but overall, the failure is less dangerous than in a porcelain housing. Polymer-housed arresters can pass the ANSI housing test where a specified fault current is applied for at least 0.1 sec, and all components of the arrester must remain confined within the enclosure. Polymer-housed arresters can typically pass these criteria for a 5-kA fault current for 1/2 sec ($\int I dt = I \cdot t = 2500$ C). Porcelain-housed arresters fail violently for these levels of current. Lat and Kortschinski (1981) ruptured porcelain arresters with fault currents

TABLE 13.5 Commonly Applied Arrester Duty-Cycle Ratings

Nominal System Voltage (V)	Four-Wire Multigrounded Neutral Wye	Three-Wire Low-Impedance Grounded	Three-Wire High-Impedance Grounded
2400			3 (2.55)
4160Y/2400	3 (2.55)	6 (5.1)	6 (5.1)
4260			6 (5.1)
4800			6 (5.1)
6900			9 (7.65)
8320Y/4800	6 (5.1)	9 (7.65)	
12000Y/6930	9 (7.65)	12 (10.2)	
12470Y/7200	9 (7.65) or 10 (8.4)	15 (12.7)	
13200Y/7620	10 (8.4)	15 (12.7)	
13800Y/7970	10 (8.4) or 12 (10.1)	15 (12.7)	
13800			18 (15.3)
20780Y/12000	15 (12.7)	21 (17.0)	
22860Y/13200	18 (15.3)	24 (19.5)	
23000			30 (24.4)
24940Y/14400	18 (15.3)	27 (22.0)	
27600Y/15930	21 (17.0)	30 (24.4)	
34500Y/19920	27 (22.0)	36 (29.0)	

Source: Adapted from IEEE Std. C62.22-2009, *IEEE Guide for the Application of Metal-Oxide Surge Arresters for Alternating-Current Systems*. Copyright 2009 IEEE.

Note: MCOV ratings are shown in parenthesis.

totaling as low as 75 C (6.8 kA for 11 msec, another failed at 2.7 kA for 50 msec). Expulsion fuses may prevent explosions in porcelain arresters at low short-circuit currents but not at high currents (current-limiting fuses are needed at high currents).

A polymer housing keeps water out better than a porcelain housing (water initiates many failure modes). Polymer-housed arresters—although better than porcelain-housed arresters—are not immune from moisture ingress. Moisture can enter through leaks in fittings or by diffusing through the polymer material. One utility in a high-lightning area has found polymer-housed arresters with moisture ingress degradation. These show up on thermal imaging systems where an arrester with moisture ingress may be 50°C hotter than adjacent arresters. The utility replaces any arrester with significant thermovision temperature discrepancies. Lahti et al. (1998, 1999) performed high humidity tests and hot-water immersion tests on polymer-housed arresters. Arresters with the housing directly molded onto the arrester body performed well (no failures). Those with housings pressed on and fitted with caps at the ends often allowed moisture in through leaks in the end caps.

13.4.3 Other Technologies

Many older arrester technologies are still in place on distribution circuits. See Figure 13.15 for examples. Older arresters can be a source of reliability problems. The most

prevalent is the gapped silicon-carbide arrester. Silicon carbide is a nonlinear resistive material, but it is not as nonlinear as metal oxide. It requires a gap to isolate the arrester under normal operating voltage. When an impulse sparks the gap, the resistance of the silicon carbide drops, conducting the impulse current to the ground. With the gap sparked over, the arrester continues to conduct 100 to 300 A of power follow current until the gap clears. If the gap fails to clear, the arrester will fail. Annual failure rates have been about 1% with moisture ingress into the housing causing most failures of these arresters (an Ontario-Hydro survey found 86% of failures were from moisture (Lat and Kortschinski, 1981)). Moisture degrades the gap, failing it outright or preventing it from clearing a surge properly. Darveniza et al. (1996) recommended that gapped silicon-carbide arresters older than 15 years can be progressively replaced with metal-oxide arresters. Their examinations and tests found a significant portion of silicon-carbide arresters had serious deterioration with a pronounced upturn after about 13 years. Externally gapped arresters can also contribute power quality problems; they can fail internally and cause repeated voltage sags and fuse operations as the gap flashes over.

Under-oil arresters are another protection option. Metal-oxide blocks, mounted inside transformers, protect the windings with almost no lead length. Eliminating the external housing eliminates animal faults across arrester bushings; on pad-mounted transformers, connector space is freed. Since the arrester blocks are immersed in oil, thermal characteristics are excellent, which improves TOV characteristics (Walling (1994) shows tests where external arresters failed thermally during ferroresonance but under-oil arresters survived). The main disadvantages of under-oil arresters are related to failures. If the blocks fail, either due to lightning or other reason, the energy in the long fault arc around or through the arrester blocks makes transformer tank failures more likely (Henning et al., 1989). Even if the transformer tank does not fail, since the arrester is a fundamental component of the transformer, an arrester failure is a transformer failure: a crew must take the whole transformer back to the shop.

Most metal-oxide arresters are gapless, but a gapped metal-oxide arrester is available. A portion of the metal-oxide blocks that would normally be used is replaced with a gap. This improves the protection. When the gap sparks over, the surge current creates less voltage because there is less metal oxide. Once the overvoltage clears, the metal oxide provides considerable impedance to clear the gap with very little power follow current. The gapped arrester also has good TOV capabilities if the gap does not spark over. If a lightning stroke or ferroresonance sparks the gap, TOVs can fail the arrester more quickly. Another disadvantage is the gap itself, which was the most unreliable part of the gapped silicon-carbide arrester.

13.4.4 Isolators

Distribution arresters have isolators that remove failed arresters from the circuit. The isolator has an explosive cartridge that blows the end off of a failed arrester, which provides an external indication of failure. The isolator itself is not designed to clear

the fault. An upstream protective device normally must clear the fault (although, in a few cases, the isolator may clear the fault on its own, depending on the available short-circuit current and other parameters).

Crews should take care with the end lead that attaches to the bottom of the arrester. It should not be mounted such that the isolator could swing the lead into an energized conductor if the isolator operates. The proper lead size should also be used (make sure it is not too stiff, which might prevent the lead from dropping).

Occasionally, lightning can operate an isolator in cases where the arrester is still functional. One study found that 53% of arresters removed due to operation of the isolator were because the isolator operated improperly (Campos et al., 1997) (this ratio is much higher than normal).

Arrester isolators have a small explosive charge similar to a 0.22 caliber cartridge. The firing mechanism is a gap in parallel with a resistor. Under high currents, the gap flashes over. The arc through the gap attaches to the shell and generates heat that fires the shell. The heat from an arc is roughly a function of $\int I\,dt$, which is the total charge that passes. Most isolators operate for a total charge of between 5 and 30 C as shown in Figure 13.14. A significant portion of lightning flashes contains charge reaching

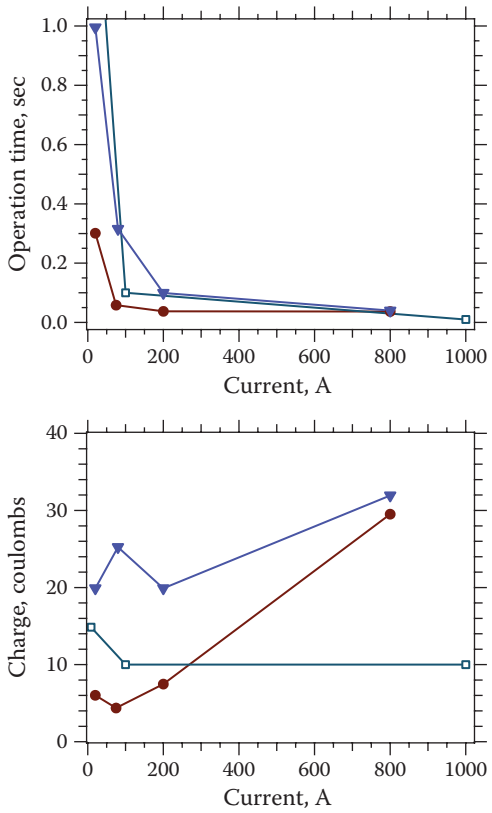


Figure 13.14 Operation time and charge required to operate isolators for different current levels (from three manufacturers).

these amounts. Even though only a portion of the lightning current normally flows into arresters, a significant number of events will still cause isolator operation.

Isolators should coordinate with upstream protective devices. Some small fuses can blow before the isolator clears (the melting time of fuses varies as $\int I^2\,dt$, but the isolators vary as $\int I\,dt$, so there is some crossover point). Most small transformer fuses may clear in less than a half-cycle for faults above 1000 A (the clearing time depends on the timing of the fault relative to the next zero crossing). A 1/2-cycle fault of 1 kA is 8.3 C, which may not fire an isolator. This is a safety issue since line crews may replace a blown fuse right next to a failed arrester that was not isolated properly.

13.4.5 Arrester Reliability and Failures

Modern arresters are reliable components with failure rates much less than 1% annually. They do have somewhat of a bad reputation though, probably because there were bad products produced by some manufacturers during the early years of metal-oxide arresters. And, their tendency to fail violently did not help.

One manufacturer states a failure rate less than 0.05% for polymer-housed arresters. This is primarily based on returned arresters, which are a low estimate of the true failure rate; arresters are almost a throw-away commodity; not all failures are returned. Arresters may also fail without utilities noticing; if the isolator operates and a circuit breaker or recloser closes back in, the failed arrester is left with a dangling lead that may not be found for some time. Ontario Hydro (CEA 160 D 597, 1998) has recorded failure rates averaging about 0.15% in a moderately low-lightning area with about one flash/km^2/year. About 40% of their arrester failures occurred during storm periods.

Lightning arresters fail for a variety of reasons. Moisture ingress, failure due to lightning, and temporary overvoltages beyond arrester capability are some of the possibilities. Early in my career, I was involved with lab tests of arresters and EMTP modeling to evaluate system conditions such as ferroresonance, presence of distributed generation, and regulation voltages (Short et al., 1994). The main conclusion was that well-made arresters should perform well. More problems were likely for tightly applied arresters (such as using a 9-kV duty-cycle arrester with a 7.65-kV MCOV on a 12.47/7.2-kV system), so avoid tightly applying arresters under normal circumstances.

Older arresters can be a source of reliability issues. See Figure 13.15 for examples. Darveniza et al. (2000) inspected several arresters damaged in service in Australia. Of the gapped metal-oxide arresters inspected, both polymer- and porcelain-housed units, moisture ingress caused most failures. Of the gapless metal-oxide arresters inspected, several were damaged under conditions that were likely ferroresonance—arresters on riser poles with single-pole switching or with a cable fault. Another portion was likely from severe lightning, most likely from multiple strokes. Most of the failures occurred along the outer surface of the blocks. A small number of metal-oxide arresters, both polymer and porcelain, showed signs of moisture ingress damage, but overall, the metal-oxide arresters had fewer problems with moisture ingress than might be expected.

Silicon-carbide arrester | Expulsion arrester | Peroxide-pellet arrester

Figure 13.15 Examples of older arresters.

Lightning causes some arrester failures. Figure 13.16 shows an example. The standard test waves (4/10 or 8/20 μsec) do not replicate lightning very well but are assumed to test an arrester well enough to verify field performance. The energy of standard test waves along with the charge is shown in Table 13.6. Charge corresponds well with arrester energy input since the arrester discharge voltage stays fairly constant with current.

Studies of surge currents through arresters show that individual arresters only conduct a portion of the lightning current. Normally, the lightning current takes more than one path to the ground. Often, that path is a flashover caused by the lightning; the flashover is a low-impedance path that "protects" the arrester. The largest stroke through an arrester measured during an EPRI study with more than 200 arrester years of monitoring using lightning transient recorders measured 28 kA (Barker et al., 1993). During the study, 2% of arresters discharged more than 20 kA annually. The largest energy event was 10.2 kJ/kV of MCOV rating (the arrester did not fail, but larger than normal 4.7-cm-diameter blocks were used).

Manufacturers often cite 2.2 kJ/kV of MCOV rating as the energy capability of heavy-duty arresters. The actual capability is probably higher than this. If test results from station-class arresters (Ringler et al., 1997) are translated to equivalent distribution size blocks, heavy-duty arresters should withstand 6 to 15 kJ/kV of MCOV (the 100-kA test produces about 4 to 7 kJ/kV of MCOV). Metal-oxide blocks exhibit high variability in energy capability, even in the same manufacturing batch.

Darveniza et al. (1994, 1997) found that multiple strokes are more damaging to arresters. Less energy is needed to fail the arrester. The failures occur as flashovers along the surface of the metal-oxide blocks. The block surface coating plays an important role; contamination and moisture increased the probability of failure. Five 8/20-μsec test waves were applied within an interval of 40 msec between each. A set of five

Figure 13.16 Lightning flash that failed an arrester. The circuit in the foreground curves around to the right about a mile beyond the visible poles. Flashovers occurred at poles on either side of the strike point. An arrester failed on one of the poles. (From Niagara Mohawk Power Corporation. Copyright 1991. Reprinted with permission.)

10-kA impulses applies about 4 kJ/kV of MCOV. Many of the arrester designs failed these tests. The best design had a housing directly molded onto the blocks.

Longer-duration surges also fail arresters at lower energy levels. Tests by Kannus et al. (1999) on polymer-housed arresters found many failures with 2.5/70-μsec test waves with a peak value of about 2 kA. As with multiple impulse tests, the outside of the blocks flashed over. Some arresters failed with as little as 0.5 kJ/kV of MCOV. Moisture ingress increased the failure probability for some arrester designs (Lahti et al., 2001).

TABLE 13.6 Approximate Energy and Charge in ANSI/IEEE Arrester Test Current Waves

(ANSI/IEEE C62.11-1987) Test Wave	Energy, kJ/kV of MCOV	Charge, C
100 kA, 4/10 μsec	4.5	1.0
40 kA, 8/20 μsec	3.6	0.8
10 kA, 8/20 μsec	0.9	0.2

This brings us to a common but difficult-to-answer question, should we use normal-duty or heavy-duty arresters? Heavy-duty arresters have more energy capability. This reduces the chance of failure due to severe lightning or temporary overvoltages such as ferroresonance. They also have lower discharge voltages (although the extra margin is not usually needed for protecting overhead equipment). Normal-duty arresters cost less, so the question remains as to whether the extra capability of the larger arrester is worth it. For most locations, heavy-duty arresters are appropriate, except in low-lightning areas with less than 0.5 flashes/km^2/year. However, this depends on the environmental exposure (how many trees are around), utility stocking and standardization considerations (e.g., are transformer arresters the same as arresters at riser poles?), and cost considerations.

13.5 Equipment Protection

Insulation coordination of distribution systems involves some simple steps:

1. Choose the arrester rating based on the nominal system voltage and the grounding configuration.
2. Find the discharge voltage characteristics of the arrester.
3. Find the voltage that may be impressed on the insulation, considering any lead length and for cables, any traveling wave effects.
4. Finally, ensure that the impressed voltage is less than the equipment insulation capability, including a safety margin.

As with many aspects of distribution engineering, standards help simplify applications. Normally, utilities can standardize equipment protection for a particular voltage, including arrester rating, class, and location, and exceptions are rarely needed. Construction framing drawings specify how to apply arresters to minimize lead length.

13.5.1 Equipment Insulation

Distribution insulation performance is characterized with the *Basic Lightning Impulse Insulation Level* (BIL). BIL is the peak-withstand voltage for a 1.2/50-μsec impulse wave. IEEE Std. 4-1995 defines voltage impulse test waves as t_1/t_2 μsec, where t_1 is the equivalent time to crest based on the time taken to rise from 30% to 90% of the crest (see Figure 13.17). The time to half-value t_2 is the time between the origin of the 30 to 90% virtual front and the point where it drops to half-value. The equipment must withstand a certain number of applications of the test wave under specified conditions.

The standard BIL ratings for distribution equipment are 30, 45, 60, 75, 95, 125, 150, 200, 250, and 350 kV. Most equipment has the BILs given in Table 13.7.

Some insulation is also tested with a chopped wave. A chopped wave has the same characteristic as the 1.2/50-μsec wave, but the waveshape is chopped off after

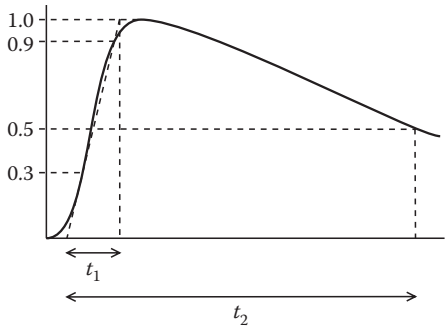


Figure 13.17 Standard impulse voltage test wave. (IEEE Std. 4-1995. © 1995 IEEE.)

TABLE 13.7 Distribution Equipment Insulation Impulse Levels (BIL and CWW)

Voltage Class (kV)	BIL (kV)	CWW (kV)[a]
5	60	69
15	95	110
25	125	145
35	150	175

[a]For transformers: Other equipment may have different CWW.

2 or 3 μsec. Since the voltage stress does not last as long, with most equipment, the chopped wave withstand (CWW) is higher than the BIL. The CWW values given in Table 13.7 are for transformers (IEEE C57.12.00-2000). For transformers and other oil-filled equipment, insulators, and other air mediums, assume CWW = 1.15 · BIL. For cable insulation, assume they are equal; CWW = BIL.

Insulation withstands higher voltages when the voltage is applied for shorter periods. The volt-time or time-lag characteristic of insulation shows this effect with the time to failure of a given crest magnitude. The volt-time characteristic of air insulation turns up significantly; oil-filled insulation turns up less, and solid insulation, very little. For solid insulations such as EPR and XLPE, the small turnup is why the CWW is the same as the BIL.

13.5.2 Protective Margin

Insulation coordination for distribution systems involves checking to see if there is enough margin between the voltage across the insulation and the insulation's capability. A protective margin quantifies the margin between the voltage the surge arrester allows (protective level) and the insulation withstand. For overhead transformers and other overhead equipment, we evaluate two protective margins,

both in percent; one for the chopped wave and one for the full wave (IEEE Std. C62.22-2009):

$$PM_{CWW} = \left[\frac{CWW}{FOW + Ldi/dt} - 1\right] \cdot 100$$

$$PM_{BIL} = \left[\frac{BIL}{LPL} - 1\right] \cdot 100$$

where

CWW = chopped wave withstand, kV
FOW = front-of-wave protective level, kV
BIL = basic lightning impulse insulation level, kV
LPL = lightning impulse protective level, kV
Ldi/dt = the lead wire voltage due to the rate of change of the current, kV

Both margins should be over 20% (IEEE Std. C62.22-2009), and for various reasons, we are safer having at least 50% margin. The chopped-wave protective margin includes voltage due to the rate of change of current through the arrester leads.

Protective margins for common voltages are shown in Tables 13.8 and 13.9. The BIL margin is high in all cases, but with long lead lengths, the CWW margin is low enough to pose increased risk of failure.

The lead length component is very important; the lead voltage can contribute as much as the arrester protective level for long lengths. A length of wire has self-inductance, and a fast-rising current induces a voltage across this inductance. The arrester lead inductance is approximately 0.4 μH/ft (1.3 μH/m). Commonly, a rate of current change is assumed to be 20 kA/μsec. Together, this is 8 kV/ft of lead length (26 kV/m). This is not an unreasonable rate of rise to use in the calculation; 20 kA/μsec is about the median value for subsequent strokes during the rise from 30% to 90%. Consider the lead lengths on both the energized side and the ground side of the arrester.

Lead lengths less than 3 ft (1 m) are necessary to achieve a 50% margin for protecting overhead equipment. The easiest approach is to tank mount arresters. Pole or crossarm mounting makes it harder to keep reasonable lead lengths. It is important to remember that lead length includes the ground lead as well as the phase wire lead, and the lead length path is along the path that the lightning current flows from the

TABLE 13.8 Typical BIL Protective Margins for Common Distribution Voltages (Using the 10-kA LVL)

System Voltage (kV)	Arrester MCOV (kV)	BIL (kV)	LPL (kV)	PM_{BIL}
12.47Y/7.2	8.4	95	32	197%
24.9Y/14.4	15.3	125	58	116%
34.5Y/19.9	22	150	87	72%

TABLE 13.9 Typical CWW Protective Margins for Common Distribution Voltages (Assuming 8 kV/ft, 26 kV/m of Lead Length)

System Voltage (kV)	Arrester MCOV (kV)	CWW (kV)	FOW (kV)	*Ldi/dt* (kV)	PM_{CWW} (%)
No Lead Length					
12.47Y/7.2	8.4	110	36	0	206
24.9Y/14.4	15.3	145	65	0	123
34.5Y/19.9	22	175	98	0	79
3-ft (0.9-m) Lead Length					
12.47Y/7.2	8.4	110	36	24	83
24.9Y/14.4	15.3	145	65	24	63
34.5Y/19.9	22	175	98	24	43
6-ft (1.8-m) Lead Length					
12.47Y/7.2	8.4	110	36	48	31
24.9Y/14.4	15.3	145	65	48	28
34.5Y/19.9	22	175	98	48	20

phase wire to the ground (see Figure 13.18). Some important, but obvious directions for arrester application are

1. *Do not coil leads*—While this may look tidy, the inductance is very high.
2. *Tie the ground lead to the tank*—The NESC (IEEE C2-2012) requires arrester ground leads to be tied to an appropriate ground. To achieve any protection, the ground lead must be tied to the tank of the equipment being protected. Without attaching the ground lead to the tank, the transformer or other equipment is left completely unprotected.

Arrester versus fuse placement has been debated. Tank mounting an arrester protects the transformer best, but since the transformer is downstream of the fuse, the lightning surge current passes through the fuse. Lightning may blow the fuse

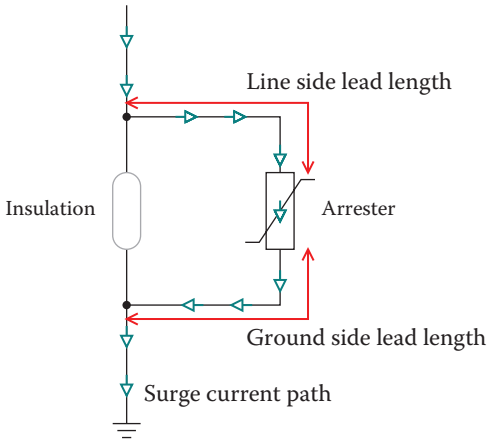


Figure 13.18 Lead length.

unnecessarily, and many utilities have histories of nuisance fuse operations. Applying the arrester upstream of the fuse keeps the surge current out of the fuse, but usually results in long lead lengths. I prefer the tank-mounted approach along with using larger fuses or surge-resistant fuses to limit unnecessary fuse operations.

13.5.3 Secondary-Side Transformer Failures

Single-phase residential-type transformers (three-wire 120/240-V service) may also fail from surge entry into the low-voltage winding. This damage mode has been extensively discussed within the industry (sparking competing papers from manufacturers) and summarized by an IEEE Task Force (1992). Lightning current into the neutral winding of the transformer (usually X2) induces possibly damaging stresses in the high-voltage winding near the ground and line ends, both turn to turn and layer to layer. Lightning current can enter X2 from strikes to the secondary or strikes to the primary (where it gets to the neutral through a surge arrester or flashover, see Figure 13.19).

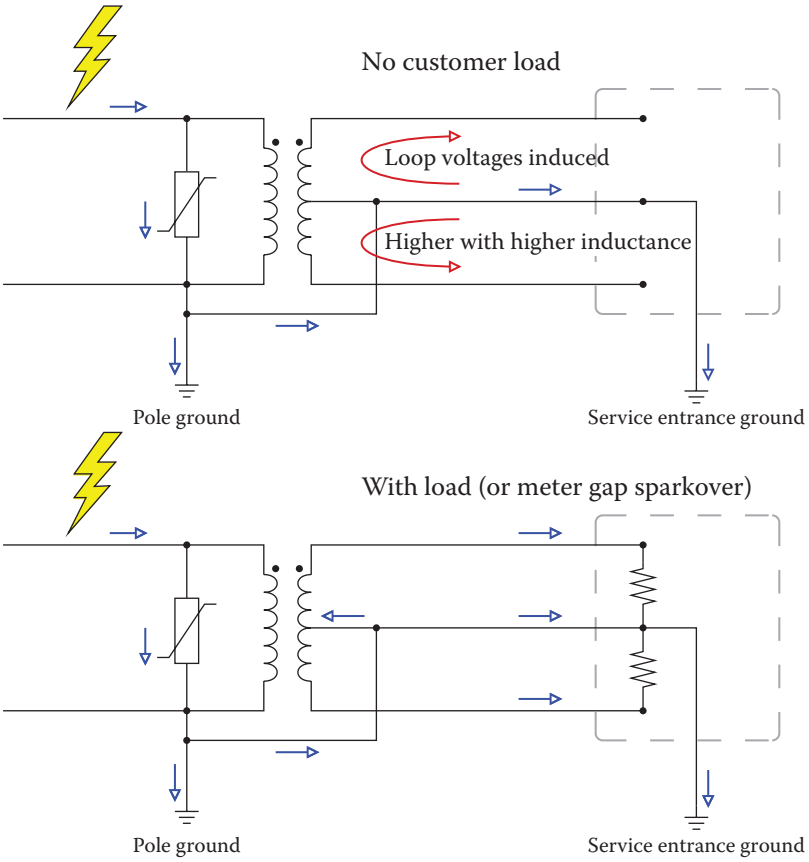


Figure 13.19 Surge entry via the secondary.

The most concern with secondary surge entry is on small (<50 kVA) overhead transformers with a noninterlaced secondary winding (padmounted transformers are also vulnerable). The primary arrester does not limit the voltage stresses on the ends of the primary winding. Currents couple less to the high-voltage winding on transformers with an interlaced secondary winding, which is used on core-type transformers and some shell-type transformers. Smaller kVA transformers are most prone to damage from this surge entry mode.

When the surge current gets to the transformer neutral, it has four places to go: down the pole ground, along the primary neutral, along the secondary neutral toward houses, or into the transformer winding. Current through the secondary neutral creates a voltage drop along the neutral. This voltage drop will push current through the transformer when the load is connected to the customer (Figure 13.19). The voltage created by flow through the neutral is partially offset by the mutual inductance between the secondary neutral and the phases (tighter coupling is better). The major factors impacting secondary surge severity are

- *Interlacing*—For a balanced surge (equal in both windings), the inductance provided by the transformer is approximately the hot leg to hot leg short-circuit reactance. Transformers with interlaced secondaries have significantly lower inductances (see Table 13.10). Higher transformer inductance induces a higher voltage on the primary-side winding.
- *Transformer size*—Smaller transformers have higher inductances, inducing a higher voltage on the primary-side winding.
- *Grounding*—Better grounding on the transformer helps reduce the current into the transformer. Poor grounding sends more current into the transformer and more current into houses connected to the transformer. Other nearby primary grounds help to reduce the current into the transformer.
- *Secondary wire*—Since triplex has tighter coupling than open-wire secondaries (and less voltage induced in the loop), a secondary of triplex has less current into the transformer neutral terminal.
- *Multiple secondaries*—The worst case is with one secondary drop from the transformer; several in parallel reduce the current by providing parallel paths.
- *Secondary length*—Longer secondaries are more prone to failure (more voltage induced in the loop).

In normal lightning areas, this surge failure mode is normally neglected. In high-lightning areas, using interlaced transformers leads to a lower failure rate (by a factor

TABLE 13.10 Typical Transformer Inductances

Interlaced Transformers		Noninterlaced Transformers	
10 kVA core	17.4 μH		
10 kVA shell	18.1 μH	10 kVA shell	204 μH
15 kVA shell	17.8 μH	15 kVA shell	257 μH
25 kVA shell	22.6 μH	25 kVA shell	124 μH

Source: Adapted from EPRI TR-000530, *Lightning Protection Design Workstation Seminar Notes*, Electric Power Research Institute, Palo Alto, CA, 1992.

of three for lightning-related failures according to Goedde et al. (1992)). Utilities may use secondary arresters or spark gaps to reduce the transformer failure rate on noninterlaced units. Goedde also reported that transformer failure rates reduced to 0.05% (from their normal 0.2 to 1%) on 25,000 transformers that they made with secondary arresters. Either a metal-oxide secondary arrester or a secondary spark gap effectively protects transformers from secondary-side failure modes. Economically, secondary-side surge protection can make sense in higher-lightning areas. An IEEE Task Force report (1992) (based on Ward, 1990) cites that about 1% of a transformer's first cost is saved for every 0.1% reduction in failure rate.

13.6 Underground Equipment Protection

Underground equipment is susceptible to lightning damage; in the normal scenario, lightning hits an overhead line near the cable, and a surge travels into the cable at the riser pole. The most important item that makes cable protection difficult is

- *Voltage doubling*—When a surge voltage traveling down a cable hits an end point, the voltage wave reflects back, doubling the voltage.

Normally, for the analysis of underground protection, we assume no attenuation in the surge and that the voltage doubles at open points. The surge impedance of the cable is approximately 50 Ω, which is lower than the 400 Ω overhead line surge impedance. So, if a lightning current has a choice between the cable and an overhead line, most of it enters the cable. Normally though, the cable has a surge arrester at the riser pole, and a conducting surge arrester has an impedance of less than 5 Ω (for an arrester with LPL = 30 kV and a 10-kA stroke, LPL/I = 30 kV/10 kA = 3 Ω), so the surge arrester conducts most of the current. Surges travel more slowly on cables, roughly one-half of the speed of light. Transformers along the cable have little effect, and a transformer termination is the same as an open circuit to the surge.

The CWW equals the BIL for the cable (so, we do not have the extra 15% for the chopped-wave protective margin). Since the BIL and CWW are the same, we only need one protective margin equation:

$$\mathrm{PM}_{\mathrm{CWW}} = \left[\frac{\mathrm{BIL}}{V_t} - 1\right] \cdot 100$$

where V_t is the total voltage impressed across the insulation. With an arrester at the riser pole and no arresters in the underground portion, we must use twice the voltage at the riser pole, including the lead length:

$$V_t = 2(\mathrm{FOW} + Ldi/dt)$$

So

$$\text{PM}_{\text{CWW}} = \left[\frac{\text{BIL}}{2(\text{FOW} + Ldi/dt)} - 1\right] \cdot 100$$

Table 13.11 shows protective margins for several voltages using a riser-pole arrester. All the margins are unacceptable, except for the 12.47-kV case with no lead length (the 24.9-kV case is barely acceptable as per the standards). With a heavy-duty arrester (FOW = 36 kV) for the 12.47-kV case, the protective margin drops to

$$\text{PM}_{\text{CWW}} = \left[\frac{95}{2(36)} - 1\right] \cdot 100 = 32\%$$

While a 20% protective margin is considered acceptable as per IEEE C62.22-2009, there are many reasons why it is prudent to design for larger margins. First, insulation in cables and transformers can degrade with time. Second, nonstandard lightning waveshapes, 60-Hz cable charging effects, and extreme rates of rise may increase the voltage above what we have estimated. Ideally, a 50% margin or better is a good design objective. To have a 50% margin with the riser-pole arrester, the lead length must be less than 4 in. (10 cm). Figure 13.20 shows how to obtain the smallest lead length possible. To obtain minimum lead length, be sure to jumper to the arrester first and tie the ground lead to the cable neutral. Figure 13.21 shows examples of poor lead lengths, particularly on the ground sides of the arresters.

Table 13.11 shows that it was difficult to obtain reasonable protective margins with just an arrester at the riser pole. In the next section, we will discuss how to increase margins by adding an open-point arrester to prevent voltage doubling.

Arresters should be placed downstream of the riser-pole fuses if possible. Then, an arrester failure or an animal across the arrester will blow the fuse rather than forcing a mainline protective device operation (interrupting many more customers than if

TABLE 13.11 Typical Underground Protective Margins with a Riser-Pole Arrester, No Other Arresters, and Using 8 kV/ft (26 kV/m) of Lead Length

System Voltage (kV)	Arrester MCOV (kV)	CWW (= BIL) (kV)	FOW (kV)	*Ldi/dt* (kV)	V_t (kV)	PM_{CWW} (%)
No Lead Length						
12.47Y/7.2	8.4	95	29	0	58	64
24.9Y/14.4	15.3	125	51	0	102	23
34.5Y/19.9	22	150	77	0	154	−3
3-ft (0.9-m) Lead Length						
12.47Y/7.2	8.4	95	29	24	106	−10
24.9Y/14.4	15.3	125	51	24	150	−17
34.5Y/19.9	22	150	77	24	202	−26

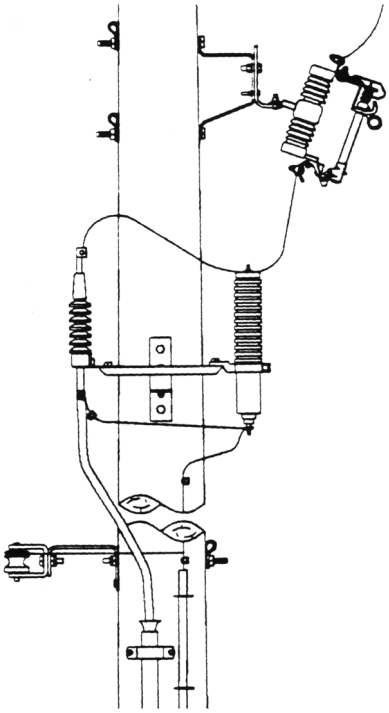


Figure 13.20 Minimum lead length on a riser pole. (IEEE Std. 1299/C62.22.1-1996. © 1997 IEEE.)

Figure 13.21 Arrester applications with long lead lengths.

a fuse had operated). If the arrester isolator fails to operate (which can happen), the failure may be extremely hard for the crews to find. A fuse helps localize the failure.

Arresters upstream of fuses can cause further problems. If the arrester fails and the isolator operates, crews may reclose the circuit successfully if they do not find the failed arrester. This leaves the equipment unprotected. Worse yet, the failed arrester body may start to track across the bracket. Eventually, the arrester bracket will flashover, causing a hard-to-find permanent fault. With arresters upstream of a fuse, arrester lead lengths are longer, and the equipment is not protected as well against lightning surges. This can lead to more lightning-caused equipment failures.

13.6.1 Open-Point Arrester

For grounded 15-kV class systems, an arrester just at the riser pole is sufficient, but only if it is a riser-pole-type arrester and only if the arrester is right across the pothead bushing (minimal lead length). For higher-voltage applications, we need additional arresters. Putting an arrester at the end of the cable prevents doubling. Although the voltage cannot double, reflections that occur before the endpoint arrester starts full conduction will raise the voltage in the middle of the cable (see Figure 13.22). To account for the reflected portion, use

$$V_t = \text{LPL}_{\text{riser}} + \frac{1}{2}\text{LPL}_{\text{openpoint}}$$

where $\text{LPL}_{\text{riser}}$ is the 10-kA protective level of the riser-pole arrester, and $\text{LPL}_{\text{openpoint}}$ is the 1.5-kA protective level of the open-point arrester. The lower-current protective level of the open-point arrester is used since the riser-pole arrester drains off most of the current leaving much less in the cable (with a surge impedance of 50 Ω, a 35-kV

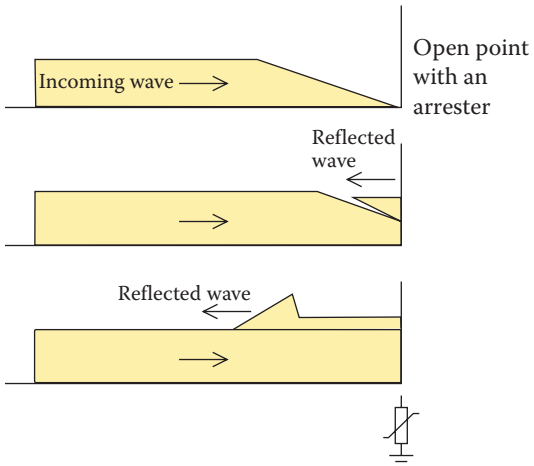


Figure 13.22 Voltage reflections with an open-point arrester.

TABLE 13.12 Typical Underground Protective Margins with a Riser-Pole Arrester and an Open-Point Arrester

System Voltage (kV)	Arrester MCOV (kV)	BIL (kV)	LPL_{riser} (kV)	$LPL_{openpoint}$ (kV)	V_t (kV)	PM_{BIL} (%)
12.47Y/7.2	8.4	95	27	32	43	121
24.9Y/14.4	15.3	125	48	58	77	62
34.5Y/19.9	22	150	72	90	117	28

voltage surge corresponds to 0.7 kA of current). Note that the protective level of the open-point arrester is higher (it is a light-duty arrester).

The portion of the wave that is reflected before the open-point arrester starts to conduct adds to the incoming wave. Because of this, surges with low rise times cause the most severe overvoltage (contrary to most overvoltage scenarios). We have neglected the riser-pole lead length for the reflected voltage, primarily because lead length causes a short-duration voltage on the front of a fast-rising surge. This is just the sort of surge that the open-point arrester handles well because it immediately starts conducting.

With an open-point arrester, we still need to include the lead length in the chopped-wave margin calculation (we just do not add any factor for a reflection from the end of the cable). Protective margins in Tables 13.12 and 13.13 show that we have more leeway with lead length if we have an open-point arrester.

Several options are available for arresters on cable systems. Elbow arresters attach to padmounted transformers, switching enclosures, or other equipment with 200-A loadbreak connectors (IEEE Std. 386-2006). A parking-stand arrester attaches to the enclosure and allows the open, energized cable to be "parked" on an arrester (with a 200-A elbow connector). A bushing arrester fits between a cable elbow and an elbow bushing. Under-oil arresters used in padmounted transformers are another option for protecting underground equipment; they have good thermal performance and have cost advantages.

Normally, we neglect attenuation in cables. This is the conservative approach. Owen and Clinkenbeard (1978) found that a 1/40-μsec wave injected into a cable attenuated less than 5% even at 6000 ft (1800 m). Attenuation increases significantly with frequency. Owen and Clinkenbeard found that a sparkover voltage wave attenuated by 40% after 6000 ft (1800 m) (the sparkover voltage is a narrow voltage spike—on a gapped arrester, it is the portion of voltage that occurs before the gap sparks over).

TABLE 13.13 Typical CWW Underground Protective Margins with a Riser-Pole Arrester and an Open-Point Arrester

System Voltage (kV)	Arrester MCOV (kV)	CWW (= BIL) (kV)	FOW (kV)	*Ldi/dt* (kV)	V_t (kV)	PM_{CWW} (%)
3-ft (0.9-m) Lead Length						
12.47Y/7.2	8.4	95	29	24	53	79
24.9Y/14.4	15.3	125	51	24	75	67
34.5Y/19.9	22	150	77	24	101	49

Most significantly, for cable protection, attenuation softens the lead length inductive kick. The attenuation depends on the cable type. Zhou and Boggs (2002) showed that EPR has an order of magnitude higher attenuation than TR-XLPE, mainly because of higher dielectric losses in the cable. Their EMTP simulations of cable voltages were significantly lower on EPR cable than on TR-XLPE cable, especially with long lead lengths, because of the difference in attenuation.

For cable protection, utilities are wise to have high protective margins. Most of the history verifying distribution overvoltage protection practices comes from arresters applied with over 50% protective margin. Effective lightning protection helps limit high failure rates that have been experienced in the industry (and riser poles expose a significant amount of equipment to overvoltages). Several other factors can cause margins to be less than they appear:

- *Quadrupling*—Barker (1990) showed that voltages can as much as quadruple for bipolar surges into the riser-pole arrester. While lightning currents are not known to have bipolarities, induced voltages from nearby strikes can induce bipolar waveshapes.
- *System voltage*—The system voltage or trapped charge can add to the voltage in the cable. If lightning hits a line at a time when the system voltage happens to be at a peak of the opposite polarity, the arrester will not go into complete conduction until the voltage impulse has compensated for system voltage. On a 12.47Y/7.2-kV system, this adds another $\sqrt{2}(7.2) = 10.18$ kV to the traveling wave.
- *Insulation deterioration*—Transformer and cable insulation degrades over time, which reduces the margin of protection provided by arresters.

The application of arresters is both a science and an art and should be applied based on local conditions. Higher-lightning areas justify better protection (a higher protective margin), especially if a utility has high historical cable failure rates. As always, we must weigh the cost against the risk.

13.6.2 Scout Arresters

Another option for protecting cables is to use *scout* arresters, arresters applied on the overhead line on both sides of the riser pole (Kershaw, 1971). A scout arrester intercepts and diverts a lightning current that is heading toward the riser pole. Since most of the current conducts through the closest arrester, less voltage gets in the cable at the riser pole (unless lightning hits almost right at the cable). Virginia Power has applied scout arresters to riser poles to try to reduce high failure rates of certain types of cables at 34.5 kV (Marz et al., 1994). Transient simulations done by Marz et al. found improved protective margins with the scout arresters.

Scout arrester effectiveness depends on grounding the scout arresters well. Without good grounding, the ground potential rises at the scout arrester, causing high voltage on the phase and neutral wire (but little voltage difference between them). When the surge arrives at the riser pole, the low-impedance ground path offered by the cable drops the neutral potential (and increases the phase-to-neutral voltage). This pulls significant current through the riser-pole arrester (and sends a voltage wave down the

cable), which reduces the effectiveness of the scout arresters. The lower the impedance of the scout arrester grounds, the lesser this effect occurs.

13.6.3 Tapped Cables

If cables are tapped, complex reflections can cause voltage to more than double, with voltage at an open point reaching over 2.8 times the peak voltage at the riser pole (see Figure 13.23 and Hu and Mashikian (1990)). The voltage varies depending on the lengths of each section beyond the tap point. For tapped cables with no open-point arresters, find both the BIL and chopped protective margins and include a 2.6 multiplier in the BIL protective margin calculation (this is not the worst case but applies some extra safety):

$$\mathrm{PM_{BIL}} = \left[\frac{\mathrm{BIL}}{2.6(\mathrm{LPL})} - 1\right] \cdot 100$$

$$\mathrm{PM_{CWW}} = \left[\frac{\mathrm{BIL}}{2.6(\mathrm{FOW}) + Ldi/dt} - 1\right] \cdot 100$$

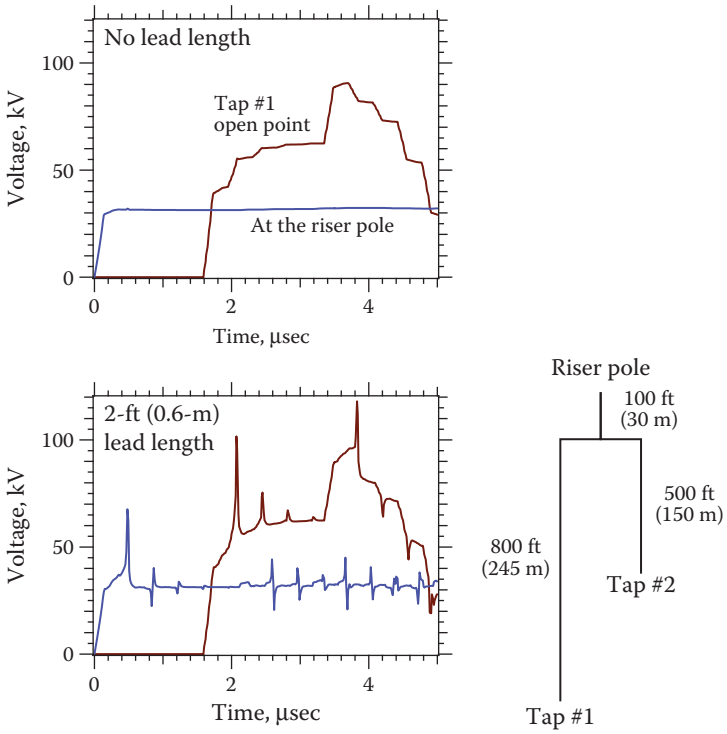


Figure 13.23 Transient simulation of traveling waves on a tapped cable (0.5-µsec risetime).

The lead length voltage is not doubled in the chopped-wave protective margin since the inductive voltage spike from the lead length does not coincide with the reflections causing the highest overvoltage. On tapped cables, applying open-point arresters to both open points provides the safest protection. Arresters at the tap points are also an option for protection.

13.6.4 Other Cable Failure Modes

Lightning may also puncture the jackets in a jacketed cable. Ros (1993) demonstrated that lightning current into a riser-pole ground created enough ground potential rise to puncture jackets and leave pinholes. 50-mil jackets punctured with 150 to 160 kV, and 80-mil jackets punctured with 155 to 170 kV. The voltage impressed across the cable jacket is the surge current times the ground resistance at the riser pole, which may be very high with poor grounds. Ros' tests found semiconducting jackets did not allow nearly the voltage to develop across the jacket.

Lightning can also damage cables from strikes above the ground. EPRI tests found that rocket-triggered lightning strikes to the ground above buried cables caused extensive damage (Barker and Short, 1996). Lightning normally breaks down the soil and arcs to the cable (see Figures 13.24 and 13.25). We tested three cable configurations: unjacketed direct buried, jacketed direct buried, and jacketed cable in conduit. All were single-conductor 220-mil XLPE cables with a full copper neutral. Lightning above the ground damaged them all to varying degrees. Lightning melted most

Figure 13.24 Lightning flash triggered by a rocket trailing a wire. (From Electric Power Research Institute. Copyright © 1993. Reprinted with permission.)

Figure 13.25 Cable and conduit damage observed from rocket-triggered lightning flashes above the ground. (From Electric Power Research Institute. Copyright © 1993. Reprinted with permission.)

strands of the concentric neutral and punctured the jacket and conduit if present. In some cases, lightning also damaged the insulation shield. What made the damage particularly bad was that lightning hit the soil surface and continued an arcing path 3 ft (1 m) underground directly to the cable. Measurements showed that 15 to 25% of the lightning currents reached the padmounted transformers on either side of the flash point. This type of cable damage would not show up immediately. More likely, cable failure would accelerate from increased water entry and localized neutral heating. Voltages we measured across the cable insulation were not a significant threat (they were less than 17 kV).

The tests also pointed to secondary voltages as a concern. We found nearly 4 kV on the closest transformer secondary. Surge entry into the secondary stresses the transformer insulation and sends possibly damaging surges into homes. Current entering into the secondary neutral terminal of the transformer induces voltages that stress the primary winding. Williams (1988) presented evidence that padmounted transformers fail from secondary-side surge entry in similar percentages to overhead transformers.

During the rocket-triggered lightning tests, strokes to the cable attached from as far away as 15 ft (5 m). Furrows from trees to underground cables as long as 300 ft (100 m) have been found (Sunde, 1968). Sunde derived a model for lightning attraction to buried cables based on the lightning current and the soil resistivity. The number of flashes attracted to cables depends on flash density, the peak current magnitude, and the ground resistivity. Higher peak lightning currents make longer jumps to cables. Cables in higher-resistivity soil attract flashes from farther away. The Sunde model predicts that cables attract strikes within the following radius:

$$r = \begin{cases} 0.079\sqrt{\rho \cdot I_p} & \rho \le 100\ \Omega \cdot \text{m} \\ 0.046\sqrt{\rho \cdot I_p} & \rho \ge 1000\ \Omega \cdot \text{m} \end{cases}$$

where

r = attractive radius, m
ρ = soil resistivity, Ω-m
I_p = peak lightning current, kA

Using the IEEE distribution of peak first strokes, this gives the following collection rates to cables:

$$N = \begin{cases} 0.092 N_g \sqrt{\rho} & \rho \le 100\ \Omega \cdot \text{m} \\ 0.053 N_g \sqrt{\rho} & \rho \ge 1000\ \Omega \cdot \text{m} \end{cases}$$

for N in flashes/100 km/year (multiply by 1.609 for results in flashes/100 mi/year) and N_g in flashes/km^2/year. For resistivities in the region that Sunde left out (100 to 1000 Ω · m), either interpolate the results from each equation or use the closest equation. For 1000 Ω · m soil with $N_g = 1$, cables attract 2.7 flashes/100 mi/year (1.7 flashes/100 km/year). For areas in trees, cables collect more flashes; EPRI (1999) recommends doubling the number of strikes for areas in trees.

These flashes to cables puncture jackets and conduits. The amount of heating damage to the neutral and to the insulation is primarily a function of the total charge in the lightning flash (since arcs exhibit a fairly constant voltage drop at the point of attachment, the energy is a function of $\int I dt$). Burying shield wires above the cables is one way to offer protection against this type of damage. An AT&T handbook (1985) provides estimates on shield-wire effectiveness. Note that there is no current power industry practice for this type of protection, and the amount of damage (percent of cable faults) is unknown.

13.7 Line Protection

Line protection is the attempt to reduce the number of lightning-caused faults. Utilities have increased interest in line protection as one way to improve reliability and power quality. Since lightning can flash over a 230-kV or 500-kV transmission line, we should not be surprised that protecting a 13-kV distribution line is difficult. To protect against direct hits, we need either a shield wire or arresters to divert the stroke to the ground without a flashover. Lightning strokes close to a line may induce enough voltage to flash over the line insulation. Induced voltages are easier to contain since induced voltages have much lower magnitudes than direct strike voltages. Maintaining enough insulation capability is the normal way to limit induced voltage flashovers. Line arresters can also greatly reduce induced voltage flashovers from nearby strokes.

13.7.1 Induced Voltages

Lightning strikes near a distribution line will induce voltages into the line from the electric and magnetic fields produced by the lightning stroke. These *induced* voltages

are much less severe than direct strikes, but close strikes can induce enough voltage to flash insulation and damage poorly protected equipment.

The charge and current flow through the lightning channel creates fields near the line. These fields induce voltages on the line. The vertical electric field is the major component that couples voltages into the line (magnetic fields also play a role). As the highly charged leader approaches the ground, the electric field increases greatly, and when the leader connects, the electric field collapses very quickly. The rapidly changing vertical electric field induces a voltage on a conductor, which is proportional to the height of the conductor above the ground. The induced voltage waveform is usually a narrow pulse, less than 5 or 10 μsec wide, and it may be bipolar (negative then positive polarity).

Most measurements of induced voltages have been less than 300 kV, so the most common guideline for eliminating problems with induced voltages is to make sure that the line insulation capability (CFO) is higher than 300 kV. Lines with insulation capabilities less than 150 kV have many more flashovers due to induced voltages.

A simplified version of a model developed by Rusck (1958, 1977) approximates the peak voltage induced by nearby lightning. Rusck's model can be simplified to estimate the peak voltage developed on a conductor (IEEE Std. 1410-2010):

$$V = 36.5\frac{I \cdot h}{y}$$

where

V = peak-induced voltage, kV
I = peak stroke current, kA
h = height of the line, usually ft or m
y = distance of the stroke from the line

This equation is for an ungrounded circuit. For a circuit with a grounded neutral or shield wire, the voltage from the phase to the neutral is less. For normal distribution line conductor spacings, multiply the answer by 0.75 for lines with a grounded neutral. So, for a 30-ft (10-m) distribution line, a 40-kA stroke 200 ft (60 m) from the line induces 165 kV on a line with a grounded neutral. Most lines are immune from strikes farther than 500 ft (150 m) from the line.

Higher earth resistivities will amplify induced voltages (Ishii, 1996; Ishii et al., 1994). Borghetti et al. (2007) compare rigorous simulations that account for earth resistivity to the Rusck model used in IEEE 1410, and Borghetti et al. (2004) show the impact in scenarios with line arresters. Darveniza (2007) proposed a modification to the Rusck model that adjusts the effective line height to account for earth resistivity:

$$h_{\text{eff}} = h + 0.15\sqrt{\rho}$$

where
h_{eff} = the effective conductor height, m
ρ = earth resistivity, Ω-m

Models of attraction to distribution lines show that for lines out in the open, most flashes that do not hit the line are too far away to induce a particularly high voltage across the insulation. For environmentally shielded lines—those with nearby trees and buildings—fewer strikes hit the line, but the line should have higher induced voltages because lightning strokes could hit closer to the line.

EPRI sponsored rocket-triggered lightning tests in 1993 that showed induced voltages could be higher than predicted by Rusck's model for some strikes (Barker et al., 1996). For strikes to the ground 475 ft (145 m) from the line, voltages were 63% higher than Rusck's model. Hydro Quebec and New York State Electric and Gas sponsored another round of tests in 1994 that were also led by P. P. Barker. Closer strokes, strokes 60 ft (18 m) from the line, induced less voltage than the Rusck model.

Table 13.14 compares the rocket-triggered lightning measurements with the Rusck model. High ground resistivity at the Florida test site (500 to 1000 Ω-m) probably explains why the 475-ft (145-m) measurements were higher than the Rusck prediction. Why the closer measurements are lower is not verified. My best guess is because these strokes were triggered from rockets launched on a 45-ft (14-m) tower. Since the tower is above the ground, the positive charge on the tower shields some of the negative charge in the downward leader, so the electric field inducing voltages into the line is smaller. Environmentally shielded lines should act similarly to the tall tower. The charge collected on the tree should shield the line and reduce the induced voltage.

The three induced voltage data points when normalized for a 30-ft (10-m) tall distribution line fit the following equation (with y in meters):

$$V = \frac{9.8I}{\left(1 + \frac{y}{121}\right)^{1.8}}$$

Figure 13.26 shows estimates of induced voltages with insulation level for both open ground and for lines that are environmentally shielded (usually by trees). One is based on Rusck's model using the approach from IEEE Std. 1410-2010. Another is

TABLE 13.14 Comparison of Induced Voltage Measurements to Rusck Predictions

Distance	Number of Data Samples	Rusck Prediction V_{ind}/I_s	Rocket-Triggered Lightning Measurements V_{ind}/I_s
60 ft (18 m)	20	12.2	5.25
400 ft (125 m)	8	1.7	2.67
475 ft (145 m)	63	1.4	2.24

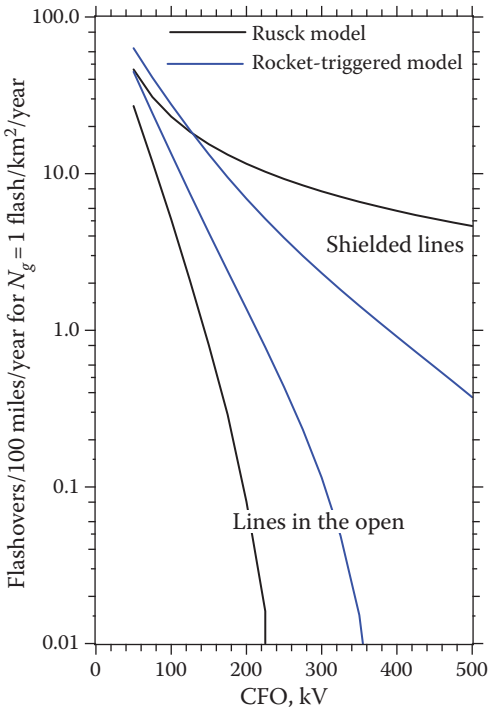


Figure 13.26 Induced voltage flashovers versus insulation level for a line with a grounded neutral.

based on the curve fit of the triggered lightning results, which shows more reasonable answers for environmentally shielded lines.

13.7.2 Insulation

High insulation levels on structures help prevent induced voltage flashovers. Insulation levels are also critical on some types of line protection configurations with shield wires or arresters. Note that for a normal distribution line, higher insulation levels may actually stress nearby cables and transformers more. With high insulation strengths, a higher voltage develops across the insulation before it flashes over. By allowing a larger magnitude surge on the line before flashover, damage to nearby equipment is more likely. The flashover of the insulation acts as an arrester and protects other equipment.

The critical flashover voltage (CFO) of self-restoring insulation (meaning no damage after a flashover) is the voltage where the insulation has a 50% probability of flashing over for a standard 1.2/50-μsec voltage wave. For insulators, manufacturers' catalogs specify the CFO. CFO and BIL are often used interchangeably, but they have slightly different definitions. A statistical BIL is the 10% probability of flashing over for a standard test wave. Normally, CFO and statistical BIL are within a few percent of each other.

TABLE 13.15 CFO of Common Distribution Components (by Themselves)

Component	kV/ft	kV/m
Air	180	600
Wood pole or crossarm	100	350
Fiberglass standoff	150	500

Lightning may flash along several paths: directly between conductors across an air gap or along the surface of insulators and other hardware at poles (normally the easiest path to flashover). We need to consider phase-to-ground and phase-to-phase paths. At a pole structure, the flashover path may involve several insulating components: the insulator, wood pole or crossarm, and possibly fiberglass. Wood and fiberglass greatly increase the structure insulation.

Table 13.15 shows the CFO of common components. When more than one insulator is in series, the total insulating capability is less than the sum of the components. When insulation is subjected to a voltage surge, the voltage across each component splits based on the capacitance between each element. Normally, this voltage division does not split the voltage by the same ratio as its insulation capability, so one component flashes first leaving more voltage across the rest of the components.

The simplest way to estimate the insulation level of a structure is to take the CFO of the insulator (usually about 100 kV) and add the wood length at 75 kV/ft (250 kV/m). Often, the wood provides more insulation than the insulator. Estimate the air-to-air gap using 180 kV/ft (600 kV/m). The air gap between conductors usually has higher insulation than the path along the insulator and wood. So, most flashovers occur at the poles, the weakest point. Typical distribution structures generally have CFOs between 150 and 300 kV. And, to eliminate induced voltage flashovers, we try to have 300 kV of CFO.

Another way to estimate the structure of CFO of several components in series is to take the square root of the sum of the squares of each component. Another more precise way to estimate the structure of CFOs is with the extended CFO-added method described by Jacob et al. (1991) and Ross and Grzybowski (1991). The total CFO is found from the primary insulation CFO plus additional components as

$$\mathrm{CFO} = \mathrm{CFO}_{\mathrm{ins}} + \mathrm{CFO}_{\mathrm{add.sec}} + \mathrm{CFO}_{\mathrm{add.third}}$$

Table 13.16 shows the component CFO values for several combinations using the summarized and simplified version in IEEE Std. 1410-2010. These values for CFO components are based on wet tests using the minimum of the negative and positive polarity values. For $\mathrm{CFO}_{\mathrm{add.third}}$, use 20 kV/ft (65 kV/m) for wood poles and 60 kV/ft (200 kV/m) for fiberglass standoffs. To estimate wet CFO from dry test data, multiply the dry values by 0.8.

TABLE 13.16 Primary CFO and CFO Added by Second Components

CFO of Primary Insulation			CFO Added by a Second Component	
		CFO_{ins} (kV)		$CFO_{add.sec}$ (kV/m)
Polymer insulator			Wood pole	210
			Fiberglass pole	410
Ceramic pin-type insulator			Wood pole	235
	ANSI 55-4	105	Wood crossarm	250
	ANSI 55-5	120	Fiberglass pole	400
	ANSI 55-6	140	Fiberglass crossarm	250
			Fiberglass standoff	315
Vertical ceramic insulator string	1 × 4 in.	75	Wood pole	90
	2 × 4 in.	165	Wood crossarm	160
	3 × 4 in.	250	Fiberglass crossarm	250
			Fiberglass standoff	315
Horizontal ceramic insulator string	1 × 4 in.	75	Wood pole	90
	2 × 4 in.	165	Wood crossarm	295
	3 × 4 in.	250	Fiberglass crossarm	250
			Fiberglass standoff	315
		CFO_{ins} (kV/m)		
Wood	Pole	330		
	Crossarm	360	Wood pole	65
Fiberglass	Pole	470	Fiberglass standoff	200
	Standoff	500		
Air		600		

Source: Adapted from IEEE Std. 1410-2010, *IEEE Guide for Improving the Lightning Performance of Electric Power Overhead Distribution Lines*. With permission.

13.7.2.1 Practical Considerations[*]

Equipment and support hardware on distribution structures may severely reduce CFO. These "weak-link" structures may greatly increase flashovers from induced voltages. See Figure 13.27 for examples. Several situations are described below.

Guy wires. Guy wires may be a major factor in reducing a structure's CFO. For mechanical advantage, guy wires are generally attached high on the pole in the general vicinity of the principal insulating elements. Since guy wires provide a path to the ground, their presence will generally reduce the configuration's CFO. The small porcelain guy-strain insulators that are often used provide very little in the way of extra insulation (generally less than 30 kV of CFO).

A fiberglass-strain insulator may be used to gain considerable insulation strength. A 20-in. (50-cm) fiberglass-strain insulator has a CFO of approximately 250 kV.

[*] This section is adapted from IEEE Std. 1410-1997. Copyright 1997. The author chaired the IEEE working group on the lightning performance of distribution lines during the development and approval of this book.

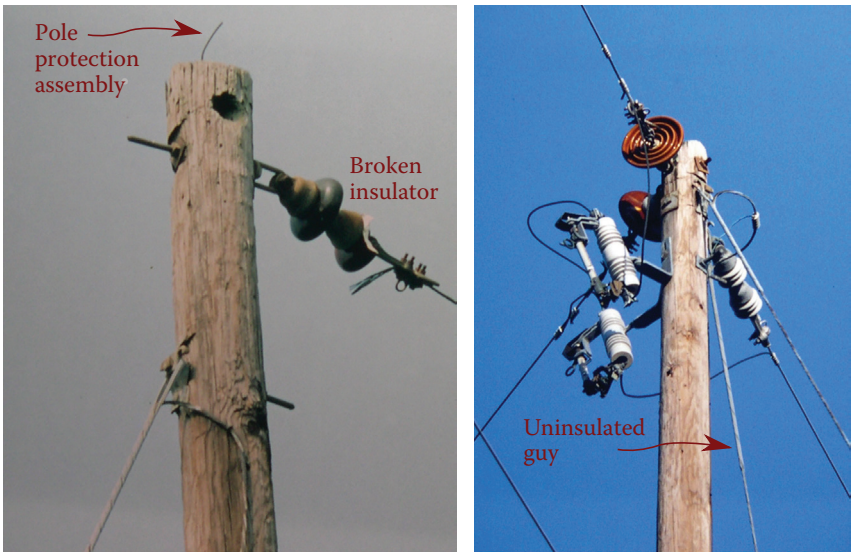


Figure 13.27 Examples of weak-link pole structures. (Courtesy of Duke Energy.)

Fuse cutouts. The mounting of fuse cutouts is a prime example of unprotected equipment that may lower a pole's CFO. For 15-kV class systems, a fuse cutout may have a 95-kV BIL. Depending on how the cutout is mounted, it may reduce the CFO of the entire structure to approximately 95 kV (approximately because the BIL of any insulating system is always less than the CFO of that system).

On wooden poles, the problem of fuse cutouts may usually be improved by arranging the cutout so that the attachment bracket is mounted on the pole away from any grounded conductors (guy wires, ground wires, and neutral wires). This is also a concern for switches and other pieces of equipment not protected by arresters.

Neutral wire height. On any given line, the neutral wire height may vary depending on the equipment connected. On wooden poles, the closer the neutral wire is to the phase wires, the lower the CFO.

Conducting supports and structures. The use of concrete and steel structures on overhead distribution lines is increasing, which greatly reduces the CFO. Metal crossarms and metal hardware are also being used on wooden pole structures. If such hardware is grounded, the effect may be the same as that of an all-metal structure. On such structures, the total CFO is supplied by the insulator, and higher CFO insulators should be used to compensate for the loss of the wooden insulation. Obviously, trade-offs should be made between lightning performance and other considerations such as mechanical design or economics. It is important to realize that trade-offs exist. The designer should be aware of the negative effects that metal hardware may have on lightning performance and attempt to minimize these effects. On wooden pole and crossarm designs, wooden or fiberglass brackets may be used to maintain good insulation levels.

Multiple circuits. Multiple circuits on a pole often cause reduced insulation. Tighter phase clearances and lesser wood in series usually reduces insulation levels.

This is especially true for distribution circuits built underneath transmission circuits on wooden poles. Transmission circuits will often have a shield wire with a ground lead at each pole. The ground lead may cause reduced insulation. This may be improved by moving the ground lead away from the pole with fiberglass spacers.

Spacer-cable circuits. Spacer-cable circuits are overhead distribution circuits with very close spacings. Covered wire and spacers (6 to 15 in. [5 to 40 cm]) hung from a messenger wire provide support and insulating capability. A spacer-cable configuration will have a fixed CFO, generally in the range of 150 to 200 kV. Because of its relatively low insulation level, its lightning performance may be lower than a more traditional open design (Powell et al., 1965). There is little that can be done to increase the CFO of a spacer-cable design.

A spacer-cable design has the advantage of a messenger wire that acts as a shield wire. This may reduce some direct-stroke flashovers. Back flashovers will likely occur because of the low insulation level. Improved grounding will improve lightning performance.

Spark gaps and insulator bonding. Bonding of insulators is sometimes done to prevent lightning-caused damage to wooden poles or crossarms, or it is done to prevent pole-top fires. Spark gaps are also used to prevent lightning damage to wooden material (this includes Rural Electrification Administration specified pole-protection assemblies (REA Bulletin 50-3, 1983)). In some parts of the world, spark gaps are also used instead of arresters for equipment protection.

Spark gaps and insulator bonds will greatly reduce a structure's CFO. If possible, spark gaps, insulator bonds, and pole-protection assemblies should not be used to prevent wood damage. Better solutions for damage to wood and pole fires are local insulator–wood bonds at the base of the insulator.

13.7.3 Shield Wires

Shield wires are effective for transmission lines but are difficult to make work for distribution lines. A shield-wire system works by intercepting all lightning strokes and providing a path to the ground. If the path to the ground is not good enough, a voltage develops on the ground with respect to the phases (called a *ground potential rise*). If this is high enough, the phase can flashover (it is called a *backflashover*).

Grounding and insulation are important. Good grounding reduces the ground potential rise. Extra insulation protects against backflashover. As an example, consider Figure 13.28 where a 22-kA stroke (which is on the small size for lightning) is hitting a distribution line. The ground potential rises to 400 kV relative to the phase conductor, enough voltage to flashover most distribution lines.

To keep the insulation high, use fiberglass standoffs to keep the ground wire away from the pole to maximize the wood length. Also, make sure guy wires and other hardware do not compromise insulation.

Ground the shield wire at each pole. Lightning has such fast rise times that if a pole is not grounded, and a lightning strike hits the shield wire, it will flashover before the grounds at adjacent poles can provide any help in relieving the voltage stress.

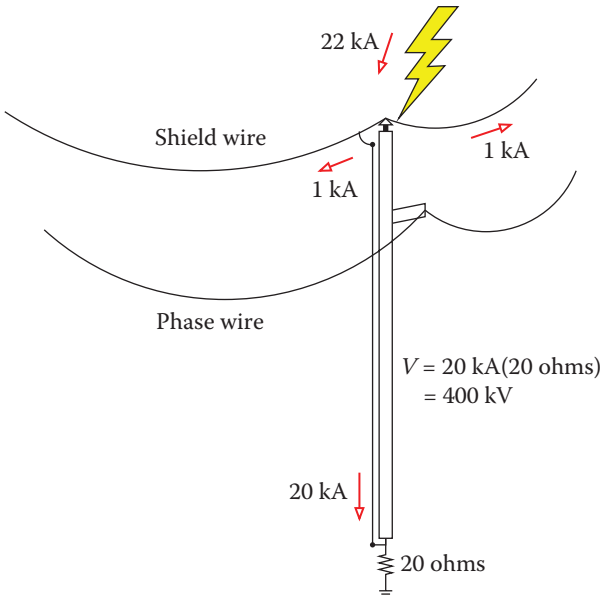


Figure 13.28 Shield-wire lightning protection system.

At all poles, obtain a ground that is 20 Ω or less. Good grounding is vital! The exposed sections of a circuit such as at the top of a hill or ridge should have the most attention. Getting adequate grounds may require

- More than one ground rod. Make sure to keep them spaced further than one ground rod apart
- Deeper ground rods
- Chemical soil treatments
- Counterpoise wires (buried lengths of the wire)

Figure 13.29 shows estimates of performance versus grounding for several insulation levels based on the approach of IEEE Std. 1410-2010. To ensure that lightning hits the shield wire and not the phase conductors, maintain a shielding angle of 45° or less (as defined in Figure 13.30).

13.7.4 Line Protection Arresters

Arresters are normally used to protect equipment. Some utilities are using them to protect lines against faults, interruptions, and voltage sags. To do this, arresters are mounted on poles and attached to each phase. For protection against direct strikes, arresters must be spaced at every pole (or possibly every other pole on structures with high insulation levels) (McDermott et al., 1994). There are a lot of arresters, and the cost prohibits widespread usage. The cost can only be justified for certain sections of the line that affect important customers.

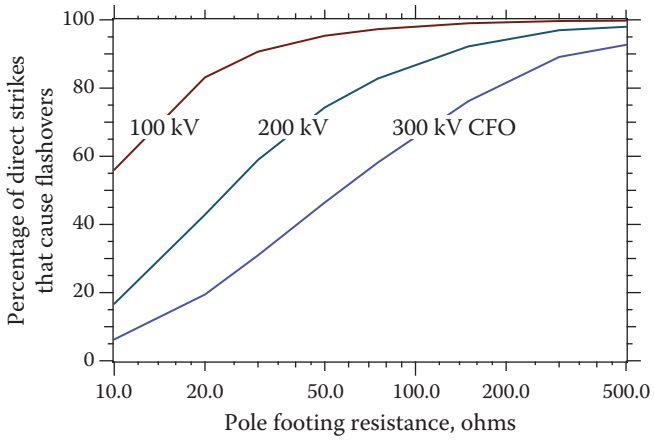


Figure 13.29 Performance of a shield wire depending on grounding and insulation level.

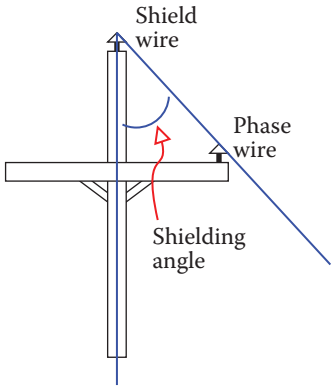


Figure 13.30 Shield wire shielding angle.

Arresters have been used at wider spacings such as every four to six poles by utilities in the southeast for several years. This grew out of some work done in the 1960s by a task force of eight utilities and the General Electric Company (1969a,b). Anecdotal reports suggest improvement, but there is little hard evidence. Recent field monitoring and modeling suggest that this should not be effective for direct strikes. One of the reasons that this may provide some improvement is that arresters at wider spacings improve protection against induced voltages. Nevertheless, arresters applied at a given spacing are not recommended as the first option. Fixing insulation problems or selectively applying arresters at poles with poor insulation are better options for reducing induced voltage flashovers.

For direct strike protection, arresters are needed on all poles and on all phases. The amount of protection quickly drops if wider spacings are used. Lead length is not as much of an issue as it is with equipment protection, but it is always a good practice to keep lead lengths short. The arrester rating would normally be the same as the existing arresters.

Grounding is normally not an overriding concern if arresters are used on all phases. If grounds are poor, one effect is that surges tend to get pushed out away from the strike location (since there is no good path to the ground). One of the implications is if just a section of line is protected (such as an exposed ridge crossing), then grounding at the ends is important. Good grounds at the end provide a path to drain off the surge.

One concern with arresters is that they may have a relatively high failure rate. Direct strikes can cause failures of nearby arresters. Something in the range of 5 to 30% of direct lightning strikes may cause an arrester failure. This is still an undecided (and controversial) subject within the industry. It is recommended that the largest block size available must be used (heavy-duty or intermediate-class blocks) to reduce the probability of failure.

Field trials on Long Island, NY, of arresters at various spacings did not show particularly promising results for distribution line protection arresters (Short and Ammon, 1999). The Long Island Lighting Company (LILCO) added line arresters to three circuits. One had spacings of 10 to 12 spans between arresters (1300 ft, 400 m), one had spacings of five to six spans (600 ft, 200 m), and one had arresters at every pole (130 ft, 40 m). Arresters were added on all three phases. We also monitored two other circuits for comparison. None of the three circuits with line arresters had dramatically better lightning-caused fault rates than the two circuits without arresters. Statistically, we cannot infer much more than this since the data is limited (always a problem with lightning studies). One of the most significant results was that the circuit with arresters on every pole had several lightning-caused interruptions, and theoretically, it should have had none. Missing arresters are the most likely reason for most of the lightning-caused faults. One positive result was that the arrester failure rate was low on the circuit with arresters on every pole.

Automated camera systems captured a few direct flashes to the line during the LILCO study. Figure 13.31 shows a direct stroke almost right at a pole protected by arresters (arresters were every five to six spans on this circuit). Ideally, the arresters on that pole should divert the surge current to the ground without a flashover. The arresters prevented a flashover on that pole, but two of the three insulators flashed over one pole span away. An arrester at the struck pole also failed.

Another field study showed more promise for line arresters. Commonwealth Edison added arresters to several rural, open feeders in Illinois (McDaniel, 2001). ComEd uses an arrester spacing of 1200 ft (360 m); as a trial, they tightened the arrester spacing to 600 ft (180 m) on 30 feeders (and all existing arresters that were not metal oxide were replaced). The 30 feeders with the new spacing were compared to 30 other feeders that were left with the old standard. Over three lightning seasons of evaluation, the upgraded circuits showed that circuit interruptions improved by 16% (at a 95% confidence level). Note that most of the interruptions were transformer fuse operations.

Another way to apply arresters is to use them only on the top phase. The top phase is turned into a shield wire. When lightning hits the top phase, the arrester conducts and provides a low-impedance path to the pole ground. Just as with a shield-wire system, grounding and insulation are critical. A top-phase arrester application cannot be used on typical three-phase crossarm designs because there is no top phase.

Figure 13.31 Lightning-caused fault on a Long Island Lighting Company 13-kV circuit. (Short, T. A. and Ammon, R. H., Monitoring results of the effectiveness of surge arrester spacings on distribution line protection, *IEEE Transactions on Power Delivery*, vol. 14, no. 3, pp. 1142–50, July 1999. © 1999 IEEE.)

In areas where grounding is poor and arrester failure is a concern, arresters can be used with a shield-wire system. The shield wire takes away most of the energy concerns, and the arresters protect against backflashovers. This provides very good lightning protection (and is very expensive).

13.8 Other Considerations

13.8.1 Role of Grounding

With poor grounding, lightning strikes to distribution lines subject more equipment to possibly damaging surges due to ground potential rise. Lightning current must flow to the ground somewhere. If the pole ground near the strike point has high impedance, more of the surge flows in the line, exposing more equipment to possible overvoltages. At the point of a direct stroke to a distribution conductor, the huge voltages flash over the insulation, shorting the phase to the neutral. From there, the lightning travels to the closest ground. If there is no proper pole ground nearby, the next most likely path is down a guy wire. If the path to the ground is poor, the phase conductor and neutral wire all rise up in voltage together. This surge (on both the phase and neutral) travels down the circuit. When the surge reaches another ground point, current drains off

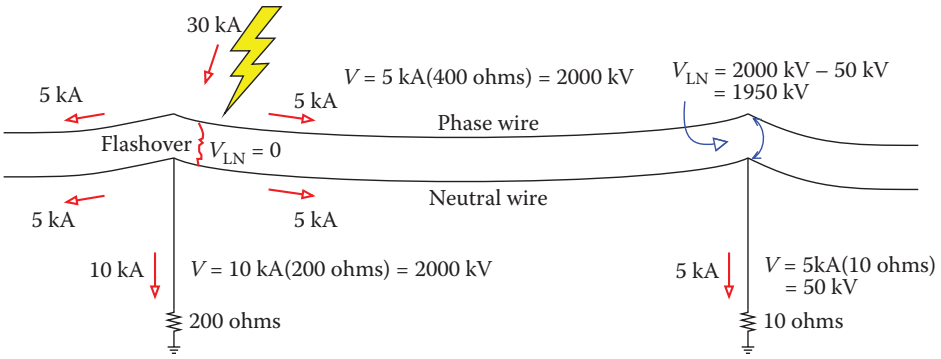


Figure 13.32 Impact of grounding.

the neutral wire, which increases the voltage between the phase and the neutral. The voltage across the insulation grows until a surge arrester conducts more current to the ground or another insulation flashover occurs. Figure 13.32 shows a drawing describing the ground potential effect, and Figure 13.1 shows a photograph of a direct strike that caused another flashover remote from the flash point.

Good grounding helps confine possible lightning damage to the immediate vicinity of the strike. If the distribution insulation flashes over, the short circuit acts as an arrester and helps protect other equipment on the circuit (as long as grounds are good). With poor grounding, a single direct strike can cause multiple flashovers (see Figure 13.33).

Normally, the ground resistance right at a piece of equipment protected with an arrester does not impact the primary-side protection of that piece of equipment. The primary surge arrester is between the phase and ground. For a lightning hit to the primary, the arrester conducts the current to the ground and limits the voltage across the equipment insulation (even though the potential of all conductors may rise with poor grounding). The important factor for stresses on equipment farther from the strike location is the ground potential rise and the resistances of grounds in the near vicinity of the strike.

Grounding plays a role for transformers, as they are vulnerable to surge current entering through the secondary. Poor grounding pushes more current into the transformer on the secondary side and increases the possibility of failure. Poor grounding also forces more current to flow into the secondary system to houses connected to the transformer. And, poor grounding may also push more current into telephone and cable television systems.

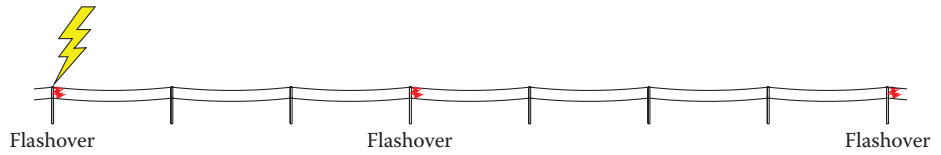


Figure 13.33 Cascading flashovers.

13.8.2 Burndowns

The lightning arc itself can pass enough charge to burn small primary and secondary wires although sometimes, it is hard to tell whether it is the lightning or the fault arc that does most of the damage. Normally, it is the power-frequency arc that does the most damage. Chisholm et al. (2001) cites a damage rate on Hydro-One's primary distribution system of 0.13/100 mi/year (0.08/100 km/year) for an area with a GFD of about 1 flash/km^2/year. This is about 1% of the lightning flashes hitting circuits.

The lightning arc causes damage the same way that a fault current arc (and also an arc welder) does: the heat of the arc melts conductor strands. Damage is mainly a function of the charge in the flash. Lightning tends to be more damaging than the equivalent ac fault arc. A negative direct current is about 50% more damaging than an ac passing equal coulombs. Negative flashes are more destructive than positive flashes; it takes about 3 times the charge for a positive stroke to cause the same damage as a negative stroke. Lightning also tends to stay in one place more than an arc because it does not have the motoring effect.

13.8.3 Crossarm and Pole Damage and Bonding

Although service experience indicates that lightning rarely damages wood poles or crossarms; in high-lightning areas, concern is warranted. Darveniza (1980) cites a survey by Zastrow published in 1966 that found poles failing from lightning in the range of 0.008 to 0.023% annually (versus an overall failure rate of 0.344 to 1.074% with more than half of these due to decay). Other surveys summarized by Darveniza also found minimal lightning-caused damage. Lightning overvoltages damage and shatter poles and crossarms when the wood breaks down internally rather than along the surface. If the wood is green and wet, and the surface is dry, internal breakdowns and damage are more likely. Damage within the first year of service is more likely. With an internal flashover, shattering can occur from the fault current that follows the breakdown caused by the voltage impulse. Near-surface flashovers are more common than internal flashover. Figure 13.34 shows examples of damage from near-surface flashovers. External flashovers followed by fault current can leave carbon deposits, but these are unlikely to cause mechanical damage.

If historical records show that wood damage is a problem, bonding the insulators (grounding the base of each insulator) protects the wood, but this shorts out the insulation capability provided by the wood. Better are surface electrodes fitted near the insulator pin, including wire wraps, bands, or other metal extensions attached near the insulator in the likely direction of flashover. This local bonding encourages breakdown near the surface rather than internally.

Preventative measures for lightning damage to wood also reduce the likelihood of pole-top fires. Leakage current arcs at metal-to-wood interfaces start fires (Darveniza, 1980; Ross, 1947). Local bonding using wire bands or wraps helps prevent pole damage. Bonding bridges the metal-to-wood contacts where fires are most likely to start.

Figure 13.34 Near-surface damage from impulses. (From EPRI 1021995, *Distribution Composite Crossarm Laboratory Testing*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright © 2011. Reprinted with permission.)

Local bonding is better than completely bonding the insulators because the insulation level is not compromised.

Composite crossarms with a fiberglass shell can have internal breakdowns from impulse overvoltages in dry conditions. This breakdown mode can lead to serious mechanical damage from fault current that flows after the initial flashover (EPRI 1021995, 2011). Figure 13.35 shows an example of a crossarm rupturing from internal fault current. As with wood, it may be possible to influence preferred flashover paths. In the EPRI tests, samples mounted with a center-mounting bracket had only external flashovers. This mounting bracket sandwiches the crossarm with conducting plates (see Figure 13.36) and seems to act like the local bonding described above. Samples that were mounted with a single through-bolt were susceptible to internal flashover paths. The EPRI tests also found that external flashovers may be more detrimental to composite crossarms than to wood crossarms. Carbon deposits left by arcing may lead to tracking and make the arm more susceptible to ultraviolet light degradation and water ingress.

13.8.4 Arc Quenching of Wood

Wood poles and crossarms can prevent faults from forming after lightning flashes across the wood (Armstrong et al., 1967; Darveniza et al., 1967). Whether this arc quenching occurs mainly depends on the power-frequency voltage gradient along the arc at the time of the flashover. If the power-frequency voltage happens to be near a zero crossing when the lightning strikes, the lightning-caused arc is likely to extinguish rather than become a power-frequency fault.

The voltage gradient for an arc inside wood is much higher than an arc voltage gradient in air. Darveniza (1980) found voltage gradients in wood on the order of 1000 V/in. (400 V/cm) through wood compared to about 30 V/in. (12 V/cm) for arcs in air. When dry wood insulation arcs, the path is often just barely below the surface (about a millimeter), and the arc is surrounded by wood fibers, so the arc-suppression

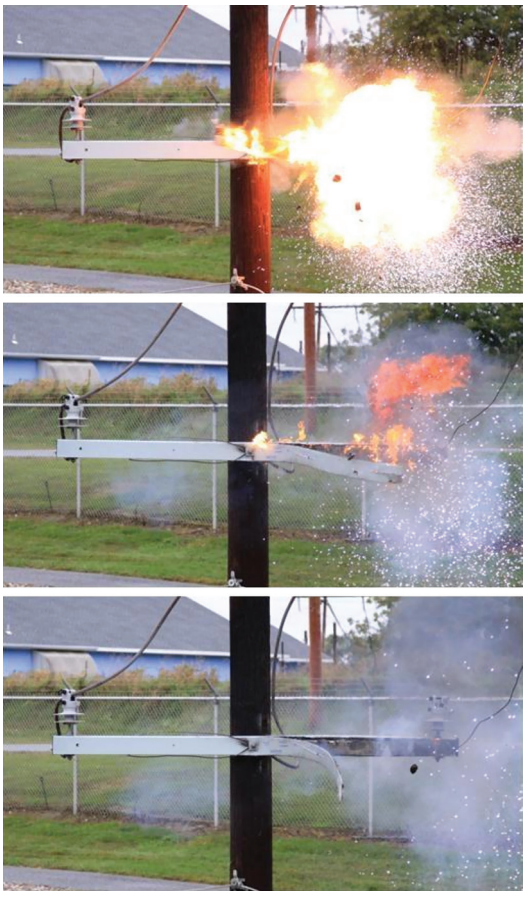
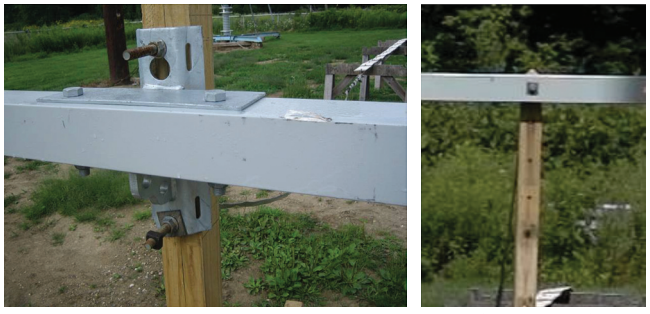


Figure 13.35 Rupture of a composite crossarm from internal fault current. (From EPRI 1021995, *Distribution Composite Crossarm Laboratory Testing*, Electric Power Research Institute, Palo Alto, CA, 2011. Reprinted with permission.)



Center mounting bracket

Through-bolt attachment

Figure 13.36 Composite crossarm attachments. (From EPRI 1021995, *Distribution Composite Crossarm Laboratory Testing*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright © 2011. Reprinted with permission.)

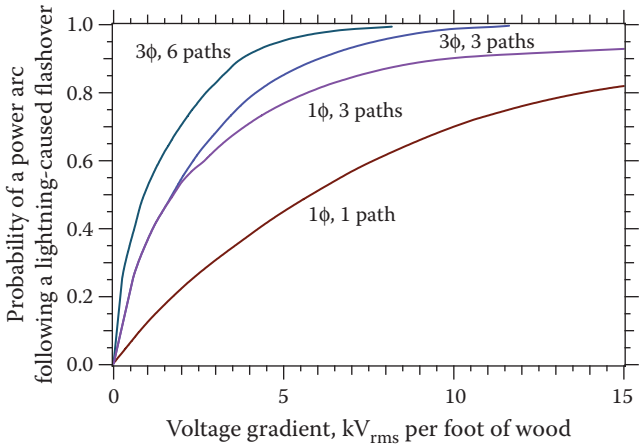


Figure 13.37 Probability of a power-frequency fault due to a lightning-caused flashover over wet wood crossarms with different numbers of flashover paths. (Adapted from Darveniza, M., *Electrical Properties of Wood and Line Design*, University of Queensland Press, 1980. With permission.)

action occurs. Wood fibers raise the arc voltage primarily by cooling it and absorbing ionized particles (similar to the arc-absorbing action of fuses). The arc voltage gradient is lower for wet wood (flashovers are no longer fully contained and tend to arc on the surface rather than just below the surface). There is considerable variability in the arc voltage, especially for wet wood. To transition from a lightning arc to a power-frequency fault, the power-frequency voltage must be higher than the arc voltage to keep the arc conducting.

Darveniza calculated several probabilities for arc quenching based on the arc voltage gradients (see Figure 13.37). Arc quenching is less likely on wet wood and when multiple phases flashover (even if the flashovers are on the same phase). To achieve significant benefit, voltage gradients must be kept less than 3 kV/ft (10 kV/m) of wood. For a 12.47Y/7.2-kV system, this is at least 2.4 ft (7.2/3 = 2.4 ft or 0.7 m) of wood in the phase-to-ground flashover paths and at least 4.1 ft (1.2 m) of wood in the phase-to-phase flashover paths. And, if we really want to count on this effect, we should at least double these lengths. Arc quenching is most likely on single-phase lines because only one phase is involved and wood distances are relatively long.

13.8.5 Protection of Distribution Equipment Controllers and Instrumentation

Pole-mounted controllers for regulators, reclosers, capacitors, and switches face particularly severe environments. Pole-mounted data acquisition faces similar stresses. Because of their location, they have significant exposure to transients from lightning strikes to nearby poles. Some utilities have had reliability problems with

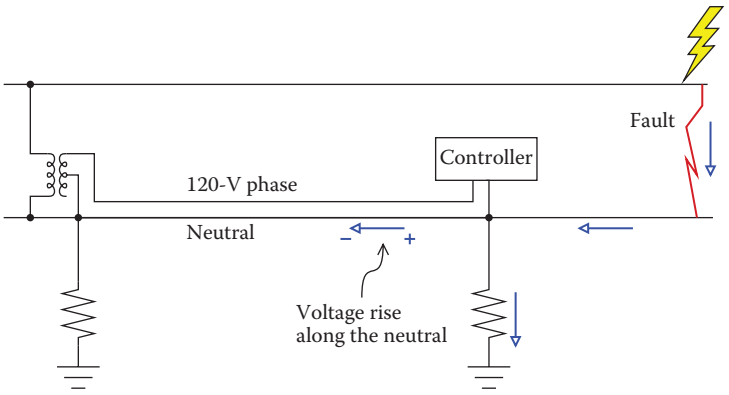


Figure 13.38 Pole-mounted controller exposure to nearby lightning.

controllers; some problems may stem from poor powering and grounding arrangements. Figure 13.38 shows how significant voltages can develop on the low-voltage supply when the power is supplied at a remote pole and a nearby lightning strike occurs. Additionally, two-port vulnerabilities can arise between the controller power and PTs. Other sources of two-port problems are current transformers and communication lines.

To help avoid two-port problems, power the controller from a PT or small transformer on the same structure as the controller. For existing installations where power is supplied remotely, add secondary surge protection at the controller. Also consider floating the secondary neutral in the control power enclosure (it is still connected to the multigrounded neutral at the remote power source location). Floating the secondary neutral may not be possible with all controllers. Flashovers could still happen between the floating neutral and the local ground, and if that happens, current through the ground loop will drive voltage differences between the now-grounded neutral and the secondary supply conductors. Note that even with the neutral floated, the controller enclosure should still be grounded for safety. Another option is to connect the secondary neutral to the local ground through a surge arrester.

Powering the controller from a small control power transformer on the same pole greatly reduces lengths of ground loops. Even with everything on one pole, a ground loop can still exist as shown in Figure 13.39. In high-lightning areas, additional protection may be warranted even with a control power transformer on the same pole. As with the remote power scenario, options include extra surge protection for the controller and floating the neutral connection inside the control box.

A shielded control cable will protect against ground lead effects. A shielded control cable will eliminate inductive coupling from current flow through the controller neutral and block capacitively coupled voltages. The shield of the cable serves as the neutral conductor with both ends of the shield bonded to the pole ground. See Figure 13.40 for an example of a capacitor controller.

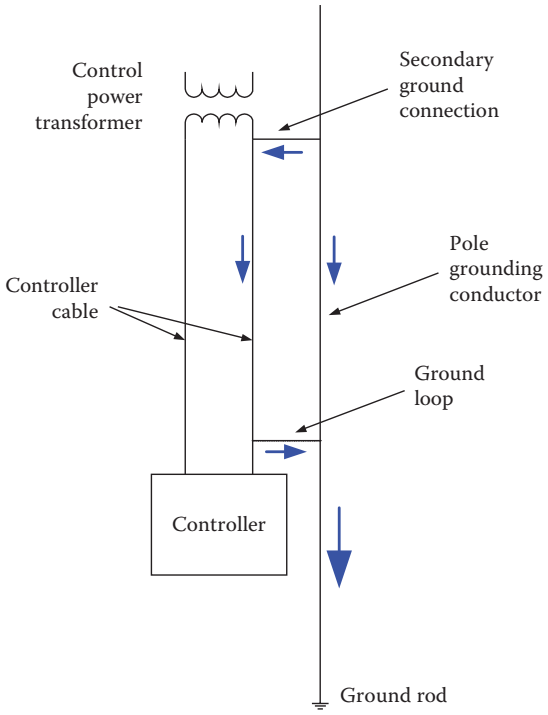


Figure 13.39 Ground loop with a local control power transformer. (From EPRI 1008573, *Grounding and Lightning Protection of Capacitor Controllers*, Electric Power Research Institute, Palo Alto, CA, 2005. Copyright © 2005. Reprinted with permission.)

For detailed evaluations and transient simulations for various control power arrangements and protection approaches, see EPRI 1008573 (2005) and/or Crudele et al. (2006).

Secondary surge arresters provide the most benefit where applied. For example, a surge arrester at the terminals of a control power transformer will protect that transformer, but this arrester will not appreciably improve the protection of the controller at the other end of the control power leads, especially if a ground loop is involved. As with primary primary-side surge protection, lead lengths should be kept short, except now, short is measured in inches (cm), not feet. For the controller, the best location for surge protection is inside the controller. Check with the controller manufacturer to make sure any extra protection added coordinates with internal controller protection; adding external protection would not help if an internal arrester has a lower discharge voltage that pulls in the surge current. The best surge protection involves protecting against all modes of voltage differences, including incoming control wiring from voltage or current sensors, switches, recloser or regulator signal leads, and antennas. Whether control power is on the pole or provided remotely, better pole grounding helps reduce surge magnitudes at the controller.

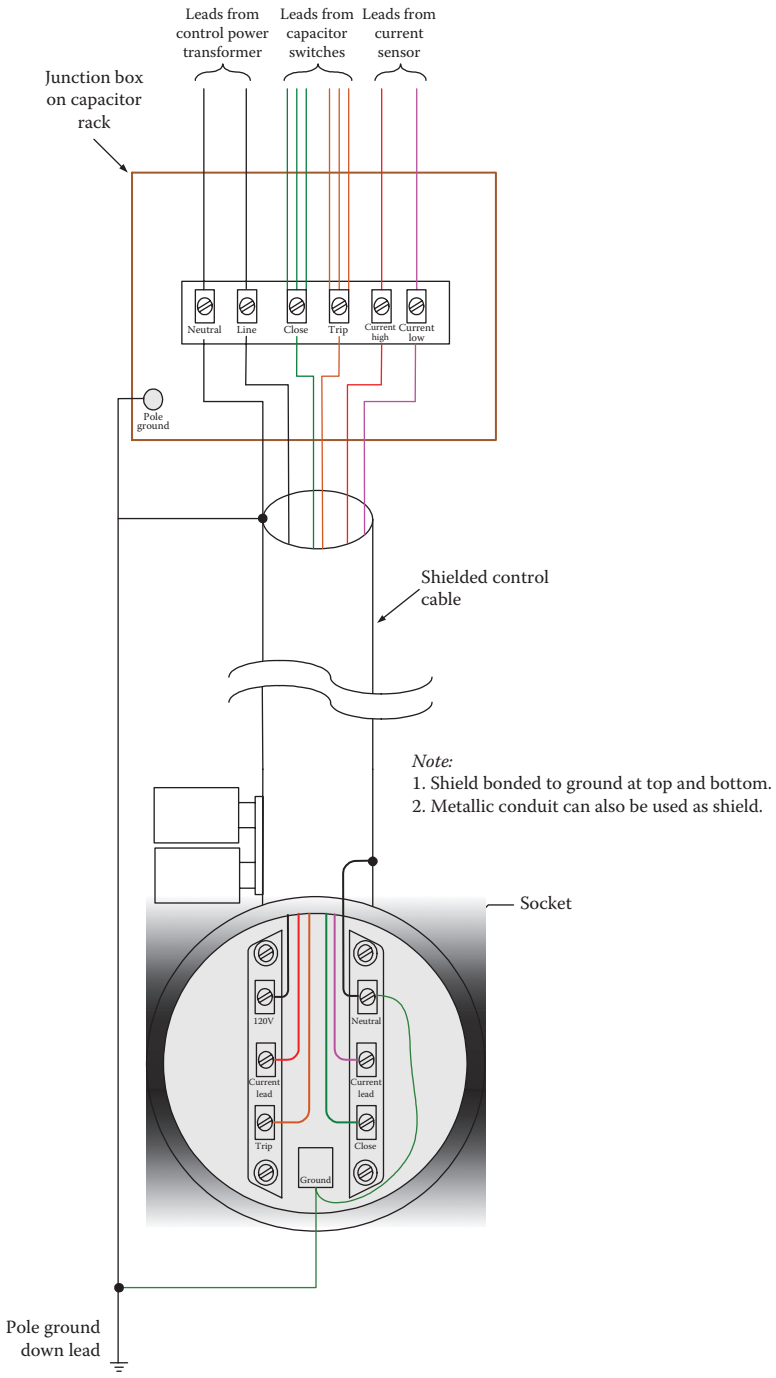


Figure 13.40 Capacitor controller with a shielded control cable. (From EPRI 1008573, *Grounding and Lightning Protection of Capacitor Controllers*, Electric Power Research Institute, Palo Alto, CA, 2005. Copyright © 2005. Reprinted with permission.)

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Check the top of your arrester and make sure you have the proper size for the voltage. Sometimes they look alike. Don't assume, it ain't good for your Fruit of the Looms.

Anonymous poster, on a near miss when a 3-kV arrester was mistakenly installed instead of a 10-kV arrester (7.2 kV line to ground)

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14

Grounding and Safety

Contents

14.1 System Grounding Configurations 726
14.1.1 Four-Wire Multigrounded Systems 726
14.1.2 Other Grounding Configurations 727
14.2 System Grounding and Neutral Shifts during Ground Faults 729
14.2.1 Neutral Shifts on Multigrounded Systems 731
14.2.2 Neutral Reactor 736
14.2.3 Overvoltages on Urban Underground Systems 737
14.2.4 Overvoltages on Ungrounded Systems 739
14.3 Equipment/Customer Grounding 741
14.3.1 Special Considerations on Ungrounded Systems 742
14.3.2 Secondary Grounding Problems 742
14.4 Ground Rods and Other Grounding Electrodes 743
14.4.1 Soil Characteristics 745
14.4.2 Corrosion and Grounding Electrodes 748
14.4.3 Resistance Measurements 751
14.5 Shocks and Stray Voltages 753
14.5.1 Biological Models 753
14.5.2 Step-and-Touch Potentials 756
14.5.3 Elevated Neutral-to-Earth Voltages 759
14.5.4 Contact Voltages 763
14.5.5 Tree Contacts 766
14.6 Protective Grounding and Personnel Protection 771
14.7 Manhole Explosions 775
14.8 Arc Flash 778
References 791

Grounding is one of the main defenses against hazardous electric shocks and hazardous overvoltages. Good equipment grounding helps reduce the chances that line workers and the public get shocks from internal failures of the equipment. System grounding determines how loads are connected and how line-to-ground faults are cleared. Most North American distribution systems have effective grounding; they have a neutral that acts as a return conductor and as an equipment safety ground.

14.1 System Grounding Configurations

14.1.1 Four-Wire Multigrounded Systems

There are several grounding configurations for three-phase power distribution systems. On distribution systems in North America, the four-wire, multigrounded neutral system predominates. Figure 14.1 shows how loads normally connect to the four-wire system. One phase and the neutral supply single-phase loads. The neutral carries unbalanced current and provides a safety ground for equipment. Low cost for supplying single-phase loads is a major reason why the four-wire system evolved in North America. More than half of most distribution systems consist of single-phase circuits, and most customers are single phase. On a multigrounded neutral system, the earth serves as a return conductor for part of the unbalanced current during normal and fault conditions.

Four-wire multigrounded systems have several advantages over three-wire systems. Four-wire systems provide low cost for serving single-phase loads:

- Single cables for underground single-phase load (and potheads and elbows and pad-mounted transformer bushings)
- Single-phase overhead lines are less expensive
- Single-bushing transformers
- One arrester and one fuse for a single-phase transformer
- The neutral can be located lower on the pole
- Lower rated arresters
- Lower insulation required; transformer insulation can be graded

Extensive use of single-phase lines provides significant cost savings. The primary neutral may be shared with the secondary neutral for further cost savings. And

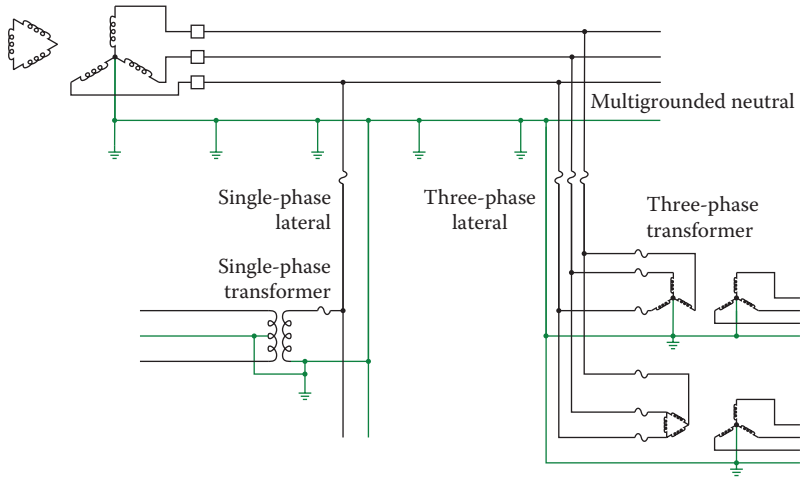

Figure 14.1 A four-wire multigrounded distribution system.

flexibility increases: upgrading a single-phase line to two- or three-phase service on overhead lines is a cost-effective way to upgrade a circuit following load growth.

Safety. The multigrounded neutral provides significant safety benefits for crews and end users. If a transformer pole-ground down lead gets broken, little safety margin is lost. With the transformer still connected to the multigrounded neutral, there is still a low-impedance path to earth, which protects against internal faults in the transformer.

The underbuilt neutral also partially blocks access to the phase conductors (to ladders or bucket trucks). It warns crews that high-voltage phase conductors are overhead. And, if a phase wire breaks, there is a good chance that it will contact the neutral as it falls (if the neutral does not catch it, it might result in a high-impedance fault).

The substation transformer normally provides the grounding source, the low-impedance path to zero sequence. On circuits converted from an ungrounded configuration to a grounded configuration, a grounding transformer, usually a zig-zag transformer, may provide the zero-sequence source, so a neutral can be added. A grounding transformer must not be disconnected during the operation of the distribution line. If the grounding transformer becomes disconnected, a single line-to-ground fault causes high overvoltages on the unfaulted phases. Load unbalances may also create overvoltages if the grounding transformer is disconnected.

14.1.2 Other Grounding Configurations

Most other distribution configurations are three-wire systems, either grounded or ungrounded. Figure 14.2 shows a three-wire unigrounded service. A unigrounded system is grounded at one place, normally the substation. Many older distribution systems are three-wire systems, including 2400-, 4160-, and 4800-V systems. Many utilities have portions of these circuits that are holdovers from installations in the

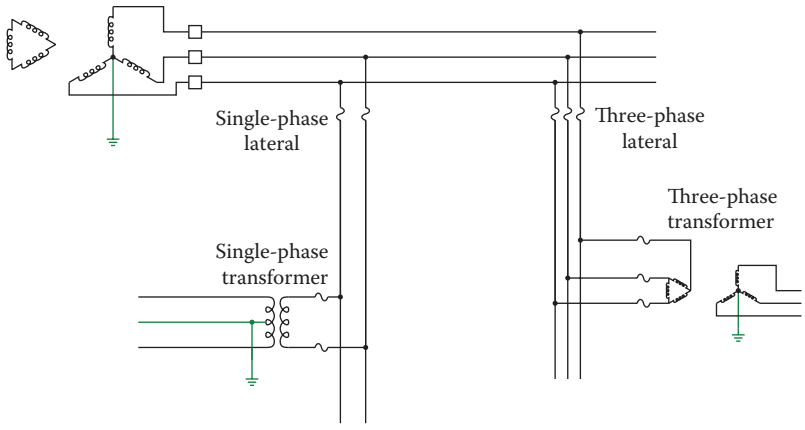

Figure 14.2 A three-wire unigrounded distribution system.

1920s to the 1940s. Whether unigrounded or ungrounded, three-wire systems have the following advantages:

- Lower cost for three-phase loads
- Lower stray voltage
- Easier detection of high-impedance faults
- Lower magnetic fields

European distribution designs are normally three-wire systems. All load is three phase or phase-to-phase connected, so there is no need for a neutral. But without the neutral, these systems must do without the multigrounded safety ground. Most European designs make up for the lack of a multigrounded primary ground by having a multigrounded secondary neutral, which is grounded at equipment and at each customer. Since European designs tend to have extensive secondary systems and many houses on each transformer, the secondary ground provides a safe grounding conductor.

Some parts of the world use a *single-wire earth-return* (SWER) distribution system. The earth can carry all of the return current. On earth-return systems, the resistance of ground electrodes is critical. Poor ground connections can cause low end-use voltage and create very dangerous step-and-touch potentials to the transformer tank. The single-wire system is used extensively in Australia to serve remote rural customers with single-phase service; a high primary voltage (33 kV) is normally used, which keeps currents low. Note that the National Electrical Safety Code (NESC) (IEEE C2-2012) does not allow an earth-return system; it prohibits using the earth as the sole conductor for any part of the circuit.

Other types of grounding such as high-resistance grounding or high-reactance grounding are rarely used on distribution circuits. European systems occasionally use a three-wire *resonant*-grounded system, where the substation transformer neutral is grounded through a tapped reactor (Peterson coil). The coil is tuned to cancel the line-to-ground capacitance. It is an ungrounded system. The main advantage is that it can operate with one phase faulted. On overhead distribution circuits, the main advantage is that temporary faults clear by themselves without opening a breaker or recloser. Without the tuning reactor, the capacitance creates enough current to maintain the fault arc (especially with cables). In the past, it was hard to keep the reactor in tune with the system capacitance. Clerfeuille et al. (1997) describe a resonant grounding distribution system that uses an adaptively tuned reactor that continuously maintains proper tuning.

The five-wire design is a new approach that may reduce stray voltage and magnetic fields and also make high-impedance faults more easily detectable. The fifth wire is an isolated neutral that carries all of the unbalanced return current. Under normal conditions, the five-wire design operates very similar to the four-wire design with one major exception: all the return current is confined to the neutral that is isolated from ground. The multigrounded ground wire continues to perform the safety functions associated with a multigrounded system. New York State Electric and Gas (NYSEG) converted a section of circuit to a five-wire configuration as a research project, and monitoring results showed reduction in stray voltage and magnetic fields along with promising

results that high-impedance faults could be detected (EPRI 1000074, 2000; Short et al., 2002). Challenges found during the project were interfacing between the standard four-wire section and the five-wire section, how to insulate the fifth wire, surge protection on the fifth wire, how to protect against an open neutral, and crew acceptance. Increased cost of the five-wire system would also factor in any real installation.

14.2 System Grounding and Neutral Shifts during Ground Faults

The system grounding configuration determines the overvoltages that can occur during a line-to-ground fault. A single line-to-ground fault shifts the ground potential at the fault location. The severity of this ground reference shift depends on the grounding configuration (see Figure 14.3). On a solidly grounded system with a good return path to the grounding source, little reference shift occurs. On an ungrounded system, a full offset occurs—the line-to-ground voltage on the unfaulted phases rises to the line-to-line voltage, 1.73 per unit. On a multigrounded distribution system with a solidly grounded station transformer, overvoltages above 1.3 per unit are rare.

Two factors relate the overvoltage to the system voltage:

Coefficient of grounding:

$$\text{COG} = V'_{\text{LN}}/V_{\text{LL}}$$

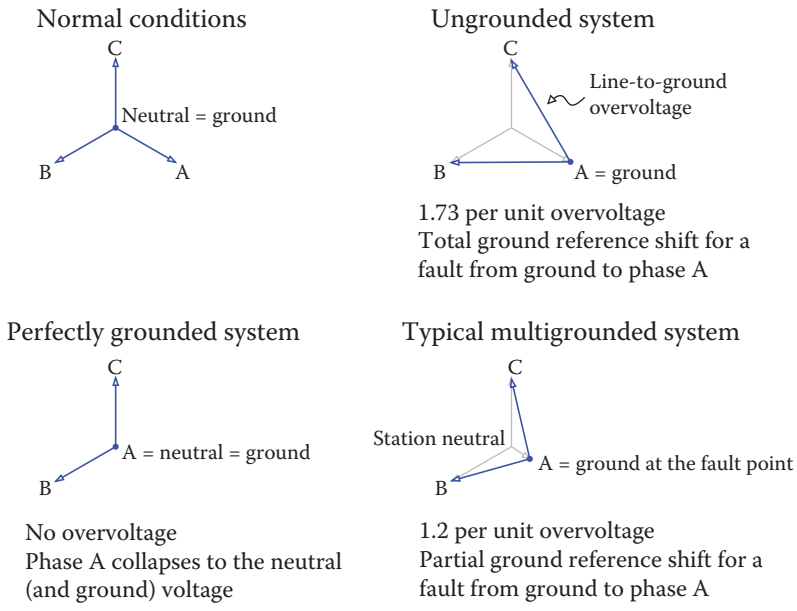

Figure 14.3 Ground potential shifts and overvoltages depending on the grounding configuration.

Earth fault factor:

$$\text{EFF} = V'_{\text{LN}} / V_{\text{LN}}$$

where

V'_{LN} = maximum line-to-ground voltage on the unfaulted phases during a fault from one or more phases to ground

$V_{\text{LN}}, V_{\text{LL}}$ = nominal line-to-neutral and line-to-line voltages

A system is "effectively grounded" if the coefficient of grounding is less than or equal to 80% (the earth fault factor is less than 138%) (ANSI/IEEE C62.92-1987). This is met approximately with the following conditions:

$$X_0/X_1 < 3$$

$$R_0/X_1 < 1$$

For a single line-to-ground fault on phase A, the voltages on phases B and C are

$$V_b = \left(a^2 + \frac{Z_1 - Z_0}{2Z_1 + Z_0 + 3R_F} \right) E$$

$$V_c = \left(a + \frac{Z_1 - Z_0}{2Z_1 + Z_0 + 3R_F} \right) E$$

where

Z_1 = positive-sequence impedance

Z_0 = zero-sequence impedance

$a = 1\angle 120°$

R_F = fault resistance

E = line-to-neutral voltage magnitude prior to the fault

For a double line-to-ground fault, the voltage on the unfaulted phase is

$$V = \frac{3Z_0 + 6R_F}{Z_1 + 2Z_0 + 6R_F} E$$

In some cases, the double line-to-ground fault causes overvoltages that are slightly higher than the single line-to-ground fault. But since single line-to-ground faults are so much more common, we often design for the single line-to-ground fault. For single line-to-ground faults, the voltage is always worse with the fault impedance $R_F = 0$. For double line-to-ground faults, it may not always be worse with $R_F = 0$. Figure 14.4 shows overvoltage charts as a function of X_0/X_1 and R_0/X_1. This includes overvoltages due to single line-to-ground faults and for double line-to-ground faults (assuming that $R_F = 0$).

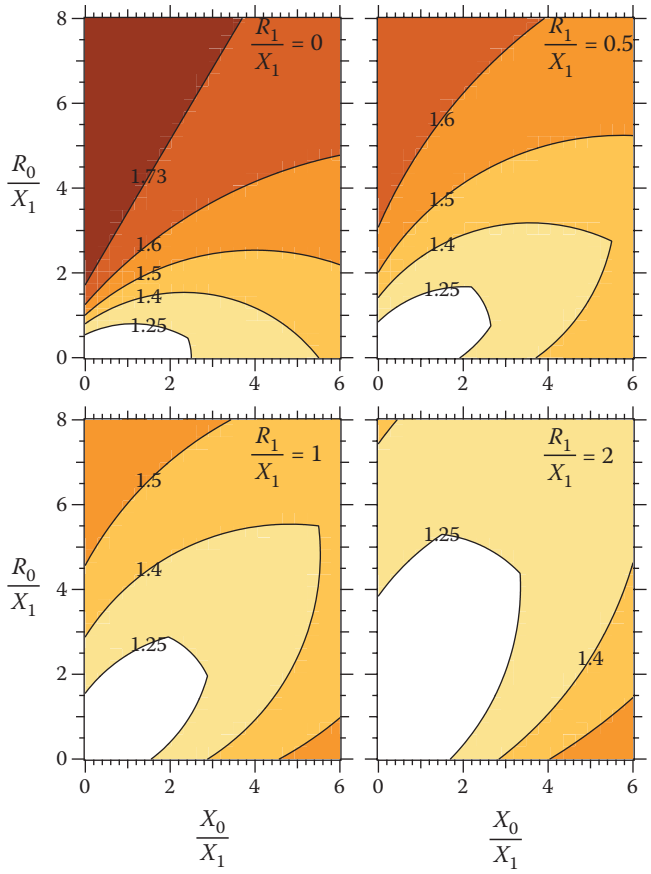

Figure 14.4 Maximum overvoltages in per unit for line-to-ground faults based on X_0/X_1 and R_0/X_1 (the contours mark the threshold of voltage).

IEEE suggests the overvoltage multiplier factors for different systems shown in Table 14.1 (IEEE C62.92.4-1991). The multipliers include the neutral shift during line-to-ground faults at a voltage of 105% (so, the ungrounded system has an overvoltage of $1.73 \times 1.05 = 1.82$).

The higher overvoltage factor of 1.35 for multigrounded systems with metal-oxide arresters was identified as a more conservative factor for four-wire systems because of the reduced saturation of newer transformers and use of metal-oxide arresters (they are always connected, so they are more sensitive to overvoltages than older arresters, which have an isolating gap).

14.2.1 Neutral Shifts on Multigrounded Systems

On four-wire systems with a multigrounded neutral, standard short-circuit calculation programs calculate overvoltages incorrectly. The problem is not symmetrical

TABLE 14.1 Overvoltage Factors for Different Grounding Systems

System	Overvoltage Factor
Ungrounded system	1.82
Four-wire multigrounded system (spacer cable)	1.5
Three- or four-wire unigrounded system (open wire)	1.4
Four-wire multigrounded system (open wire; gapped arrester)	1.25
Four-wire multigrounded system (open wire; metal-oxide arrester)	1.35

Source: Data from IEEE C62.92.4-1991, *IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part IV—Distribution*.

components; the problem is with the impedance of the return path, the zero-sequence impedance. When the impedance of the neutral is rolled into the zero-sequence impedance, the neutral is modeled as being perfectly grounded; ground resistances are ignored.

Assuming the neutral is perfectly grounded incorrectly models overvoltages. Lat (1990) analyzed overvoltages with several techniques and found that the traditional calculation method has serious shortcomings versus modeling each ground and line section separately. We need to model each line section between grounds as shown in Figure 14.5. Standard short-circuit programs would not model this detail; we need a flexible steady-state analysis program such as EMTP.

Lat's analysis and additional work by Mancao et al. (1993) showed several interesting findings:

- *Fault location*—Overvoltages are highest for faults near the substation. This contradicts the common belief that the highest overvoltages are for faults at the end of the circuit (based on the standard symmetrical components method).
- *Feeder length*—Overvoltages are higher on shorter feeders (assuming the same number of grounds per unit length, see Figure 14.6). The ground return path has a higher impedance on shorter lines because there are fewer grounds beyond the fault location.
- *Neutral size*—A larger neutral provides a better return path.
- *Ground rod resistance and number of ground rods*—More ground rods and lower rod resistances reduce overvoltages (see Figure 14.7). But the results are not particularly sensitive to ground rod resistance values.

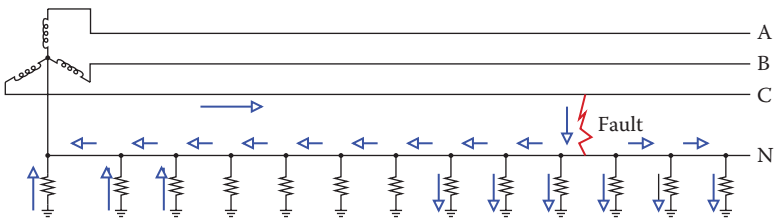

Figure 14.5 Fault current paths for a line-to-ground fault.

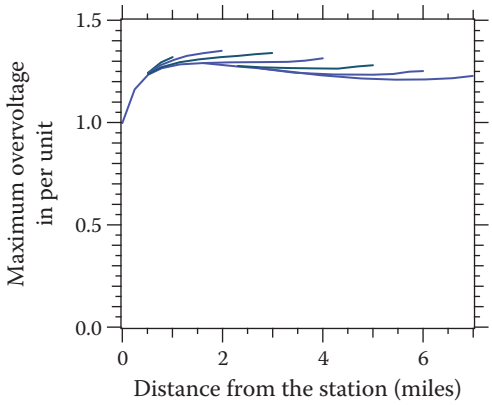

Figure 14.6 Overvoltages for different fault locations on feeders of different lengths. 3/0 ACSR phase conductors, 1/0 ACSR neutral, 4-ft (1.2-m) spacings, four 25-Ω grounds/mile (normally, there are many more grounds than this). (Adapted from Lat, M. V., *IEEE Transactions on Power Delivery*, vol. 5, no. 2, pp. 936–46, April 1990. Copyright 1990 IEEE. With permission.)

- *Neutral reactor*—A neutral reactor on the substation transformer causes a higher overvoltage, mainly for faults near the station.

Hydro Quebec staged faults on rural circuits and measured the neutral voltages and currents (Rajotte et al., 1995). The measured neutral offsets compared very well with simulations done with Lat's modeling approach. But they compared well only if customer's grounds were modeled. On this circuit, the customer grounds contributed more to grounding the line than the utility ground rods. There were

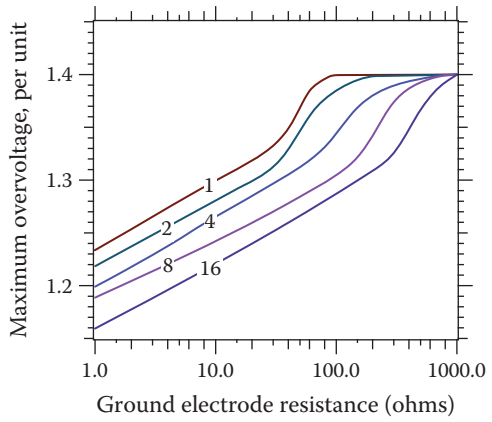

Figure 14.7 Effect of ground rod resistance and spacings. Each curve is labeled with the number of grounds per mile. (Adapted from Lat, M. V., *IEEE Transactions on Power Delivery*, vol. 5, no. 2, pp. 936–46, April 1990. Copyright 1990 IEEE. With permission.)

three times more customer ground rods, and their average resistance was almost eight times lower. It is not unusual for customer grounds to be better than utility grounds, as customer grounds are often tied to water pipes and wells. More extensive measurements of ground rods and customer grounds on 16 rural feeders found an equivalent of 47 Ω for ground rods and 16 Ω for customer ground connections (these equivalents are the inverse of the average admittance) (Rajotte et al., 1995).

If the neutral conductor breaks, overvoltages are much higher. Mancao et al. (1993) found overvoltages as high as 1.58 per unit on simulated systems for faults downstream of an open point in the neutral. The worst case is for a fault just past the break, but even a fault several miles from the open point causes higher than normal overvoltages.

Figure 14.8 shows simulated divisions of current for several neutral sizes for a fault near the end of the circuit. Near a line-to-ground fault, most of the current is in the neutral. In the middle, more flows through the earth. Near the station, additional current returns to the neutral. And, some current returns via grounds beyond the fault location. Larger neutrals carry more return current.

An IEEE Working Group (1972) stated that transformer saturation holds down overvoltages based on transient network analyzer evaluations. But others disagree. Field tests found that saturation did not lower the peak voltage (Rajotte et al., 1995). A transformer core saturates when the flux is highest. The flux is 90° out of phase with the voltage. The peak flux occurs when the voltage crosses through zero. So, when a transformer saturates, it distorts the voltage but does not appreciably limit the peak voltage.

Normally, the highest overvoltages are for single line-to-ground faults, but in some cases slightly higher overvoltages occur for double line-to-ground faults. These cases normally involve large conductors (high *X/R*).

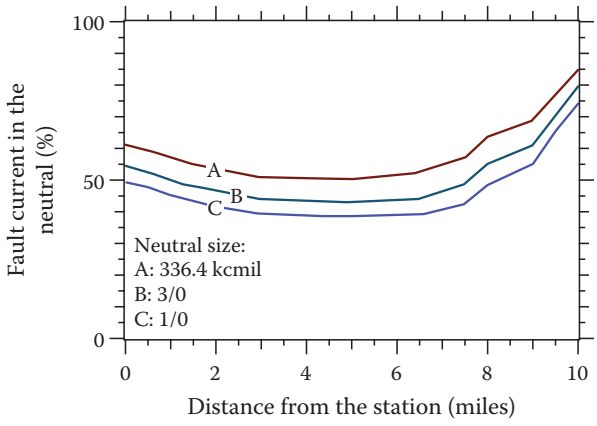

Figure 14.8 Division of fault current between the neutral and earth. Armless construction, 336-kcmil phase conductors, four 25-Ω grounds per mile. (Adapted from Mancao, R. T., Burke, J. J., and Myers, A., *IEEE Transactions on Power Delivery*, vol. 8, no. 1, pp. 139–45, January 1993. Copyright 1993 IEEE. With permission.)

Spacer cable systems have higher overvoltages because of the messenger wire (not because of the tighter phase and neutral spacings). An IEEE Working Group (1972) found overvoltages between 1.36 and 1.45 per unit with spacer cable having a 5/16-in. or 3/8-in. copperweld messenger with a 30% conductivity. If a spacer cable uses a lower-resistivity messenger or has a separate neutral, overvoltages are similar to those of open-wire configurations. ESEERCO (1992) simulated different spacer cable configurations and found overvoltages of about 1.5 per unit on configurations with just a 3/8-in. copperweld messenger. With a 1/0 ACSR neutral added to the spacer cable, the overvoltages dropped to 1.3 per unit.

Underground cables normally have lower overvoltages. Rajotte et al. (1990) simulated overhead and underground systems and found that the neutral shift was a factor of 10 lower on underground systems. Urban locations, whether overhead or underground, have many more grounds, so overvoltages and other grounding issues such as stray voltage are less likely.

However, circuits of cables with tape shields or lead sheaths can have significantly higher overvoltages. On these cables, the tape shields have very high resistance. Figure 14.9 shows how the overvoltage on the unfaulted phases increases with distance of the fault from the substation for an example scenario. This example assumes that the sheath is perfectly grounded. If poorly grounded, more current will return through the high-resistance sheath and increase the overvoltage. Utilities normally use tape shield or lead sheathed power cables in urban areas where distances are fortunately short. The high resistance also contributes to transients; the *X/R* ratio is low enough that faults often spark and cause transients at each zero crossing. In a resistive circuit, when the arc clears at a zero crossing, the voltage builds up slowly, which delays the arc breakdown. When the arc does

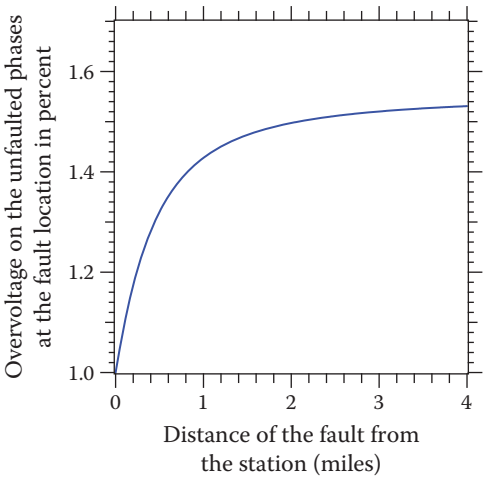

Figure 14.9 Voltage on the unfaulted phases for a system with 500-kcmil, triplex, copper-conductor, tape-shield cables. 12.47 kV, $Z_1 = 0.0292 + j0.0355\ \Omega/1000$ ft, $Z_0 = 0.3765 + j0.2882\ \Omega/1000$ ft, $Z_{src} = j0.7\ \Omega$.

restrike, a transient can occur because of the trapped voltage just prior to the arc restrike.

14.2.2 Neutral Reactor

A reactor connected between the substation transformer neutral point and the substation ground reduces ground fault currents. This limits duty on equipment, but it reduces the effectiveness of the grounding system. During line-to-ground faults, the voltages on the unfaulted phases are higher. A neutral reactor of $X\ \Omega$ adds $3jX\ \Omega$ to the zero-sequence impedance. The overvoltage is most pronounced for faults near the substation. Beyond a few miles, the line impedance dominates.

Figure 14.10 shows an example of the trade-off between fault current at the substation bus and neutral reactor impedance on a 12.47-kV system. A 0.5 Ω reactor increases the Z_0/Z_1 ratio to 3.1, which reduces the fault current to under 6 kA at the substation bus while still keeping the overvoltage below 130%. A reactor larger than this must be considered carefully to avoid subjecting metal-oxide arresters and customer's loads to undue overvoltages.

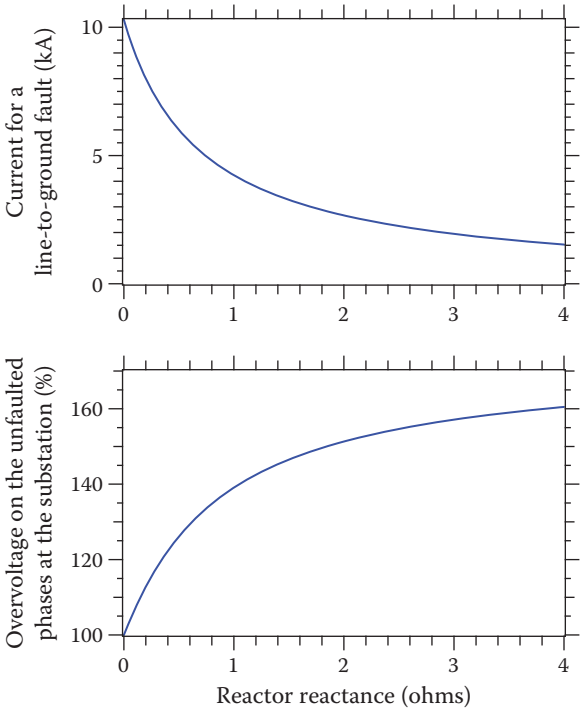

Figure 14.10 Trade-off between overvoltage on the unfaulted phases and fault current for a single line-to-ground fault at the substation bus for different size neutral reactors (12.47-kV circuit with a 20-MVA, 9% transformer, subtransmission impedance neglected).

This graph was developed from a simplified equation for overvoltages. With all circuit resistances equal to zero, the voltage magnitude in per unit on the worst unfaulted phase for a bolted single line-to-ground fault simplifies (Westinghouse Electric Corporation, 1950) to

$$V = 1.732\frac{\sqrt{X_0^2 + X_0X_1 + X_1^2}}{2X_1 + X_0}$$

where

$$X_0 = X_{0,\text{circuit}} + 3X_{\text{reactor}}$$

14.2.3 Overvoltages on Urban Underground Systems

Urban underground circuits feeding predominantly network load can have overvoltages from neutral shifts during faults. Figure 14.11 shows several key features of these underground systems: (1) a neutral reactor, (2) significant cable capacitance from adjacent circuits, and (3) load is connected through delta–wye transformers, meaning that all loads are connected line-to-line on the primary side. When a fault occurs, neutral shifts cause the following:

- *Initial transient spike*—In the first half cycle after the start of the fault, the voltage spikes up on the unfaulted phases. This is due to the transformer neutral reactor initially opposing the flow of current (and creating an extra-large neutral shift).
- *60-Hz neutral shift overvoltage*—During a line-to-ground fault, the current through the neutral reactor shifts the neutral reference and exaggerates an overvoltage on the unfaulted phases.
- *Breaker-trip ringing*—After the breaker trips to clear the fault, all three phases have a ringing transient overvoltage. This is caused by the oscillation of the transformer neutral reactor and the line-to-ground-connected capacitance due to the cables. Basically, the L–C circuit rings after the shifted neutral point snaps back to zero potential.

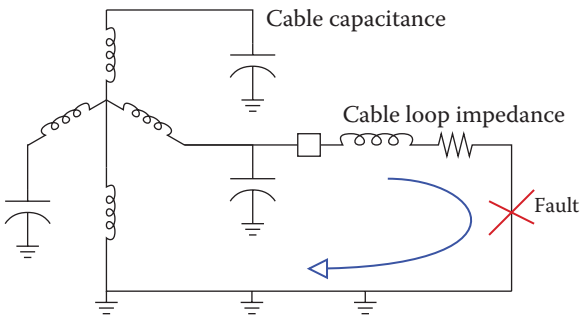

Figure 14.11 Simplified model of an underground primary supplying network load.

All three of these are zero-sequence voltages. They appear only on the line-to-ground voltages (and not on the line-to-line voltages). This can be seen when looking at the sum of the line-to-ground voltages of the typical event shown in Figure 14.12. The zero-sequence voltage reveals all three parts of the transient—the initial transient ringing, the 60-Hz neutral shift, and the ringing when the breaker trips. None of these appear on the line-to-line voltages.

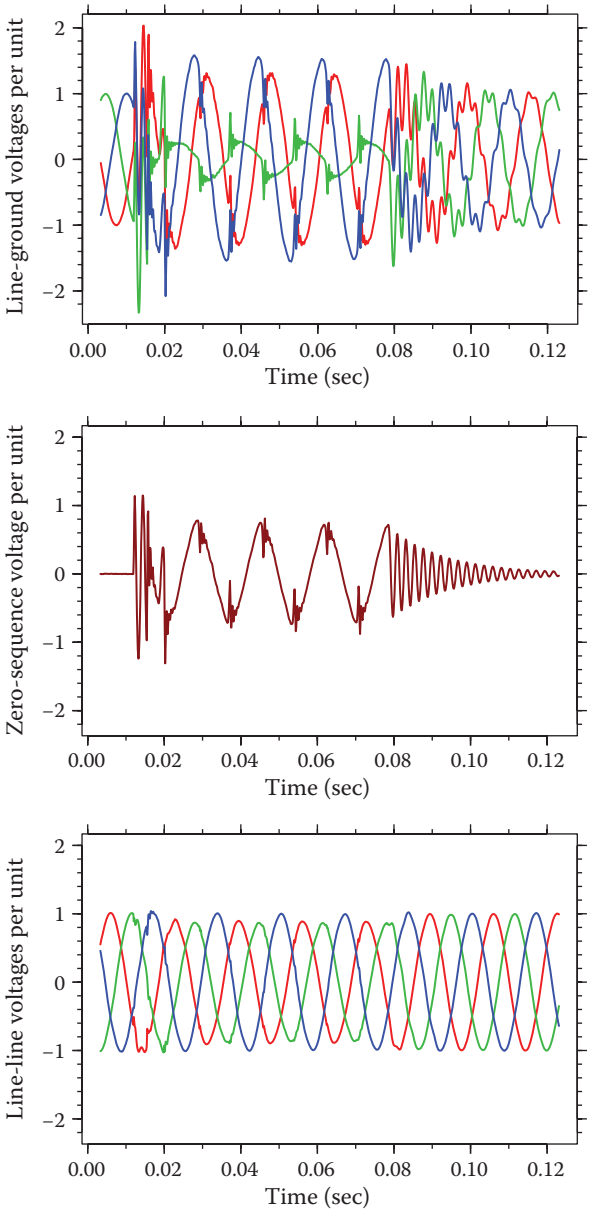

Figure 14.12 Example transient measurement at the substation on an underground system.

Because of delta–wye transformers, customer load is connected phase to phase, so it does not see these overvoltages. Utility equipment does see these line-to-ground stresses. There is some evidence that these stresses contribute to successive faults on network supplies (EPRI 1009528, 2004; EPRI 1012924, 2005). These can be failures on different feeders fed from the same substation within a short time frame, occasionally almost instantaneously but more often many minutes or a few hours after the first fault. These may also be feeder restoration failures, where a second fault is discovered on the same feeder. Both failure types increase the likelihood of causing an outage of a secondary grid. In the worst case, faults can cascade until the feeders are no longer capable of sustaining the load on a secondary grid.

14.2.4 Overvoltages on Ungrounded Systems

Many older distribution systems are ungrounded, typically operating at 2400 or 4800 V. Although ungrounded systems have no intentional ground, they are grounded through the line's capacitance. Under normal conditions, the phase-to-ground voltage equals the phase-to-phase voltage divided by $\sqrt{3}$ if the total line-to-ground capacitance on each phase is the same.

Ungrounded systems may have extra-high overvoltages under certain conditions:

- *Resonance*—The line-to-ground capacitance can resonate with the system reactance.
- *Arcing ground faults*—A restriking ground fault can create significant line-to-ground voltage.

The main impact of these overvoltages is stress on insulation and impact on arresters (higher-rated arresters are necessary). A bolted line-to-ground fault on one phase draws very little current on an ungrounded system. The current is normally much less than 10 A, so the system may continue supplying power. This is an operational advantage of the ungrounded system. Because it can operate through line-to-ground faults, ungrounded systems may have higher reliability. Most lower-voltage ungrounded systems (2400 or 4800 V) are very resistant to trees.

Figure 14.13 shows a simplification of an ungrounded system that shows how resonances can create overvoltages.* For a bolted single line-to-ground fault on a phase, the voltages on phases B and C can become extremely high if the system capacitance resonates with the inductance, which occurs when

$$X = X_C/3$$

where

X = reactance of the system, Ω

X_C = line-to-ground capacitance, Ω

* The simplified circuit shows how resonance occurs, but the circuit is actually more complicated than shown. The capacitance is not necessarily lumped on the source side of the line impedance, it is distributed along the line (although circuit taps may concentrate the capacitance at points on the line). The figure also ignores the line-to-line capacitance and the system load.

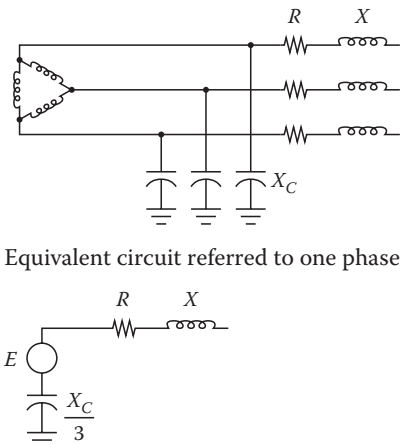

Figure 14.13 Ungrounded system schematic.

The overvoltage reaches a maximum when at the resonant point and can reach significant voltages for ratios of X_C/X of up to 15. Normal line capacitances and reactances are well away from the resonant point; even cable capacitances are too low to cause resonance. For example, 10 mi (16 km) of cable with a capacitance of 0.5 μF/mi (0.9 μF/km) has an impedance of 530 Ω, and line impedances are less than 1 Ω/mi. Even with several circuits in parallel (more capacitance), such resonances are unlikely. For a more thorough analysis, see Peterson (1951).

Resonances can occur when high reactances are accidentally connected to ground. Figure 14.14 shows ground fault scenarios that may cause overvoltages when three-phase distribution transformers become connected to ground.

Ungrounded systems are also susceptible to arcing ground faults. An intermittent, restriking fault from ground to a phase conductor may spark high voltages, possibly as high as five per unit. Consider the equivalent single-phase circuit in Figure 14.13. This series circuit is a classic restriking circuit often studied for switching capacitive loads, but now, the restriking is in an arc to ground instead of in the circuit interrupter. The voltage can ratchet up as the restriking charges the system capacitance. Since the intermittent ground fault may last for hours, this overvoltage mode subjects

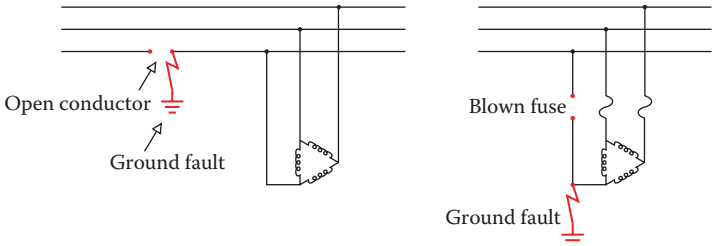

Figure 14.14 Accidental connections of reactances to ground that may cause high overvoltages on ungrounded systems.

equipment to continued overvoltages. The overvoltages are likely to be chaotic and random because of the random restriking times.

Fortunately, end users do not see the overvoltages from neutral shifts or from arcing ground faults. The overvoltage is line to ground, and all loads are connected line to line. But utility equipment insulation from the primary to the equipment case does see the voltage, especially surge arresters, which are sensitive to overvoltages.

14.3 Equipment/Customer Grounding

The NESC (IEEE C2-2012) places several requirements on grounding systems. The NESC requires effective grounds on

- Surge arresters
- Primary, secondary, and common neutrals
- Unguarded metal or metal-reinforced supporting structures
- Other intentionally grounded wires
- Instrument transformers
- Cable concentric neutrals
- Most equipment, including transformers, capacitors, regulators, reclosers, and sectionalizers
- Uninsulated guy and messenger wires
- Customer meters

Some items that may be ungrounded on overhead circuits are insulators, cutouts, and some open-air switches. For multigrounded systems, the grounded conductor may serve as the ground for many applications. On a multigrounded system, the NESC requires ground electrodes at transformer locations and at customer meters. For an effectively grounded neutral (from an NESC safety perspective) there must be at least four grounds in each mile (1.6 km) of the entire line. Customer meter grounds do not count (they are not necessarily under the control of the utility). Also, the neutral must be continuous.

The NESC does not allow the earth as the sole conductor for any part of the circuit.

On systems without a multigrounded neutral, where a grounding electrode is required, it must be less than 25 Ω. If it is higher than that, another grounding electrode must be made. The second electrode must be at least 6 ft (1.8 m) from the first. Note that there is no requirement on the final resistance (it can still be greater than 25 Ω and meet this rule). It should be low enough so that a protective device will clear for a fault from the primary through the grounding electrode.

The NESC does not require a specific grounding resistance for multigrounded systems. Multigrounded systems achieve their performance mainly by having many grounds in parallel, so the resistance of individual electrodes is less significant. Still, many utilities use the ungrounded NESC approach for all grounding points: drive one rod; if it is more than 25 Ω, drive another.

At least 20 ft (6.1 m) must separate grounding electrodes of different systems (Clapp, 2011; IEEE C2-2012). The primary and secondary are "different systems."

Grounding electrodes of different systems may not be bonded above or below ground.

The NESC requires grounding conductors for surge arresters to be at least #6 copper or #4 aluminum. Other grounding electrodes may be smaller, but they must be able to handle the fault current they will see. For multigrounded systems, ground down leads from the neutral to the grounding electrode will normally not carry significant current. The critical connection is between the equipment frame and the neutral. First and most importantly, make sure there is such a connection. The connection between the frame and the neutral must be designed to take the entire fault current for a line-to-ground fault from the line to the equipment case. Since the fault current duration plays a role in whether the wire will handle the fault, we must consider the fault interrupter. For most applications where normal-sized fuses are used, a #4 or #6 copper bonding conductor is sufficient. For situations with high fault currents and where a station breaker clears the fault, a larger conductor or parallel conductors may be needed.

Since the tank-to-neutral connection is critical on multigrounded systems, on transformers, utilities typically tie two connections from the transformer tank. One runs from the tank to the pole ground lead, which is attached to the primary neutral. Another runs from the secondary neutral terminal of the transformer (X2) to the neutral.

14.3.1 Special Considerations on Ungrounded Systems

Systems that do not have a multigrounded neutral—ungrounded or unigrounded systems—have special grounding considerations. Without the multigrounded neutral, the secondary neutral grounding system is the whole grounding system. If a transformer fails from the primary to the secondary (a high-to-low fault), the secondary grounding system must be effective enough to prevent unsafe voltages on customer wiring. Crews should make sure that distribution transformers are grounded as well as possible and that customer meters are grounded as well as possible.

On systems without a multigrounded neutral, the NESC requires the primary surge arrester to be separate from the secondary ground. The NESC does allow interconnection of the primary and secondary grounds through a spark gap as long as the 60-Hz breakdown value of the gap is at least twice the primary circuit voltage but not necessarily more than 10 kV. If a spark gap is used, an additional ground electrode must be attached, not including the customer's grounds, and the extra ground must be at least 20 ft (6.1 m) from the arrester's grounding electrode.

14.3.2 Secondary Grounding Problems

Many complaints are related to grounding problems on the secondary. Some common problems are shown in Figure 14.15. One of the most common power quality complaints is due to an open secondary neutral. If the neutral is open or has a poor connection, the unbalanced current must return through the grounding electrodes

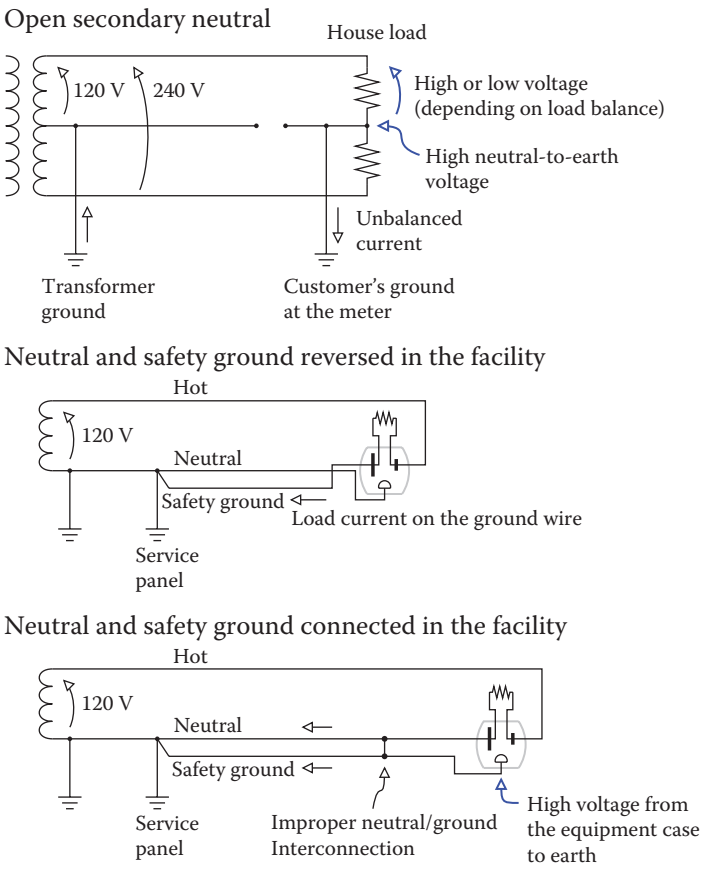

Figure 14.15 Common secondary problems.

(these can have high impedance). The customer may see this as light flicker, and high voltage may occur on the less loaded of the two secondary legs.

Another common problem on secondary systems is when load is connected to the equipment safety ground (the green wire) instead of the neutral wire, or the ground wire is wrongly connected to the neutral wire somewhere within the facility. Both situations violate the National Electrical Code (NEC) (NFPA 70, 2011). Currents flowing in the grounding conductor wire increase shock hazards. Other secondary problems that can occur are isolated grounds, ground loops, and missing safety grounds.

14.4 Ground Rods and Other Grounding Electrodes

The earth, the soil, has very low resistance, primarily because there is so much of it. The trick is getting from the concentrated grounding electrode to the soil beneath that is almost infinite by comparison.

Ground rods are the most common grounding electrode. The NESC requires at least an 8-ft (2.45-m) rod; iron or steel rods must be at least 5/8 in. (15 mm) in

diameter; copper-clad stainless steel, or stainless steel-clad rods must be at least 1/2-in. (12 mm). Rods should be driven to at least 8 ft (2.45 m). If a driven rod hits a rock bottom, the depth may be less than 8 ft (2.45 m). Strategies are to drive the rod at an angle or to use another type of ground such as a buried strip. NESC requires buried strips to be at least 10 ft (3 m) and have a total surface area of at least 5 ft^2 (0.47 m^2). Guy anchors are not allowed as grounding electrodes.

The resistance to ground of a ground rod is

$$R = \frac{\rho}{2\pi L}\left(\ln\frac{4L}{a} - 1\right)$$

where

ρ = soil resistivity, Ω-m
L = length of the ground rod, m
a = radius of the ground rod, m

As a good approximation for 10-ft (3.3-m) ground rods, the resistance in ohms equals the ground resistivity in Ω-m divided by three. Divide earth resistivity by 2.5 for an 8-ft rod.

Rod diameter has little impact on the electrode resistance; the diameter is needed mainly for mechanical strength and to ensure the rod has enough material to survive corrosion.

Twenty percent of the resistance of a ground rod occurs within 1.2 in. (3 cm) of the rod, and half of the resistance is in the first 6 in. (15 cm) (IEEE Std. 142-1991). These numbers vary with the ground resistivity.

The number of rods and the length are the main factors that influence the resistance. Rods can be driven deeper. Normally, crews drive a section and then thread on another rod section to pound it in deeper. Deeper rods are best when lower levels of the soil have lower resistivity, normally because of more moisture.

Multiple ground rods in parallel effectively reduce the overall resistance. But, if two ground rods are too close together, they act as one ground rod with a larger diameter, reducing much of the gain of using parallel rods. One common rule: separate the rods by a distance of at least the length of one of the ground rods. The NESC requires ground rods to be at least 6 ft (1.8 m) apart. Even with these separations, the resistance of n ground rods in parallel is more than $1/n$ times the resistance of a single rod. Table 14.2 shows multiplying factors and final resistances for rods placed symmetrically one rod length apart.

The NESC allows other grounding electrodes. Water piping systems make fantastic grounds if they are available; grounds less than 1 Ω are common. Unfortunately, conducting water pipes are not typically installed anymore, so water system grounds are less common. Gas piping systems are not allowed as grounding electrodes.

The NESC allows the concentric neutral of a cable to be a ground for direct-buried cables of at least 100 ft (30 m). The cable neutral must be bare or have a semiconducting

TABLE 14.2 Resistance of Multiple Rods

Number of Rods	Multiplying Factor	Total Resistance as a Percentage of One Rod
2	1.16	58%
3	1.29	43%
4	1.36	34%
8	1.68	21%
12	1.80	15%
16	1.92	12%
20	2.00	10%
24	2.16	9%

Source: Data from IEEE Std. 142-1991, *IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems*.

jacket with a radial resistivity not exceeding 10 Ω-m (meaning that 30 m of cable has a resistance of 0.33 Ω across the jacket).

The NESC allows other "made" electrodes other than ground rods, including buried wires, strips, and plates. These are especially appropriate in areas with a rock bottom. Buried wires must have at least a 0.162 in. (4 mm) diameter, be at least 100 ft (30 m) long, and be at least 18 in. (0.45 m) deep (less is allowed if a rock bottom is hit). Strips must be at least 10 ft (3 m) long, buried at least 18 in. (0.45 m) deep, and have a total surface area on both sides of 5 ft^2 (0.47 m^2). Plates must be buried at least 5 ft (1.5 m) deep and have a total surface area of at least 2 ft^2 (0.185 m^2). Both plates and strips must have a thickness of at least 0.06 in. (1.5 mm) wide for nonferrous metals and at least 0.25 in. (6 mm) wide for ferrous metals. Table 14.3 shows resistance calculations for several different configurations.

Two-pole grounding techniques, butt plates and wire wraps (see Figure 14.16), are available but have several deficiencies (Clapp, 2011). A driven ground provides more than twice the surface area of a butt plate. Additionally, pole movement can reduce the contact between the butt plate or wire wrap and the earth, and the pole can draw moisture out of the soil enough to increase its resistivity. The NESC only considers butt plates and wire wraps as appropriate in areas with low ground resistivity (less than 30 Ω-m), and even then, two such grounds must be used, and they must not be used as the sole ground at transformer locations.

14.4.1 Soil Characteristics

Soil resistivity is the resistance of a certain volume of soil. Normally, resistivity is specified in Ω-m, the resistance between opposite faces of a cube of soil with a volume of 1 m^3. Units of Ω-cm are also common—the resistance between faces of a cube with a volume of a cubic centimeter: Ω-cm = 100 × Ω-m.

Soil resistivities vary widely. Rich, moist organic soil may have a resistivity of 10 Ω-m, while bedrock may have resistivities greater than 10^4 Ω-m. Resistivity

TABLE 14.3 Ground Electrode Resistance Calculations

Hemisphere radius a	$R = \frac{\rho}{2\pi a}$
One ground rod length L, radius a	$R = \frac{\rho}{2\pi L}\left(\ln\frac{4L}{a} - 1\right)$
Two ground rods $s > L$; spacing s	$R = \frac{\rho}{4\pi L}\left(\ln\frac{4L}{a} - 1\right) + \frac{\rho}{4\pi s}\left(1 - \frac{L^2}{3s^2} + \frac{2L^4}{5s^4}\cdots\right)$
Two ground rods $s < L$; spacing s	$R = \frac{\rho}{4\pi L}\left(\ln\frac{4L}{a} + \ln\frac{4L}{s} - 2 + \frac{s}{2L} - \frac{s^2}{16L^2} + \frac{s^4}{512L^4}\cdots\right)$
Buried horizontal wire length $2L$, depth $s/2$	$R = \frac{\rho}{4\pi L}\left(\ln\frac{4L}{a} + \ln\frac{4L}{s} - 2 + \frac{s}{2L} - \frac{s^2}{16L^2} + \frac{s^4}{512L^4}\cdots\right)$
Right-angle turn of wire length of arm L, depth $s/2$	$R = \frac{\rho}{4\pi L}\left(\ln\frac{2L}{a} + \ln\frac{2L}{s} - 0.2373 + 0.2146\frac{s}{L} + 0.1035\frac{s^2}{L^2} - 0.0424\frac{s^4}{L^4}\cdots\right)$
Three-point star length of arm L, depth $s/2$	$R = \frac{\rho}{6\pi L}\left(\ln\frac{2L}{a} + \ln\frac{2L}{s} + 1.071 - 0.209\frac{s}{L} + 0.238\frac{s^2}{L^2} - 0.054\frac{s^4}{L^4}\cdots\right)$
Four-point star length of arm L, depth $s/2$	$R = \frac{\rho}{8\pi L}\left(\ln\frac{2L}{a} + \ln\frac{2L}{s} + 2.912 - 1.071\frac{s}{L} + 0.645\frac{s^2}{L^2} - 0.145\frac{s^4}{L^4}\cdots\right)$
Six-point star length of arm L, depth $s/2$	$R = \frac{\rho}{12\pi L}\left(\ln\frac{2L}{a} + \ln\frac{2L}{s} + 6.851 - 3.128\frac{s}{L} + 1.758\frac{s^2}{L^2} - 0.490\frac{s^4}{L^4}\cdots\right)$
Eight-point star length of arm L, depth $s/2$	$R = \frac{\rho}{16\pi L}\left(\ln\frac{2L}{a} + \ln\frac{2L}{s} + 10.98 - 5.51\frac{s}{L} + 3.26\frac{s^2}{L^2} - 1.17\frac{s^4}{L^4}\cdots\right)$
Ring of wire, depth $s/2$ diameter of ring D, diameter of wire d	$R = \frac{\rho}{2\pi^2 D}\left(\ln\frac{8D}{d} + \ln\frac{4D}{s}\right)$
Buried horizontal strip length $2L$, section a by b, depth $s/2$, $b < a/8$	$R = \frac{\rho}{4\pi L}\left(\ln\frac{4L}{a} + \frac{a^2 - \pi ab}{2(a+b)^2} + \ln\frac{4L}{s} - 1 + \frac{s}{2L} - \frac{s^2}{16L^2} + \frac{s^4}{512L^4}\cdots\right)$
Buried horizontal round plate, radius a, depth $s/2$	$R = \frac{\rho}{8a} + \frac{\rho}{4\pi s}\left(1 - \frac{7}{12}\frac{a^2}{s^2} + \frac{33}{40}\frac{a^4}{s^4} + \cdots\right)$
Buried vertical round plate, radius a, depth $s/2$	$R = \frac{\rho}{8a} + \frac{\rho}{4\pi s}\left(1 + \frac{7}{24}\frac{a^2}{s^2} + \frac{99}{320}\frac{a^4}{s^4} + \cdots\right)$

Source: Adapted from Dwight, H. B., Calculation of resistance to ground, *AIEE Transactions*, 55, 1319–28, December 1936; IEEE Std. 142-1991, *IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems*. Copyright 1992 IEEE.

depends on the soil grain characteristics (size, variability, and density) as well as moisture and chemical content. See Table 14.4 for typical values.

Soil resistivity often varies significantly with depth. In most areas, resistivity improves significantly with depth as moisture increases, and normally, grounds driven down to the water table provide a very good ground. In other areas, an underlying bedrock significantly increases resistivity at lower levels (and makes driving

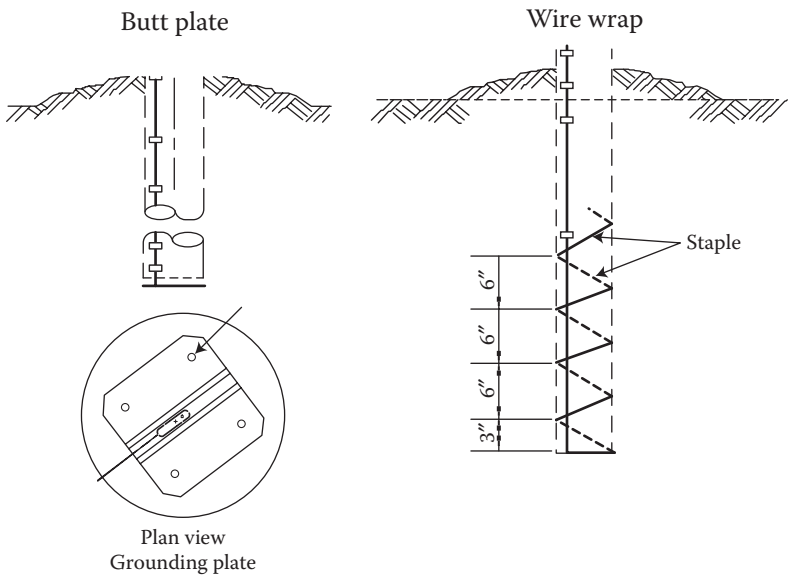

Figure 14.16 Butt plate and wire wrap grounds. (From RUS 1728F-803, Specifications and Drawings for 24.9/14.4 kV Line Construction, United States Department of Agriculture, Rural Utilities Service, 1998.)

ground rods difficult). Several different layers of soil with different resistivities may be present. A two-layer soil model is often used for engineering analysis.

Soil resistivity is primarily affected by

- *Moisture*—Moisture is one of the main factors determining soil resistivity. The dryer the soil, the higher the resistivity. Changes in moisture level throughout the year are the biggest reason for the change in ground electrode resistance. Once the moisture exceeds 22%, resistivity changes very little (IEEE Std. 142-1991).
- *Temperature*—Above the freezing point of water, temperature does not impact resistivity significantly. Below freezing, resistivity rises significantly.
- *Salts*—The presence of soluble salts significantly impacts the resistivity.

Figure 14.17 shows these three main effects for different example soils. These effects are somewhat interrelated and depend on the soil's specific characteristics.

One option to reduce ground electrode resistivity is to use chemical treatments or backfills to reduce the soil resistivity near the electrode. Bentonite backfills or salt treatments such as sodium chloride or calcium chloride significantly reduce the soil resistivity. If soil treatments are used to enhance ground rods, make sure to consider the effect on corrosion. Some chemical treatments increase the metal corrosion rate. Also, consider the environmental impacts and regulations. Most normal distribution grounding needs outside of the substation do not warrant chemical enhancement.

If a grounding electrode sustains significant current, the current may dry out the surrounding soil and increase the resistance of the electrode. With a multigrounded

TABLE 14.4 Resistivity of a Variety of Soils along with Resistances of a 10-Ft Ground Rod

Soil	Average Resistivity, Ω-m	Resistance of a 5/8 in. (16 mm) × 10 ft (3 m) Rod, Ω
Well-graded gravel, gravel–sand mixtures, little or no fines	600–1000	180–300
Poorly graded gravels, gravel–sand mixtures, little or no fines	1000–2500	300–750
Clayey gravel, poorly graded gravel, sand–clay mixtures	200–400	60–120
Silty sands, poorly graded sand–silts mixtures	100–500	30–150
Clayey sands, poorly graded sand–clay mixtures	50–200	15–60
Silty or clayey fine sands with slight plasticity	30–80	9–24
Fine sandy or silty soils, elastic silts	80–300	24–90
Gravelly clays, sandy clays, silty clays, lean clays	25–60[a]	17–18[a]
Inorganic clays of high plasticity	10–55[a]	3–16[a]

Source: Adapted from IEEE Std. 142-1991, *IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems*. Copyright 1992 IEEE.

[a]Soils highly influenced by moisture.

system, several grounds share current, but on systems with isolated grounds, sustained current through a grounding electrode may degrade the electrode's resistance (another good reason to use multiple grounding electrodes in parallel whenever possible).

The resistivity of soil is normally very linear, but for very high voltage stresses, the soil breaks down, and arcing in the soil reduces the effective resistivity. For a ground rod, the soil breaks down only when high current flows into the rod, normally from lightning (a localized effect) or from faults with very little sharing between ground rods. The breakdowns improve the resistance of a grounding electrode.

14.4.2 Corrosion and Grounding Electrodes

Corrosion is a major consideration for grounding electrodes. Ground rods are normally copper-clad steel or galvanized steel. Most grounding wires are copper. Steel and aluminum corrode too quickly for grounding use. One problem with copper is its attractiveness to thieves. In problem areas, copper-clad steel has reduced thefts since it has less commercial value.

Mixing metals significantly increases corrosion. The problem is galvanic corrosion. Different metals create an electrochemical battery in the soil. A voltage develops between grounding electrodes made of different metals (or between a grounding

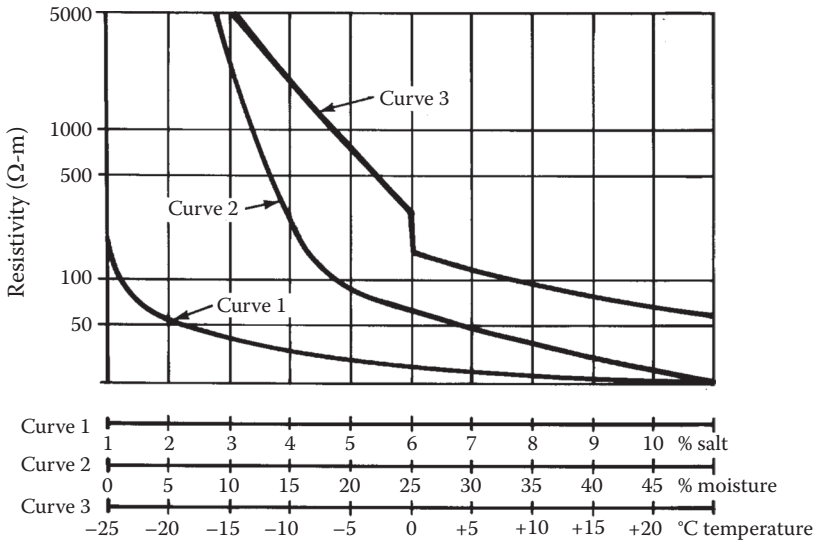

Figure 14.17 Effect of salt, moisture, and temperature on soil resistivity. (IEEE Std. 80-2000, *IEEE Guide for Safety in AC Substation Grounding*. © 2000 IEEE.)

electrode and another metallic object in the ground). When these electrodes are connected, current flows in the earth between the metal objects, corroding one of the metals at a much higher-than-normal rate.

Galvanic corrosion between dissimilar metals can eat up grounding electrodes. Galvanic corrosion operates on the same principle as a battery (batteries release their energy with controlled corrosion). Pure metals are unstable; they are found in nature as ores and must be refined to a pure state. Metals corrode to return to their natural state. Iron dissolves in a corrosive electrolyte and gives up electrons, forming a positive ion. Some of the iron ions attach to free oxygen and become iron oxide (rust). At low corrosion rates, the metal reaches equilibrium with the surrounding electrolyte that prevents additional iron from releasing electrons. Two different metals separated by an electrolyte (a conducting medium) have a voltage difference between them as they give up electrons at different rates. If these different metals are electrically connected together, current flows between the metals and increases corrosion.

Consider a galvanized-steel ground rod next to a copper ground rod. The galvanized rod is coated with zinc. The zinc releases more electrons into the electrolyte, so it becomes positively charged relative to the copper rod. At the zinc surface (the positive terminal, the anode), the flow of this dc current dissolves the zinc at an increasing rate. At the copper rod (the negative terminal), the galvanic circuit decreases the rate of corrosion. Figure 14.18 shows the galvanic series for several different metals. When dissimilar metals form a galvanic circuit, the most anodic of the metal corrodes (corrosion slows down, stops, or even reverses on the cathodic metal).

In fact, most corrosion occurs by the same action. An anode and a cathode develop between different portions of a metal, and galvanic currents flow between them,

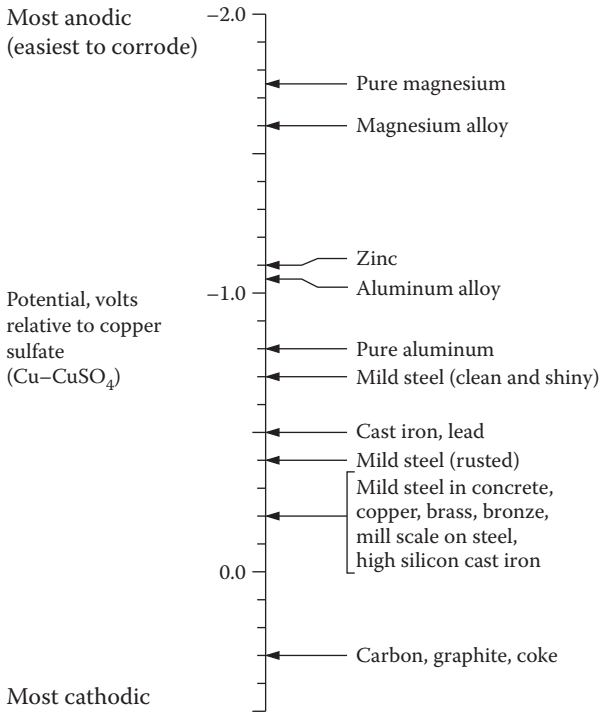

Figure 14.18 Relative potentials of various metals in an electrolyte.

corroding the anode. One part of a metal may become anodic to another in several ways based on differences in impurities in the metal, mechanical stresses, and oxygen concentration.

Copper has naturally good properties that limit corrosion. When copper corrodes, it becomes copper oxide; the copper-oxide layer greatly reduces the corrosion rate and protects the underlying copper. Copper is normally the most cathodic element, so it rarely corrodes because of dissimilar metals, but it may help corrode other grounding electrodes.

A zinc coating on a steel ground rod (which is a galvanized steel rod) provides corrosion protection for the rod. Zinc by itself is resistant to corrosion because it develops a self-protecting zinc-carbonate film that retards further corrosion. In addition, the zinc provides galvanic protection to the steel core. If part of the rod has exposed steel (due to cuts, scratches, or corrosion of the zinc), the zinc acts as a very large anode to the small area of exposed steel. Galvanic action reduces the corrosion on the exposed steel (the cathode).

With lower soil resistivity, galvanic currents are higher, so grounding electrodes corrode faster. Resistivity is the main soil parameter that determines corrosion. Other factors that increase corrosion are very high or very low pH levels, high water content, and the presence of chlorides (salts) and sulfates.

To limit excessive corrosion caused by different metals, avoid using different grounding rods (either stick with galvanized steel or with copper-clad steel). Provide

as much separation as possible between ground electrodes of different metals. Consider the presence of guy anchors and other possible buried wires, including bare concentric neutral cables and water pipes. With galvanized steel rods, use steel or aluminum pole ground leads. With copper-clad steel rods, use copper down leads.

14.4.3 Resistance Measurements

The NESC does not specify how a ground measurement should be taken. IEEE Std. 81-1983 documents several of the methods of measuring grounds. Normally, on systems with a multigrounded neutral, the actual impedance is not critical, so neither is the measurement. (Just make sure ground rods are connected.) On systems without a multigrounded neutral, individual grounds (and ground resistance checks) are more important.

Accurate ground electrode measurements of a concentrated electrode (ground rods, anchors, or short strips of wire) are normally performed using a three-point method (AEMC Instruments, 1998; Biddle Instruments, 1982; IEEE Std. 81-1983). Two auxiliary ground probes are driven into the earth forming a straight line with the test electrode. The tester injects current I through the electrode under test and the outer auxiliary electrode. The tester measures voltage V between the test electrode and the inner auxiliary electrode. If the middle electrode is out of the influence of the outer two electrodes, the resistance of the test electrode is V/I.

The *fall of potential* method is the most common three-point technique (see Figure 14.19). It requires several measurements. Take several measurements with the

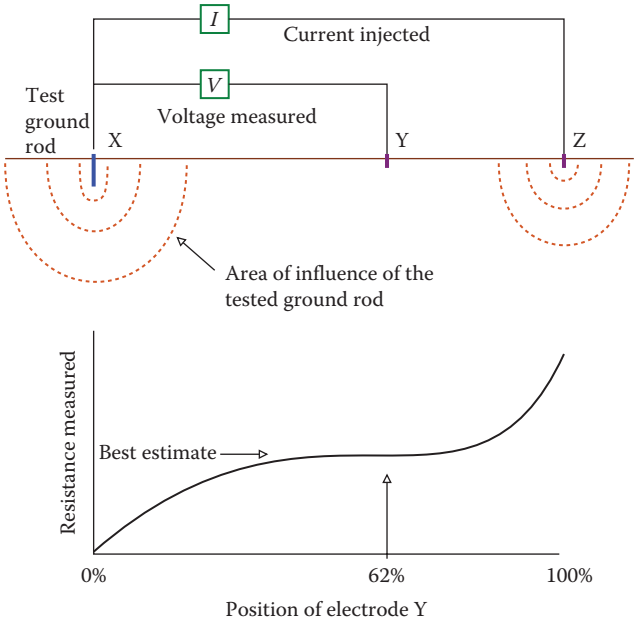

Figure 14.19 Three-point ground-electrode measurement.

middle electrode at different locations between the test electrode and the outer electrode. Plot the resistance versus the distance, and pick the resistance from the portion of the curve where resistance flattens out. The point where the fall-of-potential curve flattens out is most likely near 62% of the distance from the test electrode to the outer electrode. A simplified version is just to measure near the 62% mark.

The three-point methods must be done with the ground electrode disconnected from the multigrounded neutral and connections to other grounds that may interfere (including cable TV and telephone grounding connections). When disconnecting a grounding conductor from the multigrounded neutral, crews should know that a significant potential can develop between the neutral and the disconnected ground if a line-to-ground fault occurs somewhere on the line.

To have adequate spacing with the three-point method, normally, the outer electrodes must be spaced at least 75 to 100 ft apart (23 to 30 m). Deeper grounds or wider grounds (strips or multiple ground rods) require more distance between the electrodes.

If an excellent ground is available nearby as a reference, the two-point measurement technique is suitable. Just like an ohmmeter, the tester injects current through the grounding electrode under test and the reference ground. The resistance reading is the sum of both grounds, so if the reference ground is very good (like a water piping system), the reading is predominantly the resistance of the test electrode. A multigrounded neutral can be used as the ground reference but only if the frequency of the injected signal is different from the standard power frequency (normal power-frequency current flows can foul the ground reading). As with the three-point method, the ground electrode must be disconnected from the multigrounded neutral.

A convenient ground electrode tester is a clamp-on device that tests a grounding electrode by clamping around the grounding lead. The clamp-on unit only works on electrodes connected to a very good ground like the multigrounded neutral (it relies on the good ground). It works just like the two-point test. The clamp-on is a current transformer that couples a voltage to the grounding lead; the voltage is in the lower kilohertz range. The resistance of the grounding electrode is the voltage divided by the current (if all of the parallel grounds provide a low-impedance path, the resulting impedance is only the grounding electrode).

The clamp-on ground-resistance tester more than adequately tests ground-rod connections on systems with a multigrounded neutral. It is fast and convenient, crews do not have to disconnect the ground rod, and it tests the connector continuity. Since values of individual grounds are not as critical on multigrounded neutral systems, the clamp-on's accuracy is good enough for most grounding checks on distribution circuits.

Ground resistivity is normally measured using the four-point method. Four electrodes of the same size are driven to the same depth in a straight line with equal spacing between them. A tester injects current through the outer two electrodes and measures the voltage between the inner two electrodes. The distance between two electrodes determines the depth at which the average resistivity is measured. If the electrode spacing is at least 20 times the electrode depth, the resistivity is

$$\rho = 2\pi AR$$

where

ρ = earth resistivity, Ω-m
A = electrode spacing, m
R = resistance reading from the ground tester, Ω

Since the rod spacing determines the depth at which the resistivity is measured, testing with multiple electrode separations shows how the soil varies with depth. But keep in mind that other buried equipment, pipes or cables, may give false readings.

14.5 Shocks and Stray Voltages

Contact with high-voltage utility circuits poses dangers to utility workers and the public. Electricity is dangerous. Just a small amount of current through a person's body can kill. Backhoes, kites, downed wires, trees into lines—direct and indirect contacts to utility circuits may occur in many ways. When equipment fails or external factors cause line-to-ground faults, current flow into the ground can pose step and touch potential hazards to the public and to utility workers. Many electric dangers are invisible. When a crane boom accidentally contacts an overhead primary wire, there may be no visible or audible indications from the ground to warn someone, to prevent someone from grabbing the crane's door handle and being electrocuted.

Even under normal operating conditions, the multigrounded neutral may be imperfectly grounded and may have a voltage above that of true ground. Under certain conditions, this voltage potential may shock people when they touch metallic equipment that is connected to the neutral. These same elevated neutral-to-earth voltages (NEV) also cause concern on dairy farms and other agricultural facilities. The term "stray voltage" is often used to mean elevated neutral-to-earth voltages, but it has also come to be used to describe any abnormal voltage, whether a nuisance or a hazard.

Given all of the possible hazards in dealing with high voltage and given the great lengths of distribution line in operation, utilities do a very good job of safely operating their lines and minimizing accidents. Several components help maintain a safe system—designs with good clearances and ample mechanical strength, public education to avoid things like kites into overhead lines, proper overcurrent protection schemes, effective grounding, and rapid response and repair.

14.5.1 Biological Models

The body's resistance is an important part of the electrical circuit in possible shocking situations. The body's internal resistance is about 300 Ω. Resistance, including the skin contact resistance, is in the range of 500 to 5000 Ω (IEEE Std. 80-2000 and many other publications) but varies widely as shown in Table 14.5. It is common to use a resistance of 1000 Ω and assume that the hand and foot contact resistances are zero (as in IEEE Std. 80-2000). The 1000 Ω is used for the path from one hand to the other, from hand to foot, and from foot to foot (all are roughly the same impedance).

TABLE 14.5 Human Resistance Values for Several Contact Conditions

	Resistance Range, Ω	
	Dry	Wet
Finger touch	40,000–1,000,000	4000–15,000
Hand holding wire	15,000–50,000	3000–6000
Finger-thumb grasp (interpolated)	10,000–30,000	2000–5000
Hand holding pliers	5000–10,000	1000–3000
Palm touch	3000–8000	1000–2000
Hand around 3.8 cm (1.5 in.) pipe (or drill handle)	1000–3000	500–1500
Two hands around 3.8 cm (1.5 in.) pipe	500–1500	250–750
Hand immersed in water		200–500
Foot immersed in water		100–300
Human body, internal, excluding skin	200–1000	

Source: Adapted from Lee, R. H., Electrical safety in industrial plants, *IEEE Spectrum*, June 1971. With permission. Copyright 1971 IEEE. (Also in IEEE Std. 902-1998, *IEEE Guide for Maintenance, Operation, and Safety of Industrial and Commercial Power Systems*.)

Much of this impedance is concentrated at the extremities, the forearm, and the ankle and shin. For more information on biological impacts and models, see Reilly (1998) and the IEEE Working Group on Electrostatic and Electromagnetic Effects et al. (1978).

Electric current *does* the damage. Table 14.6 shows electrical effects on people for different ranges of currents. Currents as low as 0.1 mA are perceptible to some, and currents above 1 mA are perceptible to most. Above the "let-go" current, at about 5 to 25 mA, the hand and arm muscles involuntarily clench, and a person may be unable to release an electrified object. These current levels may be quite painful but do not cause permanent damage. A person may have severe breathing difficulties for currents above 30 mA, which in some cases may cause death.

Electrocution can occur for currents through the heart on the order of 60 to 100 mA; 250 mA through the heart is almost always fatal (without life-saving emergency care). These levels of current interfere with the heart's internal electrical pacemaker and force the heart to stop beating properly. During this ventricular fibrillation, the heart muscle fibers contract erratically and unpredictably, leading quickly to death from lack of oxygen to the brain. Above 5 A, current can burn tissue.

The destructive effect of current is a function of the energy into the body; assuming a constant resistance, the energy input is a function of I^2t. One commonly cited model, Dalziel's formula, describes the relationship between fibrillation and the duration of current (Dalziel, 1946, 1972) as

$$I = \frac{116}{\sqrt{t}}$$

TABLE 14.6 Threshold Levels for 60-Hz Contact Currents

rms Current mA	Threshold Reaction/Sensation
Perception	
0.09	Touch perception for 1% of women
0.13	Touch perception for 1% of men
0.24	Touch perception for 50% of women
0.33	Grip perception for 1% of women
0.36	Touch perception for 50% of men
0.49	Grip perception for 1% of men
0.73	Grip perception for 50% of women
1.10	Grip perception for 50% of men
Startle	
2.2	Estimated borderline hazardous reaction, 50% probability for women (arm contact)
3.2	Estimated borderline hazardous reaction, 50% probability for women (pinched contacts)
Let-Go	
4.5	Estimated let-go for 0.5% of children
6.0	Let-go for 0.5% of women
9.0	Let-go for 0.5% of men
10.5	Let-go for 50% of women
16.0	Let-go for 50% of men
Respiratory Tetanus	
15	Breathing difficulty for 50% of women
23	Breathing difficulty for 50% of men
Fibrillation	
35	Estimated 3-sec fibrillating current for 0.5% of 44-lb (20-kg) children
100	Estimated 3-sec fibrillating current for 0.5% of 150-lb (70-kg) adults

Source: Adapted from IEEE Working Group on Electrostatic and Electromagnetic Effects, Delaplace, L. R., and Reilly, J. P., *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-97, no. 6, pp. 2243–52, November/December 1978. Copyright 1978 IEEE.

where

I = minimum body current in mA necessary to cause ventricular fibrillation for at least 0.5% of the population for a 110-lb (50-kg) adult

t = duration of the current, sec

Larger people are able to withstand higher currents. A more general formulation of Dalziel's formula includes body weight as

$$I = \frac{\sqrt{S}}{\sqrt{t}}$$

where

S = body weight, kg

Dalziel's formula applies for the time ranges of faults, from about one-half cycle to 3 sec (it may not apply for longer- or shorter-duration currents).

Electricity can kill at astonishingly low energies. A 100-mA current through a body resistance of 500 Ω is only 50 W of power.

If an electrical shock stops normal heart action, cardiopulmonary resuscitation (CPR) can supply some oxygen to the brain until emergency care arrives. In many cases, resuscitation after electrical shocks is possible with a defibrillator. The electric current causing ventricular fibrillation shuts down the heart's electrical system but may not significantly damage organs or nerves. Note that a victim of fibrillation may not immediately become unconscious and can deny needing help (death may be quick or take hours). Always call emergency help immediately, and apply CPR if appropriate.

Currents above 5 A can permanently burn tissue. Fast fault clearing helps reduce the amount of tissue damage and increases the likelihood of successful emergency care.

While current does the damage, voltage plays an important role. Normally, 120-V secondary voltages are not as dangerous as higher voltages (but 120 V kills many people every year). In many shocking situations, 120 V may produce painful shocks but not kill (the circuit resistance including contacts is often high enough to limit the current). But 120 V can kill: remember bathtubs. Current in the path depends primarily upon what resistance is in the current's path—wet versus dry skin, shoe resistance, glove resistance, and other impedances in the circuit path. To reach 100 mA, the total resistance must be less than 1200 Ω, which can happen, especially if contacted when wet. Higher secondary voltages such as 480 V are more likely to kill. Above 600 V, the skin offers no extra resistance; the voltage punctures right through, leaving only the internal body resistance or about 300 Ω. Above 2400 V, the voltage drives currents high enough for burning and tissue damage.

14.5.2 Step-and-Touch Potentials

Step-and-touch potentials are very important in substations because during ground faults, all of the ground current returns to the substation transformer. The current that returns through the earth can create a significant voltage gradient along the ground and between the ground and conducting objects. A touch potential is normally considered a hand-to-foot or a hand-to-hand contact; a step potential creates a path through the legs from one foot to the other (see Figure 14.20).

The approximate impedance of one foot-to-ground contact is

$$R = 3\rho$$

where

ρ = earth resistivity, Ω-m

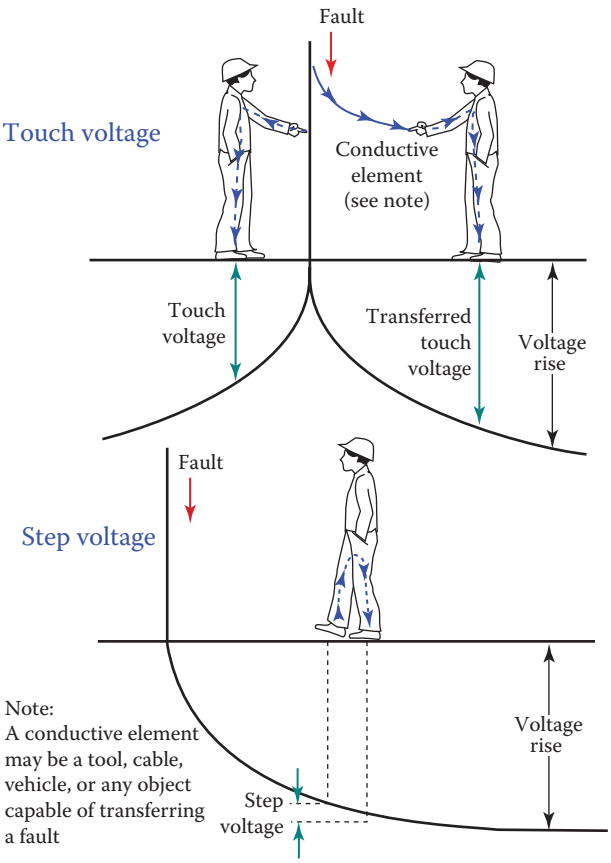

Figure 14.20 Paths for touch and step potentials. (From WAPA, Chapter 1: Personal protective and vehicle grounding, in *Power System Maintenance Manual*, Western Area Power Administration, U.S. Department of Energy, 1997.)

For a step potential, two of the foot contact resistances are in series with the body resistance R_B, so the body current I_B is

$$I_B = \frac{V_{\text{step}}}{R_B + 6\rho}$$

With a hand-and-feet touch potential, the circuit impedance is two foot contact resistances in parallel plus the body resistance. For this touch potential, the body current is

$$I_B = \frac{V_{\text{touch}}}{R_B + 1.5\rho}$$

Step-and-touch potentials are of concern during normal conditions and during a ground fault. Under normal conditions, unbalanced current can raise the neutral-to-earth voltage. This is not normally dangerous, but it can cause annoying shocks and concerns on farms (see the next section on elevated neutral-to-earth voltage). Step-and-touch potentials during faults are more dangerous. This is an important design consideration in substation grounding. Unfortunately, outside the substation, we cannot control many situations nearly as well. The multigrounded neutral helps reduce the chance of dangerous step-and-touch potentials during line-to-ground faults. First, by creating a low-impedance path back to the source, faults are cleared quickly by fault interrupters. And, having multiple grounding electrodes tied together helps reduce touch potentials at the fault point. Away from the substation on systems with multigrounded neutrals, step potentials are usually not dangerous since fault current spreads between several grounding electrodes.

Simulations by Rajotte et al. (1990) help define the touch potentials between the multigrounded neutral and the earth. Figure 14.21 shows neutral-to-earth voltages on overhead and underground systems for different fault locations and earth resistivities. Underground circuits have touch voltages an order of magnitude less than overhead circuits because less current flows in the earth due to the cable neutral being the preferred return path (the reason being the tight coupling with the phase conductor).

The highest ground potential rise is normally at the fault location, but Rajotte simulated cases where an underground section followed an overhead section: the maximum potential rise was sometimes at the pothead rather than the fault location.

Using a reactor on the substation transformer neutral helps limit step-and-touch potentials. While utilities normally use these neutral reactors to limit fault currents,

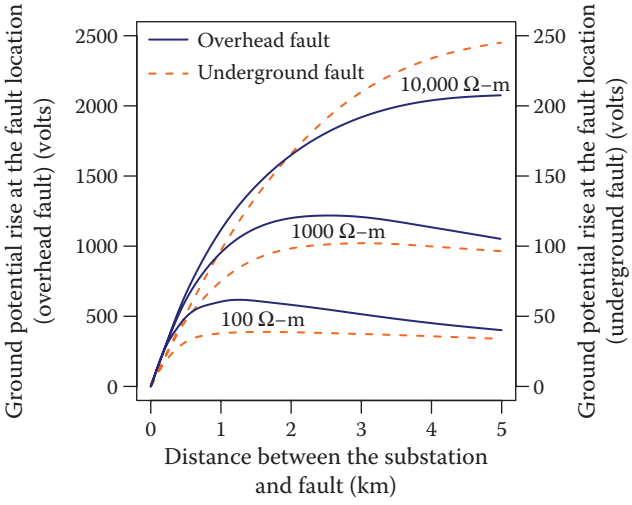

Figure 14.21 Neutral-to-earth voltages during line-to-ground faults on 25-kV overhead and underground circuits. (Adapted from Rajotte, Y. et al., *IEEE Transactions on Power Delivery*, vol. 5, no. 2, pp. 1026–1033, April 1990. Copyright 1990 IEEE. With permission.)

the reduction of the ground fault current also reduces step-and-touch potentials and reduces current in grounding and bonding connectors.

14.5.3 Elevated Neutral-to-Earth Voltages

Elevated neutral-to-earth voltage can cause touch voltages that lead to complaints from residential customers, but most concern has centered around dairy farms. On farms, milking cows are subjected to a voltage between the milking equipment and the earth they are standing on. Cows and people have somewhat similar discomfort responses. Currents above 1 mA may cause discomfort for cows. The Wisconsin Public Service Commission defines a "level of concern" of 1 V for the cow contact voltage, which corresponds to 2 mA of current through a 500 Ω resistor (Reines et al., 1995). Figure 14.22 shows a U.S. Department of Agriculture guideline on the effects of voltage on milk production.

The amount of current through an animal's body depends on the neutral-to-earth voltage, the animal's resistance, and the characteristics of the soil (especially its moisture) and/or concrete.

In a stray voltage investigation at barns, voltage is normally measured across a 500-Ω resistor, which represents the typical resistance of a cow.

Stray voltage has stirred significant public attention. The "danger" of elevated neutral voltages has been exaggerated in some articles in the press. Studies have found

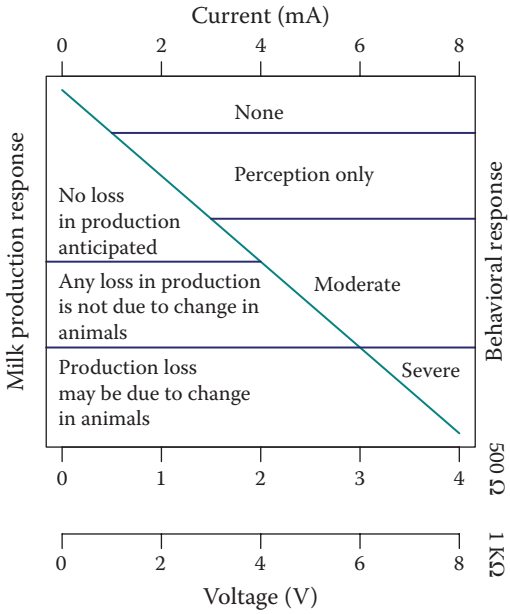

Figure 14.22 Milk production and behavioral responses to stray voltage based on current. (From USDA, Effects of electrical voltage/current on farm animals: How to detect and remedy problems, in *Agriculture Handbook No. 696*, U.S. Department of Agriculture, 1991.)

mixed results when trying to quantify the effect of voltage on milk production, reduced food or water intake, somatic cell count, and other important physiological effects. The Wisconsin Public Service Commission database of stray voltage field surveys found little correlation between milk production and electrical parameters such as cow contact current (Reines et al., 1995, 1998). A report of scientific advisors to the Minnesota Public Utilities Commission found some correlation between elevated neutral-to-earth voltage and high-health herds and low-health herds, but other factors were more significant (Minnesota Public Utilities Commission, 1998). The CEA (1992) found no significant effect on cows' behavior or production for touch voltages of 1 or 2.5 V. Some change in water and feed consumption were noted for 5-V touch voltages.

Many elevated neutral-to-earth voltage problems are due to improper facility grounding and bonding. The NEC (NFPA 70, 2011) covers the issues that could cause problems. Many neutral voltage problems originate on the secondary system. Improper bonding or other violations of the NEC can create excessive voltages between equipment frames and the earth. Another common problem is failed equipment insulation—a failure to a bonding frame (in a motor, for example) can create contact voltages that do not draw enough current to blow a fuse or trip a breaker. So, identifying if the problems originate on the secondary is the first step in any stray voltage investigation. The easiest way to determine if secondary problems are the culprit is to trip the main breaker or pull the meter. If the touch voltage exists after the secondary loads have been removed, then local problems are ruled out; the problems are likely due to a primary neutral-to-earth voltage or a secondary voltage due to other customers on the same secondary. Secondary-side fixes include using a larger neutral, fixing poor neutral connections, balancing 120-V load, and fixing NEC grounding or bonding violations.

Regardless of the origin of the voltage, localized bonding can eliminate touch potentials. In a barn, we can bury wires or sheets of metal just under the earth that a cow stands on during milking. Bonding the buried wires or sheets to the milking equipment creates an equipotential plane that eliminates shocks during milking. Another local solution option is an active voltage suppression device that reduces shocks by actively countering the touch voltage.

EPRI (1999) investigated several residential shocking incidents, many related to swimming pools. Pools are often involved in shock incidents because wet skin has lower resistance and is more susceptible to shock. Many pool-related shocking sensations were found in cases where handrails, ladders, or decks were not bonded. The NEC requires all metallic parts of a pool to be bonded together, including ladders, concrete decks, and diving boards as well as lights and pumps. Voltage differences between bonded and unbonded metal or conducting elements cause shocking situations. The bonded parts of the pool are at the neutral potential (which may be at an elevated potential relative to the earth). Unbonded parts float to a different voltage. Decks in contact with the earth that are not bonded will be at earth potential. Bonding helps eliminate annoying shocks, but more importantly, it reduces the chance of electrocution if the unbonded part happens to become energized at 120 V. Hot tubs and outdoor water faucets are also involved in shocking incidents (faucets are grounded, the soil beneath is at earth potential).

In swimming pools, the most effective protection from NEV is bonded rebar or reinforcing wire mesh in the concrete. During the steady-state NEV testing on an EPRI test pool, voltage potentials between the water and the surrounding deck (with reinforcing wire) never exceeded 100 mV (EPRI 1020096, 2010). For pools where the owner does not have wire mesh in the concrete and does not want to replace the existing deck with the wire mesh, the next best option is a double or triple ground ring. See Figure 14.23 for a comparison of options in tests under steady-state NEV tests.

Neutral-to-earth voltages cannot be analyzed with existing load-flow programs. To accurately model stray voltage, a more general steady-state circuit analysis program such as EMTP is needed. Accurate modeling involves modeling the neutral and the individual grounding electrodes.

Neutral-current harmonics can occasionally contribute to stray voltages, primarily from the third harmonic, which adds in the neutral (see Tran et al. (1996) for a more complete analysis). Leap et al. (2002) showed an example where the rms stray voltage at one location on Portland General Electric's system increased from 0.4 to 8.3 V after adding a 1200-kvar capacitor bank. The capacitor resonated with the system impedance and drew third-harmonic current into the neutral, enough to significantly raise the neutral voltage relative to remote earth. Reducing the size of the capacitor to 300 kvar reduced the stray voltage acceptably.

Figure 14.24 shows distributions of the neutral impedance measured at several locations on 16 rural feeders (Rajotte et al., 1997). Even though the ground resistances of these circuits varied over orders of magnitude, the neutral impedance stayed consistent and fairly low. This highlights one of the main advantages of the multigrounded neutral—many grounds overcome poor ground resistivity, providing

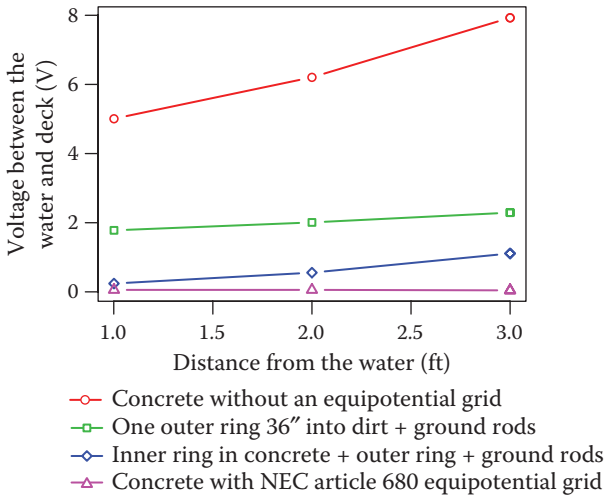

Figure 14.23 Comparison of tests of swimming pool protection options. (From EPRI 1020096, *Guidebook for Evaluating Elevated Neutral-to-Earth and Contact Voltages in Distribution Systems: Part 1: Swimming Pools, Water Bodies, and Other Wet Areas*, Electric Power Research Institute, Palo Alto, CA, 2010. Copyright 2010. Adapted with permission.)

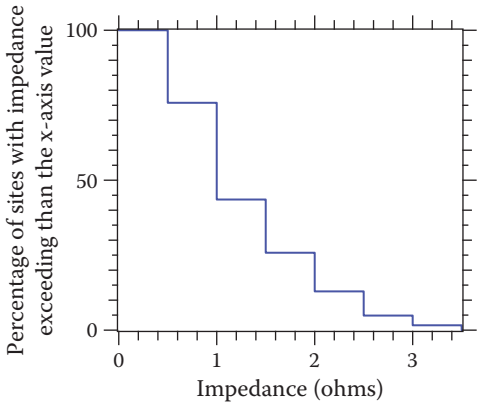

Figure 14.24 Distribution of measured impedances of the multigrounded neutral on rural circuits. (Data from Rajotte, Y. et al., Characterization of the ground impedance of rural MV lines on Hydro-Quebec's system, *CIRED 97*, June 1997.)

an effective return path regardless of the performance of individual grounds. Even with such low impedances, neutral-to-earth voltages can reach several volts given enough current unbalance.

High neutral-to-earth voltages are more likely near the substation and far from the substation. Utility-side solutions to stray voltage include

- *Balancing*—Balancing load among the phases reduces the earth-return current (and thus the neutral-to-earth voltage).
- *Single-phase lines*—Converting single-phase sections to two or three phase reduces the neutral-to-earth voltage.
- *Neutral*—Upgrading the neutral size provides a lower-impedance path for earth-return current.
- *Capacitor banks*—Check capacitor banks for blown fuses. If a grounded-wye capacitor has a blown fuse, the unbalance can create excessive neutral current.

Another utility option is to use a neutral isolation device. Isolating the secondary neutral keeps utility neutral-to-earth voltages away from customer equipment. Keeping the primary neutral separate from the secondary is difficult. Make sure phone, cable television, and metal water pipes are all disconnected; this may require coordination with other utilities. The NESC allows using a spark gap as a neutral separation device: the 60-Hz breakdown voltage of the gap must not exceed 3 kV. Other neutral separation devices are possible although they may not be approved by the NESC (the NESC allows devices that "perform an equivalent function" as a spark gap). A saturating reactor has been proposed as an interconnecting device. Under normal conditions, the reactor is a high impedance (unsaturated), but under fault conditions, the reactor saturates and becomes a much lower impedance (but a saturating reactor may allow narrow voltage spikes through). The reactor has a surge arrester in parallel to conduct lightning-type surges. Another interconnecting device uses a solid-state switch—when a controller detects high voltage, it fires thyristors in

parallel to short out the neutral connection. Use neutral isolation devices sparingly. Widespread usage reduces the effectiveness of the multigrounded neutral since the isolation devices disconnect the secondary grounds from the primary grounds.

14.5.4 Contact Voltages

A contact voltage is a nontraditional touch voltage due to an abnormal condition that causes a potential between two conductive surfaces that a person or animal can touch at the same time. Contact voltages often result from damaged insulation on phase conductors, but improperly connected equipment can also cause contact voltage. Contact voltage has also been called stray voltage or urban stray voltage. Contact voltages can be present for significant time, and voltage can fluctuate with changing environmental conditions. This is a type of high-impedance fault—there will not be enough current to operate a protective device (like a limiter), but the source is strong enough to be hazardous to people and animals.

Contact voltages in an urban setting were brought to attention because of the unfortunate electrocution of Jodie Lane from contact to a service box that was energized due to an improperly insulated 120-V joint that came in contact with the metal frame of the service box. During the investigation, the voltage on the service box measured 57 V (NY State PSC Order 04-E-0160, 2004).

In urban areas, root causes of failures in junction boxes and other underground facilities include aged and deteriorated cable insulation, corrosion from salt, grounding problems, animals, and poor workmanship. In street lights, duct damage or collapse, neutral corrosion, miswiring, and use of temporary connections can contribute to failures. Table 14.7 shows a breakdown of 3056 contact voltages detected by Con Edison in the New York City area. A majority of these contact voltages are from streetlights and streetlight services. Problems under the utility's responsibility are mainly secondary cable issues. 94% of these issues were identified by mobile detection units. Hanebuth (2011) reported that of Con Edison's shock reports, 69% were on sidewalks, 12% were on street and traffic lights, 4% were at manholes and service boxes, 3% were on overhead, and the rest were "other."

Voltage levels of concern depend on many variables as noted in previous sections and include body type and contact resistance. Dorr (2009) compiled published levels of voltage of concern for humans. 60 V is a common threshold of concern cited. Although voltage is an indicator of risk at a particular site with contact voltage, it is not a reliable indicator because of intermittency. Most contact voltages are from faults to 120-V circuits. As environmental conditions change, the voltage on the energized object can vary as the contact impedance at the failure point varies. Equipment energized at 5 V at one time could be 120 V (full line voltage) two days later and 0 V another time.

Utilities can inspect for energized objects in several ways. Crews can directly measure voltage on objects with voltmeters or with handheld capacitive "pen" testers. Once an energized object is found, measurements with voltmeters can help determine the source. Important considerations for these measurements are the selection

TABLE 14.7 Sources of contact Voltages Detected by Con Edison

Contact source	Percentage	Subtotals
Utility responsibility		46.4%
UG streetlight service	13.0%	
UG service	10.8%	
UG service neutral	6.0%	
UG main	4.0%	
Secondary burnout	3.6%	
UG streetlight neutral	2.7%	
Crab	1.1%	
Abandoned service	1.0%	
Other	4.4%	
Other responsibility		53.6%
Defective internal streetlight wiring	40.4%	
Defective customer equipment	7.4%	
Defective contractor equipment	1.9%	
DOT/city streetlight neutral	1.6%	
Other	2.2%	

Source: Data from Con Edison, Contact Voltage Test & Facility Inspection Annual Report, Consolidated Edison Company, submission to the New York Public Service Commission, 2012.

of ground reference and shunt resistor to eliminate capacitively coupled voltages (Kalokitis and Prazan, 2011). In cases where the object is painted, the tester must ensure that the tip of the probe touches bare metal. Disconnecting nearby sources is one way to narrow down the source of the fault. Note that one source can energize multiple objects.

Mobile electric field detectors can also be used in underground areas to survey large swaths of exposed equipment using electric field detection. (This only works in areas without overhead systems because the radiated electric fields from overhead lines can swamp that from energized objects.) Mobile detectors will detect electric fields from all surfaces, not just utility equipment. If a mobile detector indicates an issue, the crew can stop and locate the source or sources of the electric field. Because the mobile detector is testing all conductive surfaces, it also finds large numbers of energized objects not normally tested, including sidewalks, fences, and scaffolding.

When elevated potentials are measured, it can be difficult to determine the root cause of the voltage. Is it an elevated neutral-to-earth voltage? Is it from insulation failure causing a contact voltage? Other sources are also possible, including magnetic induction from current flow on parallel conductors or from electric field coupling from high-voltage lines (both relatively uncommon). The voltage waveform can give strong indications of the source of the voltage issue (EPRI 1020096, 2010; Dorr et al., 2013). If the voltage has significant harmonics present—more than 10% voltage total harmonic distortion (THD)—the source is likely to be from an elevated neutral-to-earth voltage. Elevated neutral voltages are generally from residual load current (the sum of the phase currents), so neutral-to-earth voltage

should match the waveform and harmonic content of this load current. If the voltage has small harmonics, normally less than 3% V_{THD}, the source is likely to be from a contact voltage from insulation failure. For contact voltage, the harmonic content will match that of the voltage source, and harmonics on system voltages are normally low. See Figure 14.25 for examples of each of these. Although contact voltages are common from 1 V to full line voltage, if higher voltages are measured (especially those above 8 V), the source is likely to be contact voltage from faulted equipment rather than elevated neutral voltages.

During flooding, utility equipment can become submerged. In testing of a pad-mounted transformer and a pedestal, EPRI measured relatively low touch potentials (EPRI 1020092, 2010). With the door closed, touch voltages from the water to the case on a transformer were less than 0.5 V. Even with the door open, touch voltages were less than 6 V. In these cases, the secondary compartment was energized with 120/240 V, and water conductivities from 67 µS/cm (tap water) to 1005 µS/cm were tested. When the same equipment was energized at 450 V, touch voltages increased but still remained below 1 V when the door was closed. Current flows through the water were about 0.5 to 2 A for the 120/240-V condition. Results for the pedestal were similar.

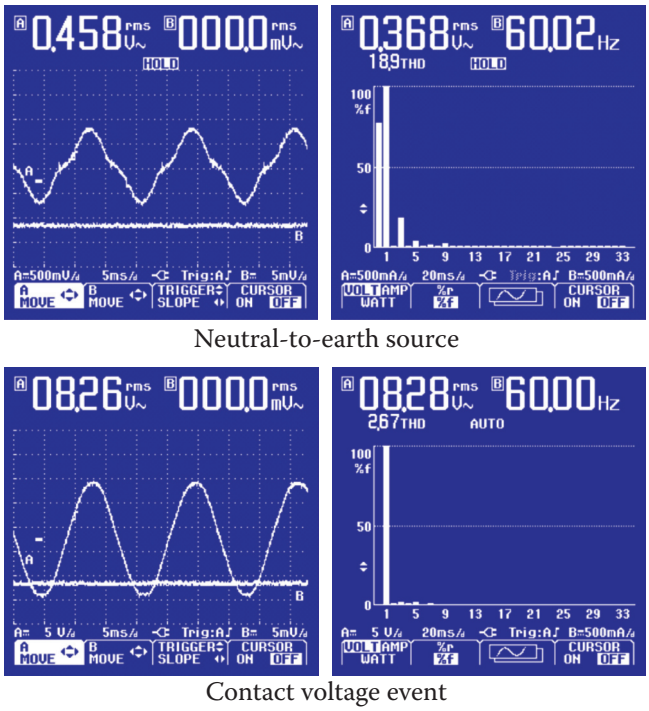

Figure 14.25 Example neutral-to-earth and contact voltages. (From EPRI 1020096, *Guidebook for Evaluating Elevated Neutral-to-Earth and Contact Voltages in Distribution Systems: Part 1: Swimming Pools, Water Bodies, and Other Wet Areas*, Electric Power Research Institute, Palo Alto, CA, 2010. Copyright 2010. Reprinted with permission.)

14.5.5 Tree Contacts

A tree in contact with an energized phase conductor may create touch potential hazards under certain conditions. For a tree in contact with one conductor, the resistance of the tree is high enough to remain a high-impedance connection; it will not draw enough current to operate a fuse or other protective device, but it may be enough to create significant touch potentials. St. Clair (1999) reported two electrocutions from tree contacts to 12.47-kV lines, one a tree trimmer and another at ground level where a man leaned against a tree that had fallen into conductors. Almost all of the time, tree contacts to distribution conductors are not hazardous because a tree draws little current when in contact with the primary and because the bark provides a high-resistance barrier. Under just the wrong conditions, touch voltages may become hazardous: if the bark barrier is breached, if a person has two low-resistance contacts (to two different tree parts or to the tree and ground), and if the energized primary conductor contacts a large limb or the tree trunk.

The body current for a touch potential to a tree involves many factors, including the resistance of the tree, the tree's resistance to ground in the earth, the conductor voltage, and a person's hand and foot contact resistances. The tree resistance is an important component of the electrical circuit, and it varies considerably. Hoffmann et al. (1984) measured a poplar tree and found the distribution of impedances shown in Figure 14.26, with impedances of 1.8 kΩ/ft (6 kΩ/m) near the base of the tree rising to 25 kΩ/ft (80 kΩ/m) near the top of the tree. The total impedance of this tree was 320 kΩ, which would draw from 0.2 to 0.7 A from a 12.47-kV line. Hoffman also found resistances from the base of the tree to ground of about 300 Ω for soil resistivities near 600 Ω-m. Defandorf (1956) measured resistances to ground in the range of

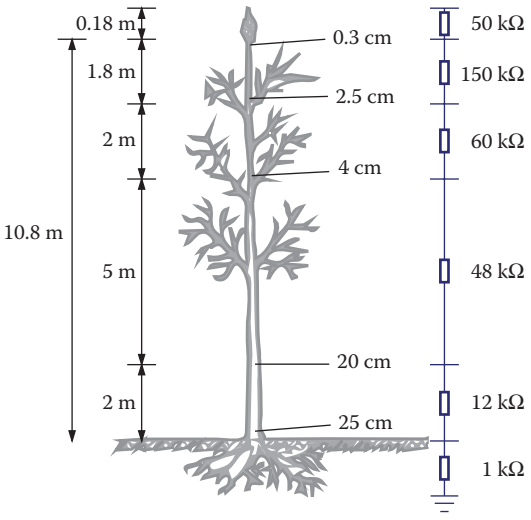

Figure 14.26 Resistance measurements on a live poplar tree. (From Hoffmann, E., Rheinbaben, H. v., and Stosser, B., *CIGRE Session*, 22–03, September 1984. With permission.)

10 to 40 kΩ for a tulip tree at typical distribution conductor heights, which would draw only 0.2 to 0.7 mA from a 12.47-kV line (7.2 kV line to ground). Hoffman et al. tested a tree contact to a 20-kV line, which drew 80 mA initially but rose to 600 mA with a potential at 6.6 ft (2 m) reaching 4 kV. Niagara Mohawk (Finch, 2001) tested several trees at 7.62 kV from line to ground—the highest current was just under 0.5 A (see Table 14.8). Larger tree limbs have lower resistances, so the most dangerous scenario is a primary conductor solidly contacting a large branch or the main trunk. Tree bark and shoes and the insulation that they provide often limit such currents below the let-go threshold.

Williams (1999) found tree touch voltages for a tree contacting a 12-kV circuit at 7 ft varied between 90 and 130 V (open circuit). But he found that the current through a shorting jumper at 7 ft (2.1 m) tied to a ground rod 2 ft (0.6 m) from the tree drew less than a milliamp of current (imperceptible to some people).

Texas A&M researchers tested several scenarios involving tree contacts to a single-phase portion of a 12.47-kV circuit (Butler et al., 1999). At 7 ft (2.1 m), the step voltages ranged from 200 to 1000 V. Voltage gradients along the bottom portion of the tree reached as high as 118 V/ft (387 V/m) during the tests. The current into the tree during the tests was about 1 to 2 A. Although they did not make any current measurements through a resistor or jumper, we can verify that these voltages can produce dangerous currents. For an 800-V step potential across 6 ft (1.8 m) of the tree and 2 A of current flow, this length of tree represents a resistance of about 400 Ω. For a body in parallel with the tree resistance, the current through the body is determined by a current divider. For this scenario with 2 A of current from the utility primary through the tree, any body with contact resistance less than 3600 Ω causes a possibly fatal 100 mA through the body. Trees passing this level of current hissed and crackled, which hopefully warns bystanders to stay away.

EPRI evaluated currents and touch voltages for several tree contact scenarios (EPRI 1016219, 2007; EPRI 1018463, 2008). For all tests where contacts were in the outer crown of tree, when energized at 7.2 or 7.6 kV, all total currents were less than 175 mA (see Table 14.9), and hand-to-foot touch voltages were less than 1 V when

TABLE 14.8 Current Drawn by Several Trees in Contact with 7.62 kV from Line to Ground

Location	Specimen	Maximum Current, mA
Test 1	Black gum	92
Test 2	Black gum	69
Test 3	Black cherry	110
Test 4	Black cherry	100
Test 5	White ash	37
Test 6	Aspen	484
Test 7	Red maple	125.5

Source: Adapted from Finch, K., Understanding tree outages, *EEI Vegetation Managers Meeting*, Palm Springs, CA, May 1, 2001.

TABLE 14.9 Maximum Touch Voltages and Peak Currents from Contact

	Peak Voltage at 1.5 m, V (No Bark Contact)	Peak Current, mA
Austrian pine, 7.2-kV contact		
Small twig in outer crown	42	35
Small branch, outer crown	64	62
Small branch	138	110
Pin oak, 7.6-kV contact		
Small twig in outer crown	4	37
Small twig in outer crown	12	75
Small branch, outer crown	28	175
Silver maple, 7.6-kV contact		
Small twig in outer crown	4.6	11
Small twig in outer crown	8	17
Small branch, outer crown	21	45

Source: Adapted from EPRI 1018463, *Overhead Distribution Vegetation Challenges: Touch Potential Voltage at Ground Level and Aloft in Trees Contacting Energized Distribution Conductors*, Electric Power Research Institute, Palo Alto, CA, 2008. With permission.

including bark contacts. Overall, the risk to the public is quite low for contacts to small branches in the outer crown.

The resistance of a tree's trunk and branches depends strongly on the diameter. Smaller branches in the outer crown add significantly to the overall impedance path and reduce currents drawn from the distribution line. Figure 14.27 shows tree resistances as a function of branch or trunk diameter using data from Hofmann et al. (1984) and EPRI 1018463 (2008).

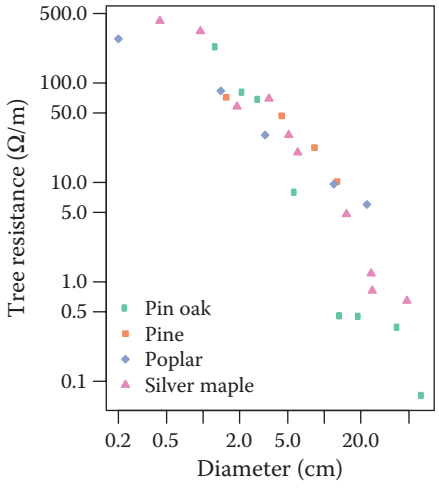

Figure 14.27 Resistance per length based on the diameter of the branch or trunk of the tree.

Figure 14.28 Open flame on a silver maple branch energized at 7.6 kV. (From EPRI 1016219, *Optimal Design of Overhead Distribution Systems: Understanding Touch Voltage Potential Risks Due to Tree-to-Conductor Contacts on Distribution Circuits*, Electric Power Research Institute, Palo Alto, CA, 2007. Copyright 2007. Reprinted with permission.)

Currents in the hundreds of milliamperes can be drawn if the contact point is to a larger-diameter main structural component of the tree. Such a condition may ignite flames and cause audible noise and often will not sustain because it burns itself clear. Two cases of ignition occurred during EPRI testing. Figure 14.28 shows flames igniting on a silver maple. In a similar event on a pin oak, current grew for several minutes until the branch burned clear of contact as shown in Figure 14.29. Hydro Quebec (Malo and Nguyen, 2007) reported similar results on tests of contacts on 25-kV circuits: smoke and arcing were visible along with audible noise, and the arc burned itself clear within an average of 7 min.

For touch voltages involving trees, bark plays an important role as a high-resistance barrier. The most conductive portion of a tree is the woody xylem tissue that

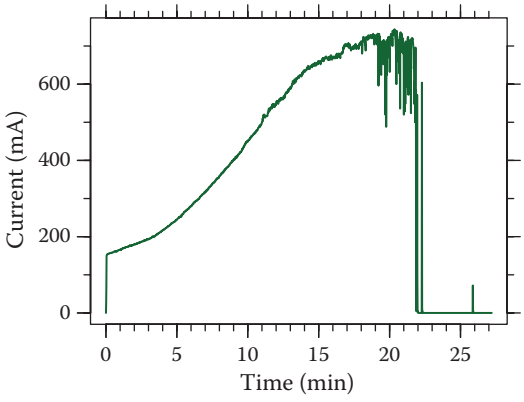

Figure 14.29 Current measured for contact with a pin oak that resulted in open flame. (Adapted from EPRI 1016219, *Optimal Design of Overhead Distribution Systems: Understanding Touch Voltage Potential Risks Due to Tree-to-Conductor Contacts on Distribution Circuits*, Electric Power Research Institute, Palo Alto, CA, 2007. Copyright 2007. With permission.)

transports nutrients (ions) in water solution from the roots to the leaves. This is the outer portion below the bark. Bark provides a relatively high-impedance barrier consisting of dry, corky tissue. During the EPRI tests, the overall impedance dropped significantly in cases where the bark burned through and contact was made with the underlying woody tissue. Risk increases if someone breaches the bark barrier, by cutting through it with a saw for example.

Wet soil lowers the earth resistivity and "grounds" the tree better, so more current will flow from the line. Foot-to-earth contact resistances are also lower with drenched soil, which draws more current through your body.

A climber aloft in close proximity to a conductor may experience elevated voltage gradients and available body current. This would be particularly true if the climber's weight deflects a larger branch into contact with an energized conductor. The level of current encountered may be high enough to trigger a startle reaction or potentially a more serious electrical injury. Contact impedance and the bark barrier normally limit body currents, so breaches of the bark are again the worst case.

Strategies to reduce the possibility of tree-related shocks include the following:

- Educate the public on the dangers of climbing trees in the vicinity of power lines.
- Educate the public on the dangers of cutting trees in the vicinity of power lines, especially aloft.
- Trim trees away from power lines, particularly large-diameter branches.
- Train tree-trimming crews and ground support crews properly.
- Use covered wire instead of bare wire.

Wooden poles can also cause dangerous touch potentials if a phase conductor contacts the pole directly. The U.S. National Institute for Occupational Safety and Health has documented more than one case where an electrical worker died when helping guide the butt of a pole into its hole at ground level after the top of the pole contacted a live distribution circuit. A key difference between poles and trees is that a worker is likely to be in series with a pole as it is being set whereas tree contacts normally involve parallel paths through the body. Resistance of wood poles plays an important role. Wood poles have a wide resistance, depending primarily on their internal moisture content and surface moisture (the resistance is largely independent of the pole species). Poles normally have higher resistance than live trees because they are drier. Stewart (1936) measured resistances of approximately 500 to 10 MΩ/ft (1600 to 30 MΩ/m) on a variety of treated and untreated poles. The lowest resistances are for new poles with moisture contents above 30%. Surface moisture, due to humid weather or rain, decreases a pole's resistance. Seasoned dry poles normally have resistances above 2.5 MΩ/ft (8 MΩ/m) when dry and 50 kΩ/ft (160 kΩ/m) when wet. A pole ground run along the pole will short circuit the pole's resistance and increase possible body currents. Wood pole contacts can pull more current at higher system voltages. If grounds are applied to poles before setting, the grounds will short circuit some of the pole's resistance and increase hazards. Insulating conductors and/or using pole guards to insulate the pole are options that reduce risks when setting poles.

14.6 Protective Grounding and Personnel Protection

Extensive repair or maintenance or installation work requires working the circuit deenergized. Remember the line worker's gospel:

If it is not grounded, it is not dead!

Or, better yet:

If it is not tested and grounded, it is not dead!

During deenergized work on a structure, protective grounds tie the phase conductors to a ground point. The main hazards this protects against are

- *Inadvertent energization*—Another worker could close a disconnecting switch, or another energized circuit could fall into the deenergized circuit. A switch failure could also inadvertently energize a circuit. Backfeed through transformer or capacitor banks or customer-side generation are also hazards.
- *Neutral-potential rise*—A fault on a circuit connected to the same grounding system can raise the neutral potential. Normally, this is a short-duration event.
- *Induction*—Fault current in closely coupled circuits can cause elevated voltages on any of the conductors being worked.

With a properly grounded protection system, line workers do not need rubber gloves. The combination of lockout and tagout (LOTO) procedures and protective grounds provide protection to the worker.

Utilities use two types of protective grounding systems: bracketed grounds and work-site grounds (IEEE Std. 1048-2003). Bracketed grounds are attached on structures on both sides of the work site. Work-site grounds are attached on the work-site structure. Work-site grounds protect workers (lower possible body currents) better than bracketed grounds. Work-site grounds provide the best protection, but keep them far enough away so that they do not interfere with the work on the structure and so the work does not disturb the jumpers. With work-site or single-point grounds, it is safest to have the grounding set on the source side of the work site. But, be careful, many lines may be energized from more than one direction. A work-site ground creates an equipotential zone that limits voltage differences. On overhead lines, this equipotential zone can be created by installing grounding jumpers between all three phases and the multigrounded neutral.

Many utilities also make a bond to a pole band on the pole. Bonner et al. (1989) found that this pole band reduced worker currents in some cases. For wooden poles, Wallace et al. (2006) argue that this band around the pole does not provide significant additional protection based on fault tests. For steel poles or other conductive poles, bonding to the pole is important to create an equipotential zone.

Note that if a pole has a transformer, and the cutout on the transformer is open or the fuse is blown, backfeeds from customer-side generation may energize the bottom of the open cutout (Lee and Hsu, 2002). This can be avoided by jumpering from the bottom of the cutout to another grounded conductor. Uninsulated guys, messengers, conductive booms, and other conducting objects must be accounted for to maintain an equipotential zone.

Bracketed grounds can effectively protect workers on multigrounded systems, but protection depends on distances to the bracket grounds, fault currents, and other variables. Puget Sound Power & Light allows bracket grounds up to 250 ft from the worker (King, 1990). If grounds are farther than one span, rubber gloves or other work practices may be appropriate (based on a thorough review).

Normally, crews tie protective grounds to the multigrounded neutral. On circuits without a multigrounded neutral, crews tie bonds together at a pole band, which may be bonded to a driven ground rod or guy anchor or other grounding point (see Figure 14.30). Crews may tie individual grounding jumpers from each phase to the neutral (or other bonding point), or they may jumper the three phases together and tie another jumper from a phase jumper to the pole ground. Excessive jumper lengths should be avoided. Protective grounds are normally applied to the multigrounded neutral first and then to the nearest phase conductors in order. Grounds are normally removed in reverse order of application. Grounds are normally applied with live-line insulated equipment: hotsticks and gloves.

In addition to protective grounding, isolation and/or insulation are also options for personnel protection, either alone or in combinations. *Isolation* is the separation of conductors that may be energized. Crews can isolate by opening cutouts, switches, or disconnecting conductors. A visible gap is preferable. *Insulation* is separation by a dielectric that may include insulating gloves, insulating boots, line hose, dielectric boots, and rubber mats.

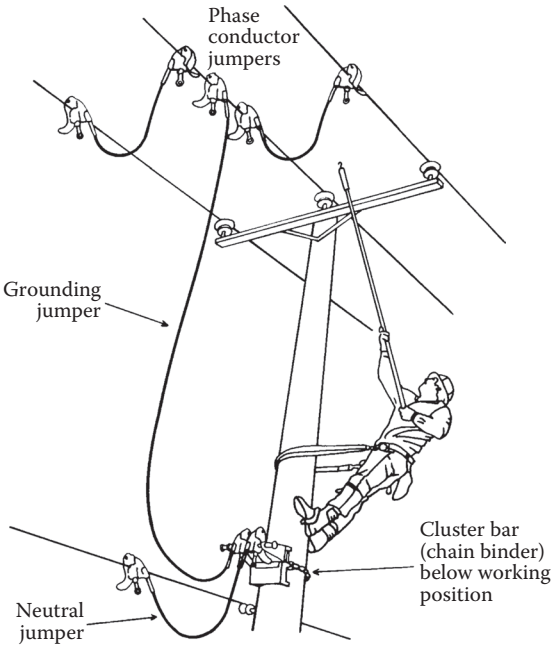

Figure 14.30 Work-site protective ground. (From Hubbell/Chance, Tips of the trade: Grounding, Bulletin 09-9001, 2000. With permission.)

Testing the line for voltage before installing jumpers is safer; attempting to jumper an energized line is extremely dangerous—a jumper that causes a fault creates an arc flash along with magnetic forces that can swing the jumper. A variety of testers attached at the end of live-line tools are available.

When the work is done, the protective grounds should not be removed until everyone is clear of the work site. When removed, the phase end should be removed first with an appropriate hotline tool.

On three-phase circuits, grounding all three phases is generally preferred since all three conductors on the pole become grounded. If the circuit is accidentally energized, a three-phase fault has higher fault current and may trip protective equipment more quickly. A three-phase fault also keeps most of the fault current out of the ground, which reduces step-and-touch potentials.

Protective grounding jumpers must withstand the heat generated during a fault, and they must withstand the mechanical forces. ASTM F-855 (1997) specifies requirements for grounding cables, clamps, and ferrules. Be sure to evaluate fault duties and X/R ratios when purchasing to assure that you have the correct equipment; for more information, see Kennerly and Eblen (2013).

Maintenance and proper application of grounding jumpers is important. Always clean conductor surfaces and tighten all terminals. Utilities should test protective-grounding sets periodically.

Underground work has special protective grounding issues (IEEE ESMOL Subcommittee 15.07, 2004). With insulated cables, protective grounding at the work site is often not possible. Both phase conductors and neutrals may be inaccessible at the work location, and as part of work to make a splice, workers will expose these and work with both such that local bonds are difficult. Normally, the cable is opened and bracket grounds are placed at the nearest switching points, but this may be hundreds of feet (meters) from the work site. In urban installations, duct banks often have several cables. Faults on adjacent cables may induce voltages at the work site (see Figure 14.31). The sheath covering the cable limits capacitive coupling between phases, but inductive coupling may induce voltages on the cable sheath. Since the cable sheaths are tied together, a portion of the fault current flows along the cable under repair; this current induces voltage in the cable phase conductors.

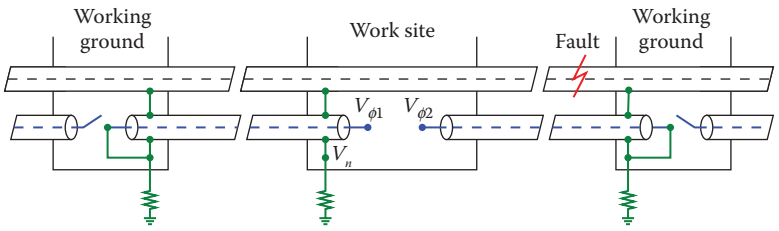

Figure 14.31 An underground cable under repair with a fault on an adjacent cable. (Adapted from Rajotte, Y. et al., *IEEE Transactions on Power Delivery*, vol. 5, no. 2, pp. 1026–1033, April 1990. Copyright 1990 IEEE. With permission.)

Field tests by Rajotte et al. (1990) found very small neutral-to-earth voltages in the manhole, less than 20 V on a 25-kV circuit with a 4800-A fault current. The voltages were low because the circuit tested had low ground resistivity (50 Ω-m) and many connections to ground.

On cables, the highest touch voltages occur between the two phases of the separated cable, and the highest voltages occur when the protective grounds are far from the work site. The voltages on the phase conductor are induced by current flow in the cable's concentric sheath. Since the phase and the concentric neutral have tight inductive coupling, significant voltage develops on the phase conductor for current flow through the concentric neutral. Rajotte et al. (1990) measured 169 V on the phase conductor of the cable; the protective ground on that cable was 1.6 mi (2.5 km) from the work site. The voltage between the two cables ($V\phi_1 - V\phi_2$ in Figure 14.31) reached 221 V. The two phase conductors have voltage of opposite polarity, so the voltage between the two is the sum of the voltages. The best way to reduce the voltages on the phase conductors is to keep the protective grounds close, preferably right at the work site, but as noted, this can be difficult on underground systems.

The voltage induced between the phase conductor and the neutral depends on the fault current (I) and the distance to the protective ground (d):

$$V_{\phi-N} = k\, d\, I$$

where k is a factor in ohms per unit length that is the coupling factor to the phase conductor; k depends on the number of cables in the duct bank, their size, and their position. Rajotte et al. (1990) calculated $k = 0.016$ Ω/mi (0.01 Ω/km) for a configuration with five 750-kcmil cables and $k = 0.1$ Ω/mi (0.06 Ω/km) for a configuration with two 350-kcmil cables. The voltage between two cable phase conductors is based on the sum of the length to the protective grounds on each side since the voltages add.

Some utilities use additional methods beyond bracket grounds to reduce risks on underground systems. Jumpering neutrals across cables to be cut is one option to reduce touch voltages. Grounding mats can be used to create an equipotential zone in a manhole or URD splice situation. Because cable conductors have to be exposed during splicing, this is not a complete equipotential zone, but it can reduce certain touch voltages. Insulated boots are an attractive option for vaults and manholes in urban underground because boots are often needed anyway because of water and mud in these facilities. It is difficult to use insulated gloves when splicing because it increases the likelihood of contaminating splices. Tying the rebar into the local ground is an option for creating an equipotential zone in vaults and manholes.

Lockout-tagout procedures are critical for personnel protection. In overhead situations, local protective grounds protect workers in most cases of inadvertent energization because the work-site grounds are so close to a worker. In underground scenarios, because protective grounds have to be remote in most cases, lockout–tagout procedures are critical. Unlike hazards from neutral voltage rise or from induction which are almost always short duration, a lockout–tagout failure can present a continuous hazard—the first fault can be that which the worker creates. While lockout–tagout failures are unusual, they can be very hazardous when they do happen. The

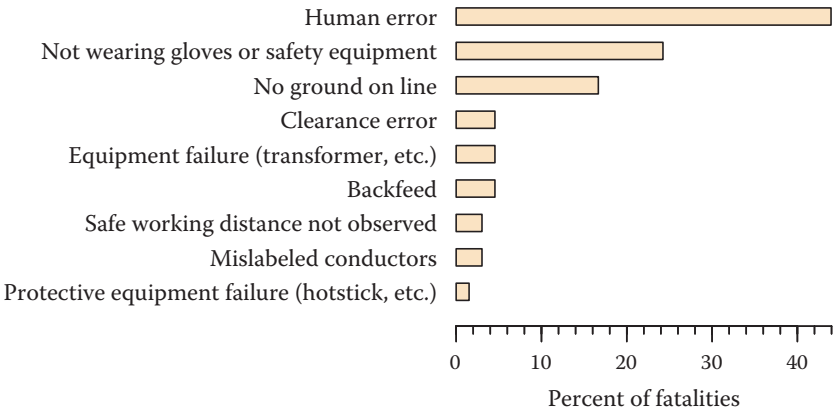

Figure 14.32 Transmission and distribution fatalities (4 to 46 kV) by cause from 1988–1990 from the International Brotherhood of Electrical Workers (IBEW) database ($n = 66$). (Data from EPRI 1001917, *Live Working Application Guide*, Electric Power Research Institute, Palo Alto, CA, 2002.)

probability of lockout-tagout failures depends on a utility's safety culture and the effectiveness of a utility's switching procedures.

When cutting cables, crews should use a cable spiking tool from a remote location. This prevents accidently faulting a live cable. Especially in locations with multiple cables, mistakes are possible when identifying cables. Even within one manhole or vault, cable identification can be tricky.

Before reenergization, crews must remove all protective grounds. Reenergizing into a set of grounding leads introduces other hazards, like failure of nearby equipment from fault current to the ground leads.

The Occupational Safety and Health Administration (OSHA) regulates several aspects of utility operations and equipment related to safety in OSHA Standard 29 CFR parts 1910 (Occupational Safety and Health Standards) and 1926 (Safety and Health Regulations for Construction). The Lineman's and Cableman's Handbook (Shoemaker and Mack, 2011) also has useful safety information.

Following proper procedures and using common sense are critical. Most accidents are not from equipment failure (see Figure 14.32); they are from human failure—carelessness, doing something stupid. The best piece of safety equipment is a brain—an alert, well-trained, and cautious brain.

14.7 Manhole Explosions

In urban underground systems, manholes and other underground enclosures can occasionally have explosions and other events that put the public at risk (Figure 14.33). Energetic events can launch manhole covers and even lift up the roof slab of a manhole. Flammable gas buildup from overheated or burning secondary cable is a leading

Figure 14.33 Example manhole event. (From EPRI 1015889, *Manhole Event Risk Management Strategies: High-Level Overview*, Electric Power Research Institute, Palo Alto, CA, 2008. Copyright 2008. Reprinted with permission.)

cause of such events. Primary arcs, natural gas pipe leaks, and electric cables burning into natural gas lines are other causes of manhole events.

Walsh and Black (2002, 2005) developed models for explosions in manholes, both for flammable gas buildup and for primary arcing faults. Generally, flammable gas explosions can cause more extreme forces on the manhole cover. For primary arcs, the energy released is the product of fault current, duration, and arc voltage. A fault with a current of 10 kA with an arc voltage of 2 kV and a duration of 0.2 sec releases 4 MJ. Typical EPRI tests with 10% methane in a 345-ft^3 (9.8-m^2) manhole release 40 MJ of energy and last 0.5 sec. With primary arcing events, smaller structures are worse because there is less volume of air relative to the energy released. With gas buildup, larger structures are worse because they can hold more flammable gas (EPRI 1015889, 2008).

The main improvement for primary arcing events is faster relaying. Manhole inspections and cable diagnostics are other tools to help reduce these events.

Overheated cable insulation can generate hydrogen, carbon monoxide, methane, ethylene, and acetylene. The explosive magnitude depends on the concentration of flammable gas as a portion of volume. At 10% to 12% concentration by volume of a UL gas mixture, manhole events can be very energetic, lifting roof slabs weighing 10 tons. Carbon monoxide and other flammable gases generated by cable faults can also migrate into customer facilities.

In 120/208-V cable, faults generally have high arcing impedance and often arc with currents well below what would be needed blow a cable limiter. Arcing can sustain until it burns itself clear, and arcing can also be intermittent. Sustained arcing is more likely in wet, muddy ducts. Heating causes thermochemical decomposition of organic material (pyrolysis) in cable insulation and some duct materials. Arcing can begin where cable insulation has been damaged (possibly during installation) or has deteriorated from thermal aging. Heated insulation becomes brittle and can crack. Once cracked, electrical tracking and carbonization can occur at the cracks, especially with salt water. Road salts applied during the winter can especially trigger faults in secondary cables. Zhang et al. (2009) reported that 71% of the manhole events on the Consolidated Edison occurred in structures containing mud, and the winter failure rate was three times higher than that at other times. They also reported that older cable is more likely to degrade because it has a lower oxidation induction temperature.

Zhang et al. (2009) describe two types of events, one electrically driven and a more common event driven by combustion. In the electrically driven event, high arc energies at the fault burn up oxygen, and then pyrolysis rapidly generates gases that are pushed to the nearest manholes. With sufficient air flow, combustion of cable insulation may sustain in the duct. Often, these become smoldering events, and sometimes combustion can sustain. These combustion-driven events tend to develop more slowly than the electrically driven event and can drive gases to spread to multiple manholes. Simulations by Zhang et al. (2011) show gas generation increases with increasing airflow in combustion-driven events, suggesting that ways to reduce airflow may reduce the severity of combustion-driven events.

One large utility with 70,000 manholes and 180,000 service boxes has approximately 1400 events annually (EPRI 1015221, 2007). Of 1523 events, 2% were explosions, 9% were displaced covers, 17% were fires, and 72% were smokers (EPRI 1015889, 2008).

Flammable gases can migrate along ducts from one manhole to another, and events have taken place where manhole covers have been dislodged at multiple locations. EPRI 1015889 (2008) estimated gas can migrate at approximately 0.5 to 1 ft/sec (0.15 to 0.3 m/sec) along a 4-in. (10-cm) empty duct. Burning cables have also been reported to damage primary cables.

Vented manhole and service box covers (Figure 14.34) reduce the risk of flammable gas buildup in underground enclosures. If an explosion does occur, a vented cover responds similarly to a solid cover; there is marginal pressure relief during an event. The main benefit of vents is to release gases to prevent accumulation. Vented covers do not help for events driven by primary-voltage fault arcs. Venting does allow debris to more readily enter structures, including mud, rocks, and road salt. Vented covers can become clogged, making them act like nonvented covers, and the clog can be difficult to clean even with an air compressor (EPRI 1015223, 2007). Rain is unlikely to be able to naturally clean clogged covers.

A manhole cover with controlled pressure relief has been shown to provide pressure relief while still containing the cover. The cover in Figure 14.35 has a fixed latch and a breakaway latch with two shear pins. In tests of small and medium events, this manhole cover successfully relieved pressure and contained the manhole cover (EPRI

Figure 14.34 Vented manhole cover. (From EPRI 1015889, *Manhole Event Risk Management Strategies: High-Level Overview*, Electric Power Research Institute, Palo Alto, CA, 2008. Copyright 2008. Reprinted with permission.)

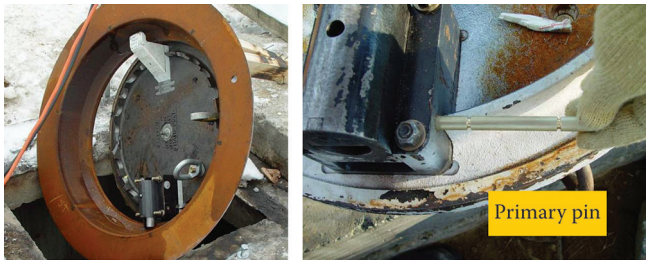

Figure 14.35 Bottom view of a manhole cover with controlled pressure relief. (From EPRI 1015889, *Manhole Event Risk Management Strategies: High-Level Overview*, Electric Power Research Institute, Palo Alto, CA, 2008. Copyright 2008. Reprinted with permission.)

1012305, 2006). In a major event, the secondary shear pin may break and release the cover, but in major-event tests, the roadbed lifted before the shear pin broke.

14.8 Arc Flash

Arc flash from faults on distribution circuits is a safety issue that can impact work practices, protection requirements for line and substation workers, and relay and other overcurrent protection settings and practices. The severity of an arc flash event depends on many factors, including the worker position relative to the fault, the fault duration, the fault current magnitude, and the gap spacing and arc length as it bridges the gap through the air. Generally, the most dangerous locations are where fault currents are high and clearing times are long. Some include

- Live glove work in a substation with high-side fusing
- Racking out a circuit breaker

- Open-air work on circuits with slow relays
- Work on 480-V self-contained meters
- Any work in 480-V secondary networks, especially network protector maintenance

Industry data on arc flash incidents is sparse. An industry group, including the IBEW, OSHA, the National Electrical Contractors Association, and the EEI evaluated OSHA utility electrical accident data from 1995 to 2003 (IBEW, 2005). The breakdown of electrical accident cause was 80% from contact, 10% from falls, 6% from being struck by objects, and 3% from arc burns. An update of this data to 2006 is shown in Table 14.10. This data mainly includes severe accidents (two–thirds involved fatalities). Clearly, contact is a much more important cause for utility electrical accidents. When considering changes to work practices or equipment to improve arc flash protection, we should take care not to negatively impact the likelihood of accidents from contact, falls, or other causes.

Analyzing arc flash and determining the level of incident energy that might occur and comparing to worker clothing is an overcurrent coordination problem, much like protecting against conductor burndown or transformer damage. For arc flash, the goal is to greatly reduce the chance of burns to workers if an arc occurs near a worker. We want a protective device to clear the fault before a fault arc could cause incident energy in excess of the rating of the clothing.

The severity of an arc flash event is normally quantified as the incident energy that would reach a worker, normally given in terms of cal/cm^2. Flame-resistant (FR) clothing systems have an arc thermal performance value (ATPV) rating, based on ASTM test standards (ASTM F1959, 2006). This rating is the incident energy in cal/cm^2 on the clothing surface that has a 50% probability of causing a second-degree skin burn. The goal of an arc flash analysis is to ensure that workers have an ATPV protection sufficient to handle the incident energy that might be expected in a given work scenario. Out of 17 responses to an EPRI survey, seven use minimum ATPV ratings from 5 to 8 cal/cm^2, and nine use 8 cal/cm^2 or more (EPRI 1020544, 2009). 65% of responses reported that they vary clothing rating by project type. Some utilities allow short sleeve FR shirts for live-line work where arms are covered by rubber sleeves.

A number of approaches are available for estimating arc flash. The two most commonly cited methods are the ARCPRO program (Kinectrics, 2002) and the IEEE

TABLE 14.10 Annual Averages for Electrical Accidents from OSHA Form-170 Accident Reports

Main Cause	Average Number Annually
Contact	35.9
Falls	9.9
Arc flash/burn	4.9
Struck by	4.8
Caught between	2.6

Source: Adapted from EPRI 1018694, *Distribution Arc Flash: Industry Practices*, Electric Power Research Institute, Palo Alto, CA, 2009. With permission.

Note: 1995–2006 data.

1584 method (IEEE Std. 1584-2002). The IEEE 1584 method is based on curve-fit regressions to mainly three-phase arc-in-a-box tests and is most suitable for arcs in equipment and other arc-in-a-box scenarios. ARCPRO is based on a single arc in open air, so it is most suitable for overhead, open-air scenarios.

IEEE 1584-2002, was developed by the IEEE Industry Applications Society, a society focusing on industrial and commercial power. IEEE 1584 is the most widely adopted approach to arc flash analysis. The method for estimating arc flash incident energies is based on tests performed at several short-circuit labs. From this test set, regression was used to find equations to best fit the test data. IEEE 1584 assumes a three-phase fault and is mainly geared toward arc-in-a-box evaluations. The IEEE 1584 working group developed the following equations to fit the test results for systems below 15 kV:

$$lgE_n = K_1 + K_2 + 1.081 \log_{10} I_a + 0.0011G$$
$$E_n = 10^{lgE_n} = 10^{K_1+K_2} I_a^{1.081} 10^{0.0011G}$$
$$E = C_f E_n \frac{t}{0.2}\left(\frac{610}{D}\right)^x$$

where

lgE_n = base 10 log of incident energy E_n
E_n = incident energy, normalized to a distance of 24 in. (610 mm) and a duration of 0.2 sec, cal/cm^2
E = incident energy, cal/cm^2
K_1 = −0.792 for open configurations
= −0.555 for box configurations (enclosed equipment)
K_2 = 0 for ungrounded and high-resistive grounded systems
= −0.113 for grounded systems
I_a = arc current, kA
G = distance between buses, mm (see Table 14.11)
C_f = calculation factor for a 95% confidence, 1.0 for medium voltage and 1.5 for low voltage
t = fault duration, sec
D = distance from the possible arc point to the person, mm
x = distance exponent (see Table 14.11)

The IEEE 1584 spreadsheet uses the gap between conductors based on the equipment type selected as given in Table 14.11. The gap between conductors is not a direct input.

The arc current can be found from the bolted fault current as follows:

$$\log_{10} I_a = K + 0.662 \log_{10} I_{bf} + 0.0966V + 0.000526G + 0.5588V \log_{10} I_{bf} - 0.00304G \log_{10} I_{bf}$$

TABLE 14.11 IEEE 1584 Factors for Equipment and Voltage Class

System Voltage (kV)	Equipment Type	Gap between Conductors (in.)	Gap between Conductors G (mm)	Distance Factor x
0.208–1	Open air	1.2	32	2.000
	Cable	0.5	13	2.000
	Switchgear	1.2	32	1.473
	MCC and panels	1	25	1.641
>1–5	Open air	4	102	2.000
	Cable	0.5	13	2.000
	Switchgear	4	102	0.973
>5–15	Open air	6	153	2.000
	Cable	0.5	13	2.000
	Switchgear	6	153	0.973

Source: Adapted from IEEE Std. 1584-2002, *IEEE Guide for Performing Arc-Flash Hazard Calculations*. With permission.

where

I_a, arc current, kA
I_{bf}, bolted fault current, kA
K, −0.153 for open configurations
−0.097 for box configurations (enclosed equipment)
V, system voltage, kV
G, distance between buses, mm

Above 15 kV, the IEEE 1584 guide and companion spreadsheet default to the Lee method (Lee, 1982). The Lee method is the oldest arc flash calculation method. It is a simple model of a single, open-air arc. For medium-voltage applications, the Lee method produces unrealistically high predictions of incident energies. For 25- and 35-kV scenarios, consider using the 15-kV results from the IEEE spreadsheet as suggested in EPRI 1022697 (2011) and Short (2011). Figure 14.36 shows time–current curves based on IEEE 1584 that are suitable for medium-voltage switchgear. A protective device should clear before the time indicated on the appropriate curve. For different clothing, the curves can be shifted. For 4-cal/cm^2 clothing, the protective device must operate twice as fast as with 8-cal/cm^2 clothing.

IEEE 1584 provides the typical working distances given in Table 14.12 and defines working distance as the distance from the worker to the front of the equipment plus the distance from the front of the equipment to the potential arc source in the equipment.

ARCPRO is a commercial program for analyzing arc flash incident energies, developed by Kinectrics. The ARCPRO algorithm is based on the work of Bingwu and Chengkang (1991), but it is not completely described in any peer-reviewed paper. The ARCPRO model assumes the following (Cress, 2008): a vertical free burning arc in air, an arc length much greater than arc diameter, a one arc column, either phase-phase, or phase-ground, no electrode region heat transfer, and an optically thin plasma and gas. Cress (2008) reported that ARCPRO was verified with over 300 test

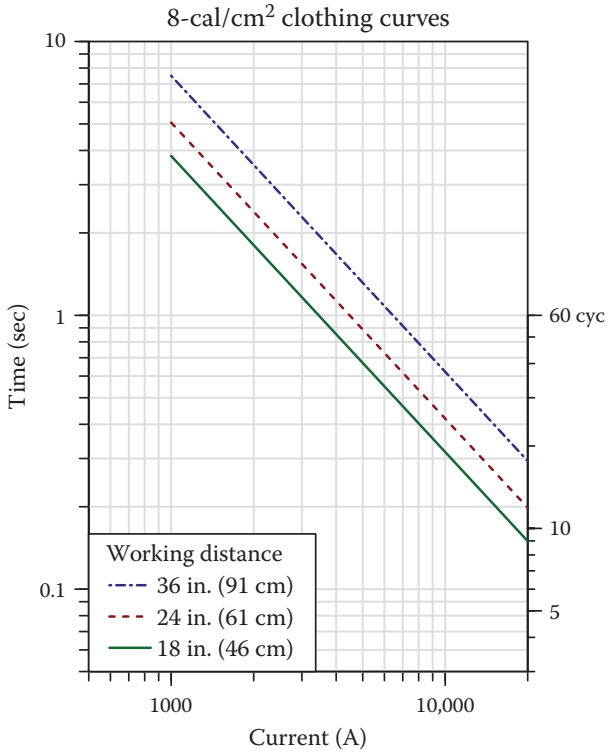

Figure 14.36 Arc flash time–current curves for medium-voltage switchgear based on IEEE 1584 and 8 cal/cm^2 clothing.

TABLE 14.12 IEEE 1584 Typical Working Distances

Classes of Equipment	Typical Working Distance, in.
5- and 15-kV switchgear	36
Low-voltage switchgear	24
Low-voltage MCCs and panelboards	18
Cable	18

Source: Adapted from IEEE Std. 1584-2002, *IEEE Guide for Performing Arc-Flash Hazard Calculations*. With permission.

points for arc energy and incident energy for currents from 3 to 25 kA, arc durations from 4 to 35 cycles, distances from 8 to 24 in. (20 to 60 cm), and with gaps from 1 to 12 in. (2.5 to 30 cm).

The key input parameters for arc flash analysis are

- *Working distance*—Distance from the worker to the fault arc is an important input. Incident energies drop significantly with distance, normally as a power of $1/d^{1.5}$ to $1/d^2$.
- *Arc length*—Some arc flash models like ARCPRO include an arc length. The arc energy increases almost linearly with arc length. Arc lengths and arc voltages are

primarily a function of gap spacings, not the system driving voltage. The arc length is different than the shortest gap between energized conductors or between an energized conductor and ground. Because a fault arc can move and elongate, the arc length is normally longer than the gap length. IEEE 1584 includes a gap length internally in calculations.

- *Fault current*—For medium-voltage arc flash, engineers commonly assume a bolted fault. For low-voltage arc flash (under 1000 V), the arc impedance will reduce the fault current appreciable, so the arcing current is needed.
- *Duration*—The duration is based on the clearing time of the upstream protective device(s) based on its time–current characteristics. For very long or indeterminate clearing times, a worker self-extraction time is sometimes assumed as a maximum duration to consider. IEEE 1584 mentions two seconds for this duration. Even 2 or 3 ft of movement away from the fault or to the side will dramatically reduce incident energies.
- *Fault type*—Whether the fault is a single phase-to-ground fault, a phase-to-phase fault, or a three-phase fault will affect the fault current and the duration. For faults in equipment, three-phase faults are commonly assumed, as it is likely for the fault to expand to involve all three phases.

The NESC (IEEE C2-2007) starting with the 2007 edition requires an arc flash assessment be performed on systems above 1000 V. They do not provide specifics in general but do offer a table with default assumptions based on an ARCPRO analysis for open-air with single phase-to-ground faults. NESC footnotes specify a 15-in. (38-cm) separation distance from the arc to the employee for glove work and arc lengths as follows: 1–15 kV = 2 in. (5 cm), 15.1–25 kV = 4 in. (10 cm), 25.1–36 kV = 6 in. (15 cm). Figure 14.37 shows time–current curves for 8-cal/cm^2 clothing based on ARCPRO with the 15-in. (38-cm) working distance along with various arc lengths. Because Short and Eblen (2012) found that the default arc lengths in the NESC are low, longer arc lengths are also shown.

As an overcurrent protection problem, two related assumptions are made for arc flash:

1. The incident energy increases linearly with time. If you double the duration, the incident energy doubles. All of the modeling approaches make this same assumption.
2. At lower currents and longer durations, the main impact is due to lower current. Most models have almost a linear relationship between arcing current and incident energy: if the current doubles, the incident energy doubles.

At longer durations, these assumptions are uncertain. As in Figure 14.37, incident energies often become more of a concern where fault currents are lower and durations are longer. Arc flash models have been mostly tested with durations less than 0.5 sec. At longer durations, several factors can come into play: the arc can move and/or elongate (increasing energy), the arc may involve additional phases (increasing energy), and the arc may self-extinguish (decreasing energy).

Another consideration is arc impedance. At low voltages, this is important to consider. Above 1000 V, a bolted fault is most appropriate. The arc in an arc flash scenario involves relatively low arc resistances. A 3-ft (1-m) arc has a voltage of about 1400 V. If

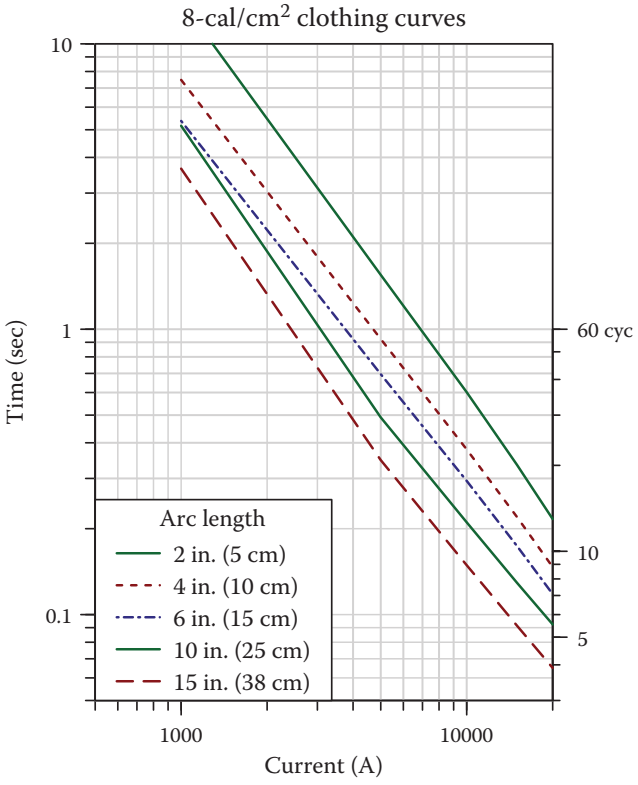

Figure 14.37 Arc flash time–current curves for overhead glove work based on ARCPRO with a 15-in. (38-cm) working distance and 8 cal/cm^2 clothing.

the fault current at that point in the line was 1000 A, then the arc resistance is about 1.4 Ω. A 1-ft (0.3-m) arc with the same fault current has a resistance of 0.47 Ω. Most fault arcs have resistances of 0 to 2 Ω, so that can be used as guidance to find the minimum fault current.

Wilkins et al. (2005) and Stokes and Sweeting (2006) showed that electrode orientation makes a significant difference in the direction in which the energy from the arc projects and a significant difference in incident heat energy. Wilkins et al. (2008) showed that arc sustainability and incident energy are also impacted by insulating barriers.

A number of relaying options are available to reduce incident energies, depending on the application (Buff and Zimmerman, 2008). Common approaches include reducing clearing times by enabling a fast trip and disabling reclosing during maintenance work. Other options are available to coordinate relaying times with clothing capabilities and with work practices.

Arc flash for glove work in overhead distribution is important to understand as that work is common. For gloving work, utilities can normally use 4 to 8 cal/cm^2 clothing using the NESC assumptions for arc length. Once initiated, a fault arc in open air can grow and move quickly. Magnetic forces from the fault current dominate the arc movement. The fireball is normally pushed in the same direction as the

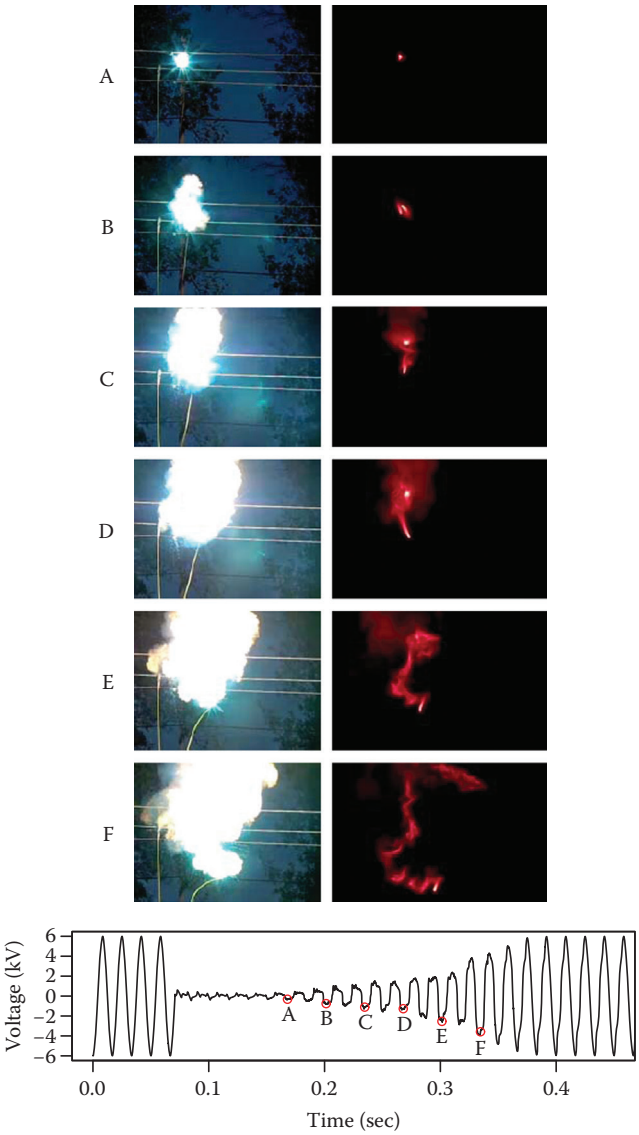

Figure 14.38 Video snapshots and voltage waveform for a jumper pulling an elongating arc. (From EPRI 1018693, *Distribution Arc Flash: Analysis Methods and Arc Characteristics*, Electric Power Research Institute, Palo Alto, CA, 2009. Copyright 2009. Reprinted with permission.)

arc, and it also rises vertically from thermal forces. Even in open air, some fault scenarios are directional, meaning the fireball is focused in one direction (like a flamethrower), similar to arc-in-a-box-type faults.

Even if arcs start across a short gap, the arc length and arc voltage can increase rapidly. Figure 14.38 shows results from a test with a phase-to-phase jumper tied solidly at one end and through a #12 wire at the other to mimic a case where a worker accidently jumpers an energized phase to a grounded conductor or to another

energized phase. During the test, the #12 wire acts as a fuse and burns away within a short time, and the arc is free to move. In this particular event, the #12 wire took several cycles to burn away because more than one wire was jumpered to the stirrup. Once the connector wire burned away, the voltage and arc length increased to several feet (more than 1 meter) until the fault self-cleared. The 4160-V source was unable to sustain an arc that long. For 15 to 35-kV systems, much longer arcs could be possible. Staged tests show that the energy released into the fireball surrounding the arc tends to get pushed magnetically away from the source, especially in a phase-to-phase event, moving at tens of feet per second. Arc movement can also cause the arc to contact a worker. Arc movement can play a role in guidance for worker positioning. Working alongside a line is relatively safe because arcs are likely to motor past the worker. On a dead-end structure, positioning on the open side of the dead-end has the highest risk because arcs will push toward the worker.

Testing (EPRI 1018693, 2009; Short, 2011) showed that conductor covers are effective at reducing the likelihood of flashovers to protected conductors from a fault initiated elsewhere. This helps support an analysis assumption of just a single line-to-ground fault, and supports having crews cover energized conductors as much as possible.

Testing has shown that the NESC arc lengths are unrealistically short (EPRI 1022697, 2011; Short and Eblen, 2012), so consider longer arc lengths in analysis. Adequate and reasonable arc lengths are still undecided in the industry. While testing has shown that the NESC arc lengths are unrealistic, more industry experience, including evaluation of incidents and incident rates, is needed to determine the most appropriate assumptions for overhead arc flash analysis.

Arc flash analysis is still in its infancy, and further advances in modeling and protection are expected. Arc flash energies are equipment specific. In some cases, existing methods do not adequately predict performance. Short and Eblen (2012) show test results for a medium-voltage padmounted switch with incident energies three times that predicted by IEEE 1584. The higher incident energies were caused by the horizontal bus configuration, which projected arcs out the front of the enclosure (see Figure 14.39). They provide the following equation to relate incident energy to fault current, duration, and working distance:

$$t^{1.35} = \frac{E\, d^{2.10}}{k \cdot 3547 I^{1.50}}$$

where

E = incident energy, cal/cm^2
I = fault current, kA
d = working distance, in. (1 in. = 2.54 cm)
t = duration, sec
k = safety multiplier to increase incident energy predictions

This equation is based on a regression model with an average fit. By adding a safety multiplier of $k = 1.15$, we shift the clothing curve to cover most of the test points used to develop the model, especially at larger incident energies.

Figure 14.39 Example arc flash in a medium-voltage padmounted switch. (From EPRI 1022697, *Distribution Arc Flash: Phase II Test Results and Analysis*, Electric Power Research Institute, Palo Alto, CA, 2011. Copyright 2011. Reprinted with permission.)

Another surprise in these measurements is that the incident energy is not linear with time. Most arc flash calculations (including IEEE 1584 and ARCPRO) assume that the heat rate is constant, so doubling the duration doubles the incident energy. Based on the regression model for the medium-voltage switch, if you double the duration, incident energy increases by a factor of 2.55.

The nonlinear effect of duration may be at least partially explained by the propagation of the fireball as time progresses. The fireball takes time to reach the calorimeters. Assuming that a significant portion of the energy absorbed by a calorimeter is from convection from the hot gases, the incident energy will increase the longer the calorimeter is engulfed in the fireball. The rate of expansion of the fireball diminishes with time.

Arc flash in manholes or vaults has the additional hazards of crews working in confined space. Testing by Con Edison has shown that arcs initiated in splices and cables can be highly directional (see Figures 14.40 and 14.41). In a series of tests of failures initiated in solid-dielectric splices at 24 kA for 12 cycles (0.2 sec), maximum incident energies at 18 in. (46 cm) had a median of 19.4 cal/cm^2 and varied from 8 to almost 40 cal/cm^2. Variability was due to directional variations and variability in arc energies. The arc voltage can vary based on how the splice faults, how far the path is from the phase to the neutral, and how the arc bends and lengthens once the fault starts. The arc voltages had a median of 1.1 kV and a typical range between 0.7 and 1.5 kV; these correspond well with tests done by Hydro Quebec on cable and splice failures reported by Koch and Christophe (1993). See Chapter 8 for more information. Comprehensive tests of incident energies from cable or splice failures with measurements at different distances have not been done. Neither IEEE 1584 nor ARCPRO match the Con Edison results very well, but of the two approaches, IEEE 1584 is

Figure 14.40 Con Edison PILC splice failure test. (From EPRI 1018693, *Distribution Arc Flash: Analysis Methods and Arc Characteristics*, Electric Power Research Institute, Palo Alto, CA, 2009. Copyright 2009. Reprinted with permission.)

closer. It may be better to extrapolate the Con Edison results at 24 kA and 12 cycles by assuming that incident energies vary linearly with current and duration.

For low-voltage arcs, arc sustainability is an important consideration—arcs will self-extinguish in many scenarios. Arc sustainability depends on the size and spacings of internal buses and conductors. Arcs are more likely to sustain with tight spacings between conductors and tight cabinet spacings that help contain the arc and fireball. Larger conductors or busbars provide more material to hold the arc. Below 250 V, it is rare to find conditions where high-current arcs can sustain in an arc flash scenario. At 480 V, arc sustainability is highly dependent on equipment. Table 14.13 shows 2012 NESC requirements for minimum clothing needed for workers for different types of

Figure 14.41 Infrared filtered video frames of an EPR splice failure. (From EPRI 1018693, *Distribution Arc Flash: Analysis Methods and Arc Characteristics*, Electric Power Research Institute, Palo Alto, CA, 2009. Copyright 2009. Reprinted with permission.)

TABLE 14.13 NESC Clothing Systems by Equipment

	Nominal Voltage Range and cal/cm²	
Equipment Type	50–250 V	251–600 V
Network protectors	4	Study needed
Metal-clad switchgear/motor control centers	8	40
Self-contained meters/cabinets	4	20
Subsurface/pedestal-mounted equipment	4	8
Padmounted transformers	4	4
CT meters and control wiring	4	4
Open air (includes lines)	4	4

Source: Adapted from IEEE C2-2012, *National Electrical Safety Code*. With permission.

low-voltage equipment in lieu of a study. If the equipment is not covered by this table, a detailed study may be needed. This table is partially based on tests documented by Eblen and Short (2010, 2012; EPRI 1018693, 2009; EPRI 1020210, 2009).

Self-contained meter sockets at 480 V can have significant incident energies. Tests of arc flash in single-socket 200-A enclosures showed incident energies generally below 25 cal/cm², and incident energy decreases as available fault currents increase. At higher fault currents, arcs self-clear faster by burning up electrodes. Ringed meter sockets tend to focus energies more than ringless designs because the enclosure opening is smaller (EPRI 1023267, 2011). Multisocket and 320-A meter enclosures can contribute much more incident energy because faults may not self-clear due to the size of electrodes in this equipment (EPRI 1022002, 2011). Note that these energies can be much higher than the 20 cal/cm² listed for self-contained meters in the 2012 NESC. This equipment should be deenergized before work. CT-style meter enclosures have very low incident energies because the small voltage leads into the enclosures act like fuses and extinguishes the arcs quickly.

Live network-protector maintenance at 480 V has significant arc flash hazards, and several workers have been killed in accidents. Network protectors have substantial busbar and tight spacings, and spot networks often have fault currents exceeding 100 kA usually without overcurrent devices that can clear quickly for faults in protectors. Options to reduce hazards in 480-V spot networks include (EPRI 1022002, 2011)

- *Deenergize the feeder*—This deenergizes the source side of the network protector and reduces fault current, and most importantly, it greatly reduces energized buswork in protectors.
- *Open adjacent network protectors*—This limits fault current. Maintenance may need to be scheduled when the network load is low enough to allow this.
- *Heavy arc suits*—100 cal/cm² suits are available, and many network protector sites have incident energies less than this (depending on assumptions for clearing time and working distance) or can be reduced to this level by opening adjacent protectors.
- *External fuses or disconnects*—This option allows crews to completely deenergize a network protector. Opening the external fuse or disconnect can be treated as an open-air application if the only exposure is line to ground.

- *Safer protectors*—Options include deadfront designs, remote racking, and relaying to detect faults and trip the network.

IEEE 1584 is an appropriate approach for analyzing 480-V spot networks, and because this application is not covered by the 2012 NESC, a study is needed. Utilities normally assume either a self-extraction time that limits duration or assume that internal network protector fuses operate. Both assumptions allow work in many spot networks with available arc flash suits. Both assumptions also have disadvantages. Utilities use two main working distances for calculations: 18 in. (45.7 cm) and 24 in. (61 cm). To use 24 in. (61 cm), confirm that tools and working procedures are compatible with the 24-in. distance. Distance is important because incident energies are approximately 35% lower at 24 in. (61 cm) than at 18 in. (45.7 cm).

Some 480-V equipment has less risk of arc flash. This includes many CT cabinets, overhead line work, and the secondary compartment of padmounted transformers. In each of these, the electrode spacings are wide enough and/or the compartment is large enough that arcs expand out and have difficulty sustaining.

The energy in an arc increases with arc current. The severity of an arc flash does not necessarily increase with fault current. Some of the most hazardous scenarios are at lower fault currents because clearing times are longer. Many overcurrent protection devices such as fuses and relays have inverse time operating characteristics, meaning that it takes longer to operate for lower currents. In addition, at 480 V, in some equipment, the worst condition is not the highest current because at higher currents, the fault burns itself out or blows itself out faster at higher currents. For 480-V self-contained meters, faults with an available fault current of 12 kA had incident energies that were three times that of faults with a bolted fault current of 44 kA.

At 8 cal/cm^2, the NFPA 70E (2012) requires face protection (balaclava or arc-rated face shield). Most utilities do not require face protection beyond standard safety goggles even if they specify that calorie rating (like 8 cal/cm^2). In a survey (EPRI 1020544, 2009), utilities cited several issues with wearing face protection, including limited visibility, heat stress, communication difficulties, worker discomfort, and the possibility that a face shield could make things worse by trapping hot gases under the shield (chimney effect). Many utilities do use additional face protection for high-incident-energy scenarios, like 480-V self-contained meters or racking out certain circuit breakers.

Use of a worker "self-extraction time" is an area of debate. This assumption considers the time it would take for someone to get out of the way of the arcing energy. In a survey, half of the utilities considered a self-extraction time in calculations, and a majority of these assumed 2 sec (EPRI 1020544, 2009). Risk factors to consider include the work being done and fault current magnitudes. For overhead line work, if the self-extraction time only comes into play at fault currents that are below the minimum bolted fault currents on the line, then this assumption carries little risk. If the assumption applies to high fault-current scenarios in an underground vault with minimal maneuvering space, the risk may be high.

Proper work practices are critical for arc flash protection. The best protection method is to avoid starting arcs. Training and education, good communications,

supervision, using appropriate personnel, providing and using appropriate tools, and having sensible procedures will help reduce risks.

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Some crane and digger operators think that "up just a touch" means a bare minimum of 12 inches.

Powerlineman law #41, By CD Thayer and other Power Linemen,
http://www.cdthayer.com/lineman.htm

15

Distributed Generation

Contents

15.1 Characteristics of Distributed Generators 800
15.1.1 Energy Sources 800
15.1.2 Synchronous Generators 801
15.1.3 Induction Generators 806
15.1.4 Inverters 806
15.1.5 Modeling Small Generators 809
15.2 Islanding Issues 810
15.2.1 Effect of Transformer Connections on Overvoltages 812
15.2.1.1 Overvoltage Relays and 59G Ground Fault Detection 815
15.2.1.2 Effectively Grounding a Grounded-Wye–Grounded-Wye Transformer Connection 816
15.2.1.3 Sizing a Neutral Grounding Reactor on a Grounded-Wye–Delta Connection to Maintain Effective Grounding 817
15.2.2 Anti-Islanding Protection 818
15.2.3 Active Anti-Islanding 819
15.2.4 Relaying Issues 820
15.2.5 Self-Excitation 823
15.2.6 Ferroresonance 825
15.2.7 Backfeed to a Downed Conductor and Backfeed Voltages 826
15.2.8 Overvoltages from Inverters with Light Load 827
15.3 Protection Issues 827
15.3.1 Trade-Off between Overvoltages and Ground Fault Current 831
15.3.2 Fuse-Saving Coordination 832
15.4 Power Quality Impacts 833
15.4.1 Voltage Regulation 833
15.4.2 Harmonics 838
15.4.3 Flicker 839
15.4.4 Other Impacts on Power Quality 842
15.4.5 High-Quality Power Configurations 842
15.5 Generator Reliability 843
References 847

Distributed generation (DG) or embedded generation (the European term) refers to generation applied at the distribution level. DG is often defined as the utilization of small, modular power generation technologies dispersed throughout a utility's distribution system to reduce T&D loading or load growth and thereby defer the upgrade of T&D facilities, reduce system losses, improve power quality, and improve reliability.

No exact size or voltages are accepted as definitions of DG. An IEEE standard (IEEE Std. 1547-2003) applies to generation under 10 MW. Distribution substation generation is normally considered as DG; sometimes, subtransmission-level generation is also considered as DG since many of the application issues are the same. The related terms—nonutility generator (NUG) and independent power producer (IPP)—refer to independent generation that may or may not be at the distribution level. A broader term, distributed resources (DRs), encompasses distributed generation, backup generation, energy storage, and demand side management (DSM) technologies.

Smaller-sized generators continue to improve in cost and efficiency, moving closer and closer to the performance of large power plants. At the same time, utilities face significant obstacles when building large facilities—both power plants and transmission lines. Utilities or end users can install modular distributed generation quickly. This local generation reduces the need for large-scale utility projects. Distributed generation can allow utilities to defer transmission and distribution upgrades. Also, DG reduces losses and improves voltage. With the right configuration, distributed generation can also improve customer reliability and power quality. Photovoltaics (PVs) are becoming increasingly popular and cost effective for end users.

Both utilities and end users can install distributed generators, usually for different reasons. Distributed generators are most cost effective from the customer's perspective if the customer has a need for

- *Cogeneration*—Using the generator waste heat locally significantly improves the economics of many applications. The uses include process steam, heating water, facility heat, or running air conditioning.
- *Reliability*—Many locations need backup generation for reliability purposes. Once they are bought, running them full time or for peak shaving becomes more economical.
- *Subsidies*—Tax credits or other subsidies are available, especially for photovoltaics.

Utilities mostly need local generation with

- *Overloaded circuits*—Distributed generation can delay infrastructure upgrades.
- *Generation shortages*—If a utility needs generation anywhere it can get it, the utility or end users can quickly install distributed generation.

Applying generation closer to the load benefits the transmission and distribution infrastructure. Local generation can relieve overburdened transmission and distribution facilities as well as reduce losses and voltage drop.

While offering benefits and opportunities, generation is not always easy to integrate into the existing distribution systems (Barker and De Mello, 2000; CEA 128 D 767, 1994; EPRI 1024354, 2012; EPRI TR-111489, 1998; IEEE 1547.2-2008; IEEE Working Group, 2004; Walling et al., 2008). Distribution systems were never designed to include generation; they were designed for one-way power flow, from the utility substation to the end users. Generators violate this basic assumption, and generators can disrupt distribution operations if they are not carefully applied. One of the most critical situations is that a distribution interrupter may isolate a section of circuit,

and the generator might continue supplying the load on that section in an *island*. Islanding poses safety hazards, and islanded generators can cause overvoltages on the circuit. In addition to islanding, generators can disturb protection, upset voltage regulation, and cause other power quality problems. We will investigate many of these issues in this chapter, how to identify problems and options for fixing them.

In addition to the technical difficulties, distributed generation raises several other issues. How do we meter a generator? What is a fair price to pay a generator injecting power into the system? How can distributed generators be dispatched or controlled, especially if they are owned by end users? How can we apply the generators to optimal locations on the system, rather than just accepting it wherever end users install it?

End-use generation can provide the end user with many benefits, including backup power capability, lower monthly bills, and possibly cogeneration opportunities. Many distributed generation technologies can supply isolated loads in stand-alone applications, but also having a utility supply adds considerable value. Even for end users who have local generation sufficient to cover all of their kilowatt-hour needs, having the utility source improves local reliability, power quality, and ability to accommodate various load-use patterns (EPRI 1001668, 2003). The presence of the utility distribution system solves many of the problems with customer-owned generation systems:

- *Reliability*—Generators must be applied in a redundant manner to achieve the reliability of traditional utility distribution service. Together, a utility service along with local generators has much higher-than- normal reliability.
- *Matching load*—Many small generators are most economical when they run at full power all the time, but most loads have an average power demand that is well below the peak. A utility source allows the generator to run at full power, and the utility can offset the power for the load. In addition, much of the renewable generation is intermittent. Without a utility interconnection, renewable sites must have energy storage and technology that are immature and expensive. The flexibility added by the utility supply allows for easy future expansion and load shifts. In addition to real power, loads require reactive power, and because the utility service can supply the reactive power, this allows local generation to supply only real power.
- *Load following and source stiffness*—Many distributed generation designs have limited load-following capability. Step changes in load or motor starting can deeply affect the voltage and frequency. The utility source is generally a stiff supply compared to most generator options. A stiff supply helps maintain frequency, controls voltage flicker from varying loads, controls harmonics, and provides torque to start motors. A utility source will often have a source impedance of less than 5% of the supply capability. Rotating generators normally have at least a 20% source impedance. In stand-alone applications, a synchronous generator will often have 2 to 3 times the kVA rating of the largest block of motor load for direct online motor starts. Because of harmonics, adjustable-speed drives may need a synchronous generator rated with twice the kVA rating of the drive in a stand-alone application. Inverter-based generation typically has little overcurrent capability, meaning it is a weak source, especially for supplying motor starting current.

The utility supply has the benefit of tying thousands of generators together, providing reliability and matching load. In the future, small generators may be

applied locally in ways that gain some of these same benefits as the bulk utility system. *Microgrids* tie generators together on a localized scale to gain many of the reliability and load matching advantages of the traditional utility grid (EPRI 1003973, 2001).

Distributed generation technologies continue to advance: cost comes down and performance improves. Projections of penetration of DG into the electrical system vary widely. Since natural gas delivers energy at a cost that is roughly one-fourth to one-third of the cost of electric energy, if an efficient, low-capital-cost, and low-maintenance distributed generator becomes available, gas energy delivery has an advantage over electric energy delivery. Utilities must prepare for several scenarios and consider distributed generators as another tool for supplying end users with electric power.

This chapter focuses on the application of generators on radial distribution systems. The application of generators on spot or grid networks requires special considerations because of the use of network protectors that operate on reverse power flow. For more information, see EPRI 1019937 (2010), Smith (2001, 2002), National Renewable Energy Laboratory (2005, 2009), and IEEE Std. 1547.6-2011.

15.1 Characteristics of Distributed Generators

15.1.1 Energy Sources

Several energy sources drive distributed generators, including

- Reciprocating engines
- Combustion turbines
- Microturbines
- Wind turbines
- Fuel cells
- Steam turbines
- Photovoltaics

Three power converters convert the power output of the energy source into interface with standard 50- or 60-Hz systems:

- Synchronous generator
- Induction generator
- Inverter

Historically, reciprocating engines and combustion turbines interface through synchronous generators. Fuel cells, some microturbines, some wind turbines, and photovoltaics interface through inverters. Some microturbines and wind turbines also interface through induction generators.

Several factors are considerations for the energy source: the stability and/or variability of the power source, the ability to follow changes in load, and the reliability (availability) of the source.

On reciprocating engines, combustion turbines, and microturbines, the burn rate of the fuel/air mixture controls the power output. The real power output is controllable and responds to load changes fairly quickly. These combustion-based generators are normally very stable sources (unless the fuel supply is poor).

Wind turbines and photovoltaics produce variable output that is normally not controllable. One of the main concerns of wind turbines on distribution circuits is the possibility of voltage flicker due to pulsating output, mainly because the tower shades the blades for part of their rotation. Sunshine variability also causes variation in solar-panel outputs, but the changes are normally slow enough to limit flicker problems except in rare cases, although other types of voltage regulation issues can occur. Neither of these can follow the load. Energy-storage systems (batteries, ultracapacitors, and flywheels) can be used to help manage power variations but such storage devices can be costly to implement.

Fuel cells have load-following capability, but it is significantly slower than combustion generators. Fuel cells and photovoltaics have no natural provision to provide short-time overloads (some manufacturers include batteries or ultracapacitors to add this capability). This helps control fault currents but limits their ability to supply motor starting current and respond to loads.

The availability and reliability of the energy source plays a role in some applications. Combustion engines and turbines are easily dispatchable. Photovoltaics and wind generation are nondispatchable; the energy source is not always available. Small hydro units may or may not be dispatchable, depending on the water levels.

15.1.2 Synchronous Generators

The workhorse power generator for over a century, the synchronous generator is the power converter of choice for many distributed power sources. Reciprocating engines and gas turbines above 500 kW nearly always interface with a synchronous generator. A synchronous generator can operate independently or in synchronization with the utility. Most distribution-scale generators are salient-pole machines with four or six poles driven by 1800- or 1200-rpm reciprocating engines (with some even slower in larger units). Distribution-scale gas turbines spin faster but are normally geared down to drive a salient-pole generator at 1800 rpm.

Synchronous generators can operate at leading or lagging power factor and can operate in a voltage control or voltage-following mode. Most distributed synchronous generators use a voltage-following control mode with no intent to directly regulate voltage. This differs from large generators on the electric system, which have controls to regulate voltage (within the limits of the var capability). Distributed generators normally follow the utility voltage and inject a constant amount of real and reactive power (so, the power factor stays constant). Normally, most DG operators run at unity power factor since that produces the most watts for a given kVA rating. However, lagging or leading operation (in what is called a fixed power factor mode) can be useful to achieve certain operating objectives. For example, a generator producing vars in a fixed power factor mode can help support the var demands of the

power system and correct for inductive loading. On the other hand, a unit consuming vars in a fixed power factor mode can help mitigate voltage change caused by the real component of the DG output.

Synchronous generators consist of a three-phase armature winding and field winding usually on the rotor. The three-phase ac power system connects to the armature winding on the stator (the outside, nonmoving part) of the synchronous machine (Figure 15.1). The stator wraps around the outside of the generator, so it can couple magnetically with the rotating magnetic field produced on the rotor. The rotor has a dc magnetic field rotating at synchronous speed. The rotor has several poles around the shaft. Each pole is a piece of iron with a coil wrapped around it (the field winding). The field winding forms an electromagnet that creates the dc magnetic field. A separate device, an exciter, generates the dc current for the field winding. The rotating dc magnetic field induces an emf in the stator (armature) winding, which drives power into the ac system. For more detailed descriptions, see one of the many machine books available, such as Fitzgerald et al. (1971).

A voltage source (the emf induced on the armature) behind a reactance models a synchronous machine well. Several impedances come into play depending on the scenario:

- *Subtransient reactance*—X_d'' is the positive-sequence impedance that determines the three-phase fault current during the first few cycles. Normally, X_d'' is between 10% and 30% on the machine rating. Higher values of X_d'' limit the short-circuit current the machine supplies but reduce the capability of the machine to respond quickly to load changes.

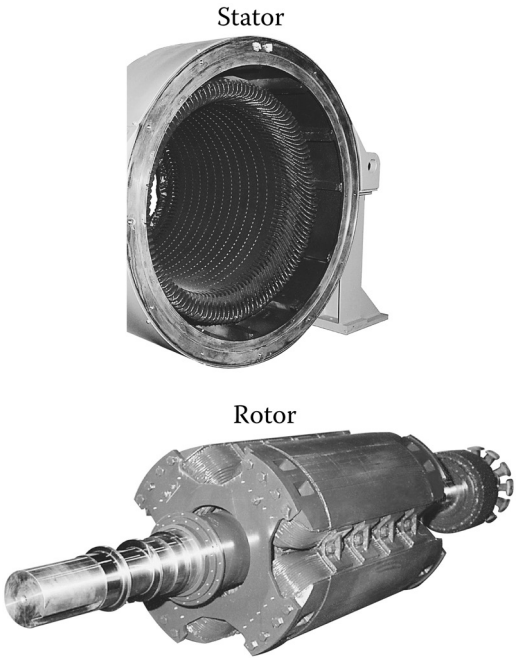


Figure 15.1 Synchronous generator. (Courtesy of Caterpillar, Inc.)

- *Negative-sequence reactance*—X_2 impacts the current under voltage unbalance. X_2 is equal to the average of X_d'' and X_q'' (the direct and quadrature impedances) and is typically 10 to 30% on the machine rating.
- *Zero-sequence reactance*—X_0 affects ground fault currents and the flow of triplen harmonics. The zero-sequence reactance is normally very low, even less than 5% on the machine rating.

In the absence of better information, assume $X_d'' = 20\%$, $X_2 = 25\%$, and $X_0 = 5\%$ on the machine rating. In the past, this information was hard to obtain for small machines, but now, most generator manufacturers supply them. Table 15.1 shows values of small generator constants from tests, with the characteristics of machines C and D being most representative. Most of the parameters in the table are only needed for very detailed simulations.

For fault calculations, the voltage behind the subtransient reactance is normally in the range of 1.0 to 1.3 per unit with a typical value of 1.1. The power factor ranges from 0.8 lagging to unity. So, with the voltage at 1.1 per unit and $X_d'' = 20\%$, the initial three-phase fault current is 5.5 times the generator rating.

Under a fault, sudden load change, or other transient condition, the subtransient reactance (X_d'', which is often denoted as just X'') dominates. After a time equal to

TABLE 15.1 Small Synchronous Generator Constants in per Unit on the Machine Base

Machine	A	B	C	D
kVA	69	156	781	1044
kW	55	125	625	835
V	240/480	240/480	240/480	240/480
rpm	1800	1800	1800	1800
H_{gen}	0.26	0.20	0.40	0.43
pf	0.80	0.80	0.80	0.80
X_d	2.02	6.16	2.43	2.38
X_d'	0.171	0.347	0.254	0.264
X_d'' (sec)	0.087	0.291	0.207	0.201
X_q	1.06	2.49	1.12	1.10
X_q''	0.163	0.503	0.351	0.376
T_{do}' (sec)	0.950	1.87	1.90	2.47
T_d' (sec)	0.080	0.105	0.198	0.273
T_{do}'' (sec)	0.078	0.013	0.024	0.018
T_d'' (sec)	0.004	0.011	0.020	0.014
T_{qo}'' (sec)	0.045	0.020	0.016	0.009
T_q'' (sec)	0.007	0.004	0.005	0.003
r_a	0.011	0.034	0.017	0.013
T_a (sec)	0.014	0.022	0.038	0.032
X_0	0.038	0.054	0.051	0.074
X_2	0.125	0.375	0.279	0.260

Source: Adapted from Gish, W. B., *IEEE Transactions on Power Systems*, vol. PWRD-1, no. 2, pp. 231–9, April 1986. Copyright 1986 IEEE.

the subtransient time constant (T_d''), which ranges from 1 to 10 cycles, the transient reactance (X_d') more accurately models the generator response.

The direct-axis impedance (indicated by the subscript *d*) is the effective impedance for changes that are in sync with rotation (50- or 60-Hz events). Quadrature-axis impedances (subscript *q*) are the impedances seen with the rotor out of phase with the stator field. For fault calculations, we only need to consider the direct-axis impedances. For unbalance or harmonics, the quadrature-axis impedances have impacts.

The *saturated* subtransient reactance (X_{dv}'') is used for short-circuit studies and for harmonics. The subscripted "*v*" means constant voltage; the impedance is the value of *V/I* at rated voltage and no load for a short circuit on the generator terminals (which is a high-current condition that saturates the magnetic core, which results in a lower impedance). Another version of subtransient reactance, the unsaturated reactance (X_{di}'') is used for stability studies. Usually, if it is not indicated which value it is, it is the saturated value, X_{dv}''.

The negative-sequence reactance (X_2) and the subtransient reactance (X_d'') are mainly determined by the damper windings on the rotor. On a salient-pole machine, damper windings are a shorted winding wound around each pole. Damper windings react to dampen out transients on the machine. The torque produced by the damper windings slows down a machine that is running faster than synchronous speed, and it speeds up a machine that is running slower than synchronous speed. Damper windings are like the rotor on a squirrel-cage induction machine (in fact, a squirrel-cage induction machine is a synchronous machine with damper windings and no field on the rotor). At synchronous speed, no current flows in the damper windings since the flux on the rotor is dc, but if transients act to change the frequency relative to the synchronous speed, currents flow in the damper windings and create torque to counteract the disturbance. The damper windings also react to other stator currents that are not 50- or 60-Hz positive-sequence currents (significantly, negative-sequence currents and harmonic currents).

The negative-sequence impedance determines the current flow due to negative-sequence voltages. The impedance to harmonic voltages is also approximately the negative-sequence impedance. The negative-sequence impedance is the same whether the generator is under steady-state, transient, or subtransient conditions.

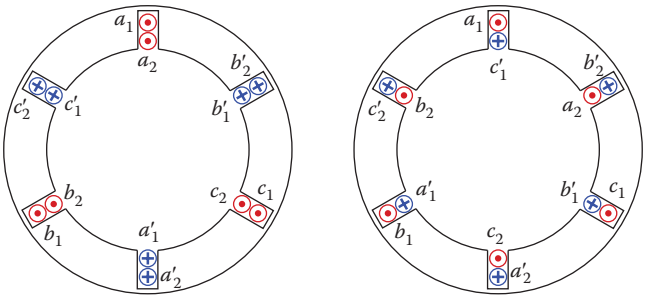
The zero-sequence impedance of a synchronous machine can have extremely low impedance. It is enough of a problem that many generators are ungrounded or grounded through an impedance to prevent the flow of zero-sequence current. Many generators are not braced to handle the fault current for a line-to-ground fault at the terminals of the machine. Single-phase faults cause more mechanical stress and are of higher magnitude. Ground fault currents are 30 to 40% higher than three-phase fault currents (E/X_d'' vs. $3E/(2X_d'' + X_0) \approx 1.3$ to $1.4E/X_d''$). The zero-sequence impedance is the same whether it is under steady-state, transient, or subtransient conditions.

The reason that the zero-sequence impedance is so low is that magnetic fields from zero-sequence currents in the stator winding tend to cancel each other. If the fields cancel and couple very little to the rotor, the impedance is very low.

The zero-sequence impedance varies significantly with design. The most prominent difference is due to the pitch of the stator winding. A pole pitch is the number of degrees that the rotor has to move to change from one pole to the other. In a two-pole machine, one pole pitch is 180°, and in a four-pole machine, it is 90°. The *pitch factor* (or just the *pitch*) of the stator winding is the portion of the pole pitch that the stator winding spans. A full-pitch stator winding spans the full pitch. A fractional pitch winding spans less than the full pitch. Figure 15.2 shows a comparison of a full-pitch winding and a 2/3-pitch winding. In this figure, each phase has two windings (e.g., a_1 and a_2); the current in each winding goes out on one slot conductor (like a_1) and returns in another slot conductor labeled with the prime notation (like a'_1). The 2/3-pitch winding reduces the zero-sequence impedance the most. Because the two conductors in each slot have current in opposite directions, the fields cancel almost completely (since $a = b = c = -a' = -b' = -c'$ for zero-sequence current). Other common pitch factors are 5/8 and 3/4.

Synchronization is important when connecting synchronous generators. If a large machine is out of synch with the utility when it is connected, the sudden torque can damage the generator, and the connecting switch and other devices will have a large voltage disturbance. To avoid these problems, synchronizing relays are required for synchronous generators to ensure that the voltage, frequency, phase angle, and phasing are the same on the utility and generator. Normally, the generator is brought up to speed, and the field current is adjusted to bring the voltage close to the utility system. The frequency is more precisely adjusted to bring it within 0.5 Hz of the power system. Then, the synchronizing relay allows closing when the two voltages are within 10° (CEA 128 D 767, 1994).

Load rejection overvoltage (when load is suddenly lost on a generator operating at high power) is another element to consider with synchronous machines. The sudden unloading of a machine can result in a rise in the output voltage of the machine due to the excitation level momentarily being too high for the given amount of loading that remains. This may lead to a temporary overvoltage issue in some cases.



Full-pitch winding 2/3-pitch winding

Figure 15.2 Comparison of a full-pitch and a 2/3-pitch stator winding for a two-pole machine with a double-layer stator winding with one slot per phase per pole.

15.1.3 Induction Generators

Induction generators are used in a few distributed generation applications, such as wind-turbine applications, microturbines, and internal combustion engines, where the speed of the prime mover varies. Induction generators are simpler than synchronous generators. They do not have exciters, voltage regulators, governors, or synchronizing equipment. This can keep the capital cost and maintenance cost lower but comes at the disadvantage of not being able to provide reactive power control. Induction generators would also not normally be useable for units intended to operate as intentionally islanded standby generators. Induction generators can unintentionally island if a source of sufficient vars is available; this type of islanding can be problematic as discussed later.

An induction generator is the same as an induction motor except the prime mover turns the rotor faster than synchronous speed. An induction generator needs supplemental excitation, either supplied by the utility system or local capacitors.

To start some induction generators, the utility may accelerate the prime mover to operational speed, drawing inrush to 5 or 6 times the generator rating just like motor starting. A reduced-voltage starter using a reactor or autotransformer reduces the inrush. If possible, the prime mover can accelerate the shaft to near-synchronous speed before closing in; this softens the inrush when connecting. This type of connection draws inrush of up to 3 times the generator rating. Since the induction machine cannot generate voltage on its own, the timing of the connection is generally unimportant.

Even though the induction generator cannot create voltage on its own, the generator can self-excite with capacitors. Reclosing into a self-excited generator with local capacitors can damage the shaft and other equipment. Self-excited induction generators with capacitors can also result in potentially damaging overvoltages on the island they are powering, so care must be exercised to avoid such conditions.

Under transient conditions, induction machines respond similarly to synchronous machines. Under fault-type transient conditions, $X_1 = X_2 = 20\%$ (the locked-rotor impedance) and $X_0 = 5\%$. The voltage behind the positive-sequence impedance is also about 1.1 per unit. The main difference between synchronous and induction machines is that the generator driving voltage collapses more quickly in an induction machine.

15.1.4 Inverters

Many types of small generators best interface with utility and utilization power through an inverter. Photovoltaics and fuel cells generate dc. Wind turbines and microturbines generate incompatible frequencies, so they are best applied by rectifying to dc and then converting back into ac with an inverter.

The two main classes of inverters are

- Line commutated
- Self-commutated

A three-phase line-commutated inverter is the simplest and least-expensive converter. Thyristors (also called silicon-controlled rectifiers or SCRs) in a full-wave bridge configuration convert from dc to ac by switching current (see Figure 15.3). Thyristors can switch large amounts of current at low loss. The inverter controls when to turn on the thyristor by applying a voltage pulse to the gate of the thyristor; the thyristor does not turn off until the next current zero.

Since a line-commutated inverter draws currents in square waves, it creates large harmonics, primarily the 5th, 7th, 11th, and 13th. Line-commutated inverters require significant reactive power from the system, between 10% and 40% of the inverter rating. It is possible to use 12-, 18-, or 24-pulse bridge designs with phase-shifting transformers to reduce harmonics.

Line-commutated inverters do not provide significant fault current. The reactor in the inverter limits the fault current. Most designs limit current to 100 to 400% of the inverter rating. Usually, inverters have overcurrent protection that removes the firing pulses when current exceeds some threshold. The duration of fault current output also depends on the amount of capacitance on the inverter dc bus. Note that a harmonic filter on the output can increase the momentary fault value.

The concept of line commutation of a thyristor- (or SCR-) based inverter must not be confused with the same term applied to a "self-commutated" transistor-based inverter. The line-commutated terminology is sometimes loosely (and incorrectly) applied to transistor-based inverters when the transistor gating signals are controlled by a circuit that is monitoring the utility 60-Hz line voltage. That use of the term has a different meaning than when "line commutated" is used to describe a thyristor (or SCR) inverter and can cause confusion. In general, transistor-based inverters are considered self-commutating inverters.

Most inverters used today in DG are of the self-commutating type based on transistors. The self-commutated inverter can generate its own sinusoidal voltage. Although several self-commutated configurations are around, the most common is the fast switching PWM design using IGBTs or other switchable power electronic components. IGBTs can be turned on and off quickly. By controlling the timing and duration of pulses, the controller can shape the current supplied to the system. A common three-phase configuration is a three-phase bridge (the same as Figure 15.3, but with IGBTs instead of thyristors). In a grid-connected application, a PWM inverter can control the power factor; in a stand-alone application, the inverter can operate alone and control voltage. PWM inverters normally have switching frequencies from 1 to

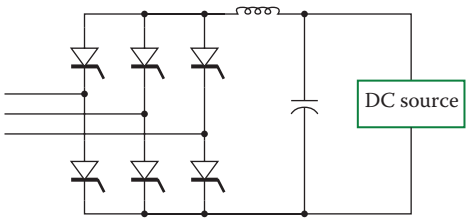


Figure 15.3 Common three-phase bridge inverter line-commutated configuration with thyristors.

10 kHz. They produce little low-order harmonics, and the high-frequency harmonics near the switching frequency can be filtered with relatively small filters. Generally, PWM designs have distortion well within IEEE Std. 519-1992. This type of inverter is the workhorse of the modern PV industry used for everything from small-scale residential installations to large-scale multimegawatt systems.

Self-commutated inverters may be voltage controlled or current controlled. The voltage-controlled inverter is simpler; the controller creates a reference voltage. The current-controlled mode is more suitable for distributed generators; the controller uses the utility voltage as a reference and injects current at the proper angle (usually at unity power factor). Current-controlled inverters produce little fault current. Overcurrent protection removes current almost immediately after an overcurrent (manufacturers implement this to protect their equipment; IGBTs have very limited overcurrent capability). The current pulse before the controller stops firing is typically less than 2 per unit peak and lasts about 200 to 300 μs. The sustained fault levels (lasting longer than one half-cycle) tend to be less than 1.5 per unit in most cases.

Self-commutated inverters are used for most inverter-based generators. Very large units still require line-commutated inverters. With continued advances in power electronic switching technologies, larger units will migrate to self-commutated designs.

Most three-phase inverter configurations used for DG are ungrounded, meaning the neutral does not have a low-impedance grounding connection. See the example in Figure 15.3. Since they are ungrounded, this raises interfacing issues on grounded distribution circuits. Often, ungrounded inverter configurations are interfaced with grounded systems through a grounded-wye–delta transformer. This is a grounding transformer; circulating currents in the delta allow the transformer to supply unbalanced load. Some inverter configurations are grounded, such as those in Figure 15.4. Thyristors are shown, but PWM inverters with the same configurations are common. Three single-phase inverters can also supply grounded three-phase systems.

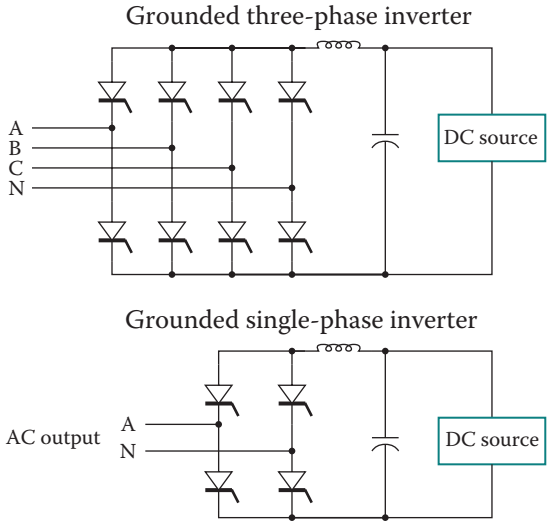


Figure 15.4 Grounded inverter configurations.

TABLE 15.2 Power Converter Characteristics from an Interconnection Perspective

Feature	Synchronous Generator	Induction Generator	Inverter
Ability to operate as an isolated (stand-alone) source	Exciter allows it to operate as a stand-alone island	Not intended for stand-alone island but still can accidentally self-excite if isolated with a capacitor	Self-commutated voltage source inverters can function as islands
Synchronism with utility	Must operate as a synchronous source	Typically operated with several percent slip	Must operate as a synchronous source
Fault contributions	4–8 times rated current for a few cycles	4–8 times rated current for a few cycles	Usually less than 2 times rated current and very short duration
Var injection and control capability	Yes—by adjusting exciter can regulate vars and inject either leading or lagging power into the system	No var control—is a lagging source (capacitors needed to correct vars)	Some inverters can vary var output and provide reactive support; most inverters operate near unity power factor
Response speed to load changes and var needs	Exciter and throttle require some time to respond	Induction generator does not have exciter control. Throttle response requires time	Inverter can respond almost instantly to detected conditions to control power and vars if suitably designed with energy storage on bus
Active anti-island	No	No	Yes

Source: Adapted from EPRI PEAC, *Distributed Generation Course*, 2002.

Whether an inverter or a rotating generator, all energy converter technologies have interconnection issues, just different ones. Table 15.2 summarizes some of the most important issues for each major power converter type.

15.1.5 Modeling Small Generators

The simplest load-flow model of distributed generators is as a negative load. The normal load models include constant power, constant impedance, and constant current. More accurate representations depend on the type of generator and its controls.

Since most synchronous DGs operate in a voltage-following mode with a set injection of real and reactive power, the most accurate model is the constant power model. In some programs, the power on each phase must be specified. A somewhat more accurate model is to keep the total power constant while the balance of the three phases is determined by the sequence parameters of the generator (Chen et al., 1991). For induction generators, the reactive power changes with voltage, but the changes are small enough that they can be modeled as constant power devices. See Barker and Johnson (2002) for more on modeling rotating machines for different scenarios.

If a synchronous generator is operated in a voltage-regulating mode, the best load-flow model is as a voltage-regulating, constant real power device. The reactive power limits would also need to be specified.

A constant-power model accurately describes forced–commutated inverters (for microturbines, fuel cells, photovoltaics, etc.), such as those using PWM. The inverters have control loops that control both real and reactive power. Line-commutated inverters can also be modeled as a constant power. They are limited in that they can only absorb reactive power and cannot supply vars to the system.

Fault contributions of rotating generators can be modeled with most distribution short-circuit programs using the appropriate subtransient and transient characteristics of the generator. Short-circuit analysis can be done using a standard short-circuit program. Although the addition of distributed generators increases the time-varying nature of the fault current, it is not enough to warrant using a stability or EMTP-type model for fault analysis. Industrial systems with large local generators are still analyzed properly with standard short-circuit analysis programs.

When considering the effects on overcurrent protection and coordination with distributed generators, we can use standard protection programs. With fault contributions from only one source, curves of two overcurrent devices can be plotted on a time–current curve that will visually demonstrate the coordination over a range of currents. With contributions from different sources, it is more difficult to plot curves in a time–current graph. It is more useful to do a table of operating times of different devices for faults at different locations.

More complicated transient and/or dynamic response modeling is sometimes warranted for large machines or large penetration levels on distribution lines (especially on weak circuits). These simulations provide better answers on possible problems related to ferroresonance, voltage flicker, stability, ground fault overvoltages, load rejection overvoltages, and islanding (EPRI TR-111490, 1998; EPRI TR-112737, 1999). Detailed full models of inverters are particularly important to get a precise answer for load rejection overvoltage or ground fault overvoltage, or the run-on times of complex islands involving multiple sources of generation with nearly matched load to generation ratios with active islanding protection. Modeling can be difficult in that the required details of control functions such as time constants are not always readily available, and worst-case value may need to be assumed.

15.2 Islanding Issues

Islanding is a major interconnection issue. Islanding is a situation where one or more generators and a portion of the utility system operate separately from the rest of the utility system. The formation of an unintentional island is a problem for the utility company. The most important concerns are

- Worker and public safety
- Damage to utility and customer equipment due to out-of-phase reclosure
- Voltage problems

- High overvoltages to utility equipment and customers caused by neutral shifts, load rejection, or ferroresonance

Distributed generators can create danger for workers and the public if unintentional islands occur for any significant length of time. Line crews might work on a section of line that they thought was deenergized. A distributed generator could energize this line, even though it is disconnected from the utility source. The danger also extends to the general public. Islanded generators may energize downed conductors within public reach (that might have been deenergized by upstream utility switchgear had the island not developed).

Once an island forms, it typically drifts out of phase with the utility system voltage. If the main system is closed into the island, the out-of-phase reclosure may cause damage to the generator, customer loads, and/or utility switchgear as well as being a significant power quality disturbance for customers upstream of the island. An island may also prevent the clearing of fault currents on the system, increasing damage at the location of the fault, and perhaps burning conductors down. See Sandia National Laboratories (2012) for guidance on assessing the risk of islanding.

The most basic means to prevent islanding is to use voltage and frequency relays on the generator to trip whenever either of these two parameters naturally migrate outside a selected window. This form of islanding protection is known as *passive* protection. Passive protection prevents islanding in most cases because when a section of the distribution system and one or more generators separate together, the output of the generator will not match the load on the island. For synchronous or induction generators, the voltage and frequency will drift, which will trip the relays in a short time. Typically, the relays are set to a tight frequency range of perhaps ±1 Hz or even ±0.5 Hz. Voltage relays have a bit wider window to allow for typical voltage regulation excursions on the circuit (±5 to 10% is typical). Later, in this chapter, the specific setting requirements as per IEEE standards are discussed.

This passive method is not limited to just voltage and frequency relaying functions. Other relaying functions are also often employed such as rate of change of frequency (ROCOF), phase jump detection, and/or impedance relaying techniques. All these various methods work in the same general way in that when the island forms, the operating parameters drift outside the desired operating window, and the unit trips. Passive protection is not perfect because there are conditions called "nondetection zones" where the load might be balanced well enough to generation and other conditions satisfied such that stable operation of the island can continue longer than desired.

A more advanced form of protection is called "active islanding protection." This uses many of the same relay functions as the passive protection, but the generator is set to periodically attempt to force a parameter into the trip zone. For example, an inverter can intentionally attempt to shift the phase angle and frequency every few cycles to see if it is still connected to the main grid or not. Active protection is more reliable than passive protection. Almost all inverters for photovoltaics use an active islanding protection scheme that is certified to a test (such as UL1741) that is coordinated with the IEEE 1547 requirements. The test says that if an island occurs and

the load is closely matched to generation, the unit will trip within 2 sec. The IEEE standard is not adequately coordinated with fast utility reclosing dead times (normally much less than 2 sec) used by many utilities, but it works nicely with slower dead times (5 sec or longer allowing for some margin). Even active protection is not 100% reliable and can be fooled in certain situations as described by Sandia (2012). A direct transfer trip can be used if there is concern that passive or active methods by themselves would not suffice.

Synchronous generators, induction generators, self-commutated inverters, and line-commutated inverters—all can island. Synchronous generators and self-commutated inverters are most likely to island because they do not require external excitation. Induction generators and line-commutated inverters can island if they have external excitation, either from capacitor banks or from other generators in the island. As mentioned, IEEE 1547-2003 has specific requirements for protection that help limit the danger of islanding.

15.2.1 Effect of Transformer Connections on Overvoltages

Generators fed from a transformer with an ungrounded high-side connection can drive a normally grounded utility circuit as an ungrounded island. When a single line-to-ground fault occurs on the distribution system and the substation breaker (or a recloser) opens, the system becomes a three-wire, ungrounded system driven by the ungrounded generator. The fault moves the potential of the ground to the phase potential (see Figure 15.5). That leaves the line-to-neutral voltage on the unfaulted phases equal to the line-to-line voltage ($\sqrt{3} = 1.73$ times the normal line-to-neutral voltage). See Figures 15.6 and 15.7 for a zoomed view of a case where temporary overvoltages occurred during an islanding event. Note the distortion in the line-to-neutral voltages due to saturation of transformers.

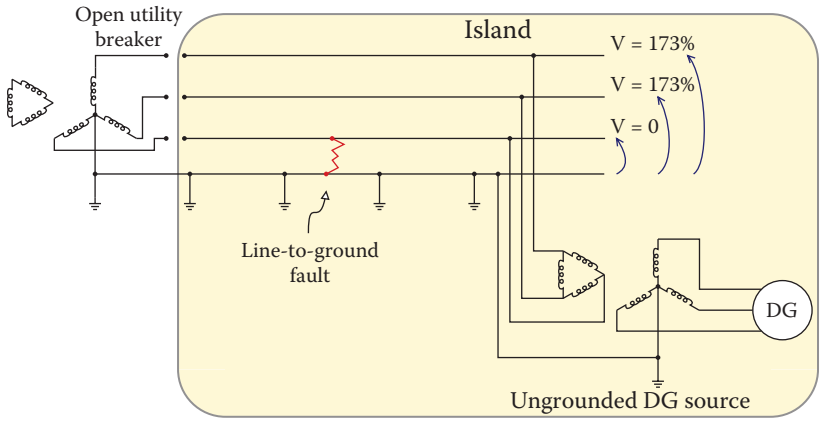
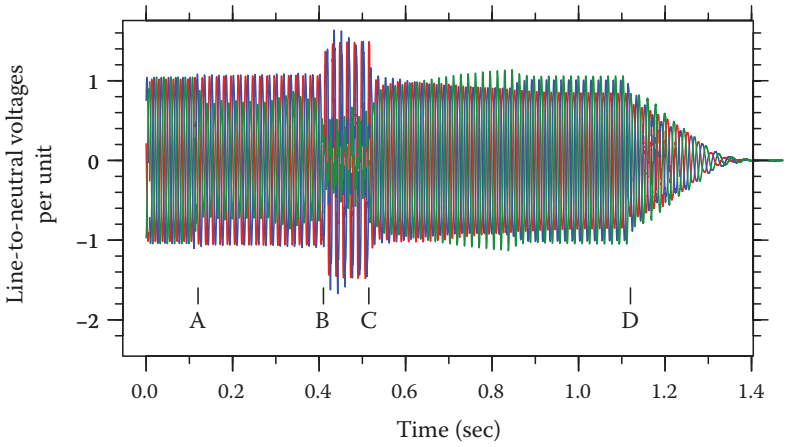


Figure 15.5 Ungrounded generator connection driving an island with a line-to-ground fault.



A: fault starts
B: substation breaker clears
C: arc self-clears
D: generator trips

Figure 15.6 Voltage waveforms from a temporary island.

The interconnection transformer configuration and the generator grounding determine if the application is effectively grounded. The most common transformer configurations (the connection notation indicates the primary-side connection and then the secondary-side (generator-side) connection) are

- *Delta–grounded wye*—Leaves the circuit ungrounded.
- *Grounded wye–grounded wye*—Can effectively ground the source *if* the generator is effectively grounded. Is ungrounded if the generator is ungrounded.
- *Grounded wye–delta*—Provides the best way to effectively ground a generator interconnection, but creates a ground source.
- *Grounded wye–delta with a grounding reactor on the high-side wye*—Limits the ground fault source while still maintaining grounding.

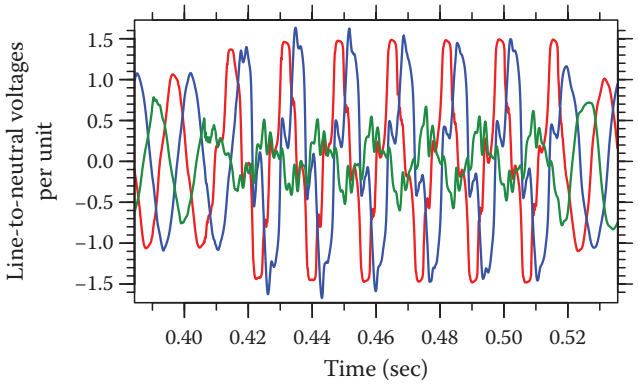


Figure 15.7 Temporary overvoltages during islanding.

Transformer/generator grounding involves a trade-off. The best grounding arrangements create sources for ground current that may interfere with distribution protection. Limiting ground current creates an interconnection that is not grounded as well (higher overvoltages).

Grounded-wye–grounded-wye transformers are widely used and are familiar to utilities. They are often the best connection if the generator is grounded. If the generator neutral connection is not grounded or does not meet effective grounding requirements, then the transformer bank does not effectively ground the source even though the neutral connections to the transformer are grounded on both sides. Some rotating machines are not designed to withstand the forces due to a line-to-ground fault on the generator terminals. For this reason, they are grounded through an impedance or ungrounded (so, they are not effectively grounded). Some inverters need isolation from the ground and are not designed to operate with a grounded-wye winding on the inverter side of the transformer. Many inverters have a built-in isolation transformer that is delta on the inverter side to wye on the 208-V or 480-V output side. The wye winding is often floating or grounded through a high impedance; many inverters have a built-in isolation transformer that is delta (inverter bridge side) to wye on the 208-V or 480-V output side. The wye winding is often grounded through high impedance or floating, so this is not effectively grounded. For grounded rotating machines, the grounded-wye–grounded-wye connection also supplies significant zero-sequence current (it is a grounding source).

Generator installers often prefer the grounded-wye–delta transformer (with the delta on the generator side). This connection grounds the connection regardless of the generator grounding (the generator may be ungrounded or grounded through an impedance to protect it from line-to-ground faults). Other advantages are reduced harmonics, isolation between the primary and secondary for ground faults, and a smaller voltage sag seen on the generator terminals. The main drawback to using the grounded-wye–delta connection is that it is a grounding bank; it feeds ground faults on the primary. This can interfere with distribution system coordination and desensitize ground relays, improperly blow fuses, or falsely operated sectionalizers, reclosers, or breakers. Large circulating currents in the delta winding on the secondary (usually due to ground faults) can also damage the interconnection transformer. Adding a reactor to the neutral connection of the primary-side wye reduces the grounding transformer effect while still maintaining acceptable grounding.

When single phasing occurs on such transformers, backfeeds on the other two phases pose a severe risk to the transformer if protection is not adequate to detect and protect against this possibility. Usually, this involves three-pole switchgear with the proper relaying to detect single phasing.

If generators interface through ungrounded transformer connections, a ground overvoltage relay limits the duration of overvoltages.

Some large generators are applied right at the distribution primary voltage, without an interfacing transformer. This has the same effects as using a grounded-wye–grounded-wye transformer. If the generator is ungrounded, islanded overvoltages are possible. Solidly grounding the generator grounds the source. Note that large generators applied without a step-up transformer can experience more direct exposure to

TABLE 15.3 Minimum Load-to-Generation Ratio Screening

		Penetration/Risk Levels		
		Very Low	Moderate	High
For ground fault overvoltage suppression	Synchronous generators	>10	10 to 5	<5
	Inverters	>6	6 to 3	<3
For islanding analysis		>4	4 to 2	<2

Source: Adapted from EPRI 1024354, *Engineering Guide for Integration of Distributed Storage and Generation*, Electric Power Research Institute, Palo Alto, CA, 2012. With permission.

1. Ratios are meant as guides for radial four-wire multigrounded neutral distribution system generator applications and are calculated based on aggregate generation on relevant power system sections.

2. "Minimum load" is the lowest annual load on the line section of interest (up to the nearest applicable protective device). Power factor of the load is assumed to be 0.9 inductive. In cases with high power factor, a slightly higher ratio may be needed.

3. Inverters are weaker sources than rotating machines; therefore, a smaller ratio is allowable if all generation is inverter based.

4. If generation application falls in the "higher penetration" category, it means some system upgrades/adjustments are likely needed to avoid power system issues.

lightning and switching surges. For such machines, extra care in the application of lightning arresters and sloping capacitors at the machine terminals may be justified to reduce winding stresses.

Arcing ground faults are another possible overvoltage mode on islands supported by ungrounded generators. On ungrounded systems, intermittent arcing grounds can create switching surge overvoltages from the restriking of the arc (see Chapter 14). A system that is designed to be ungrounded has only line capacitance between the phases and ground. An ungrounded island has the line capacitance and line-to-ground load. The load may help control arcing ground faults. If the island has grounded-wye capacitor banks, arcing ground fault overvoltages may be more likely. This is an area that needs more study.

The ratio of the minimum load in a potential island to the generator size is a good indication of the likelihood of issues with islanding and with overvoltages during islanding. Table 15.3 gives one set of guidance to screen possible DG installations (EPRI 1024354, 2012; Barker, 2013). If the minimum load-to-generation ratio is in the *high* risk level, do additional analysis to determine if extra measures are needed for the proposed application.

15.2.1.1 Overvoltage Relays and 59G Ground Fault Detection

Distributed generators usually have over- and undervoltage relays. A typical overvoltage relay uses a type 59T time-delay relay with a pickup of 5 to 10% above nominal voltage. The time setting should be set above the normal clearing time of the feeder relays but should be less than the substation breaker reclosing time. A reasonable setting is 30 to 60 cycles (ANSI/IEEE Std. 1001-1988). It is best if an instantaneous element (59I) is also used, although a higher setting (such as 40% above nominal) may be needed to prevent excessive nuisance trips. For overvoltages, primary-side measurements are best, especially if the primary winding is ungrounded. Secondary

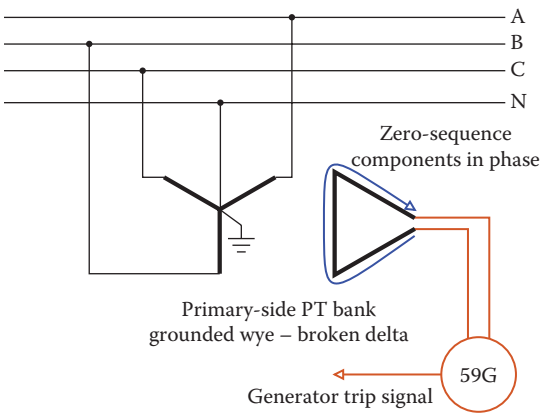


Figure 15.8 Ground fault overvoltage detection scheme (59G).

measurements cannot detect the neutral shift on an ungrounded island with a ground fault. To detect and trip on overvoltages, every phase must have a relay, not just on an individual phase and not on an average of the three phases. Undervoltage relays also provide backup for neutral-shift overvoltages by detecting the voltage sag on the phase with the line-to-ground fault.

The 59G relay detects neutral-shift overvoltages with the connection shown in Figure 15.8. The grounded-wye–broken-delta potential transformer arrangement sums the three phase-to-neutral voltages.

The main drawback of relaying schemes is that the overvoltage still occurs; even a short-duration overvoltage may damage some equipment. The overvoltage duration is limited by the speed of the relays and breaker. Depending on the speed of the relaying, these limits may not coordinate with the temporary overvoltage capability of some arresters or sensitive customer equipment. Also, if the relaying fails to operate, the overvoltage could last for some time. Another disadvantage of this approach is that primary-side potential transformers are required. Because of this, many utilities avoid ungrounded transformer connections.

15.2.1.2 Effectively Grounding a Grounded-Wye–Grounded-Wye Transformer Connection

Effectively grounded systems limit the overvoltage caused by a neutral shift to 38% above nominal. In effectively grounded systems, the ground fault current is 60% or more of the available three-phase fault current. A grounded-wye–grounded-wye transformer is effectively grounded if the generator applied to it meets effective grounding requirements. The conditions for effective grounding are approximately (ANSI/IEEE C62.92-1987)

$$X_0/X_1 \leq 3 \quad \text{and} \quad R_0/X_1 \leq 1$$

For effective grounding during islanding for a ground fault on the primary terminals, the generator must be solidly grounded or the impedance must be small enough

to meet the criteria above. For a rotating generator with a grounding reactor, the criteria (EPRI 1024354, 2012) are

$$X_{\mathrm{GN}} \leq X_{T1} + X_{G1} - X_{T0}/3 - X_{G0}/3$$

where

X_{GN} = generator neutral reactance
X_{T0} = transformer zero-sequence reactance
X_{T1} = transformer positive-sequence reactance
X_{G0} = generator zero-sequence reactance
X_{G1} = generator positive-sequence reactance

While the IEEE standards state that $X_0/X_1 \leq 3$ and $R_0/X_1 \leq 1$, in practice, it is desirable to have the generation neutral grounding scheme designed such that the X_0 and R_0 impedances are about 2/3 of these values. Doing this allows the voltage to be held not right at the edge of effective grounding (38% above nominal) but rather deeper within effective grounding, about 25% above nominal or less. This approach conforms to power quality requirements for loads and is recommended in IEEE C62.92.4-1991 for systems serving line-to-neutral loads.

15.2.1.3 Sizing a Neutral Grounding Reactor on a Grounded-Wye–Delta Connection to Maintain Effective Grounding

A grounding reactor added to a grounded-wye–delta transformer limits the zero-sequence fault contribution and limits the circulating current in the delta winding. To ensure that the connection still maintains an effectively grounded system during a possible island, the grounding reactor cannot be too large. The criteria for effective grounding is: $X_0/X_1 \leq 3$. This depends on the characteristics of the generator and interconnection transformer. For a primary ground fault at the transformer, the sequence impedances are

$$X_0 = X_{T0} + 3X_N$$

$$X_1 = X_{T1} + X_{G1}$$

where

X_N = neutral reactance
X_{T0} = transformer zero-sequence reactance
X_{T1} = transformer positive-sequence reactance
X_{G1} = generator positive-sequence reactance

To keep the interconnection effectively grounded, limit the size of the reactor according to (EPRI 1024354, 2012)

$$X_N \leq X_{T1} + X_{G1} - X_{T0}/3$$

Note that this only guarantees effective grounding for a fault right at the grounding transformer. For faults at other points on the feeder, add the zero- and positive-sequence line impedances between the fault location and the generator to X_{T0} and X_{T1}. If line impedances are considered, then the zero-sequence line resistance should also be considered. In the equations above, the resistance portion has been ignored because the X/R ratios on generators and transformers are high. Another requirement for effective grounding is that $R_0/X_1 \leq 1$. Normally, these are small, so we can ignore them except for a very large generator on a weak system. For photovoltaic inverters, the X/R ratio can be lower, and it may be necessary to use the coefficient of grounding equations in Chapter 14.

15.2.2 Anti-Islanding Protection

At most sites, voltage and frequency relays are the main protection against islanding. When a utility protective device opens and leaves an island, normally, the generation and load will not match. If the generation exceeds the load, the voltage rises and the generators speed up. The opposite occurs if the load exceeds the generation. In either case, when voltage or frequency goes outside normal limits, voltage or frequency relays should trip the generators.

Over- and undervoltage relays are an important line of defense against islanding. Typically, this consists of

- *Overvoltage time-delay relay (59T)*—A pickup of 5 to 10% above nominal voltage is generally used. The time setting should be set above the normal clearing time of the feeder relays but should be less than the substation breaker reclosing time. A reasonable setting is 1/2 to 1 sec.
- *Instantaneous overvoltage element (59I)*—An instantaneous overvoltage element is recommended (but not always used). A higher setting (such as 40% above nominal) may be needed to prevent excessive nuisance trips.
- *Undervoltage time-delay relay (27T)*—A pickup of 5 to 10% below nominal voltage is generally used. Similar time settings should be used as the overvoltage time-delay relay.
- *Instantaneous undervoltage relay (27I)*—As with the overvoltage instantaneous element, a loose setting is necessary to prevent nuisance trips (30% below nominal is reasonable).

The time-delay relays are time delays; they are not inverse-time relays. If the voltage on a 59T relay is above the magnitude setting for longer than the time setting, it trips. If the voltage drops back below the magnitude setting, the timer resets after the given reset time. Many generator protection relays allow multiple pairs of magnitude and time-delay settings to achieve a stair-step voltage–time characteristic.

For overvoltages, it is best if the detecting potential transformers are on the primary side of the generator transformer (especially if the primary winding is ungrounded). For example, the neutral shift on an ungrounded island with a ground fault will not be detected on the secondary side of the transformer. To detect and trip on overvoltages, individual relays should be on each of the three phases (not just on

an individual phase and not on an average of the three phases). The undervoltage relays will also provide backup for neutral-shift overvoltages by detecting the voltage sag on the phase with the line-to-ground fault.

The over- and underfrequency relay (81U/O) is another line of defense against islanding. Trip thresholds of ±1% are common. Wide ranges of time delays are used for a 1% setting: 0.1 sec to many seconds. Some utilities specify a wider range for the underfrequency setting to allow the generator to stay in for low-frequency events caused by system-wide disturbances. The low frequency indicates a need for generation, so it helps to have the generator remain connected.

Integrated generator relay packages are available from several manufacturers. These provide voltage and frequency relays along with other interconnection functions such as synchronization (and possibly all of the generator protection functions as well).

EEI (2000) provides guidance for applying anti-islanding relaying and other interconnection equipment for several different types of generators and interconnection transformers.

With voltage and frequency relays, there is still some chance that evenly balanced generation and load can drive islands. Since voltage and frequency relays are not 100% reliable, some large distribution generators have transfer trip protection schemes. Breakers (or reclosers) upstream of the generator send a trip signal to the generator—if the breaker operates, it trips the generator. This requires a reliable communication line between the breaker and the generator.

15.2.3 Active Anti-Islanding

Inverter-based generators can use more sophisticated ways to detect islands. If the generation and load are almost equal, an island may take some time to drift in voltage and frequency. *Active* anti-islanding inverters attempt to push the voltage and/or frequency out of normal limits. Under normal conditions, the inverter cannot budge the voltage or frequency; with the inverter connected to the utility system, the utility system fixes the voltage and frequency (assuming the utility system is much bigger than the generation).

The most promising active anti-islanding techniques are the Sandia voltage-shift and frequency-shift methods (Stevens et al., 1999). These use positive feedback to make the voltage or frequency unstable if an island is being driven by generators with this form of anti-islanding. The unstable generator in an island pushes the voltage or frequency out of range, where standard voltage or frequency relays trip the generator. Since it uses positive feedback, the Sandia method allows several of these inverters to work together. Other methods may act to cancel each other; some might try to raise frequency while others try to lower it.

With the frequency-shift method, if the inverter detects that the frequency is increasing (even slightly), the controller injects a current with an even faster frequency. On a weak system, the current controller starts to control the frequency, and in this example, the inverter forces high frequency on an island, which trips the frequency relays.

Fast voltage control devices on distribution circuits may counteract attempts to change the voltage by inverter-based generators. Most regulators and capacitor banks

are too slow to interfere in this manner. But, other generators operating in a voltage control mode will hold the island voltage intact. Rotating generators and voltage source inverters act to stabilize the island's frequency and voltage.

UL 1741 (2001) specifies an active anti-islanding test for inverter-based relays designed to test any kind of active anti-islanding inverter. Under balanced generation and load and a resonant capacitor–inductor tuned to the fundamental frequency (which tends to hold the frequency), the inverter must disconnect within 2 sec. The test does not verify the performance of multiple inverter-based generators in parallel with the same type of anti-islanding or with different types of anti-islanding. And, the test does not verify the performance of anti-islanding with rotating generators or motors in the island. The test does not conform with utility high-speed reclosing where dead times are often less than 2 sec (some fast-reclose dead times are as short as 12 cycles). The options to avoid problems include increase reclose dead times, use faster generator trip settings, or use a direct transfer trip.

15.2.4 Relaying Issues

Industry standards for distributed generator interconnection have specified standard trip thresholds. This is an effort between manufacturers and utilities to ease the complications of interconnection. Table 15.4 shows the IEEE 1547-2003 settings for disconnection of distributed generators. UL 1741 specifies a test for an inverter-based generators. No mention is made of the exact measurement location, but it implies measurement at the generator. UL 1741 specifies line-to-ground voltages for three-phase connections, and the DG should cease exporting when any of the three voltages exceeds the limits.

The main concerns with the standard overvoltage trip thresholds are that

- The 110% trip limit on overvoltages allows generators to create voltage in excess of ANSI limits (ANSI C84.1-1995).

TABLE 15.4 Trip Thresholds for Distributed Generators Based on IEEE Std. 1547-2003

Voltage Setting			Trip Time
	V	<50%	0.16 sec
50% ≤	V	<88%	2 sec
110% <	V	<120%	1 sec
120% ≤	V		0.16 sec

Note: Base voltages are the nominal voltages stated in ANSI C84.1. DR ≤ 30 kW: maximum clearing time. *DR* > 30 kW: default clearing time or the utility operator may specify different voltage settings or trip times to accommodate utility requirements.

- IEEE Std. 1547-2003 allows a relatively long time (0.16 sec or 9.6 cycles for 60 Hz) for overvoltages above 120% to exist.

Where should relays measure? Right at the generator is easiest, but not always best. To avoid islanding problems with large three-phase generators, measurement on the distribution primary is best. Transformer connections can distort the voltages and make relaying harder; secondary-side measurement on a delta–wye or wye–delta transformer connection cannot detect the overvoltages or undervoltages from a neutral shift on the primary. A second transformer with a delta–wye connection between the utility transformer and the generator interconnection point further distorts the voltages. The distribution primary is usually the most sensitive location for measuring distribution system overvoltages and undervoltages.

Overall, the best place for relay monitoring is on the primary using line-to-ground voltages. Smaller generator applications (less than 1 MW) may use other measuring locations, but consider the transformer connections to ensure effective relay sensitivity. Secondary measurements (either at the generator or at the service entrance) are appropriate for very small generators.

Another one of the questions about relaying set points is whether to use line-to-line voltages, line-to-ground voltages, or both. Generally, line-to-ground voltages are more sensitive, so they should be used, but it is not always straightforward. Figure 15.9 shows where a neutral shift has occurred on the distribution system to a line-to-ground fault. Phase A has a voltage sag, and phases B and C have voltage swells due to the neutral shift. This is a more severe neutral shift than is usual on a four-wire multigrounded distribution circuit; it could represent an island being driven by distributed generators. If a grounded-wye–grounded-wye transformer is used, the line-to-ground voltages on the secondary are most sensitive. If a delta–grounded-wye transformer is used, the line-to-line voltages on the secondary are slightly more sensitive (although, overall, the ability to sense primary line-to-ground overvoltages is reduced by the delta–wye connection). A grounded-wye–delta connection has line-to-ground voltages more sensitive to the overvoltage (again, the ability to sense primary line-to-ground overvoltages is reduced because of the transformer connection). The voltages shown assume that the DG does not change the voltage on the primary or secondary, when in reality, the DG will normally be changing the voltage on the secondary and maybe even on the primary.

One important point is that all three voltages must be measured (whether they are line-to-line or line-to-ground voltages). If voltages are assumed balanced and only one of the three voltages is used, sustained overvoltages could occur on the unmonitored phases.

Power quality disturbances also impact generators because the generator must trip for voltage excursions. An analysis of EPRI's DPQ data showed that the number of generator trips at most sites is not particularly severe. Generators at most sites should have less than five trips per year when using the IEEE Std. 1547-2003 settings (see Figure 15.10). Trips become excessive only if the generator undervoltage relaying is set at a very sensitive level.

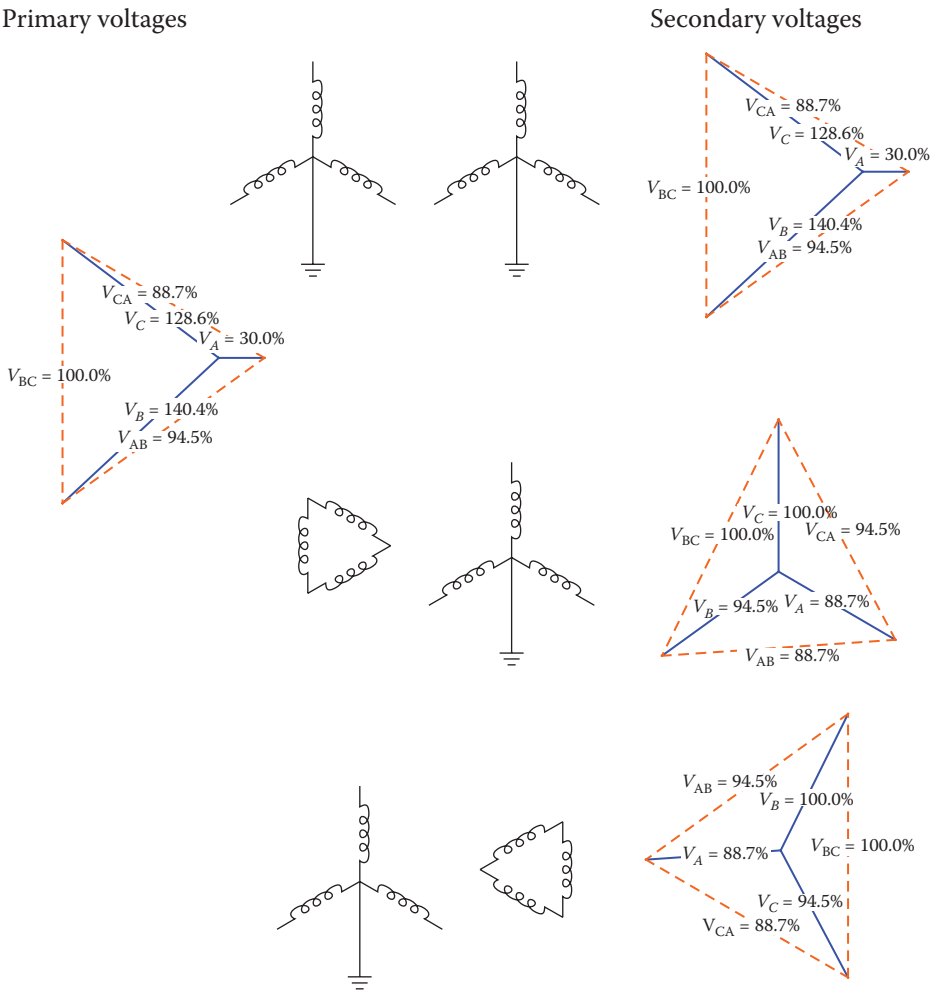


Figure 15.9 Line-to-line and line-to-ground voltages on the primary and secondary of several transformer connections for an overvoltage due to a neutral shift for a fault on primary phase A. (From EPRI 1005917, *Distributed Generation Relaying Impacts on Power Quality*, Electric Power Research Institute, Palo Alto, CA, 2001. Copyright 2001. Reprinted with permission.)

Distributed generators based on inverters can do much of the interconnection relaying in the inverter controller. Utilities worry about inverter-based relays, mainly because

- Inverter-based relays are not utility grade.
- Testing in the field is very difficult. (They do not have external test points for relay test sets.)

Inverter-based relays do have the advantage that they can perform anti-islanding relaying as discussed in the previous section.

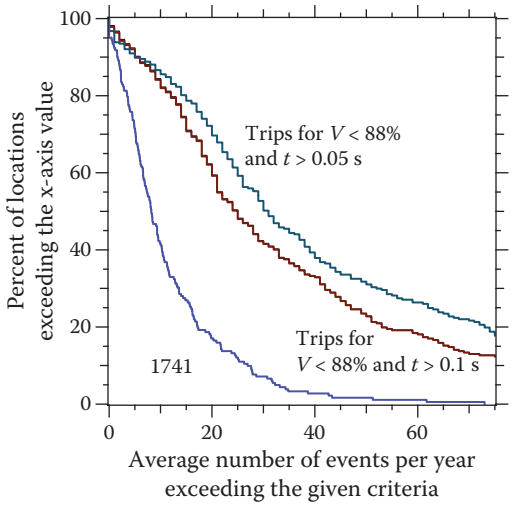


Figure 15.10 Comparison of the number of generator trips with the UL 1741 voltage/time thresholds to very sensitive trip settings (less than 88% voltage for 0.1 or 0.05 sec). (From EPRI 1005917, *Distributed Generation Relaying Impacts on Power Quality*, Electric Power Research Institute, Palo Alto, CA, 2001. Copyright 2001. Reprinted with permission.)

Many utilities require utility-grade relays for small installations, and essentially, all require them for large installations. But, what is a utility-grade relay? There is no fixed definition, but normally, they must pass industry standards (ANSI/IEEE C37.90-1989; ANSI/IEEE C37.90.1-1989; IEEE Std. C37.90.2-1995). Utility-grade relays are normally more robust than industrial relays and have test ports for external testing.

Inverter-based generators do not have external test ports for testing. Separation of the relaying component from the other controller functionalities is difficult to do because the inverter controller uses the voltage and current sensing for other control aspects.

15.2.5 Self-Excitation

During islanding, the generator can resonate with system capacitor banks (see Figure 15.11). This series resonance can happen with any type of interconnection transformer

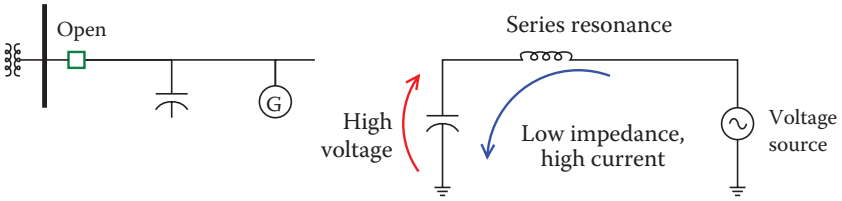


Figure 15.11 Series resonance between a generator and capacitor bank during islanding.

configuration, with or without ground faults on the system. The simplest resonance is a series resonance between the generator subtransient impedance and system capacitors. Load on the island helps hold the voltage down, so the highest voltages occur under light load. Transformer saturation is not enough to significantly reduce this type of overvoltage. This resonance is also referred to as self-excitation, the same phenomenon seen on induction motors with capacitor banks. It is also similar to a resonance seen on distribution feeders that feed low-voltage secondary networks and have capacitor banks. After a fault, the backfeed through the network transformers can resonate.

The circuit resonates when the power-frequency impedance of the capacitor equals the impedance of the inductance. And, overvoltages still occur even if the impedances do not exactly match. The criteria to determine if self-excitation may occur are that the ratio of capacitance to inductance is within a ratio of one to two (in either direction):

$$0.5 < X_C/X_L < 2$$

where

X_C = impedance of the capacitor banks = $(\text{kV}_{\text{LL}})^2/(\text{Mvar})$

X_L = impedance of the system inductance, which includes the generator impedance, the transformer impedance, and the line impedance between the generator and the capacitor bank

Load on the circuit helps hold down the overvoltage. For example, if the load is entirely resistive (R), the magnitude of the per-unit overvoltage at the capacitor is

$$V_C = \frac{RX_C}{\left|RX_L - X_C(R + X_L)\right|}$$

For cases where problems might occur, some options are

- *Reactance*—Change the reactive impedance (generator size or transformer impedance).
- *Capacitors*—Remove or change the size of the capacitor banks.
- *Relaying*—Rely on the overvoltage relaying to remove the generator during an overvoltage condition. Use an instantaneous element (59I), apply relays on each of the three phases, and use potential transformers for the relays on the primary side of the interconnection transformer.

During a line-to-ground fault with an ungrounded transformer connection, a different resonant mode can occur (Dugan and Rizy, 1984). The circuit resonates with a different combination of impedances. The zero-sequence capacitance resonates against a combination of the positive- and negative-sequence impedances and capacitances (see Figure 15.12). This overvoltage adds to any overvoltage due to a neutral shift.

The zero-sequence capacitance is most likely from grounded capacitor banks, but long cable runs may have enough capacitance. The solutions given above for positive-sequence resonances also help with this zero-sequence resonance. Another option

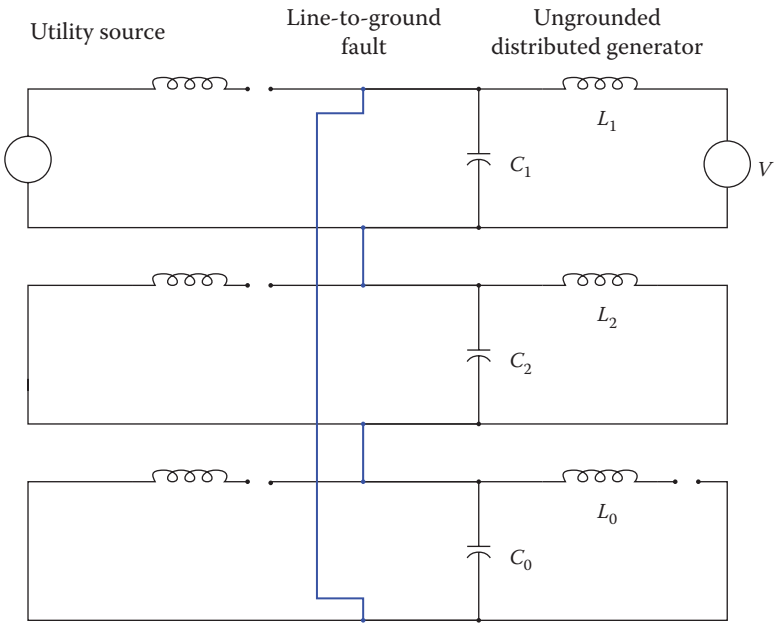


Figure 15.12 Series resonance between a generator and capacitor banks during a line-to-ground fault on an ungrounded islanding.

for this zero-sequence resonance is to unground capacitor banks (to eliminate the zero-sequence capacitance).

15.2.6 Ferroresonance

A generator in an island can drive the circuit into ferroresonance (Feero and Gish, 1986; Wagner et al., 1989). The peak voltage during this ferroresonance can reach three per unit. Both induction and synchronous generators can create ferroresonance, and it can occur with all three phases connected (single phasing is normally involved with ferroresonance). The resonance can occur no matter how the generator interconnection transformer is configured (although the overvoltage is worse if the ferroresonance occurs simultaneously with a neutral shift on an ungrounded island). Four conditions are necessary for DG islanding ferroresonance to occur:

1. The island driven by the generator must be isolated from the utility.
2. The generator must supply more power than there is load on the island.
3. The isolated circuit must have enough capacitance to resonate (30 to 400% of the generator rating). This can be due to utility capacitor banks or from capacitor banks at the generator.
4. A transformer group must be present in the island.

The ferroresonant circuit is very similar to the self-excited case in Figure 15.11, with the only addition being the distribution transformer group. When the

generator and the capacitance resonate, the overvoltage on the distribution circuit causes the transformer to saturate. The saturated transformer has a low impedance. Consider it like a switch: when it is saturated, it is a short circuit; when it is not saturated, it is an open circuit. The switching action of the saturating transformer causes the chaotic ferroresonant-type waveform. Ferroresonance tends to widen the range of capacitance over which the generator can resonate with the capacitor bank.

Solution options for this type of ferroresonance include

- *Reconfiguration*—Changing the distribution system characteristics to change the criteria given above (limit or expand the area that could island or remove or change the size of the capacitor bank).
- *Relaying*—Rely on the overvoltage relaying to remove the generator during an overvoltage condition. Use an instantaneous element (59I), apply relays on each of the three phases, and use potential transformers for the relays on the primary side of the interconnection transformer.
- *Minimum load*—A minimum load-to-generation ratio of at least three will suppress any ferroresonance and/or self-overexcitation conditions.

15.2.7 Backfeed to a Downed Conductor and Backfeed Voltages

During a line-to-ground fault where one phase opens (either due to a fuse operation or a broken conductor), backfeed through a three-phase generator can cause issues on distribution systems. While this type of backfeed occurs without distributed generators (see Chapter 5), distributed generators make backfeed more likely.

With a distributed generator on the load side of the transformer, the backfeed current and voltage (EPRI 1000419, 2000) is

$$I_F = \frac{(A - 3Z_0Z_2)V + 3Z_0Z_2V_G}{3Z_0Z_1Z_2 + R_FA}$$
$$V_F = R_FI_F$$

where

$A = Z_0Z_1 + Z_1Z_2 + Z_0Z_2$
Z_1 = positive-sequence impedance of the generator, Ω
Z_2 = negative-sequence impedance of the generator, Ω
Z_0 = zero-sequence impedance of the generator and load, Ω
R_F = fault resistance, Ω
V = line-to-neutral voltage, V
V_G = line-to-neutral voltage equivalent of the generator, V

Under an open circuit ($R_F = \infty$), the backfeed voltage is

$$V_F = \frac{(A - 3Z_0Z_2)V + 3Z_0Z_2V_G}{A}$$

The presence of the distributed generator strengthens the backfeed current and voltage. The generator provides a source of voltage, and the impedance of a rotating generator (especially the low zero-sequence and negative-sequence impedances) increases the backfeed. An induction generator does not require supplementary excitation (capacitance) to backfeed under these circumstances.

Having a 59G ground overvoltage trip relay, a directional (or even nondirectional) ground relay, and phase undervoltage relays should trip the circuit in most cases of backfeed. It is best if relaying trips the primary-side protective device (usually this is a breaker) rather than just tripping the generator, since backfeeds can still occur through the transformer even if the generator is taken offline.

15.2.8 Overvoltages from Inverters with Light Load

Inverters may cause short-duration overvoltages if islanded with light load. Bravo et al. (2011) showed an example from tests of photovoltaic inverters where overvoltages reached peaks of 200% of nominal for three cycles before the inverter interrupted operation. These overvoltages were a function of load on the local island. In one example provided by Bravo et al., overvoltages were just under 200% of nominal when the load on the island was up to 17% of the inverter rating and then the overvoltage decreased linearly as the load increased. At 66% loading on the inverter, the overvoltage was 129%.

A method used to avoid these overvoltages is to time coordinate a direct transfer trip. A transfer trip signal opens the PV interconnection breaker before the feeder breaker opens. It puts the exposure of load rejection overvoltage right at the PV equipment (which needs to be rated to handle it), but the approach avoids overvoltages for other customers on the circuit. This scheme is often possible, especially if the utility is using time–overcurrent relaying and not instantaneous relaying.

15.3 Protection Issues

Figure 15.13 shows a scenario where a distributed generator may falsely operate an upstream breaker, recloser, fuse, or sectionalizer for a fault just upstream of the protective device.

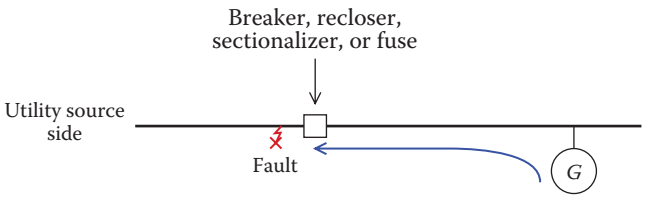


Figure 15.13 Scenario where a distributed generator trips an upstream device. (From EPRI 1005917, *Distributed Generation Relaying Impacts on Power Quality*, Electric Power Research Institute, Palo Alto, CA, 2001. Copyright 2000. Reprinted with permission.)

The fault current from the generator (and through the upstream protective device) for a three-phase fault can be found by the following equation:

$$I_{3p} = V/Z_1$$

where

Z_1 = positive-sequence impedance between the generator and upstream device. This includes the equivalent generator impedance reflected to the primary-side voltage, the transformer impedance, and the line impedance from the generator to the upstream device

V = line-to-ground voltage

This assumes that the generator voltage source is the same as the utility voltage source. A more conservative and appropriate choice is

$$I_{3p} = 1.1\ V/Z_1$$

since the internal voltage behind the generator is normally higher than one. For synchronous generators, use the subtransient reactance, $Z_1 = jX''_d$.

For a line-to-ground fault, it is more complicated because current can "route through" the generator impedances. The sequence diagram for this situation is shown in Figure 15.14. The sequence currents from the generator are

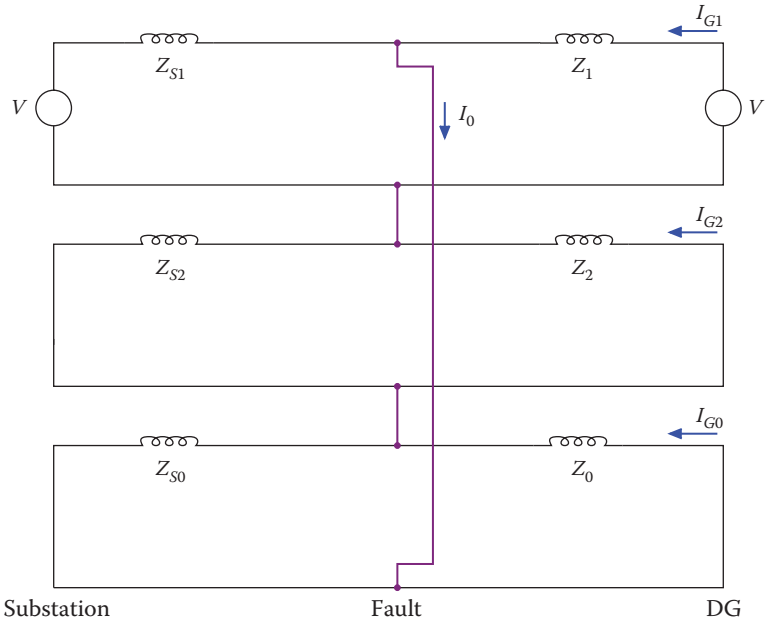


Figure 15.14 Sequence diagram of a line-to-ground fault with a downstream generator feed. (From EPRI 1024354, *Engineering Guide for Integration of Distributed Storage and Generation*, Electric Power Research Institute, Palo Alto, CA, 2012. Copyright 2012. Reprinted with permission.)

$$I_{G1} = \frac{Z_{S1}}{Z_{S1} + Z_1}\left(\frac{V}{Z'}\right)$$
$$I_{G2} = \frac{Z_{S2}}{Z_{S2} + Z_2}\left(\frac{V}{Z'}\right)$$
$$I_{G0} = \frac{Z_{S0}}{Z_{S0} + Z_0}\left(\frac{V}{Z'}\right)$$

where

$Z' = Z_{S1} \parallel Z_1 + Z_{S2} \parallel Z_2 + Z_{S0} \parallel Z_0$

Z_{S0}, Z_{S1}, and Z_{S2} = zero-, positive-, and negative-sequence impedances upstream of the fault. This includes the line impedance, the substation transformer impedance, and the transmission equivalent impedance

Z_0, Z_1, and Z_2 = zero-, positive-, and negative-sequence impedance between the generator and fault. This includes the equivalent generator impedance reflected to the primary-side voltage, the transformer impedance, and the line impedance from the generator to the upstream device

The phase relay on the faulted phase sees the following current:

$$I_{\text{faulted phase}} = I_{G1} + I_{G2} + I_{G0}$$

The ground relay operates on

$$I_{\text{ground relay}} = 3I_{G0}$$

While the line-to-ground fault current is normally smaller than the three-phase fault current, it is important because of

- *Relay sensitivity*—The upstream protective device (breaker, recloser, or sectionalizer) may have a ground relay that is more sensitive than the phase relay setting. Even if the ground fault current is lower, increased ground-relay sensitivity may cause miscoordination.
- *Grounding sources*—Two common generator transformer configurations supply significantly more ground fault current; their zero-sequence impedance is low (see Figure 15.15).
  - Grounded-wye–delta transformer connection—This grounding transformer presents a zero-sequence impedance equal to the transformer impedance (about 5% of its rating).
  - Grounded-wye–grounded-wye transformer connection with a rotating generator solidly grounded—A rotating generator has low zero-sequence impedance (5% of its rating). The total zero-sequence impedance is the transformer impedance plus the generator impedance ($Z_T + Z_{G0} \approx 5\% + 5\% = 10\%$, assuming both the transformer and generator have the same kVA rating).

To determine whether the upstream device will misoperate, compare the fault current with the pickup setting of the device. If it exceeds the pickup, then examine the

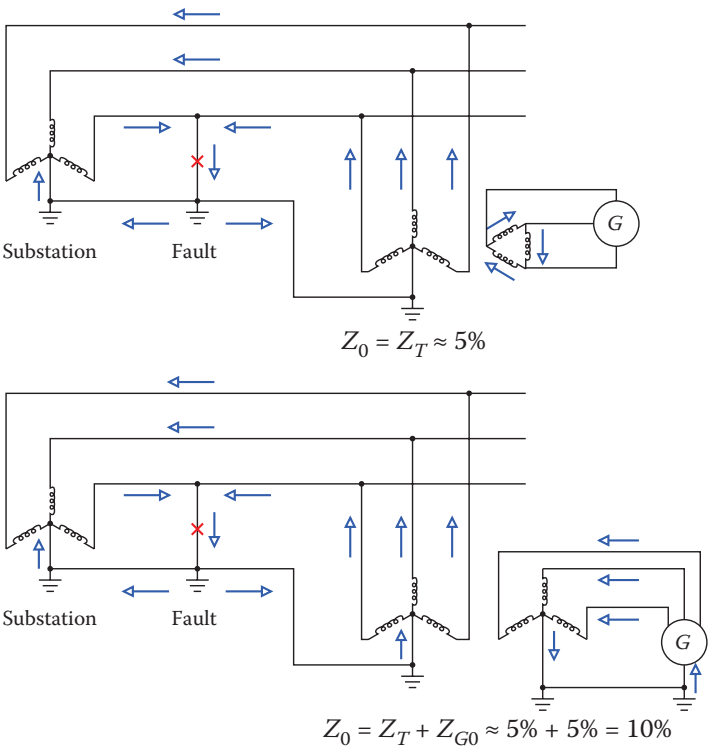


Figure 15.15 DG grounding source connections feeding single-phase faults.

time–current characteristics of the protective device. If it is an instantaneous element, then assume that it miscoordinates. If the device has a time-delay characteristic, then compare the operating time for the given fault current to the operating time of the next upstream device.

If false tripping of utility protective devices is found, there are several possible remedies. On the generator side, the corrective options are

- *Size*—Limit the size of the generator to the point where coordination is achieved.
- *Impedance*—Increase the impedance of the generator transformer or generator.
- *Ground faults*—If miscoordination occurs from ground faults, add a grounding reactor to the generator (for a grounded-wye–grounded-wye interconnection).

On the utility side, the options are

- *Settings*—Use a higher pickup setting on the upstream device or use a slower characteristic that coordinates with the generator contribution. Of course, this requires checking to make sure that the distribution circuit is still adequately protected and that the new setting coordinates with other protective devices on the distribution circuit.
- *Instantaneous*—Disable the instantaneous element or add a time delay to the instantaneous element of sufficient length to coordinate.
- *Fuses*—Use a larger and/or slower fuse.

- *Ground faults*—If it is a ground-protection issue with a grounded-wye–delta interconnection transformer, add a primary neutral reactor.

If the generator is a large rotating unit that is close to the nearby protective device, then there may be a significant offset to the fault waveshape. This may affect certain protective devices. If the device is close to miscoordinating given the equations above, then use a more advanced approach with a short-circuit program that accounts for the offset.

15.3.1 Trade-Off between Overvoltages and Ground Fault Current

The transformer/generator grounding plays important roles in supplying ground fault currents and overvoltages that may occur during islanding. Better grounding limits the overvoltage, but the generator supplies more ground fault current, which may affect coordination.

At one extreme are the sources that form grounding transformers that can provide significant fault current:

- *Grounded wye–delta*—The zero-sequence impedance of the interconnection is the transformer impedance, normally about 5% on its rating.
- *Grounded wye–grounded wye with the generator solidly grounded*—The zero-sequence impedance is about 10% (5% for the transformer and 5% for the generator).

At the other extreme are ungrounded connections, which provide no ground fault current but cause an overvoltage of 1.73 per unit on the unfaulted phases during a ground fault (note that these can feed ground faults, just not with zero sequence):

- Delta–delta
- Delta–grounded wye
- Grounded wye–grounded wye with the generator ungrounded

Where ground fault coordination is a problem, in-between approaches are often best. Adding a grounding reactor to a grounded wye–delta or adding a grounding reactor to a generator limits the ground fault current.

It is normally possible to do both—have effective grounding and reasonably limit the zero-sequence fault contribution.

Figure 15.16 shows the trade-offs with overvoltages and grounding for an example case. The case has a generator with a grounded-wye–delta transformer connection on a 12.47-kV circuit, 4 mi (6.4 km) from the substation. The transformer has a reactor in the grounded-wye primary. The example assumes a 5% transformer impedance, 20% positive- and negative-sequence reactances for the generator, and a 1.1 per-unit voltage behind the generator impedance. Reactor size determines the grounding effectiveness. The reactor impedance is shown as per-unit multiples of the transformer impedance. Except for very large generators relative to the distribution system capability, using a reactor can effectively ground the circuit (overvoltages less than 1.25 per unit) and still reasonably limit the zero-sequence current.

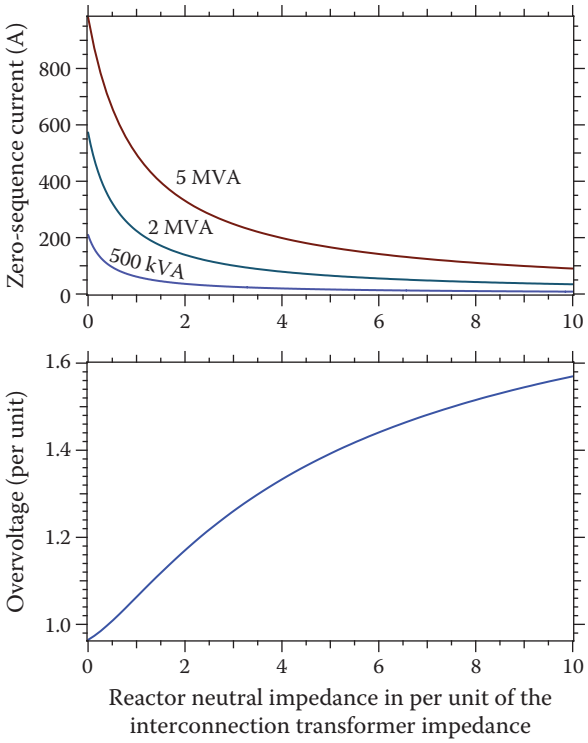


Figure 15.16 Overvoltages and zero-sequence fault contribution for a grounded-wye–delta interconnection transformer with a neutral reactor for different size generators (the overvoltage remains the same with size).

Note that a grounded-wye–grounded-wye transformer with the generator solidly grounded has similar results to the case with a reactor of 0.3 per unit in Figure 15.16. In this solidly grounded scenario, the generator supplies significant fault current.

15.3.2 Fuse-Saving Coordination

The majority of faults on overhead distribution lines are temporary (meaning the fault will be cleared if power is interrupted and restored). Temporary faults on lateral taps can be cleared by the feeder breaker before the lateral fuse blows. This is usually done with the instantaneous element of the breaker relay or recloser in the substation. This practice is known as fault selective feeder relaying or simply as "fuse saving." Distributed generators increase the fault current through the fuse, which may blow the fuse before the breaker opens.

Locations with lower fault currents are where generators are most likely to blow fuses. At locations where fault currents are already high, fuses will not coordinate with a station breaker (so, generators will not make the situation worse). Table 15.5 shows this for the commonly used K links. The smallest fuses that can coordinate during fuse saving are shown given the fault current from the substation

TABLE 15.5 Smallest K-Link Fuse That Coordinates with a Five-Cycle Breaker with a Fuse-Saving Scheme with Fault Current Contributions from the Substation and Distributed Generator(s)

Generator Fault Current (A)	Fault Current Contribution from the Substation (A)								Generator (kW)[a]
	500	1000	1500	2000	2500	3000	3500	4000	
0	40 K	80 K	100 K	140 K	140 K	200 K	200 K	200 K	0
100	50 K	80 K	140 K	140 K	140 K	200 K	200 K	—	432
200	50 K	100 K	140 K	140 K	200 K	200 K	200 K	—	864
300	65 K	100 K	140 K	140 K	200 K	200 K	200 K	—	1296
400	65 K	100 K	140 K	140 K	200 K	200 K	200 K	—	1728
500	80 K	100 K	140 K	140 K	200 K	200 K	200 K	—	2160
600	80 K	140 K	140 K	140 K	200 K	200 K	—	—	2592
700	100 K	140 K	140 K	200 K	200 K	200 K	—	—	3024
800	100 K	140 K	140 K	200 K	200 K	200 K	—	—	3456
900	100 K	140 K	140 K	200 K	200 K	200 K	—	—	3888
1000	100 K	140 K	140 K	200 K	200 K	200 K	—	—	4320

Source: Adapted from EPRI, 1024354. *Engineering Guide for Integration of Distributed Storage and Generation*, Electric Power Research Institute, Palo Alto, CA 2012. Copyright 2012. With permission.

Note: No line impedance between the generator and the fault.

[a]Assuming V_{LL} = 12.47 kV and generator X_d'' = 20%.

and a distributed generator. The generator size in the last column is specifically for a 12.47-kV system with a synchronous generator with X_d'' = 0.2; the generator fault current contributions in the first column of the table can be applied for other applications.

15.4 Power Quality Impacts

15.4.1 Voltage Regulation

Distributed generation often helps voltage on a distribution circuit because it offsets some of the voltage drop caused by loads. But, distributed generation can cause voltages outside ANSI C84.1 limits under the following scenarios:

- *Voltage boost*—Distributed generators can cause high voltages because they inject real power back upstream into the system, causing a voltage rise.
- *Regulator interaction*—Distributed generators can interact with line regulators, which can cause low or high voltages on a circuit depending on the scenario.

Distributed generators can influence distribution voltage regulation. Even if the generator is in a "voltage-following" mode, it still influences voltage by injecting power. In many cases, this is beneficial but can cause low or high voltages, depending on the scenario. Comfort et al. (2001) showed an example where a 5-MW combustion turbine raised the voltage to 130 V (1.086%), 3 mi (5 km) from the substation on a 12.5-kV circuit.

There are also concerns with generators causing high voltages on distribution circuits because of reverse power flow. It is possible to estimate the effect of a generator by using the standard voltage drop equations with reverse power flow. The voltage drop along a feeder due to a load is approximately equal to

$$V_{\text{drop}} \approx I_{\text{R}} \cdot R + I_{\text{X}} \cdot X$$

where

V_{drop} = voltage drop along the feeder, V
R = line resistance, Ω
X = line reactance, Ω
I_R = line current due to real power flow (negative for a generator injecting power), A
I_X = line current due to reactive power flow (negative for a capacitor), A

Distributed generators raise voltage the most where X/R ratios are low. The real power portion causes the largest voltage rise when the line resistance is high. If the generator injects vars such as a capacitor or has local capacitors, the voltage rise is worse.

Note that this approximation is not a substitute for a proper load flow. It does not fully model the response of the load to the change in voltage, and it does not consider regulator response. It is useful for a first cut at estimating whether the voltage rise due to the generator might be a problem for cases involving an easily simplified system model with a very small number of generators and/or "easily reduced" equivalent group of generators.

If a regulator is present with line drop compensation (LDC) enabled, also calculate the impact of the R and X compensator settings on voltage drops.

If voltage rise is a problem, there are several options:

- *Size*—Limit the size of the generator to below the level necessary to cause problems.
- *Relocation*—Relocate the generator to a more suitable location on the distribution circuit.
- *Vars*—Have the generator absorb more reactive power (by removing local capacitors or operating a synchronous generator or self-commutated inverter at reduced power factor). This is the opposite of what is normally done. Reducing the power factor of the generator causes voltage drop to counter the real power voltage rise.
- *Operation time*—Limit the operation of the generator to peak periods of the day (when the voltage drop along the circuit tends to be highest). This is not an exact solution since the highest voltages at a particular point on a feeder do not always coincide with light load. High voltages can occur at heavy load (especially close to a voltage regulator or capacitor bank on the distribution feeder).
- *Relaying*—Rely on the generator overvoltage relay to remove the generator during high voltages. This may work out fine if the high-voltage conditions are infrequent.
- *Impedance*—A utility option would be to reduce the resistance of the lines and transformers from the substation bus to the generator. This would be done by using larger conductors on lines and cables and specifying lower copper losses on transformers. Another option is to build an express feeder to the generator.
- *Regulation equipment*—Another utility-side option is to add regulation equipment (capacitors or regulators) to counteract the voltage rise from the distributed generator.

Normally, the utility only needs to consider the service voltage, but utility engineers may become involved with cases of high voltage within the facility. ANSI C84.1 voltage standards account for voltage drop within a facility in the utilization voltage standard—they do not account for a voltage rise that generators cause.

To have the least disruption to circuit voltages, distributed generators can be set to operate at a fixed lagging power factor. The voltage drop from the lagging reactive power component counterbalances the voltage rise from the real power component. The power factor can be tuned for a particular location. This approach softens any voltage changes from changes in output of the generator. Another option is for generators to adjust their reactive power output based on voltage. For normal voltage, the generator can generate leading reactive power when voltages are low and lagging reactive power when voltages are high. See Figure 15.17 for strategies to accomplish this effect (EPRI 1026809, 2012).

Figure 15.18 shows a scenario where a generator just downstream of a regulator can cause low voltage on the end of the circuit due to the regulator's LDC controller. The power injected by the generator fools the regulator into not raising voltage as much as it should.

Many regulators have a special concern—with reverse power, they ratchet to the extreme tap, causing high or low voltage (EPRI TR-105589, 1995). Most distribution regulators are bidirectional—they measure voltage on both sides of the regulator, and power flow determines which side the regulator uses for compensation. Bidirectional regulators are meant for distribution system locations where the source may change directions, commonly normally open loops that can be reconfigured. The regulator always tries to regulate the voltage on the downstream side, determined by the direction of power flow. If a downstream distributed generator injects enough real power to reverse power flow on the regulator, the regulator thinks the source has moved to the other side. It tries to regulate voltage on the upstream side of the regulator (V_1 in Figure 15.19). If the measured voltage is higher than the set point, the regulator changes its tap to try to lower the voltage. Nothing happens to the voltage upstream of the generator (V_1) since the utility source holds the voltage constant. The regulator keeps trying to lower the voltage, moving from tap to tap

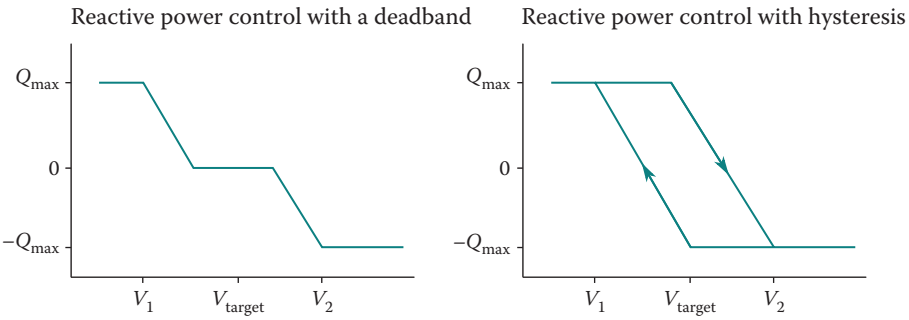


Figure 15.17 Options for reactive power control based on voltage. (Adapted from EPRI 1026809, Common functions for smart inverters, Version 2. Copyright 2012. With permission.)

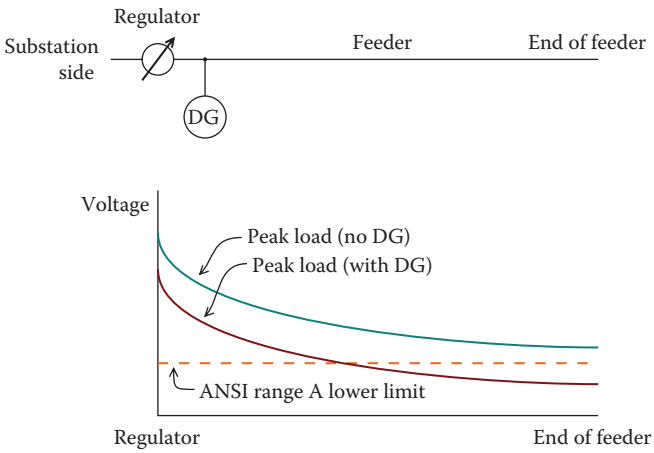


Figure 15.18 A generator just downstream of a regulator that leads to low voltage at the end of the feeder. (From EPRI 1000419, *Engineering Guide for Integration of Distributed Generation and Storage into Power Distribution Systems*, Electric Power Research Institute, Palo Alto, CA, 2000. Copyright 2000. Reprinted with permission.)

until the regulator ratchets all the way to the limit, trying to lower voltage as much as possible.

What the regulator did was to *raise* the voltage downstream of the regulator. It raised the voltage when the feeder voltage was already high—to the maximum amount. If the feeder voltage is lower than the regulator set point, the opposite occurs: the regulator

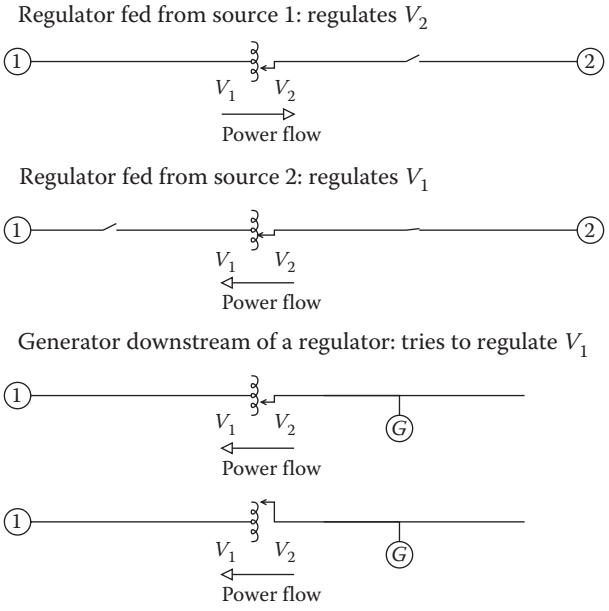


Figure 15.19 Misoperation of a bidirectional regulator due to reverse power flow.

ratchets to the extreme tap setting that causes even lower voltage downstream of the regulator. These scenarios may lead to voltage outside ANSI C84.1 limits.

If the size of the generator or generators is less than 10% of the load at the regulator, problems are unlikely. If the size exceeds this simple screening criteria and the generator is close to the regulator, then more detailed study is warranted. If problems are found, options include the following:

- *Remove LDC*—Remove the line drop compensation on the regulator. Generally, the voltage set point must be raised to provide a good voltage profile on the circuit (if so, check that the end of the circuit does not have high voltages due to the generator).
- *Settings*—Reduce the LDC settings and raise the voltage set point to a smaller amount. This moves the regulator constant voltage point closer to the regulator. The key is the location of the constant voltage point (also called the load center—the fictitious point on the feeder where voltage is held constant). Generators upstream of this point lower the voltage downstream of this point. Generators downstream of the constant voltage point are okay.
- *Advanced controls*—If problems are due to reverse power flow (on bidirectional regulators), advanced regulator controllers are available to change the operating mode during reverse power flow to prevent the regulator from dropping to the lowest tap. If power reverses, some controllers can block tap changes or move to the neutral position.
- *Relocation*—Relocate the generator to upstream of the regulator, or relocate the regulator to downstream of the generator.
- *Equipment*—Add additional regulators or switched capacitors downstream of the generator.
- *Automation*—Use an automated distribution scheme to control the regulator based on data from other locations on the circuit.

Another consideration with regulators (and switched capacitor banks) is unwanted interaction with generators (especially fluctuating sources) that can lead to tap changer cycling. Widening the regulator bandwidth setting helps avoid this. Increasing the time delay may also help prevent excessive regulator tap changes. Reducing line drop compensation can also reduce the tendency to cycle. Distributed generators (especially wind and photovoltaics) can be applied in a fixed power factor mode absorbing vars to reduce the voltage change seen on the system for a given amount of real power fluctuation. This comes at the price of heavier reactive power demand on the utility system that may increase losses and have other drawbacks.

In addition to upsetting regulation, distributed generators have the potential for significantly improving voltage profiles and voltage regulation. Generators inject real power, and many types can vary reactive power (capacitively or reactively). Distributed generators could be operated in a voltage regulation mode where voltage is regulated at the point of common coupling (or at some other point). This is a complex application that requires significant analysis to avoid problems. The fixed power factor mode mentioned above is an indirect regulation mode that can avoid some of the fighting/hunting issues that a direct regulation mode might have.

15.4.2 Harmonics

Distributed generators must adhere to strict industry standards for harmonic injection. Table 15.6 shows the industry limits on harmonics, the same limits imposed on the largest loads. PWM-based inverters and rotating generators can meet these limits, so harmonic problems should be rare. Line-commutated inverters normally need filtering to meet these limits. For these limits, IEEE Std. 1547-2003 defines the current as the greater of the local system maximum current without the generator (15 or 30 min demand) and the generator rated current (transformed to the primary if needed).

Even though most generators do not produce significant harmonics, they can still be involved with harmonic problems. Generators have higher impedances to harmonics than the normal utility connection. Synchronous generators have about a 20 to 25% impedance to harmonics on its full-load rating. Compare that with a utility source of the same size with an impedance of about 5% (approximately the service transformer impedance). If a high-harmonic load switches from the utility supply to a generator supply, the voltage distortion is worse, because the generator supply is not as stiff as the utility supply. The most prominent problem this causes is for load served by UPSs. High-voltage distortion causes the UPSs to switch to battery, which drains the battery, possibly causing an interruption to the sensitive load on the UPS.

Calculate the voltage at the nth frequency with

$$V_n = n \cdot X \cdot I_n$$

where $X = X_2$ for positive- or negative-sequence harmonics, $X = X_0$ for zero-sequence harmonics, and I_n is the harmonic current generated at the nth harmonic. Use superposition to calculate the harmonic voltage distortion due to multiple loads.

The classical model for the impedance to harmonics is the negative-sequence impedance. It is used for positive- and negative-sequence harmonics. Arseneau et al. (1979) showed that a constant impedance that linearly increases with frequency is relatively accurate. The negative-sequence impedance is $(X_d'' + X_q'')/2$. The direct-axis subtransient reactance is also a common approximation. Normally, this is accurate since X_d'' and X_q'' are usually close to each other. If no other information is available, use $X_2 = 25\%$.

EPRI tests of generators with different X_d'' and X_q'' showed that X_d'' is a better approximation for generators supplying single-phase power-supply load (EPRI 1005922, 2001; Langley et al., 2002). Single-phase power-supply load draws a burst of

TABLE 15.6 IEEE Harmonic Current Distortion Limits for Generation in Percent (IEEE 1547-2003 and IEEE Std. 519-1992)

Individual Harmonics					Total demand
$n < 11$	$11 \le n < 17$	$17 \le n < 23$	$23 \le n < 35$	$35 \le n$	Distortion
4.0	2.0	1.5	0.6	0.3	5.0

Note: Even harmonics are limited to 25% of the odd harmonic limits.

current near the voltage crest; from the generator's point of view, it is not a harmonic but more like a fault every half-cycle. So, only the direct-axis impedance plays a role. Now, if a resonance occurs, the quadrature axis is expected to play more of a role, making voltage distortion worse since $(X_d'' + X_q'')/2$ is larger than X_d''.

Generators have a low impedance to the third harmonic and other zero-sequence harmonics. It is well known that balanced in-phase third-harmonic values are zero sequence (so, $V_a = V_b = V_c$ for voltages and $I_a = I_b = I_c$ for currents). All harmonics that are multiples of three are zero sequence; 1, 4, 7, … are positive sequence, and 2, 5, 8, … are negative sequence.

A low zero-sequence harmonic impedance is usually an advantage in that it keeps the voltage distortion low for third-harmonic load currents. One problem is occasionally seen when two generators in parallel feed load and are separated from the utility. Generators also create harmonics. If the generators have different characteristics or are loaded differently, a third-harmonic current can circulate on the neutral between the generators. This can trip one or both generators on high neutral current. The circulating current is pronounced when one generator has a 3/4-pitch stator winding (which acts as a harmonic voltage source that is relatively high in third harmonics) and the other generator has a 2/3-pitch stator winding (which has a low impedance to harmonics).

15.4.3 Flicker

Large generators on weak distribution systems can generate voltage flicker. If it is large enough, any generator can cause a noticeable voltage change at starting or stopping. Voltage flicker is worse with generators that have varying power outputs, such as

- *Reciprocating engines*—Poor fuel or maintenance may result in misfiring cylinders. Misfiring leads to a fluctuating power output. Very large, low-rpm engines have a slow enough beat that the power output fluctuates under normal operations.
- *Wind turbines*—Tower shading causes flicker. As a blade passes the tower holding the turbine, the torque produced by the blade drops, so the power output drops.
- *Photovoltaics*—PV systems theoretically can cause flicker in extreme cases (in practice, the voltage variation is slow enough to limit problems).

Starting of induction generators also causes voltage flicker, just like starting an induction motor. Slower power changes normally do not cause flicker problems. For example, although PV power output varies significantly as clouds cover and then reveal the sun, the sunlight intensity change is slow enough that it does not cause severe flicker.

The flicker from reciprocating engines depends on the rotational speed of the generator and the quality of the fuel supply. Anderson and Mirheydar (1995) showed a case where misfiring cylinders caused voltage flicker on a 12-kV circuit and analyzed this problem in detail. Poor fuel was the cause—methane recovered from a former landfill.

The frequency of oscillations determines how severe the flicker is, with oscillations in the range of 5 to 10 Hz being most noticeable. The frequency of oscillation of the power stroke of a reciprocating engine operating in hertz is

$$f_F = \frac{N \cdot \text{rpm}}{30k}$$

(for 60 Hz only; for 50 Hz, divide by 25 instead of 30)
where

N = number of cylinders
rpm = rotational speed of the generator, rev/min

$$k = \begin{cases} 2 \text{ for two-cycle engine} \\ 4 \text{ for a four-cycle engine} \end{cases}$$

For all but the very slowest generators with few cylinders, the frequency of this power stroke beat is fast enough; it cannot cause flicker. But, if cylinders misfire, the frequency of power oscillation with the misfire in hertz is

$$f_{\text{PS}} = \frac{\text{rpm}}{30k}$$

For many common generators, the power oscillation frequency with misfiring cylinders lies right in the range where it is very noticeable. A four-cycle 900-rpm engine produces flicker at 7.5 Hz, at the most sensitive part of the voltage flicker curve. An 1800-rpm engine is better (and fortunately more standard); these produce flicker at 15 Hz; although this can still cause problems, it is on the less sensitive part of the voltage flicker curve.

The main way to prevent reciprocating engine flicker is controlling the fuel quality and performing proper maintenance to minimize misfiring.

Most of the experience with flicker and wind turbines comes from Europe where wind turbines have higher penetration levels (and the higher-voltage lamp filament makes flicker worse). Gerdes and Santjer (1996) found that flicker is not a problem on most wind turbines if

$$I_{\text{SC}}/I_L > 100$$

where

I_L = wind turbine rated load current
I_{SC} = three-phase short-circuit current at the point of common coupling

This ratio is also called the stiffness factor. Their measurements found most problems where the short-circuit ratio was less than 40, but there were large differences between wind turbines. Some were fine even at weak locations with a short-circuit

ratio as low as 10, but the worst performers caused flicker even with a short-circuit ratio of over 90. Variations in performance were mainly due to aerodynamic and mechanical differences. Table 15.7 shows additional screening based on the stiffness factor (EPRI 1024354, 2012; Barker, 2013).

There are several possible generator-side remedies for reducing the flicker caused by generators. These are not normally done, but some options include

- *Controls*—Use internal controls to regulate real power output to slow down the rate of output change. For example, many inverters and rotational generators include soft-start functions that allow them to slowly ramp power up over many seconds rather than step the power on.
- *Storage*—Use a battery or other energy-storage device to help reduce power output swings.
- *Vars*—Use changes in reactive power to offset the changes in real power. PWM inverters can change the reactive power output, so the generator could operate lagging when the unit is producing full real power and change to a leading power factor (to increase voltage) when the unit is not producing any real power. Synchronous generators with fast exciters may also be able to correct for flicker.
- *Size*—Limit the size of the generator to prevent flicker.

Solutions based on individual types of generators include

- *Wind turbines*—Choose a design that reduces the effect of tower shading.
- *Reciprocating engines*—Use proper fuel grades, and keep the engine tuned up.
- *Induction generators*—Use a reduced-voltage starter that uses a method such as an autotransformer, extra impedance, solid-state electronic voltage reduction, or

TABLE 15.7 System Stiffness Factor Screening

Stiffness Factor	Concern Level
>250	*Insignificant*: Absolutely no concern that flicker or voltage change will be an issue for any type of DG source.
100–250	*Nearly insignificant*: Very little concern unless a generator is started/stopped frequently or has unusual fluctuations.
50–100	*Minor concern*: Moderate concern for fluctuating sources such as wind and PV. Will need to assess rates of fluctuations and stop/start cycles but still probably not an issue in most cases.
25–50	*Significant concern*: Any generation source connecting with a stiffness factor in this range will need serious analysis of planned start/stop cycles and output fluctuations and may need some mitigation equipment.
15–25	*Very significant concern*: Generators in this range can cause serious voltage flicker and fluctuations—especially if PV or wind. Mitigation equipment and/or system changes probably are needed.
≤15	*Extreme concern*: Voltage changes may be so severe—especially for wind or PV—that project is not viable without extreme application of mitigation devices or feeder upgrades.

Source: Adapted from EPRI, 1024354. *Engineering Guide for Integration of Distributed Storage and Generation*, Electric Power Research Institute, Palo Alto, CA 2012. Copyright 2012. With permission.

transformer reconnection from wye during starting to delta during normal operation. Alternately, use a self-starter to get the generator up to speed before connecting to the grid.

Other solutions for flicker include any of the standard techniques discussed in Chapter 12 for reducing voltage flicker from fluctuating loads.

A final consideration for voltage flicker is that a large generator located on a weak system may improve the voltage flicker caused by adjacent fluctuating loads. The generator control algorithm determines how effectively it can correct voltage. A constant voltage control with a fast response (such as a synchronous generator with a fast exciter regulating voltage or a PWM inverter) is most likely to respond to flicker. Of course, a large generator located on a weak system is more likely to have other issues, such as its own flicker, voltage regulation problems, and islanding problems.

15.4.4 Other Impacts on Power Quality

Distribution systems normally do not have stability issues. That may change with large penetration of generators. The largest concern is with faults that cause the distributed generators to trip (since they have sensitive voltage sag settings). Miller et al. (2001) found that with a 40% penetration of generation on a circuit, motor load on the circuit could stall, causing a voltage collapse on the circuit.

Large penetration of distributed generators may also impact bulk system stability. Walling and Miller (2002) performed simulations of the U.S. western grid and found that a 20% penetration of distributed generation seriously erodes stability when the distributed generators trip off quickly because of voltage or frequency relays. Another concern with the bulk system stability is with active anti-islanding inverters. Significant penetration of these will degrade the overall system stability.

Large synchronous generators on a distribution system might require changes to reclosing practices. Because of the danger of reclosing into an island that is out of phase, the reclosing delay might have to be extended. Many utilities use an immediate reclose attempt, which means there is no intentional delay. Circuit breakers typically reclose in about one-third to one-half of a second. This may not give the generator time to clear, especially in a near-island situation. Extending the reclose time on utility breakers and reclosers gives the generator more time to clear.

As an alternative to extending the time before reclose, a voltage-supervising relay can block reclosing on a circuit breaker until the line voltage is dead.

15.4.5 High-Quality Power Configurations

To enhance reliability, most configurations of generators only help with long-duration interruptions, not with voltage sags, and not with momentary interruptions. Figure 15.20 shows two configurations that use continuously running generators to supply critical loads with higher-quality power. The basic idea is to use a static switch for fast transfers between the utility and the generator. The basic configurations are

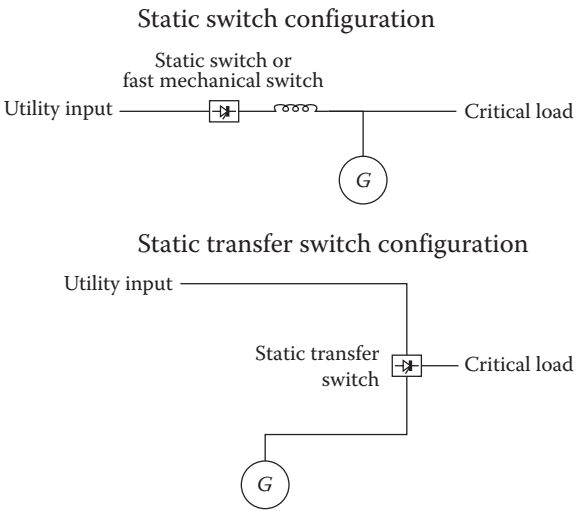


Figure 15.20 Generator configurations supplying protection against short-duration as well as long-duration interruptions. (From EPRI 1007281, *Analysis of Extremely Reliable Power Delivery Systems: A Proposal for Development and Application of Security, Quality, Reliability, and Availability (SQRA) Modeling for Optimizing Power System Configurations for the Digital Economy*, Electric Power Research Institute, Palo Alto, CA, 2002. Copyright 2002. Reprinted with permission.)

- *Online configuration:* The generator supplies some or all of the load. If a sag or interruption hits the utility supply, a static switch opens up, and the generator supplies all of the load.
- *Off-line configuration:* The load normally runs off of the generator. If the generator fails, a static transfer switch operates and switches the load to the utility input.

In both of these cases, the generator must match the load quickly. This is difficult, as many generation technologies have limited load-following capability. Some of the ways of matching generation to the load are as follows:

- Shed load by tripping load breakers to match the load to the generator.
- Use some sort of power electronics with short-term energy storage to dynamically correct for mismatches to give the generator time to match the load.

Also, consider that the generator must supply motor starting current if the critical load has motors.

15.5 Generator Reliability

Generator reliability is important when the distributed generator is critical: stand-alone customer systems, microgrids, and generation applied to relieve peak loading (it does not help if it is offline). Figure 15.21 shows that individual generators typically have availabilities ranging from 90% to 97%. This is much lower than the availability

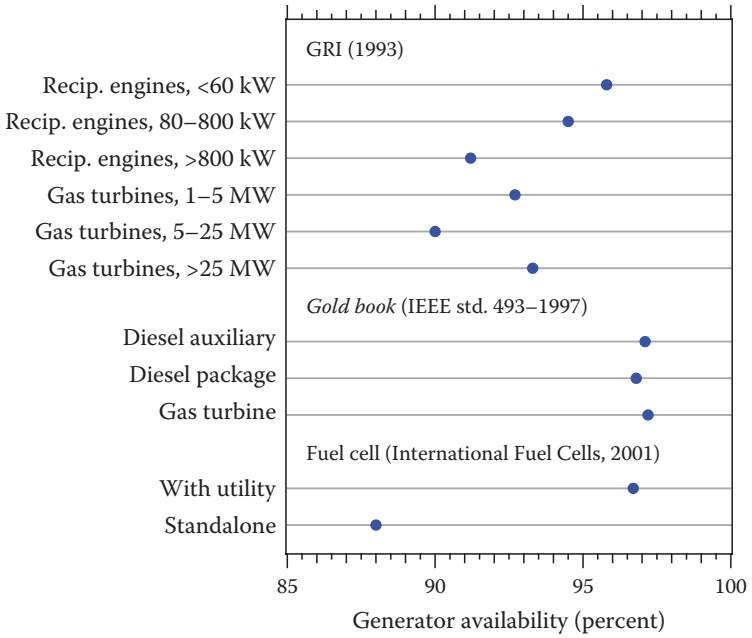


Figure 15.21 Generator availability. (From EPRI 1007281, *Analysis of Extremely Reliable Power Delivery Systems: A Proposal for Development and Application of Security, Quality, Reliability, and Availability (SQRA) Modeling for Optimizing Power System Configurations for the Digital Economy*, Electric Power Research Institute, Palo Alto, CA, 2002. Copyright 2002. Reprinted with permission.)

of typical electric utility supplies. A 97% availability is 11 days interrupted per year. The *Gold Book* (IEEE Std. 493-1997 based on Smith et al., 1990) cites failure rates of 32.9, 11.8, and 15 failures per year for diesels with auxiliary support systems, diesels packaged as units, and gas turbines.

As a supplement to a utility connection, a generator can greatly increase the reliability to the end user. Consider a utility supply with an availability of 99.966% (3.5 hours of downtime annually). If a generator with an availability of 97% (11 days of unavailability) is paralleled, the total availability of the parallel sources improves to 99.9988% (1–[1–0.97][1–0.99966]) or an average of 6 min of downtime per year. Without the utility, designing a reliable supply becomes more difficult.

Without a utility supply, any critical application needs redundant generators. Assuming that an individual generator has 97% availability, Table 15.8 shows availabilities for several combinations of generators. This data is repeated as a graph in Figure 15.22 showing the number of nines of availability (a 99.9% availability is three nines and a 99.99% availability is four nines) against the generation capacity and notations showing the configuration. The binomial distribution shows the failure probabilities for r out of n generators. The probability of exactly r successes in n trials with a probability of success p (Billinton and Allan, 1984) is

TABLE 15.8 Configurations of Redundant Generators

Number of Units Needed	Total Number of Units	Notation	Capacity (%)	System Availability
1	1	N	100	0.97
1	2	N + 1	200	0.9991
1	3	N + 2	300	0.999973
1	4	N + 3	400	0.99999919
2	2	N	100	0.941
2	3	N + 1	150	0.9974
2	4	N + 2	200	0.99989
2	5	N + 3	250	0.9999960
2	6	N + 4	300	0.99999986
3	3	N	100	0.912
3	4	N + 1	133	0.9948
3	5	N + 2	167	0.99974
3	6	N + 3	200	0.999988
4	4	N	100	0.885
4	5	N + 1	125	0.9915
4	6	N + 2	150	0.99950
4	7	N + 3	175	0.999974
4	8	N + 4	200	0.9999987
5	5	N	100	0.858
5	6	N + 1	120	0.988
5	7	N + 2	140	0.99914
5	8	N + 3	160	0.999949
5	9	N + 4	180	0.9999972
5	10	N + 5	200	0.99999986

$$P_r = {}_nC_r p^r (1-p)^{n-r} = \frac{n!}{r!(n-r)!} p^r (1-p)^{n-r}$$

So, for an example with $p = 0.97$, and three total generators, the probabilities of a given number of generators being out of service are shown in Table 15.9.

Maintenance plays a key role in the reliability of generators. Not counting downtime for maintenance, the availability of generators jumps from 97% to 99% (see Table 15.10). If maintenance can be performed at noncritical times, the reliability of the installation improves greatly.

The availabilities in Figure 15.22 are theoretical and do not include overlapping or common-mode failures. For generators, several factors contribute to common-mode failures:

- *Fuel supply*—Continuously run generators likely have a common supply of natural gas. Backup generators are more likely to have independent tanks for supply. Units with dual-fuel capability can reduce the likelihood of this failure mode.

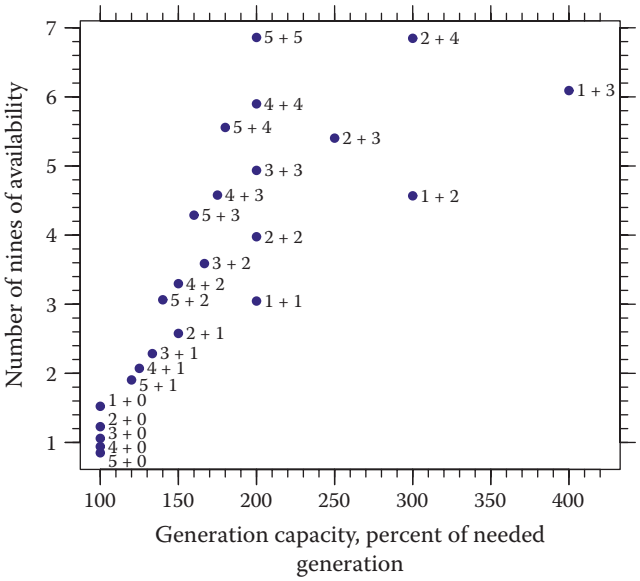


Figure 15.22 Theoretical availability with different generation configurations. The graph assumes an individual unit is 97% available. The $k + n$ notation means k generators are needed to meet the peak load, and the site has n extra generators. (From EPRI 1007281, *Analysis of Extremely Reliable Power Delivery Systems: A Proposal for Development and Application of Security, Quality, Reliability, and Availability (SQRA) Modeling for Optimizing Power System Configurations for the Digital Economy*, Electric Power Research Institute, Palo Alto, CA, 2002. Copyright 2002. Reprinted with permission.)

TABLE 15.9 Probabilities of Unit Unavailability with $p = 0.97$

Units Out of Service	Probability of the Given Number of Units Out of Service
0	$0.97^3 = 0.912673$
1 ($r = 2$, $n = 3$)	$3(0.97)^2\,(1–0.97) = 0.084681$
2 ($r = 1$, $n = 3$)	$3(0.97)\,(1–0.97)^2 = 0.002619$
3	$(1–0.97)^3 = 0.000027$
	Sum = 1.0

TABLE 15.10 Generator Availabilities (%)

	Including Maintenance	Excluding Maintenance
Diesel auxiliary	97.1	98.9
Diesel package	96.8	99.1
Gas turbine	97.2	99.4

Data source: IEEE Std. 493-1997, *IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (Gold Book)*; Smith, C. A., Donovan, M. D., and Bartos, M. J., *IEEE Transactions on Industry Applications*, vol. 26, no. 4, pp. 741–55, July/August 1990.

- *Controls*—Generators may have common controls for starting.
- *Space*—If generators are in close proximity, failure of one may require adjacent units to be shut down.
- *Design flaws*—Common design flaws may fail all units under the right conditions.

Good design, especially with redundant supporting systems, helps minimize the probability of common-mode failures, and periodic testing helps minimize hidden failures. And, because maintenance is such a large component of downtime, coordinating maintenance among parallel units and scheduling for noncritical times helps reduce the chance of failures.

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Tree Trimmer Crew Leader Dies When He Contacts Energized Power Line in Puerto Rico

A tree trimming crew was en route to a job site when they noticed that trees had fallen over a 4,000-volt power line in front of a radio tower. The damage had been caused by Hurricane Hugo. Since all the power lines in the area had been de-energized, the crew leader decided to clear the area in front of the radio tower. The crew cut and pruned the trees to clear the area, and upon finishing, returned to the truck while the crew leader made a final inspection of the work area. Crew members heard their leader cry out and ran to the work site, where they found him lying on his back. No vital signs could be detected. Investigation revealed that although the power lines had been de-energized, a gas station was using a portable gas-powered electric generator to supply electrical power to the gas pumps. Since the main circuit breaker at the gas station had not been opened, electrical current from the generator flowed back through the transformer and energized the power line at the work area.

U.S. National Institute for Occupational Safety and Health

Index

A

AAAC, *see* All-aluminum alloy conductor (AAAC)
AAC, *see* All-aluminum conductor (AAC)
Absorptivity, 62; *see also* Conductor
ac, *see* Alternating current (ac)
ACAR, *see* Aluminum conductor, alloy reinforced (ACAR)
Accelerated cable life test (ACLT), 184
Accelerated water treeing test (AWTT), 184
ACLT, *see* Accelerated cable life test (ACLT)
ACSR, *see* Aluminum conductor, steel reinforced (ACSR)
Active anti-islanding, 819
  inverters, 819
  test, 820
Active islanding protection, 811–812
Additive polarity, 211
Adjustable-speed drives (ASDs), 570, 593, 614; *see also* Programmable logic controllers (PLCs)
  dc drives, 594
  higher-horsepower drives, 594
  to improve ride through, 594
  older drives, 594
  ride-through of, 595
  synchronous flying restart, 595
  topology, 593
  voltage sag effect, 594
Advanced metering infrastructure (AMI), 304
Advanced Very High Resolution Radiometer (AVHRR), 585
AEP, *see* American Electric Power (AEP)
Aerial cables, 109
  comparison of reliability index SAIDI, 111
Air blast breaker, 431
Air insulator, 705
All-aluminum alloy conductor (AAAC), 38; *see also* Aluminum; Conductor
  burndown characteristics of, 76
All-aluminum conductor (AAC), 38; *see also* Aluminum; Conductor
  ampacities of, 63, 66, 69
  annealing curves of bare, 74
  characteristics of, 39
  covering thicknesses of covered, 41
  loss of strength of, 68
  polyethylene-covered AAC triplex, 71
  positive-sequence impedances of, 56
  temperatures based on given currents, 67
  zero-sequence and ground-return loop impedances, 57–58
Allowable starting current, 644
Alternating current (ac), 29, 203
  testing, 191–192
Aluminum, 38–39; *see also* All-aluminum alloy conductor (AAAC); All-aluminum conductor (AAC); Aluminum conductor, alloy reinforced (ACAR); Aluminum conductor, steel reinforced (ACSR); Conductor
  all-aluminum triplex ampacity, 71
  all-aluminum triplex secondaries impedance, 72
  annealing, 67–68
  burndown tests, 80
  cable conductor characteristics, 160
  and connector surfaces, 85
  geometric mean radius, 162
  IACS, 43
  maximum allowable time-current characteristics, 180
Aluminum conductor, alloy reinforced (ACAR), 38; *see also* Aluminum; Conductor
Aluminum conductor, steel reinforced (ACSR), 38, 41; *see also* Aluminum; Conductor
  ampacities of, 64
  annealing curves of bare, 74
  bare-conductor ACSR threshold-of-damage curves, 76
  burndown characteristics of, 76
  characteristics of, 40
  GMR factor, 46
  positive-sequence impedances of, 58
  skin effect, 45
  zero-sequence and ground-return loop impedances, 59
America Wood Protection Association (AWPA), 126
American Electric Power (AEP), 621
American wire gage system (AWG system), 38
AMI, *see* Advanced metering infrastructure (AMI); Automated metering infrastructure (AMI)
Ampacity, 38, 54, 56, 58; *see also* Cable's ampacity; Conductor; Overhead lines
  of ACSR, 64
  of all-aluminum conductor, 63, 66, 69
  of all-aluminum triplex, 71
  annealing, 67
  conductor temperature estimation, 67
  convected heat loss, 59
  convection losses, 60
  of copper conductors, 65
  factors impacting, 62

Ampacity (*Continued*)
multiplier, 173
neutral conductor sizing, 69–70
new ampacity based on new conductor limit, 66
operating temperatures, 67
Analysis parameters, 782–783
Animal-caused faults, 114; *see also* Animal guards; Animal-protective devices; Overhead line performance
animal-fault basics, 115
bird-caused faults, 115–116
bird-specific practices, 121
electrocuted cat and ground wire, 122
EPRI survey, 116
equipment protection against, 117
fusing, 122
identification, 116
identification based on outage inputs, 543
overhead distribution points susceptible to, 117
squirrel-caused faults, 115
Animal guards, 118; *see also* Animal-caused faults; Animal-protective devices
deteriorated, 120
flammability, 121
installation, 119
Animal-protective devices, 117; *see also* Animal guards
bushing protectors, 117
covered jumper wires, 118
covered lead wires, 117
degradation severity, 120–121
deterioration of, 121
problems with, 119
Annealing, 67
Anti-islanding protection, 818
APDs, *see* Arc protective devices (APDs)
Approximate power factor, *see* Dissipation factor
Arc, *see* Arc flash
Arc flash, 401, 778, 785, 787; *see also* Arc voltage; Equipment failures; Fault; High-impedance fault; Manhole explosions
analysis parameters, 782–783
arc impedance, 783
arc length, 403, 405, 786
arcing faults, 403
assumptions on overcurrent protection, 783
best work practices, 790–791
burndowns, 406
bus burn rates, 407
characteristics, 401–403
damage from, 405–407
developement, 784–786
distance factor, 790
distribution of times for faults, 405
distribution voltages, 404
DPQ project, 408
effect on insulators, 406
and electrode orientation, 784
EPR splice failure, 788
estimation, 779
fault data, 405
fault under oil, 419
for glove work, 784
impact on fault currents, 402
incident energies, 779, 786–787, 789, 790
insulator damage characteristics, 407
movement and evolving faults, 403–405
NESC clothing systems, 789
NESC requirement on, 783
pressure from fault arc, 406
protective device to clear fault, 779
quenching of wood, 714, 716
to reduce hazards, 789–790
resistance, 402
self-extraction time, 790
stream, 401
sustainability, 788
time–current curves, 782, 784
Arc protective devices (APDs), 81
Arc thermal performance value (ATPV), 779
Arc voltage, 401–402, 408–409; *see also* Arc flash
distribution by fault type, 410
distribution voltages, 404
and equivalent arc lengths, 408
estimates by equipment type, 411
estimates by splice failure type, 412
estimation, 409
and fault type, 409–411
histogram of, 408
on underground equipment, 411
waveform, 403, 404
Arcing ground faults, 740, 815
ARCPRO program, 779, 780, 781
Arresters, *see* Surge arresters
ASAI, *see* Average service availability index (ASAI)
ASDs, *see* Adjustable-speed drives (ASDs)
ASIDI, *see* Average system interruption duration index (ASIDI)
ASIFI, *see* Average system interruption frequency index (ASIFI)
ATPV, *see* Arc thermal performance value (ATPV)
Attenuation in cables, 695–696
Auto-loop automated distribution configuration, 521
Automated distribution
feeder, 522
supply, 521
Automated metering infrastructure (AMI), 237, 341
probability distributions of loading for transformers with, 238
Automatic circuit recloser, *see* Reclosers
Automatic reclosing, 477; *see also* Reclosing practices
Automation, 521; *see also* Reliability
auto-loop automated distribution configuration, 521
distribution feeder, 521–522
five-recloser loop, 522–523
program performance evaluation, 549
remotely controlled switches, 523
scheme enhancements, 523

Autotransformers, 247; *see also* Transformer
applications, 247
connection, 248
with equivalent circuit, 247
equivalent series impedance of, 248
rating of winding, 248
Average service availability index (ASAI), 493
Average system interruption duration index (ASIDI), 496
Average system interruption frequency index (ASIFI), 496
AVHRR, *see* Advanced Very High Resolution Radiometer (AVHRR)
AWG system, *see* American wire gage system (AWG system)
AWPA, *see* America Wood Protection Association (AWPA)
AWTT, *see* Accelerated water treeing test (AWTT)

B

Backfeeds, 262; *see also* Transformer
available backfeed current and voltage, 264, 265
and connections, 263–264
current, 263
to downed conductor, 263
equations for, 263
to fault downstream of blown, 415
high-impedance fault, 414
motor load and, 264
single-phase protective devices, 485
solution to problems, 265
voltage, 263, 826–827
Basic lightning impulse insulation level (BIL), 209, 246, 685
Bathtub curve, 525; *see also* Reliability programs
Beat frequency, 645
Bidirectional regulator misoperation, 836
BIL, *see* Basic lightning impulse insulation level (BIL)
Body current for touch potential, 766
Boring, 153; *see also* Cable installation configurations
Bracketed grounds, 771, 772
Break-before-make transfers, 604
Breaker-trip ringing, 737
Budget allocations, reliability-based, 533
Buried strip, 744
Burndown, 74, 406, 713; *see also* Overhead lines
characteristics of conductors, 77–78, 79
characteristics of small bare conductors, 76
conductor damage, 75
covered conductors, 75
damage on covered AL conductors, 80
EPRI tests, 78
options to limit, 81
solutions for small bare conductor, 81–82
test with line hose, 81
tests of covered, aluminum conductors, 80
worst-case burndown characteristics, 79
Bus tie, 568
Bushing
arrester, 695
protectors, 117
Butt plates, 745, 747

C

Cable capacitance, 167; *see also* Cable impedances
for common cable sizes and voltages, 169
Cable conductor resistance, 156; *see also* Cable impedances
ac resistance, 158
dc resistance, 157
proximity effect factor, 159
skin-effect factor, 158–159
vs. temperature, 158
Cable diagnostic focused initiative (CDFI), 192
Cable failure modes, 698–700
Cable impedances, 156; *see also* Cable capacitance; Cable conductor resistance; Underground distribution
cable dimensions for calculating, 162
common cable configurations, 166–167, 168
effects on positive and zero-sequence, 164, 165
formulas, 159–164
neutral current, 164
self and mutual, 161
sequence, 160
sheath resistances, 163
single-phase cable resistance and reactance, 165
tables, 164
zero and positive-sequence, 162
Cable installation configurations, 153–154; *see also* Underground distribution
cable diameters for small conduits, 156
communication cables, 155
conduits, 154
maximum electric field, 156
small ducts, 155
surveyed utility, 154, 155
Cable insulation, 145; *see also* Cables
cross-linked polyethylene, 147
EPR, 147–148
HMWPE, 147
insulation thicknesses for XLPE or EPR cables, 149
paper-insulated cables, 146
polyethylene, 146–147
properties of, 145, 146
TR-XLPE vs. EPR, 148
voltage rating, 148–149
Cable reliability, 182; *see also* Underground distribution; Water trees
accelerated-aging test, 184
cable failure, 188, 189
cable replacement criteria, 186
cumulative service-time failure rates, 189
failure modes, 186
failure statistics, 187
insulation thickness and, 185

Cable reliability (*Continued*)
joint failure, 191
self-clearing fault signature, 187
surges, 185
trends in URD cable specifications, 185
underground-component failure rates, 190
workmanship issues, 190
XLPE average yearly failure rate comparison, 189
Cable testing, 191; *see also* Underground distribution
ac testing, 191–192
CDFI criteria for cable assessment, 192
dc testing, 191
hi-pot testing, 191
partial discharge detection, 192
tan delta, 192–193
Cables, 144; *see also* Cable insulation; Shield; Underground distribution
bare, 152
concentric neutral, 145
conductor diameters, 150
conductors, 149
jacket, 152–153
neutral, 149, 151
semiconducting shields, 151–152
with tape shields, 735
types, 144
utility use of cable neutral configurations, 151
Cable's ampacity, 169; *see also* Ampacity; Underground distribution
cable crossings and hotspots, 179
cable number, 179
calculations, 170
common ampacity rating conversions, 176
for common distribution configurations, 172–173
conductor temperature, 175–176
conduits, 176
current unbalance, 178–179
earth interface temperature, 177–178
limiting factor, 169
loss factor, 176
moisture on thermal resistivity, 177
multiplier, 173
Neher-McGrath method, 170, 172
reduction with multiple cable circuits, 179
riser poles, 179–180
sheath losses, 173–174, 175
sheath resistance, 172
soil thermal resistivity and temperature, 176–177
spacings, 174–175
system voltage and insulation thickness, 179
temperature difference, 170
thermal circuit model, 170–171
thermal resistivity, 171, 178
effect of variables on, 174
CAIDI, *see* Customer average interruption duration frequency index (CAIDI)
Cankers, 105
Capacitor, 319, 672; *see also* Capacitor failure modes; Capacitor fusing and protection; Distribution capacitors; Harmonic resonance; Switched banks; Volt-var control
on ac power systems, 320
ambient temperatures, 326
arresters, 323
capacitance, 324
components, 320
feeder, 322
floating-wye configurations, 363–364
grounded-wye and ungrounded-wye bank comparison, 364
grounding, 362–364
harmonic scans for, 635
location from substation, 637
overhead line capacitor installation, 321
padmounted, 321
power-frequency voltages, 324
ratings, 323–326
reliability, 342–346
resistor, 325
resonances by, 632
size vs. resonant frequency, 637
standards and application guidelines, 324
substation, 321, 322
switched, 323
switching transients, 620, 621
transient overcurrent and overvoltage capability, 325
transient prevention, 626
units, 320
Capacitor failure modes, 343; *see also* Capacitor
bank issues by cause, 343
maintenance needs, 342
modern film-foil, 344
paper and paper-film, 344
per-unit current drawn by failing bank, 346
rupture curves, 345
series sections in different voltage ratings, 346
unit with failed element, 343
Capacitor fusing and protection, 346; *see also* Capacitor; Outrush
backup current-limiting fuses, 357
capacitor and transformer fuse operations, 349
capacitor bank with blown fuse, 347
cutout-related issues and solutions, 358–361
factors causing fuse, 347
fuse application guidelines, 356
fuse curves with capacitor rupture curves, 358
fusing guidelines, 355–357
fusing ratios for capacitor banks, 357
fusing recommendations for ANSI tin links, 348
hot capacitor cutout, 360
infrared image of cutouts under test, 359
minimum fuse rating, 347
neutral current monitoring, 361–363
nuisance fuse operations, 349
Cardiopulmonary resuscitation (CPR), 756
Carson's equations, 50

CBEMA curve, *see* Computer Business Equipment Manufacturers' Association curve (CBEMA curve)
CCA, *see* Chromated copper arsenate (CCA)
CDFI, *see* Cable diagnostic focused initiative (CDFI)
CEMIn, *see* Customers experiencing multiple interruptions (CEMIn)
Ceramic pin-type insulator, 705
CFO, *see* Critical flashover voltage (CFO)
Chopped wave withstand (CWW), 686
  protective margins, 688
  underground protective margins, 695
Chromated copper arsenate (CCA), 125
CI, *see* Customer interruptions (CI)
Circuit breaker, 432, 665; *see also* Circuit interrupters; Protection equipment
  distribution, 434
  interruption rating, 433
  interruption time, 433
  percent reduction, 433
  recloser ratings vs. circuit breaker ratings, 437
  short-circuit ratings, 433
  symmetrical interrupting capability, 432
Circuit breaker relays, 434; *see also* Digital relays; Protection equipment
  designations, 436
  IEEE standardized relay curve equation constants, 436
  relay curves, 436–437
  time–current characteristics, 435
  types of, 434
Circuit exposure and load density, 505
Circuit interrupters, 426; *see also* Circuit breaker; Protection equipment
  air blast breaker, 431
  methods to increase arc dielectric strength, 431
  principle, 430
  recovery voltage, 431
  SF_6 interrupter, 431–432
  vacuum devices, 431
Circular mils, 39
Circulating current method, 296; *see also* Station regulation
Clamp-on ground-resistance tester, 752
CLFs, *see* Current-limiting fuses (CLFs)
Cloud-to-ground lightning, 663
CMI, *see* Customer-minutes of interruption (CMI)
Code police, 538
Coil hold in, 593
Cold-load pickup, 429; *see also* Distribution protection
  ranges of, 430
Completely self-protected transformer (CSP transformer), 122, 216–217; *see also* Single-phase transformers
  built-in features, 216
  with internal secondary breaker, 237
  with secondary breakers, 225, 227
  under-oil fuses, 419
  unfused CSP on mainline, 464
Composite crossarm attachments, 715
Computer Business Equipment Manufacturers' Association curve (CBEMA curve), 571
Computers power supplies, 586; *see also* Ride through
  ride-through and voltage, 589–590
  ride-through capability, 587–589
  switch-mode power supply, 587
  volt–time characteristics, 588
Conductivity, 43
Conductor, 37; *see also* All-aluminum alloy conductor (AAAC); All-aluminum conductor (AAC); Aluminum conductor, alloy reinforced (ACAR); Aluminum conductor, steel reinforced (ACSR); Ampacity; Burndown; Copper; Line impedances; Overhead lines; Covered conductors; Wire
  absorptivity, 62
  ACSR, 41
  aluminum, 38–39
  annealing, 72
  arc damage, 75
  burndown characteristics of, 77–78, 79
  circular mils, 39, 40
  conversion relationships, 40–41
  copper, 39
  emissivity, 62
  factors affecting conductor selection, 54–55
  gage, 39
  heat absorbtion, 62
  heat radiation, 62
  material properties, 37
  sizes, 40, 54–56
  spacer cables, 41
  steel, 41
  stranded, 41
  temperature, 58, 73
  thermal data for short-circuit limits, 73
  time-current characteristic, 73
Conductor clashing, *see* Conductor slapping
Conductor slapping, 82; *see also* Overhead lines
  critical clearing time for, 83
  force between two, 82
  motion, 82
  solution options for, 84
Connectors, 84; *see also* Overhead lines
  bad connection, 85
  compression, 85
  factors affecting, 86
  hot-line clamps, 86
  stirrup, 86
  surface and conductors, 85
Conservation voltage reduction (CVR), 299
Constant
  current load, 279
  impedance load, 279, 396, 398
  power load, 279
Contact
  currents threshold levels, 755
  point surface, 769

Contact voltages, 760, 763–765; *see also* Arc flash; Shocks and stray voltages; Tree contacts
causes of electrical failures, 763
during flooding, 765
locating source, 764–765
mobile electric field detectors, 764
sources of, 763, 764
Coordinating devices, 456; *see also* Short-circuit protection
expulsion fuse–expulsion fuse coordination, 456
40-K expulsion link and backup current-limiting fuse, 459
fuse coordination, 457–460
100-K and 65-K link fuse coordination, 457
instantaneous element coordination, 461–463
K links and Cooper 4E single-phase hydraulic recloser, 461
maximum fault currents, 457
recloser–expulsion fuse coordination, 460
recloser–recloser coordination, 461
sequence coordination, 462
time–current curve crossover coordination, 459
Copper, 39; *see also* Conductor; Loads
ampacities of, 65
burndown characteristics of, 76
cable conductor characteristics, 160
and connector surfaces, 85
geometric mean radius, 162
IACS, 43
positive-sequence impedances of, 60
sheath resistance adjust, 163
tape shield short-circuit insulation limit, 182
upper limit, 180
zero-sequence and ground-return loop impedances, 61
Core losses, *see* No-load losses
Corona impacts traveling wave, 673
Corrosion, 748
galvanic, 748–749
prevention, 748–751
Covered conductors, 41, 108; *see also* Conductor; Overhead line performance; Spacer cables; Wire
advantages of, 109–110
burndowns, 75, 80, 81
compact armless design using, 109
comparison of reliability index SAIDI, 111
with conducting insulator ties, 112–113
covered wire tie on, 112
covering integrity, 114
damage on, 113
disadvantage, 110
Duke Energy, 111
heat absorption, 68
insulation materials, 108
loadings for covered vs. bare conductor, 114
pole structures with, 112
power-line noise, 112
properties, 113
short-circuit capability, 73
spacings, 111
Covered jumper wires, 118
Covered lead wires, 117
Covered wire tie, 112; *see also* Covered conductors
CPR, *see* Cardiopulmonary resuscitation (CPR)
Critical flashover voltage (CFO), 703, 704
by primary and second components, 705
Crossarm and pole damage and bonding, 713
Cross-linked polyethylene (XLPE), 145, 147
aging, 184
cumulative service-time failure rates, 189
maximum allowable time-current characteristic, 180
short-circuit limit of cables with, 181
yearly failure rates comparison, 189
CSP transformer, *see* Completely self-protected transformer (CSP transformer)
CT, *see* Current transformer (CT)
Current
distortion, 628, 629, 631
flow through lightning channel, 701
and voltages, 767–768
Current and voltage surge suppressor (CVSS), 599
Current-limiting fuses (CLFs), 426, 446, 603; *see also* Protection equipment
application, 446, 447, 448
arc damage to life and property, 448
backup, 446
coordination, 457–460
drawbacks of, 447–448
fulgerite, 446
transformers, 452
types of, 447
use of, 446
Current transformer (CT), 281, 336, 383
Custom-power devices, 605; *see also* Utility options
configurations, 606
Customer
loads, 23
solution options, 606–607
Customer average interruption duration frequency index (CAIDI), 493
Customer-based indices, 492
CAIDI, 493
CEMIn, 496
CI, 493
CMI, 493
SAIDI, 493
SAIFI, 492
Customer interruptions (CI), 493
Customer-minutes of interruption (CMI), 493
Customers experiencing multiple interruptions (CEMIn), 496
CVR, *see* Conservation voltage reduction (CVR)
CVSS, *see* Current and voltage surge suppressor (CVSS)
CWW, *see* Chopped wave withstand (CWW)

D

Dalziel's formula, 754, 755–756
Damper windings, 804
Dart leaders, 663
dc, *see* Direct current (dc)
δ, *see* Tan delta (δ)
Delta–grounded wye, 813
Demand side management (DSM), 798
DG, *see* Distributed generation (DG)
Dielectric constant, 145
Dielectric losses, 145
Digital relays, 434; *see also* Circuit breaker relays
  advantages of, 434–435
  disadvantages, 435
Dips, *see* Voltage sags
Direct-axis impedance, 804
Direct current (dc), 30
Dissipation factor, 146
Dissipation factor test, *see* Tan delta (δ)
Distributed generation (DG), 797, 798; *see also* Generator reliability; Islanding; Inverters; Synchronous generators
  advantages, 798, 800
  capacity, 798
  constant-power model, 810
  effects on overcurrent protection, 810
  end-use generation's benefits, 799
  fault contributions of, 810
  grounding source connections feeding single-phase faults, 830
  induction generators, 806
  issues in, 798–799
  load-flow model of, 809
  and microgrids, 800
  modeling small generators, 809–810
  normal load models, 809
  trip thresholds for, 820
Distributed Network Protocol (DNP), 338
Distributed resources (DRs), 798
Distribution capacitors, 326; *see also* Capacitor
  average power factors by circuit, 334
  current and reactive power, 326
  equipment controller protection, 716
  extra capacity as function of capacitor size, 327
  Grainger/Lee method, 330
  loss reduction for capacitor, 332
  1/2-kvar rule, 330–331
  optimal capacitor loss reduction, 330
  percent voltage rise, 329
  probability distributions of primary line losses, 333
  reactive load factor, 332
  real and reactive power profiles, 333
  reducing line losses, 329
  released capacity and voltage support, 326–329
  released capacity with improved power factor, 327
  1200-kvar bank placement, 331
  2/3 rule, 329
  voltage profiles, 328
  voltage rise, 328
Distribution line
  attraction models, 702
  fault rate vs. GFD, 662
  inspection techniques, 526–527; *see also* Reliability programs
Distribution management system (DMS), 339
Distribution Power Quality (DPQ), 408, 574
Distribution protection, 426; *see also* Short-circuit protection
  characteristic of, 427
  circuit interrupters, 426
  cold-load pickup, 429–430
  inrush, 428–429
  reach, 427–428
  standardization, 426–427
  steep time–overcurrent characteristics, 430
  system impedance, 428
Distribution SCADA (DSCADA), 341
Distribution substations, 15; *see also* Electric power distribution
  bus arrangements, 18
  feeder interrupting devices, 17
  rural, 16
  split bus, 17
  suburban, 16
  transformers, 17
  two-bank stations, 17
  urban, 16
  utilities, 17
Distribution systems, *see* Electric power distribution
Distribution transformers, 203, 232; *see also* Transformer
  cooling capability, 210
  direct-buried transformers, 210
  impedances, 208
  insulation levels for, 209
  low-frequency test, 209
  padmounted transformers, 209–210
  rise units, 232
  short-circuit capability duration, 209
  single-phase, 211
  standardized sizes, 208
  submersible transformers, 210
  through-fault capability of, 209
  transformers in underground vaults, 210
DMS, *see* Distribution management system (DMS)
DNP, *see* Distributed Network Protocol (DNP)
Doubly censored survey data, 129
Downed wire, 412
DPQ, *see* Distribution Power Quality (DPQ)
Drag hands, 284
Drifting out of phase, 811
DRs, *see* Distributed resources (DRs)
DSCADA, *see* Distribution SCADA (DSCADA)
DSM, *see* Demand side management (DSM)
Duct bank, 141

Duke Energy, 94
covered conductors, 111
failure modes, 540
outage codes, 535
restoration costs during typical year and during major storms, 553
DVR, *see* Dynamic-voltage restorer (DVR)
Dynamic-voltage restorer (DVR), 605; *see also* Utility options

E

Earth fault factor, 730
Eastern Utilities, 106; *see also* Vegetation management
ECI, *see* Environmental Consultants Inc. (ECI)
Eddy currents, 206
losses, 240
8.4-kV MCOV arrester, 674
Elbow arresters, 695
Electric power distribution, 1; *see also* European distribution systems; Loads; North American distribution systems; Primary voltage levels; Subtransmission systems; Urban networks; Distribution substations
annual utility distribution budgets, 3
circuit parameters, 5
development timeline, 29
efficiency, 25–28
entities, 3
feeder, 4, 6
infrastructure, 1–2
laterals, 5
loads, 23
losses, 26–28
mainline, 4–5
past and future, 28–30
peak vs. average losses, 28
planning, 3
primary and secondary selective schemes, 9
primary distribution configurations, 4–9
primary distribution lines, 1
primary-loop scheme, 6, 7, 8
radial circuits, 5–6, 7
66-project circuits, 26
substation with feeders, 4
Electric Power Research Institute (EPRI), 3
Green Circuits project, 302
Electrical accidents, 779
Electrical shock, 756
Electricity infrastructure, 2; *see also* Electric power distribution
Electrification, 1
Electrodes, 744–745
Electromechanical relays, 434
Electronic ballasts, 645
effect, 631–632
Elevated NEV, 759
Embedded generation, *see* Distributed generation (DG)
Emergency off circuit (EMO circuit), 591
Emissivity, 62; *see also* Conductor
EMO circuit, *see* Emergency off circuit (EMO circuit)
End-use generation's benefits, 799
Energization at voltage peak, 599
Energy sources, 800–801; *see also* Distributed generation (DG)
factors in, 800
power output quality, 801
Energy storage devices, 605
Environmental Consultants Inc. (ECI), 93
survey comparison, 505
survey of tree outage causes, 94
EPDM, *see* Ethylene propylene diene methylene (EPDM)
EPR, *see* Ethylene-propylene rubber (EPR)
EPRI, *see* Electric Power Research Institute (EPRI)
Equipment failures, 416, 540; *see also* Arresters; Fault
arc, 419
bushing ejection, 419
fault in windings, 419
due to heat, 418
internal faults, 418
overhead component failure rates, 417
permanent fault causes, 416
recloser failure, 418
service-time overhead component failure rates, 417
stand-alone arresters, 420
transformer insulation degradation, 418
turn-to-turn faults, 419
under-oil arrester, 420
weak-link fuse, 419–420
Equipment protection, 685; *see also* Underground equipment protection
arrester application, 688, 696
CWW protective margins, 688
equipment insulation, 685–686
equipment maintenance, 525–526
factors for secondary surge severity, 690
lead length, 688
protective margin, 686–689
secondary-side transformer failures, 689–690
surge entry, 689
transformer inductances, 690
Equipment sensitivities, 586; *see also* Computers power supplies; Industrial power supplies; Inrush; Ride through
industrial power supplies, 590
residential equipment, 595–596
voltage sag sensitivities, 591
Eriksson's equation, 669
Ethylene propylene diene methylene (EPDM), 121
Ethylene-propylene rubber (EPR), 145, 147–148
maximum allowable time-current characteristic, 180
short-circuit limit of cables with, 181
splice failure, 788
European distribution systems, 20; *see also* Electric power distribution
distribution layouts, 21
vs. North American distribution systems, 21–22
secondaries, 20

Expulsion fuse, 438; *see also* Protection equipment
arc, 438
clear curves, 440, 442, 444
fuse cutouts, 443–445
fuse melting time, 440
intermediate fuses, 441
interruption, 438
melt curves, 440, 441, 443
operation of, 439
preferred fuses, 441
speed ratio of fuse, 438–439
surge-resistant fuse, 442
time–current curves, 439
types of, 439
Extra-high overvoltages, 739

F

FA, *see* Forced air cooling (FA)
Fall of potential method, 751–752
False tripping of utility protective devices, 830–831
Fast reclose, *see* Immediate reclose
Fast transfer switch, 603
advantages, 604
application of, 604
to enhance power quality, 605
Fault, 367; *see also* Arc; Equipment failures; Fault location; High-impedance fault
asymmetric fault, 382
bolted fault, 384
calculations, 373–378
causes measured, 368
causing sustained interruptions, 369, 371
characteristics, 368–373
clearing protective device, 779
current, 388, 390, 564, 732, 734, 828
-current arcs, 74
distribution, 368
effect of *X/R* ratio, 380–383
impacts of asymmetry, 383
impedance, 373–377
limiting fault currents, 400–401
number of phases in fault measurement, 369
offset, 382
on overhead distribution circuits, 370
overvoltage equation in per unit, 387
percentage of, 371–372
permanent, 369
per-unit fault currents, 378, 379
point of fault on voltage waveform, 373
positive-and zero-sequence diagrams, 375
primary-to-secondary, 385–389
from primary to secondary circuit, 386, 388
profiles, 379–380, 381, 386
rates, 370
ratio of peak current to rms current, 383
recovery voltage, 381
secondary, 384–385
station-class arresters, 391
temporary, 369–370
three-phase fault current, 374
transformer connections, 378–379
transformer fuse, 388
transformer impedance, 376
transmission/subtransmission fault levels, 378
from transmission to distribution conductor, 389
underbuilt fault to transmission circuit, 389–392
voltage at, 390
Fault location, 392, 732; *see also* Fault
calculations, 393
constant-impedance load model, 396, 398
distance calculation, 395
distance error of, 398
distance to fault, 392, 394–395
impedance based location methods, 398
impedance of load, 396
line-to-ground fault, 393, 396
Ohm's law equation, 392, 393
phase-to-ground voltage, 394
predicted vs. actual distance to fault, 398, 399
reactance-to-the-fault method, 399–400
result, 397
simple fault location solution, 394
three-phase faults, 393, 396
total impedance, 396
Fault selective feeder relaying, *see* Fuse saving
Faulted circuit indicators (FCIs), 193
Faults and interruption variability, 502
FCIs, *see* Faulted circuit indicators (FCIs)
Feeder, 4, 6; *see also* Electric power distribution
capacitors, 322; *see also* Capacitor
electrical load on, 23
fault effect, 565
length, 732
substation vs. feeder capacitors, 322
Ferroresonance, 252, 614, 825–826; *see also* Transformer
arresters, 259–260
cable capacitance and no-load losses, 255
capacitive reactive power, 255, 256
example, 253
factors causing, 255–256, 258
ferroresonant circuit, 252, 253
five-legged core, 257–258
line-to-ground transformer capacitance, 258
on overhead circuits, 256
in silicon-steel distribution transformers, 254
single-phase protective devices, 485
solutions to, 259
transformer connections, 252, 254
voltages, currents and transformer flux, 254
Fiberglass insulator, 705
Field winding, 802
First stroke, 664, 665
Five-recloser loop, 522–523
Five-wire design grounding, 728; *see also* Grounding
insulation factor, 729
Fixed banks, 334; *see also* Switched banks
Flame on energized branch, 769
Flame-resistant (FR), 779

Flashovers
vs. insulation level, 703
between neutral and ground, 717
Flicker, 638, 839; *see also* Flicker solutions; Harmonic resonance; Voltage unbalance
allowable starting current, 644
beat frequency, 645
cause of, 645
electronic ballasts, 645
flickermeter, 640–641
GE flicker curve, 639, 641
and human perception, 640
impedance at transformer, 644
interharmonics—harmonic distortions, 644
noninteger harmonic amplification, 646
noninteger harmonics, 645
quantifying, 642
reference curve, 639
reference impedances, 644
due to rms changes, 645
susceptibility to, 638
tendency of different lights, 639
thresholds in fluctuating loads, 643
voltage change characterization, 640
voltage flicker propagation, 642
Flicker solutions, 646
dedicated circuit, 651
load changes, 646–647
reconductoring, 651
series capacitor, 647–650
static var compensator, 650
upgrading voltage, 651
Flickermeter, 640–641
Florida Power & Light Co. (FP&L), 75
Flux, 266
FOA, *see* Forced air cooling plus oil circulating pumps. (FOA)
Foot-to-earth contact resistances, 770
Forced air cooling (FA), 244
Forced air cooling plus oil circulating pumps. (FOA), 244
Four-point method, 752
Four-wire multigrounded systems, 726; *see also* Grounding
advantages, 726
as distribution primaries, 5
with neutral shift, 677
other grounding configurations, 727
overvoltage factors for, 732
safety of, 727
substation transformer, 727
zero-sequence self-impedance, 51
FOW, *see* Front-of-wave protective level (FOW)
FP&L, *see* Florida Power & Light Co. (FP&L)
FR, *see* Flame-resistant (FR)
Fractional pitch winding, 805
Frequency-shift methods, 819
Front-of-wave protective level (FOW), 676
Fulgerite, 446; *see also* Current-limiting fuses (CLFs)
Full-pitch stator winding, 805
Fuse blowing, 371, 468; *see also* Protection schemes; Short-circuit protection
alternative implementation of, 475
delayed instantaneous element used for, 475
drawbacks, 472–473
effects on momentary and sustained interruptions, 470
for fault on lateral, 469
on hypothetical circuit, 470
industry usage, 468–469
long-duration faults and damage, 472–473
long-duration voltage sags, 473
optimal implementation of, 474–475
substation, 476
Fuse cutouts, 369, 443–445, 706; *see also* Expulsion fuse
with load-break capability, 445
recovery voltage, 445
with slant voltage ratings, 445
Fuse saving, 468, 832–833; *see also* Protection schemes; Short-circuit protection
coordination limits of, 470–471
effects on momentary and sustained interruptions, 470
fault currents and critical distances, 472
for fault on lateral, 469
on hypothetical circuit, 470
industry usage, 468–469
optimal implementation of, 474
recloser, 476
during storms, 476
usage of, 470
used by utilities, 469
Fusing ratio, 451
Fusing table, 448

G

Gage, 39
Galvanic currents, 750
Gapped silicon-carbide arrester, 680
Generator grounding, 814
Generator reliability, 843; *see also* Distributed generation (DG)
common-mode failures, 845, 847
generator availability, 844, 846
maintenance factor, 845
probabilities of unit unavailability, 846
redundant generator configurations, 845
Generators without interfacing transformer, 814–815
Geometric mean radius (GMR), 45
GFD, *see* Ground flash density (GFD)
GMR, *see* Geometric mean radius (GMR)
Grainger/Lee method, 330
Green Circuit project, 333
Grid networks, 10, 11; *see also* Urban networks
Ground
electrode tester, 752
fault overvoltage detection scheme, 816
flash density variability, 667, 668

lead effects, protection against, 717, 719
loop length reduction, 717, 718
resistance, 712
Ground electrode, 744–745; *see also* Ground rods
buried strip, 744
butt plates, 745, 747
copper-oxide effect, 750
corrosion prevention, 748–751
galvanic corrosion, 748–749
galvanic currents, 750
in parallel, 744
potentials of metals in electrolyte, 750
to reduce resistivity, 747
resistance calculations, 746, 752
resistance of multiple, 745
soil breakeage, 748
sustained current effect on, 748
two-pole grounding, 745
wire wraps, 745, 747
zinc coating, 750
Ground flash density (GFD), 661
Ground rods, 743; *see also* Ground electrode; Soil resistivity
resistance and number of, 732, 733
resistance of multiple, 745
separation of, 744
Grounded wye–delta, 813
advantages and draw backs, 814
connection, 814
with grounding reactor on high-side wye, 813
Grounded wye–grounded wye, 813
transformers, 814
zero-sequence current, 814
Grounding, 725; *see also* Four-wire multigrounded systems; Ground electrode; Protective grounds; Ungrounded system
cables with tape shields, 735
coefficient of, 729, 730
to confine lightning damage, 712
earth fault factor, 730
electrodes, 744–745
fault current paths, 732, 734
fault location, 732
feeder length, 732
five-wire design, 728–729
four-wire multigrounded systems, 726–727
ground rods, 732, 733
grounded-wye–grounded-wye transformer connection, 816–817
high-resistance grounding, 728
impact of, 712
internal breakdowns from impulse overvoltages, 714
issues, 616–618
jumpers, 772, 773
need for secondary, 742
NESC requirement on, 741–743
neutral reactor, 733, 736–737
and neutral shifts, 729, 731
neutral size, 734
overvoltage factors for, 732
overvoltages by double line-to-ground fault, 730–731
overvoltages for faults on feeders, 733
potential shifts and overvoltages, 729
return path impedance, 732
role of, 711–713
secondary grounding problems, 742–743
spacer cable systems, 735
three-wire resonant-grounded system, 728
three-wire unigrounded distribution system, 727
for transformers, 712
in underground work, 773–774
voltage on unfaulted phases, 735
Grounding transformers, 248; *see also* Transformer
application of, 250
connection, 248–249
feeding ground fault, 249
power rating, 250
voltage unbalance, 250–251
zero-sequence current, 250

H

Harmonic-current sources, 627–628
Harmonic injection, 838
Harmonic resonance, 632, 633; *see also* Flicker; Harmonics; Telephone interference
harmonic scans for capacitors, 635
harmonic voltages, 633
multiple resonant points, 634
resonant frequency vs. capacitor size, 634, 637
solutions for, 634
Harmonic voltage, 628, 633
Harmonics, 626; *see also* Harmonic resonance; Power quality issues; Switching surges
characterizing, 628
in computer power supply, 626–627
current distortion, 628, 629, 631
distortions at substation sites, 631
effect on end-use equipment, 629–630
electronic ballast effect, 631–632
in ground return path, 636
harmonic-current sources, 627–628
harmonic voltage, 628
heating due to, 630
industry limits on, 838
motor derating, 630
recommended practice for, 628
to track, 632
voltage distortion, 629, 631
Hazard tree; *see also* Vegetation management
mitigation project, 106
program performance evaluation, 549
programs, 104–106
Hi-pot testing, 191
Higher-horsepower drives, 594
High-impedance fault, 412; *see also* Arc; Fault
arcing, 412
avoidance, 414
backfeeds, 414, 415

High-impedance fault (*Continued*)
detection of, 415
on distribution circuits, 412
frequency of, 412
problems with substation detection, 415–416
reduction, 413–414
spacer cable, 414
three-wire distribution systems, 414
tree in contact with phase conductor, 415
High-molecular weight polyethylene (HMWPE), 145, 147
cumulative service-time failure rates, 189
High-quality power configurations, 842
High-reactance grounding, *see* High-resistance grounding
High-resistance grounding, 728; *see also* Grounding
High-speed vacuum switches, 603
Higher-voltage distribution systems, 12–13, 14–15
HMWPE, *see* High-molecular weight polyethylene (HMWPE)
Horizontal ceramic insulator string, 705
Hot-line clamps, 86; *see also* Connectors
Hottest-spot conductor temperature, 245
Human resistance values, 754
Hysteresis, 206, 239
losses, 240

I

IACS, *see* International Annealed Copper Standard (IACS)
IBEW, *see* International Brotherhood of Electrical Workers (IBEW)
ICE, *see* Interruption Cost Estimate (ICE)
ID, *see* Identity (ID)
Identity (ID), 116
IEEE 1584 method, 780–781, 790
Immediate reclose, 481; *see also* Reclosing practices
delay necessary to avoid retriggering faults, 482–483
effect on sensitive residential devices, 482
minimum deionization time, 483
reclose impacts on motors, 483–484
Impedance
arc, 783
barrier by bark, 770
based location methods, 398
to harmonics model, 838
of one foot-to-ground contact, 756
of return path, 732
at transformer, 644
Incident energies, 786–787, 789, 790
Independent power producer (IPP), 798
Induced voltages, 700; *see also* Line protection
comparison of, 702
current flow through lightning channel, 701
distribution line attraction model, 702
earth resistivity on, 701
flashovers vs. insulation level, 703
rocket-triggered lightning tests, 702
Rusck's model, 701
Induction generators, 806
islanding, 812
reactive power, 809
Industrial power supplies, 590; *see also* Adjustable-speed drives (ASDs); Relays and contactors
industrial equipments, 590
PLC, 595, 596
postsag inrush, 596–599
Information Technology Industry Council (ITI), 571
Initial transient spike, 737
Input and output channels (I/O racks), 595
Inrush, 570; *see also* Equipment sensitivities; Outrush; Utility options for voltage sags
end-use devices damage, 596
energized at voltage peak, 599
following severe sags, 599
inrush-limiting circuitry, 597
post-sag, 598
voltage sags and, 599
Inrush current, 265; *see also* Transformer
factors affecting, 267–268
measured at substation, 267
peak inrush with source impedance, 267–268
residual flux during circuit interruption, 266
voltage and flux, 266
voltage transients and, 268
worst-case scenario, 265
Instantaneous flicker sensation, 641
Instantaneous interruptions, *see* Momentary interruptions
Instantaneous overvoltage element, 818
Instantaneous reclose, *see* Immediate reclose
Instantaneous undervoltage relay, 818
Insulation, 703, 772; *see also* Surge arresters; Line protection
conducting supports and structures, 706
to estimate insulation level, 704
fiberglass-strain insulator, 705
fuse cutouts, 706
insulator bonding, 707
multiple circuits, 706–707
neutral wire height, 706
porcelain guy-strain insulators, 705
spacer-cable circuits, 707
spark gaps, 707
Insulator bonding, 707
Integrated generator relay packages, 819
Interharmonics—harmonic distortions, 644
Intermediate fuses, 441
International Annealed Copper Standard (IACS), 43
International Brotherhood of Electrical Workers (IBEW), 775
Interruption Cost Estimate (ICE), 552
Interruptions; *see also* Reliability indices
costs, 551–553
damages due to, 491–492
duration distribution, 550
effect quantification, 502
occurrence, 501

Inverters, 806
active anti-islanding inverters, 819
-based relays, 822
grounded, 808
isolation from grounding, 814
line-commutated, 807
power converter characteristics, 809
self-commutated, 807–808, 812
ungrounded, 808
I/O racks, *see* Input and output channels (I/O racks)
IPP, *see* Independent power producer (IPP)
Iron losses, *see* No-load losses
Island with line-to-ground fault, 812
Islanding, 810, 812; *see also* Protection issues; Relaying issues; Transformer connection effect on overvoltages
active anti-islanding, 819
active anti-islanding test, 820
anti-islanding protection, 818
backfeed voltages, 826–827
to decrease voltage, 824
ferroresonance, 825–826
frequency relay, 819
integrated generator relay packages, 819
minimum load, 826
nondetection zones, 811
overvoltages, 799, 827
out of phase drifting, 811
to prevent, 811–812
reconfiguration, 826
relaying, 826
safety issues, 810–811
Sandia voltage-and frequency-shift anti-islanding techniques, 819
self-excitation, 823–825
series resonance, 823, 824, 825
time-delay relays, 818
trip thresholds for distributed generators, 820
zero-sequence capacitance resonance, 824
Isolation from grounding, 814
Isolators, 680–682
ITI, *see* Information Technology Industry Council (ITI)

J

Jacket, 152–153; *see also* Cables

K

Kelvin functions, 44

L

Laterals, 5.*See* also Electric power distribution
LC shield, *see* Longitudinally corrugated shield (LC shield)
LDC, *see* Line drop compensation (LDC)
Lead length, 688
on riser pole, 693
Leakage
flux, 204, 207
reactance, 207–208
Lightning, 660, 661, 662, 667; *see also* Lightning protection
activity measurement, 666
arrester failure, 684
capacitor, 672
-caused fault, 660
-caused fault correction, 666
cloud-to-ground lightning, 663
corona impacts traveling wave, 673
dart leaders, 663
data, 504
detection networks, 666
Eriksson's equation, 669
first stroke, 664, 665
flash, 663, 664, 665, 704
flash density variability, 667, 668
incidence of, 668–669
inductance, 672
negative current flash, 663, 664
predischarge currents, 673
propagation modes, 673
recloser, 665
return stroke, 662
rocket triggered flash, 698, 699
stepped leaders, 662
as storm indicator, 661
subsequent strokes, 663, 664
supplementary flashovers, 660, 661
surge impedance determines, 673
thunderstorm data, 666–667
traveling wave reflection, 671
traveling waves, 669, 670
voltage at discontinuity, 671–672
Lightning current, 683; *see also* Surge arresters
in transformer, 689, 690
Lightning impulse protective level (LPL), 676
Lightning protection, 659; *see also* Equipment protection; Grounding; Induced voltages; Line protection; Surge arresters
arc quenching of wood, 714, 716
to avoid two-port problems, 717
burndowns, 713
composite crossarm attachments, 715
crossarm and pole damage and bonding, 713
design of, 660
distribution line fault rate vs. GFD, 662
flashovers between floating neutral and local ground, 717
ground loop length reduction, 717, 718
ground resistance, 712
instrumentation protection, 716
lightning-caused fault, 660
near-surface damage from impulses, 714
pole-mounted controller exposure to lightning, 717
pole-top fires, 713
power-frequency fault due to flashover, 716
protection against ground lead effects, 717, 719

Lightning protection (*Continued*)
role of grounding, 711–713
secondary surge arresters, 718
strategy, 660
surge impedance, 670
LILCO, *see* Long Island Lighting Company (LILCO)
Line
energization, 623
reactors, 601
surge arresters, 122; *see also* Overhead line performance
Line-commutated inverters, 807; *see also* Inverters
as constant-power model, 810
islanding, 812
Line drop compensation (LDC), 834
Line-drop compensator, 284; *see also* Load-center method; Voltage regulators; Voltage-spread method
approaches for setting selection, 285
circuit, 285
regulator connection effects, 292
Line impedances, 42; *see also* Conductor; Overhead lines
Carson's equations, 50
Carson's impedances with earth return, 50
current flow in neutral conductor, 51
effect of spacings and conductor size, 54
GMR, 45, 46
IACS, 43
induction, 46
internal inductance, 45
mutual induction, 47, 48
parameters effect on zero-sequence impedance, 55
phase-to-symmetrical conversions, 47
positive-sequence impedance, 49
reactance between two parallel conductors, 45
resistance, 43–45
self and mutual impedance, 50
self-impedance, 48–49
sequence currents and sequence impedances, 48
sequence voltage drop equations, 48
simplified line impedance calculations, 49–54
skin effect, 43–45
tables, 54
zero-sequence impedance, 50–53
Line protection, 700; *see also* Surge arresters; Grounding; Induced voltages; Lightning protection
critical flashover voltage, 703, 704
lightning flash paths, 704
shield wires, 707–708
Line-to-ground
fault current, 829
and line-to-line voltages, 574
transformer capacitance, 258
voltages, 738
Line-to-line
Cables voltage rating, 148
fault, 82, 224, 393, 396
fault-current calculations, 374
and line-to-ground voltage, 822
multiple-phase faults, 352
negative-sequence voltages impact, 652
voltages, 261, 574, 822
Linear low-density polyethylene (LLDPE), 153
LLDPE, *see* Linear low-density polyethylene (LLDPE)
Load-based indices, 496; *see also* Customer-based indices
Load-center method, 285–288; *see also* Line-drop compensator
CT rating, 286, 287
impedances for, 287
maximum voltage, 288
3/8 rule, 287
voltage profiles on circuit, 286
Load rejection overvoltage, 805
constants in per unit on machine base, 803
Load tap-changing transformers (LTCs), 276
Loads, 23; *see also* Electric power distribution
coincident factor, 23, 24
coincident factor average curve, 24
demand, 23
diversity factor, 23
electric vehicles, 25
factor, 176, 235
load factor, 23
load profiles for Pacific Gas and Electric, 25
losses, 239
response, 569–570
responsibility factor, 23
Lockout and tagout (LOTO), 771
Long Island Lighting Company (LILCO), 710
Long-term flicker indicator, 641
Longitudinally corrugated shield (LC shield), 151
Loop impedance, 48–49; *see also* Line impedances
Loss angle, *see* Dissipation factor
Loss factor, 176
Loss tangent, *see* Dissipation factor
LOTO, *see* Lockout and tagout (LOTO)
Low-frequency test, 209
Low voltage due to generator position, 835, 836
Low zero-sequence harmonic impedance, 839
LPL, *see* Lightning impulse protective level (LPL)
LTCs, *see* Load tap-changing transformers (LTCs)

M

Mainline, 4–5; *see also* Electric power distribution
Major Event Day (MED), 499
Manhole explosions, 775; *see also* Arc flash
arcing impedance, 777
flammable gases, 777
heated insulation, 777
magnitude, 776
models for, 776
pressure relief, 777, 778
tools to reduce events, 776
venting, 777, 778
Master–follower, 296; *see also* Station regulation
Maximum continuous operating voltage (MCOV), 676

Maximum overvoltage, 740
Maximum touch voltages, 768
MCM, *see* Thousands of circular mils (MCM)
MCOV, *see* Maximum continuous operating voltage (MCOV)
Mean time between failure (MTBF), 492
MED, *see* Major Event Day (MED)
Metal oxide, 674, 680
Microgrids, 800
Minimum load-to-generation ratio, 815
Moderate to heavy tree cover, 585
Modified beta method, 503
Momentary interruptions, 561; *see also* Inrush; Power quality monitoring; Voltage sags
  to accurately count MAIFIE, 562
  average annual number of, 563
  determining factor affecting PQ events, 582–583
  distribution of utility MAIFI indices, 561
  energy storage devices, 605
  events, 562
  generalized linear model, 584
  to improve, 562
  load density on, 581–582
  location on, 580–581
  model for estimating $SARFI_{ITIC}$, 585
  model for predicting, 586
  number of, 561
  power quality definition of, 562
  reliability definition of, 562
  residential customers affected by, 558
  utility options for, 600
  voltage class on, 582
  voltage sags and, 579, 580
Motor derating curve, 652
Motoring, 75
MTBF, *see* Mean time between failure (MTBF)
Multigrounded neutral advantage, 761–762
Multiple circuits, 706–707
Multiple resonant points, 634

N

National Electrical Safety Code (NESC), 109, 728
  clothing systems, 789
  requirement on Arc flash, 783
  requirement on grounding, 741–743
National Rural Electric Cooperative Association (NRECA), 86
NEEA, *see* Northwest Energy Efficiency Alliance (NEEA)
Negative current flash, 663, 664
Negative-reactance control, 296; *see also* Station regulation
Negative-sequence
  impedance, 804
  reactance, 803, 804
  voltage, 229, 652
Neher-McGrath method, 170, 172
NESC, *see* National Electrical Safety Code (NESC)
Network protector, 10; *see also* Urban networks
  tripping current, 11
  2000-A, 11–12
Network transformers, 242; *see also* Transformer
  application, 243
  connection, 243
  core type, 244
  network units, 242
  properties, 243
  standard sizes, 243
Neutral impedance distribution, 761, 762
Neutral reactor, 601–603, 733, 736–737
Neutral shift
  effect, 737
  during ground faults, 729
  on multigrounded systems, 731
  overvoltage, 737
Neutral size, 734
Neutral-to-earth voltages (NEV), 753
Neutral wire height, 706
NEV, *see* Neutral-to-earth voltages (NEV)
New CBEMA curve, *see* Information Technology Industry Council (ITI)
New York State Electric and Gas (NYSEG), 728
Niagara Mohawk Power Corporation, 95; *see also* Vegetation management
  defects causing tree failure for, 105
  survey of tree outage causes, 93
  TORO, 107
NLDN, *see* U.S. National Lightning Detection Network (NLDN)
No-load losses, 239
Nondetection zones, 811
Noninteger harmonics, 645
  amplification, 646
Nonutility generator (NUG), 798
Normal-duty vs. heavy-duty, 685
North American distribution systems, 20; *see also* Electric power distribution
  distribution layouts, 21
  vs. European distribution systems, 21–22
  higher secondary voltages, 22
  secondaries, 20
Northwest Energy Efficiency Alliance (NEEA), 301
Northwest Power and Conservation Council (NWPCC), 310
NRECA, *see* National Rural Electric Cooperative Association (NRECA)
NUG, *see* Nonutility generator (NUG)
Nuisance operation, 450
NWPCC, *see* Northwest Power and Conservation Council (NWPCC)
NYSEG, *see* New York State Electric and Gas (NYSEG)

O

OA, *see* Open air (OA)
Oak Ridge National Laboratory (ORNL), 235
Occupational Safety and Health Administration (OSHA), 775; *see also* Personnel protection

1/2-kvar rule, 330–331
Open air (OA), 244
Open-point arrester, 694–696
  voltage reflections with, 694
ORNL, *see* Oak Ridge National Laboratory (ORNL)
OSHA, *see* Occupational Safety and Health Administration (OSHA)
Out of phase drifting, 811
Outage; *see also* Reliability programs
  bunching, 517
  data tracking, 531
  follow-ups, 527–528
  management, 550
  -review program, 527
Outage cause, 538; *see also* Outage databases and targeting
  animal-caused faults, 543
  codes, 538
  customer-minutes of interruption from vegetation, 541
  Duke Energy, 540
  equipment failures, 540
  outage codings and problems, 539
  standardized cause categories, 539
  unknown causes, 542–543
  vegetation CMI breakdowns, 542
  vegetation interruptions, 540–542
Outage codes, 533; *see also* Outage databases and targeting
  arrester failure, 537
  code fields, 535
  code police, 538
  coding conventions, 533
  data entry, 538
  designing, 537
  Duke Energy's system, 535, 536
  guidelines for, 537
  outage follow-up process, 533
  root-cause contributors, 534
  squirrel outage across bushing, 537–538
  for tree contact, 537
  weather, 533, 535
Outage databases and targeting, 531; *see also* Outage cause; Outage codes; Prioritizing circuits; Reliability
  CI comparison, 548
  customer interruptions, 532
  program performance evaluation, 547–549
  radial distribution circuits, 531
  regression to mean, 547, 548–549
  reliability-based budget allocations, 533
  temporal analysis, 531–533
Outrush, 350; *see also* Capacitor fusing and protection; Inrush
  back-to-back switching, 355
  from capacitor to nearby fault, 350
  factors causing, 350, 352
  field measurement of, 354
  as function of resistance to fault, 351
  fuse during, 350, 351
  fuse-opening events, 353
  melt time ratios, 353
  and nuisance fuse operations, 352, 355
  peak value of inrush current, 354
  skin effects, 352
Overcurrent protection, *see* Short-circuit protection
Overhead circuits, 141; *see also* Underground distribution
  advantages of, 141
  costs, 141
  hybrids, 144
  system maintenance, 143
  visual impact, 142
Overhead line performance, 91; *see also* Animal-caused faults; Covered conductors; Vegetation management
  anomalies found from thermal inspections, 123
  anomaly priority grading system, 125
  broken pole, 133
  comparison of reliability index SAIDI, 111
  connector issues, 124
  doubly censored survey data, 129
  factors affecting, 91
  hardening and resiliency, 131–133
  hazard function estimation, 129
  infrared issues, 124
  inspections and maintenance, 123–125
  pole decay, 125
  pole failure rates, 128–129, 130
  pole inspection rejection rates, 128
  pole inspections and maintenance, 125–131
  recloser controls, 123
  sounding test and boring, 127
  spacer cables, 109, 110, 132
  storm damage in Connecticut, 132
  theoretical strength vs. residual shell thickness, 126
  thermal inspection priority system, 125
  wood pole deterioration zones, 126
Overhead lines, 33; *see also* Ampacity; Burndown; Conductor; Conductor slapping; Connectors; Line impedances; Radio-frequency interference (RFI); Wire
  all-aluminum triplex secondaries, 72
  armless construction, 34
  conductor annealing, 72–74
  cost, 36
  crossarm construction, 36
  distribution circuits, 35
  fault-current arcs, 74
  fault withstand capability, 71
  impedances of triplex, 70
  overhead issues, 82
  pole material, 36
  polyethylene-covered AAC triplex, 71
  secondaries, 70–71
  single-phase circuit, 34, 35
  typical constructions, 33–36
Overvoltage, 799; *see also* Ungrounded system
  for different fault locations, 733
  by double line-to-ground fault, 730–731

factors, 732
from inverters, 827
relays, 815–816
temporary, 813
time-delay relay, 818
on unmonitored phases, 821

P

Pacific Gas & Electric (PG&E), 118
Pacific Northwest National Laboratory (PNNL), 299
Padmounted capacitors, 321; *see also* Capacitor
Padmounted transformers, 139
Paper-insulated lead-covered (PILC), 141, 146
Parallel distribution systems, 515–519; *see also* Radial distribution circuits
to analytically model, 517
distribution reliability applications, 516
factors in failure, 517
failures during storms, 518
hidden failures, 518
to improve reliability
outage bunching, 517
to reduce failures, 518–519
transmission failure information, 517
transmission supply comparison, 516
Parking-stand arrester, 695
Passive islanding protection, 811
PCB, *see* Polychlorinated biphenyls (PCB)
PE, *see* Polyethylene (PE)
Pennsylvania Power and Light Company (PP&L), 113
Performance of circuits, 495
Permittivity, *see* Dielectric constant
Personnel protection, 771; *see also* Protective grounds
transmission and distribution fatalities, 775
PG&E, *see* Pacific Gas & Electric (PG&E)
Phase to phase connected customer load, 739
Photovoltaics (PVs), 798
PILC, *see* Paper-insulated lead-covered (PILC)
Pitch, 805
Pitch factor, 805
PLCs, *see* Programmable logic controllers (PLCs)
Plowing, 153; *see also* Cable installation configurations
PNNL, *see* Pacific Northwest National Laboratory (PNNL)
Pole-mounted controller exposure, 717
Pole-top fires, 713
Polychlorinated biphenyls (PCB), 344
Polyethylene (PE), 140, 146
Polymer insulator, 705
Polyvinyl chloride (PVC), 152
Pool-related shocking, 760–761
Porcelain guy-strain insulators, 705
Positive flashes, 663, 665
Post-sag inrush, 598
Potential transformer (PT), 281, 336
Power
conditioner, 593
converter characteristics, 809
electronics, 30
factor, 835
frequency fault, 716
outages effect, 491
Power quality (PQ), 558
determining factors affecting, 582–583
to enhance, 605
fault location, 559–560
issues, 558
problem identification, 558–559
Power quality impacts, 833; *see also* Voltage flicker; Voltage regulation
danger of reclosing, 842
flicker, 839
harmonic injection, 838
high-quality power configurations, 842
industry limits on harmonics, 838
low impedance to third harmonic, 839
low zero-sequence harmonic impedance, 839
model for impedance to harmonics, 838
penetration effect of DGs, 842
protection against interruptions, 843
Power quality issues, 558, 613; *see also* Flicker; Harmonics; Overvoltage; Switching surges; Telephone interference; Voltage unbalance
arresters' defense, 614–615
device failures, 615, 616, 617
ferroresonance, 614
grounding issues, 616–618
overvoltages, 614
reasons for failure, 613–614
reclose transients, 618–620
voltage swells, 614, 615–616
Power quality monitoring, 607; *see also* Momentary interruptions; Voltage sags
drawback, 608
duration, 608–609
fault-recorder-type devices, 608
output contacts, 607
suitable location, 607
timing, 607
trend data, 607–608
triggers, 607
voltage and current, 607
PP&L, *see* Pennsylvania Power and Light Company (PP&L)
PQ, *see* Power quality (PQ)
Prediction model, 546
Predischarge currents, 673
Preferred fuses, 441
Pressure relief in manhole cover, 777, 778
Primary-loop scheme, 6, 7; *see also* Electric power distribution
closed-loop distribution system, 8
Primary surge arrester, 712
Primary voltage levels, 12; *see also* Electric power distribution
area coverage, 14
current, 13

Primary voltage levels (*Continued*)
higher-voltage distribution systems, 12–13, 14–15
power, 13
voltage class, 12
voltage drop, 14
Prioritizing circuits, 543; *see also* Outage databases and targeting
annual worse 5% of circuits, 544
fault-rate and prediction approaches, 547
guidelines for, 544–545
important factors, 543
misclassifications, 544, 545, 546
prediction model, 546
prioritizing subset of circuits, 546
Problem-circuit audits, 529; *see also* Reliability programs
Programmable logic controllers (PLCs), 589, 595; *see also* Adjustable-speed drives (ASDs)
sensitivity of, 596
Protection equipment, 430; *see also* Circuit breaker relays; Circuit breaker; Circuit interrupters; Current-limiting fuses (CLFs); Expulsion; Reclosers; Short-circuit protection
Protection issues, 827; *see also* Distributed generation (DG); Islanding; Relaying issues
DG grounding source connections, 830
false tripping, 830–831
fault current, 828
fuse saving, 832–833
line-to-ground fault current, 829
line-to-ground fault diagram, 828
overvoltages and ground fault current, 831–832
sequence currents, 828–829
tripping upstream device, 827
Protection schemes, 475; *see also* Fuse blowing; Fuse saving; Short-circuit protection
adaptive control by phases, 477
high–low combination scheme, 476
SCADA control of, 476–477
time delay on instantaneous element, 475–476
Protective device, 427, 463; *see also* Distribution protection
Protective grounds, 771, 772, 774; *see also* Personnel protection
bracketed grounds, 771, 772
grounding jumpers, 772, 773
insulation, 772
isolation, 772
work-site grounds, 771, 772
Protective margin, 686–689
equation, 691
Proximity effect factor, 159
PSE, *see* Puget Sound Energy (PSE)
PT, *see* Potential transformer (PT)
Puget Sound Energy (PSE), 107
Pulse-width modulation (PWM), 593
PVC, *see* Polyvinyl chloride (PVC)
PVs, *see* Photovoltaics (PVs)
PWM, *see* Pulse-width modulation (PWM)

Q

Quadrature-axis impedances, 804
Quality indicator prediction, 583–586

R

Radar, 196
Radial circuits, 5–6, 7; *see also* Electric power distribution
subtransmission circuit arrangements, 18, 19
Radial distribution circuits, 531
modeling, 514–515; *see also* Parallel distribution systems
tracking outage data, 531
Radio-frequency interference (RFI), 86, 110; *see also* Overhead lines
arcing interference, 86–87
detectors, 88
nonutility sources of, 88
problems, 88
propagation, 88
sources and solutions, 87
Rate of change of frequency (ROCOF), 811
REA, *see* Rural Electrification Administration (REA)
Reach, 427–428; *see also* Distribution protection
Reactance-to-the-fault method, 399–400
Reactive load factor (RLF), 332
Reactive power control options, 835
Reclose transients, 618–620
Reclosers, 437, 665; *see also* Protection equipment
applications, 437
designations, 438
features, 438
interrupting rating, 437
program performance evaluation, 549
recloser ratings vs. circuit breaker ratings, 437
Reclosing practices, 477; *see also* Immediate reclose; Short-circuit protection
danger of reclosing, 842
extra reclose attempts, 480
IEEE survey results, 478
number of momentary interruptions, 480
reclose attempts and dead times, 478–481
reclose success rates, 480
Reconductoring, 651
Recovery voltage, 381
dielectric strength and, 431
across protective device, 381
for three-phase grounded circuits, 445
Redundant generator configurations, 845
Regulator, 247; *see also* Voltage regulator
duration indicators and, 524
interaction, 833
Relay monitoring, 821
Relaying, 826, 834; *see also* Relaying issues
advanced, 8
functions, 811
set points, 821

Relaying issues, 820; *see also* Islanding; Protection issues
inverter-based relays, 822
line-to-line and line-to-ground voltage, 822
overvoltages on unmonitored phases, 821
relay monitoring, 821
relaying set points, 821
trip thresholds for DG, 820
utility-grade relays, 823
Relays and contactors, 591; *see also* Ride through
options to hold in, 593
ridethrough duration for interruption, 591
ride through in, 592, 593
voltage magnitude for dropout of, 592
volt–time capability of, 592
Reliability, 491; *see also* Automation; Outage databases and targeting; Parallel distribution systems; Reliability indices; Reliability programs; Restoration
-based budget allocations, 533
improvement, 523–525
improvement calculations, 519
interruption costs, 551–553
mainline reclosers, 519
radial distribution circuit modeling, 514–515
sectionalizing switches, 520–521
Reliability indices, 492; *see also* Customer-based indices
distribution of utility indices, 494
found by industry surveys, 494
load-based indices, 496
performance of circuits, 495
skewed distribution, 465
variation in utility indices, 493
Reliability programs, 523; *see also* Reliability
bathtub curve, 525
construction upgrade programs, 530
distribution line inspection techniques, 526–527
equipment maintenance, 525–526
maintenance and inspections, 525–527
outage follow-ups, 527–528
outage-review program, 527
problem-circuit audits, 529
reliability improvement, 523–525
transformer retrofit program, 525
Remotely controlled switches, 523
Repair time reduction methods, 549–550
Resistance
calculations, 746, 752
measurements on live poplar tree, 766
of multiple, 745
of trees, 767
Resistivity reduce, 747
Resonant frequency vs. capacitor size, 634
Restoration, 549; *see also* Reliability
breakdown of utility restoration costs, 552
costs, 553
distribution of interruption durations, 550
methods to reduce repair time, 549–550
outage management, 550
safety, 551
SAIDI data from four U.S. utilities, 551
surveyed utility restoration costs, 551, 552
time improvement, 549
utility restoration costs, 551, 552
Return path impedance, 732
Return stroke, 662
Reverse power flow
bidirectional regulator misoperation, 836
high voltages on distribution circuits, 834
RFI, *see* Radio-frequency interference (RFI)
Ride through; *see also* Equipment sensitivities
of ASDs, 595
capability, 587–589
of digital clocks to, 597
duration for interruption, 591
to improve, 594
in larger relay, 593
momentary interruption, 597
in relays and contactors, 592, 593
of various residential devices, 598
and voltage, 589–590
Riser pole, 139, 179
RLF, *see* Reactive load factor (RLF)
Rocket-triggered lightning tests, 702
ROCOF, *see* Rate of change of frequency (ROCOF)
Rural Electrification Administration (REA), 427
Rural Utilities Service (RUS), 127
RUS, *see* Rural Utilities Service (RUS)
Rusck's model, 701

S

Safety issues, 810–811
active anti-islanding, 819
active anti-islanding inverters, 819
active anti-islanding test, 820
anti-islanding protection, 818
anti-islanding techniques, 819
backfeed voltages, 826–827
to decrease voltage, 824
ferroresonance, 825–826
integrated generator relay packages, 819
minimum load, 826
nondetection zones, 811
over-and underfrequency relay, 819
overvoltages, 799, 827
out of phase drifting, 811
to prevent, 811–812
reconfiguration, 826
relaying, 826
self-excitation, 823–825
series resonance, 823, 824, 825
time-delay relays, 818
trip thresholds for DG, 820
zero-sequence capacitance resonance, 824
SAIDI, *see* System average interruption duration frequency index (SAIDI)
SAIFI, *see* System average interruption frequency index (SAIFI)
Sandia voltage- shift method, 819

SARFI index, 572–573
Saturating reactor, 762
SCADA, *see* Supervisory control and data acquisition (SCADA)
Scout arresters, 696–697
SCRs, *see* Silicon-controlled rectifiers (SCRs)
Secondary grid networks, 10; *see also* Grid networks
Secondary grounding system, 742–743
Secondary-side transformer failures, 689–690
Secondary surge
  arresters, 718
  factors, 690
Sectionalizing switches, 520; *see also* Reliability
  CAIDI, 520
  mainline, 531
  program performance evaluation, 549
  reducing interruption durations with closed, 521
Security, Quality, Reliability, and Availability (SQRA), 846
Self-commutated inverters, 807; *see also* Inverters
  controller, 808
  islanding, 812
Self-excitation, 823–825
Self-extraction time, 790
SEMI curve, 572
Sequence
  coordination, 462; *see also* Coordinating devices
  currents, 828–829
  line-to-ground fault, 828
Series resonance, 823, 824, 825
Service voltage, 272
SF_6, 431
Sheath, 150; *see also* Cables
  lead, 146
  losses, 173
  resistance, 172
Shield, 150; *see also* Cables
  LC, 151
  semiconducting, 151–152
  tape, 180, 181
  wires, 707–708
Shocks and stray voltages, 753; *see also* Contact voltages
  biological models, 753
  Dalziel's formula, 754, 755–756
  effect of current, 756
  electrical accidents, 779
  elevated NEV, 759
  human resistance values, 754
  impedance of one foot-to-ground contact, 756
  multigrounded neutral advantage, 761–762
  neutral impedance distribution, 761, 762
  paths for touch and step potentials, 757
  pool-related shocking, 760–761
  response to stray voltage, 759–760
  saturating reactor, 762
  solid-state switch, 762
  solutions to stray voltage, 762–763
  spark gap, 762
  stray voltage control, 761
  threshold levels for 60-Hz contact currents, 755
  touch and step potential, 756–759
Short circuit, 367; *see also* Fault; Short-circuit protection
Short-circuit protection, 426; *see also* Coordinating devices; Distribution protection; Fuse blowing; Fuse saving; Protection equipment; Protection schemes; Reclosing practices; Single-phase protective devices; Transformer fuse
  arresters, 464
  assumptions, 783
  base pickup settings, 455
  Duke Energy, 466–467
  good fault protection, 426
  lateral tap fusing and fuse coordination, 453–454
  locating sectionalizing equipment, 463–468
  reach of fuse, 454–456
  recloser examples, 465
  secondary goals of, 426
  station relay and recloser settings, 454
  tap fuse example, 466
  tee point, 465
  time–overcurrent and instantaneous station relay pickup settings, 455
  unfused CSP on mainline, 464
Short interruptions, *see* Momentary interruptions
Short-term flicker indicator, 641
Silicon carbide arrester, 680
Silicon-controlled rectifiers (SCRs), 807, *see* Thyristors
Single-phase
  circuit, 49
  faults, 804
Single-phase protective devices, 484; *see also* Short-circuit protection
  backfeeds, 485
  drawbacks, 485
  effect on interruptions, 485
  ferroresonance, 485
  motors, 486
  single-phase reclosers with three-phase lockout, 486–487
Single-phase transformers, 210; *see also* Transformer
  additive polarity, 211, 213
  core-form designs, 213, 214
  CSPs, 216–217
  distribution transformer, 211, 213
  fault current, 216
  full-winding impedance, 215
  half-winding impedances, 215
  load-full current, 210
  real and reactive impedance, 214
  secondary breaker clearing characteristics, 218
  secondary winding, 215
  shell-form design, 213, 214
  standard North American, 211, 213
  subtractive polarity, 213
  terminal locations, 211
  two-winding transformer designations, 212
  winding designations, 212

Single-pole protective devices, 265
Single vs. three-phase faults, 566
Single-wire earth-return (SWER), 728
Site power quality variations, 576–578
66-project circuits, 26
Sizing neutral grounding reactor, 817–818
Skin effect, 43, 352
  with alternating current, 44
  approximation, 158
  factor, 158–159
  at power frequencies, 156
Soil breakeage, 748
Soil resistivity, 745, 746, 748; *see also* Ground rods
  effect of salt, moisture, and temperature on, 749
  factors affecting, 747
  four-point method, 752
  and galvanic currents, 750
  ground electrode tester, 752
  three-point method, 751–752
  two-point method, 752
Solid-state switch, 762
Spacer cables, 41, 109; *see also* Covered conductors
  advantages, 112, 414
  circuits, 707
  comparison of reliability index SAIDI, 111
  disadvantages, 414
  systems, 132, 735
Spark gap, 674, 707, 762
Specific heat, 72
Speed ratio, 438–439
Splices, 84
Split bus, 17; *see also* Distribution substations
Spot network, 10; *see also* Urban networks
SQRA, *see* Security, Quality, Reliability, and Availability (SQRA)
Squeeze-ons, *see* Connectors—compression
Squirrel
  -cage induction machine, 804
  outage across bushing, 537–538
  species, 115
STATCOM, 650
Static relays, 434
Static transfer switches, 603
Static var compensators (SVCs), 650
Station-class arresters, 391
Station regulation, 295; *see also* Voltage regulation
  bus regulation settings, 296–297
  circulating current method, 296
  master–follower, 296
  negative-reactance control, 296
  parallel operation, 295–296
  var balancing, 296
  voltage drop across transformer, 295
  voltage-spread equations, 296
Station transformers, 244; *see also* Transformer
  equivalent cooling classes, 245
  hottest-spot conductor temperature, 245
  impedance of, 245
  ratings, 244
Steel conductors, 41
Stepped leaders, 662
Stiffness factor, 840–841
Stirrup, 86
Storm
  arrester failure during, 537
  classification, 497
  data, 496–497, 498
  failures during, 518
  interruption, 498, 499
  restoration costs, 553
Stray voltage, 753; *see also* Contact voltages
  control, 761
  response to, 759–760
  solutions, 762–763
Street networks, *see* Grid networks
Subsequent strokes, 663, 664
Substation
  bus voltage sags, 567
  distortions at, 631
  voltage comparison for faults, 567
  voltage profile for faults, 566
Substation capacitors, 321; *see also* Capacitor
  vs. feeder capacitors, 322
Substation transformers, 244, 727; *see also* Transformer
  loading guide, 246
Subtransient reactance, 802, 803–804
  saturated, 804
Subtransient time constant, 804
Subtransmission systems, 18; *see also* Electric power distribution
  distribution circuits, 18
  looped subtransmission system, 19
  radial configuration, 18, 19
  subtransmission voltages, 18
  transmission lines, 18, 20
Suckers, 99
Supervisory control and data acquisition (SCADA), 15
Supplementary flashovers, 660, 661
Surge, 185
  entry, 689
  impedance, 670, 673
  -resistant fuse, 442
Surge arresters, 674, 708–711, 741; *see also* Equipment failures; Insulation; Line protection
  application, 688, 693, 696
  applications, 675–676
  arrester duty-cycle ratings, 679
  arrester isolators, 681
  classes of, 676
  defense, 614–615
  for direct strikes, 709, 710
  distribution, 420
  8.4-kV MCOV arrester characteristics, 674
  energy capability of, 683
  failure, 680, 682, 683–684
  failure during lightning, 537
  failure of, 420–421
  failure rate, 710

Surge arresters (*Continued*)
gapped silicon-carbide arrester, 680
grounding and insulation level, 709
grounding at end, 710
housings, 678–679
isolators, 680–682
metal oxide, 674, 680
normal-duty vs. heavy-duty, 685
older arresters, 683
operation time and charge required to operate, 681
polymer-housed, 420
position of, 675, 692, 692
positioning, 692, 709, 710
primary surge, 712
primary surge arrester, 712
protective levels, 676, 677
ratings and selection, 676–678
reliability, 682
shielding angle, 709
significance of, 675
silicon carbide, 680
spark gap, 674
stand-alone, 420
station-class, 391
on top phase, 710
TOV capabilities of arrester manufacturers, 678
under-oil, 420
under-oil arresters, 680
upstream of fuses, 694
used with shield-wire system, 711
Sustained interruptions, 369, 470; *see also* Momentary interruptions
fault rates for faults that cause, 371
residential customers affected by, 558
temporary faults, 370
SVCs, *see* Static var compensators (SVCs)
SWER, *see* Single-wire earth-return (SWER)
Switch efficiency, 604
Switched banks, 334, 650; *see also* Capacitor
benefits, 334
centralized control, 339
difficulties, 334
distributed network protocol, 338
local controls, 335–337
1/2-kvar method, 334–335
remote or automated controls, 337–339
two-way communication, 338
var control trip and close settings, 336
voltage control, 337
voltage-controlled capacitor banks, 336
Switched capacitors, *see* Switched banks
Switched inductor, 650
Switching surges, 614, 620; *see also* Harmonics; Power quality issues
capacitor switching transients, 620, 621
capacitor transient prevention, 626
line energization, 623
prestriking, 622
transient overvoltages, 620–621
tripping of adjustable-speed drives, 624
variables impacting tripping, 625
voltage magnification, 623–624
voltage transient magnitudes, 621, 624
Switch-mode power supply, 587
Synchronous flying restart, 595
Synchronous generators, 801; *see also* Distributed generation (DG)
constants in per unit on machine base, 803
damper windings, 804
design, 802
direct-axis impedance, 804
fault calculations, 803
islanding, 812
load rejection overvoltage, 805
negative-sequence impedance, 804
negative-sequence reactance, 803, 804
operation, 801
pitch, 805
quadrature-axis impedances, 804
saturated subtransient reactance, 804
single-phase faults, 804
subtransient reactance, 802, 803–804
synchronization, 805
in voltage-following mode, 809
in voltage-regulating mode, 810
zero-sequence impedance, 804–805
zero-sequence reactance, 803, 804
System average interruption duration frequency index (SAIDI), 493, 513
annual worse 5% of circuits, 544
circuit voltage effect on, 509
data from four U.S. utilities, 551
equipment failures, 540
extremely high SAIDI days, 500
load density comparison, 508
with major events, 512
without major events, 511–512
per day probability density, 499
per day probability distributions, 498
performance of, 512
restoration, 549
variables impacting, 510, 511
vegetation interruptions, 540–542
System average interruption frequency index (SAIFI), 492
annual worse 5% of circuits, 544
comparison by load density, 507
customer density effect on, 506
effect of circuit length on, 505
equipment failures, 540
load density on, 509
restoration, 549
vegetation interruptions, 540–542
System voltage, 566

T

Tan delta (δ), 192; *see also* Dissipation factor
TDR, *see* Time-domain reflectometry (TDR)

Tee point, 465
Telephone influence factors (TIF), 635
Telephone interference, 635; *see also* Power quality issues
  capacitor location from substation, 637
  guidelines for I T, 636
  harmonics on, 635, 636
  solutions for, 637–638
  triplen harmonics, 636
  weighted factors, 635–636
Temporary overvoltages (TOVs), 676
THD, *see* Total harmonic distortion (THD)
Thermal circuit model, 170–171
Third harmonics
  generators, 839
  low impedance to, 839
  suppression of, 230
  voltage unbalance, 653
Thousands of circular mils (MCM), 40
3/8 rule, 287
Three-phase transformers, 217; *see also* Transformer
  common connections, 226
  connections with deltaconnected secondary, 221
  connections with grounded-wye secondary, 220
  construction, 217
  current flow in open wye–open delta transformer, 229
  delta configuration, 219
  delta–delta supply, 226–227
  delta–floating wye connections, 230
  delta–grounded wye, 224–225
  designations, 223
  floating wye–delta, 225–226
  floating wye–floating wye connection, 231–232
  floating-wye–grounded-wye connection, 230–231
  grounded-wye configuration, 219
  grounded wye–floating wye connections, 230
  grounded wye–grounded wye, 221–224
  grounded-wye–grounded-wye transformer, 231
  line-to-neutral voltages, 231
  loading equations, 226
  neutral stability with floating wye, 230–232
  open delta–open delta connections, 230
  open wye–open delta supply, 227–229
  power leg loading, 228
  quasiphasor diagram, 229
  sequence connections of, 232
  split in loading, 228
  three-phase connections, 219
  three-phase core constructions, 218
  for underground service, 217
  wiring diagrams for connections, 222
  wye–delta transformer connection, 220
  zero-sequence connections of, 233
  zero-sequence flux, 224
Three-point method, 751–752
Three-wire; *see also* Grounding
  distribution systems, 414
  resonant-grounded system, 728
  unigrounded distribution system, 727
Thumper, 195–196
Thunderstorm
  data, 666–667
  duration data, 502
Thyristors, 807
  current loss, 807
  as utility options with nontraditional equipment, 603
TIF, *see* Telephone influence factors (TIF)
Time–current curves, 782, 784
Time-delay relay, 593, 818
Time-domain reflectometry (TDR), 196
Time-overvoltage curve (TOV), 259
  and arrester rating, 676
  arrester TOV capabilities, 677
  capabilities of arrester manufacturers, 678
  gapped arrester, 680
TOC, *see* Total owning cost (TOC)
TORO, *see* Tree outage reduction operation (TORO)
Total harmonic distortion (THD), 628, 764
Total owning cost (TOC), 241
Touch and step potentials, 757
TOV, *see* Time-overvoltage curve (TOV)
TOVs, *see* Temporary overvoltages (TOVs)
Trade-off between overvoltages and ground fault current, 831–832
Transformer, 203; *see also* Autotransformers; Backfeeds; Distribution transformers; Equipment failures; Ferroresonance; Grounding transformers; Inrush current; Network transformers; Single-phase transformers; Station transformers; Three-phase transformers; Transformer losses
  alternating current, 203
  arrester placement, 262
  average loading distributions, 237
  basic function, 205
  basics, 204–208
  bushing ejection, 419
  core losses, 206
  equivalent cooling classes, 245
  fault in windings, 419
  fuses, 443
  grounding, 814
  guidelines for transformer replacement, 237
  IEC designations, 244
  impedance, 568
  inductances, 690
  inrush characteristics, 428
  insulation degradation, 418
  leakage flux, 204, 207
  leakage impedances, 208
  leakage reactance, 207–208
  life as function of hottest-spot winding temperature, 234
  load cycles, 234–235
  load management programs, 235
  loading distributions as function of rating, 238
  loading guidelines, 236
  loadings, 232–238

Transformer (*Continued*)
neutral-shift overvoltages, 261, 262
noninterlaced, 215
oil-filled, 208
paralleling banks, 251
pressure release valves, 419
retrofit program, 525
scaling ratios in, 206
series resistance, 206
substation transformers, 244–247
switching floating wye–delta banks, 260–262
transformer models, 205
with under-oil arresters, 420
Transformer connection effect on overvoltages, 812; *see also* Distributed generation (DG); Islanding; Relaying issues
arcing ground faults, 815
delta–grounded wye, 813
generators without interfacing transformer, 814–815
grounded wye–delta, 813
grounded-wye–delta connection, 814
grounded wye–delta with grounding reactor, 813
grounded wye–grounded wye, 813
grounded-wye–grounded-wye transformers, 814
grounding grounded-wye–grounded-wye transformer connection, 816–817
island with line-to-ground fault, 812
minimum load-to-generation ratio, 815
overvoltage relays and 59 g ground fault detection, 815–816
sizing neutral grounding reactor, 817–818
temporary overvoltages, 813
transformer/generator grounding, 814
Transformer fuse, 448; *see also* Short-circuit protection
bushing faults and, 452
cold-load pickup and inrush points, 448, 449
CSP, 452
current-limiting fuses, 452
fusing ratio, 451
fusing table, 448
group fusing, 451
looser fusing, 451
maximum 1/2-to 1-cycle fault current rating, 453
nuisance operation, 450
purpose of, 448
rupture limits for internal faults, 452
size selection, 450–451
standard fuse size, 451
tight fusing, 451
Transformer losses, 238; *see also* Transformer
costs, 242
eddy-current losses, 240
15-kV class transformer losses, 239
hysteresis losses, 239, 240
load losses, 239
loss reduction alternatives, 241
no-load losses, 239
for older transformers, 240
total equivalent losses, 241
transformer loading data from one utility, 242
Transient interruptions, *see* Momentary interruptions
Transient overvoltages, 620–621
Transient simulation of traveling waves on tapped cable, 697
Transmission-level power quality, 578–579
Traveling waves, 669, 670
reflection, 671
Tree contacts, 766; *see also* Contact voltages
body current for touch potential, 766
contact point surface, 769
current measured in, 769
currents and touch voltages, 767–768
flame on energized branch, 769
foot-to-earth contact resistances, 770
impedance barrier by bark, 770
maximum touch voltages, 768
to reduce tree-related shocks, 770
resistance measurements on live poplar tree, 766
resistance of trees, 767
tree resistance, 766, 768
Tree outage reduction operation (TORO), 107
Tree-related shocks, 770
Tree resistance, 766, 768
Tree-Retardant Cross-Linked Polyethylene (TR-XLPE), 147, 148
Tree wire, *see* Covered conductors
Trenching, 153; *see also* Cable installation configurations
Trip thresholds, 195
for distributed generators, 820
on electronically controlled reclosers, 438
standard overvoltage, 820
Triplen harmonics, 636
Tripping
of ASD, 624
upstream device, 827
variables impacting, 625
TR-XLPE, *see* Tree-Retardant Cross-Linked Polyethylene (TR-XLPE)
×2 method, 450–451
Two-phase circuit, 49
Two-point
measurement technique, 752
method, 752
Two-pole grounding, 745
2/3 rule, *see* Two-thirds rule (2/3 rule)
Two-thirds rule (2/3 rule), 329

U

UHF, *see* Ultra-high frequencies (UHF)
Ultra-high frequencies (UHF), 87
Underground distribution, 137; *see also* Cable impedances; Cable installation configurations; Cable reliability; Cables; Cable's ampacity; Cable testing; Underground fault location; Underground residential distribution (URD)
advantages of, 141

applications, 137
costs, 138, 141
disadvantage of, 143
fault withstand capability, 180–182
hybrids, 144
main feeders, 140–141
overhead vs. underground, 141–144
system maintenance, 143
tape shield, 180, 181
urban systems, 141
visual impact, 142
Underground equipment protection, 691; *see also* Equipment protection; Grounding; Surge arresters
arrester applications with long lead lengths., 693
arresters positioning, 692
arresters upstream of fuses, 694
attenuation in cables, 695–696
bushing arrester, 695
cable failure modes, 698–700
CWW underground protective margins, 695
elbow arresters, 695
lead length on riser pole, 693
open-point arrester, 694–696
parking-stand arrester, 695
protective margin, 692, 696
protective margin equation, 691
protective margins with riser-pole arrester, 695
scout arresters, 696–697
surges with low rise times, 695
tapped cables, 697–698
transient simulation of traveling waves, 697
voltage doubling, 691
Underground fault location, 193; *see also* Underground distribution
using current-limiting fuses, 193
fault indicators, 193–195
radar, 196–197
section testing, 195
thumper, 195–196
URD fault indicator application, 194
utility use of fault-locating techniques, 197
Underground primary supplying network load, 737
Underground residential distribution (URD), 137, 138; *see also* Underground distribution
circuit, 138
cost, 140
difficulties in, 140
elbows and terminations, 139
fault indicator application, 194
front-lot URD system, 139
riser pole, 139
trends in URD cable specifications, 185
Under-oil arresters, 680
Undervoltage time-delay relay, 818
Ungrounded system, 740; *see also* Grounding
arcing ground faults, 740
breaker-trip ringing, 737
extra-high overvoltages, 739
initial transient spike, 737
line-to-ground voltages, 738
maximum overvoltage, 740
neutral shift overvoltage, 737
neutral shifts effect, 737
phase to phase connected customer load, 739
by resonances, 739, 740
underground primary supplying network load, 737
utility equipment insulation, 741
Uninterruptible power supply (UPS), 563
Universal compensator method, 291
UPS, *see* Uninterruptible power supply (UPS)
Urban networks, 9; *see also* Electric power distribution
grid networks, 10, 11
network protector, 10, 11–12
spot network, 10
Urban stray voltage, *see* Stray voltage
Urban substations, 18; *see also* Distribution substations
URD, *see* Underground residential distribution (URD)
U.S. National Lightning Detection Network (NLDN), 666
Utility equipment insulation, 741
Utility-grade relays, 823
Utility indices distribution, 497
Utility options for voltage sags, 600; *see also* Utility options with nontraditional equipment
current-limiting fuses, 603
line reactors, 601
neutral reactors, 601–603
raising nominal voltage, 600–601
Utility options with nontraditional equipment, 603; *see also* Utility options for voltage sags
break-before-make transfers, 604
customer solution options, 606–607
efficiency of switches, 604
high-speed vacuum switches, 603
medium-voltage static transfer switches, 603
static transfer switches, 603
thyristors, 603
Utilization voltage, 272

V

Vacuum devices 431
Var balancing, 296; *see also* Station regulation
Var compensators, 650
Variability and weather, 496; *see also* Reliability indices; Weather normalization
distribution of utility indices, 497
extremely high SAIDI days, 500
major event day, 499
to manage skewed distributions, 500
normalized lognormal standard deviation of indices, 501
normalized standard deviation of indices, 500
reliability-based incentives, 500
SAIDI per day probability density, 499

Variability and weather (*Continued*)
SAIDI per day probability distributions, 498
standard deviation, 500
storm classification, 497
storm data, 496–497, 498
storm interruption, 498, 499
Variables affecting reliability indices, 505
circuit exposure and load density, 505
comparison of SAIFI by load density, 507
correlations and models, 507
customer density effect on SAIFI, 506
distribution configuration reliability, 508
EEI survey comparison, 505
effect of circuit length on SAIFI, 505
lengths for optimal reliability, 509
load density on SAIFI, 509
long-term reliability trends, 513–514
supply configuration, 506
voltage, 507
Vaults, 243
Vegetation management, 91; *see also* Niagara Mohawk Power Corporation; Overhead line performance
branch characteristics vs. failure probability, 99
circuit voltage and tree-caused faults, 95–96
comparison of trees causing permanent faults, 105
cost, 99–100
costs vs. performance, 101
cycle time, 100
Duke Energy, 94, 103
ECI survey, 94
electrical effects, 98–99
falling tree causing fault, 92
fault across tree branch, 97
hazard-tree mitigation project, 106
hazard-tree programs, 104–106
moisture factor, 99
Niagara Mohawk survey, 93
optimal pruning cycle, 100
outages and damage from trees, 92–96
percentage of samples faulted, 98
percentage of tree faults, 94
physics of tree faults, 96–99
progression of arcing and carbonization of branch, 97
time to fault, 98
tree maintenance and performance, 100
tree maintenance effect on performance, 102
tree pruning, 108
trees, 91
utility tree maintenance programs, 99–104
vegetation fault rate vs. time, 102
vegetation maintenance cycles, 102–104
vegetation program performance, 106–108
Venting, 777, 778
Vertical ceramic insulator string, 705
Volt–time
capability of relays and contactors, 592
characteristics, 588
Volt-var control, 299, 339; *see also* Capacitor
AMI data, 341–342
approaches to, 340
DMS-style control, 341
local control, 340
model-based control, 341
rules-based control, 340–341
Voltage
change characterization, 640
class, 12
distortion, 629, 631
divider equation, 564–565
doubling, 691
flicker propagation, 642
magnification, 623–624
magnification circuit, 623
magnitude for dropout of relays and contactors, 592
reflections with open-point arrester, 694
regulating relay, 283
on unfaulted phases, 735
Voltage flicker, 839; *see also* Power quality impacts
frequency of oscillations on, 840
from reciprocating, 839
to reduce, 841–842
stiffness factor, 840–841
Voltage-following mode, 809
Voltage optimization, 299; *see also* Voltage regulation
approaches to, 313–316
average energy savings from, 300
change in reactive power in NEEA study home, 302
CVR factors, 303, 312
daily profile grouping, 307
economic comparisons of improvement options, 315
energy reductions vs. voltage reduction, 303
energy savings vs. voltage reduction, 301
energy usage profiles by customer class, 306
EPRI and NEEA feeder CVR factors, 304
EPRI Green Circuits project, 302
equipment response to voltage, 310–313
NEEA pilot feeder study, 310
statistical distribution of customer voltages, 305
voltage and torque impact, 312
voltage impact on end-use equipment comparison, 311
voltage profile of 99.9th percentile meter voltages, 309
voltage profile of meters at peak load, 308
voltage reduction, 300–310
Voltage-regulating mode, 810
Voltage regulation, 271, 833; *see also* Power quality impacts; Station regulation; Voltage optimization; Voltage regulators; Voltage standards
bidirectional regulator misoperation, 836
end-use impacts, 273–274
equivalent circuits of uniform loads, 298
line loss and voltage drop relationships, 297–299
load factor and loss factor, 300

load flow models, 278–279
load modeling approximations, 280
load types, 279
loss factor, 299
low voltage due to generator position, 835, 836
operating at fixed lagging power factor, 835
options for reactive power control, 835
overvoltages, 274
power factor, 835
to prevent tap changer cycling, 837
primary voltage limits, 276–278
regulator interaction, 833
reverse power flow effect, 834, 835
system characteristics, 299
to tackle size of generator size and load, 837
to tackle voltage rise, 834
techniques, 276
unbalanced loads, 279
undervoltages, 274
voltage boost, 833
voltage drop, 275–276
voltage drop allocation, 276–278
voltage drop along radial circuit, 277
voltage-following mode, 833
voltage problems, 279–280
Voltage regulators, 281; *see also* Line-drop compensator; Voltage regulation
ANSI type A, 281
bidirectional, 283–284
capacitor banks and, 294
connections, 282
drag hands, 284
increased ratings with reduced ranges, 281
operations counter, 284
regulator issues, 294
regulator placement, 293
single-phase, 281
switched capacitors and, 294
tap controls, 283
three-phase, 282
voltage override, 292–293
voltage regulating relay, 283
Voltage sags, 563; *see also* Equipment sensitivities; Inrush; Momentary interruptions; Power quality monitoring; Reliability indices; Utility options for voltage sags
analysis of, 570
bus tie, 568
circuit causing, 560
commercial customers affected by, 558
damages due to, 491–492
determining factor affecting PQ events, 582–583
DPQ study, 574
effect, 594
effect of phases, 568–569
exposure, 565
factors inluencing, 579
fault current effect, 564
feeder and substation site comparison, 581
feeder fault effect, 565
feeders number, 568
to improve, 564
and inrush, 570, 599
inrush following, 599
issue between customers and utilities, 563
ITI curve, 571
line-to-ground and line-to-line voltages, 574
load density on, 581–582
load response, 569–570
location on, 580–581
minimum phase, 573, 574
and momentaries, 579, 580
occurrences of, 574–576
pattern, 574
per phase, 573, 574
predicting annual average number of events, 586
quality indicator prediction, 583–586
SARFI index, 572–573
SEMI curve, 572
sensitivities, 591
single vs. three-phase faults, 566
site power quality variations, 576–578
substation bus voltage sags, 567
substation voltage comparison for faults, 567
substation voltage profile for faults, 566
system voltage, 566
terminology confusion, 563
transformer impedance, 568
transmission-level power quality, 578–579
underground vs. overhead, 566
voltage class on, 582
voltage divider equation, 564–565
voltage regulation, 568
Voltage-spread method, 288; *see also* Line-drop compensator
reactive setting for compensation, 288
regulated voltage, 291
regulator set voltage, 289
resistive setting for compensation, 288
total desired compensation voltage, 288
universal compensator method, 291
voltage spread equations, 290
voltage swing from light to full load, 289
zero reactance method and, 289
Voltage standards, 272; *see also* Voltage regulation
ANSI, 272
ANSI C84. 1 voltage ranges for 120 V, 272
nominal system voltages and voltage ranges, 273–274
voltage classes, 272
voltage ranges, 272
Voltage swells, 614, 615–616
Voltage transient magnitudes, 621, 624
Voltage unbalance, 651; *see also* Flicker
causes of, 653
motor derating curve, 652
negative-sequence voltage, 652
percent unbalance, 651
Volume resistivity, 145

W

Water-protection method, 184
Water trees, 182; *see also* Cable reliability
  formation of, 183
  growth rate of, 183
  PE-based insulation systems and, 183
  performance tests for insulation system, 184
  water-protection method, 184
Weak-link fuse, 419–420
Weather normalization, 501; *see also* Reliability indices
  approaches, 502–503
  faults and interruption variability, 502
  increased daily SAIDI, 504
  interruption occurrence, 501
  lightning data, 504
  normalized CMI, 503
  quantifying interruption effect, 502
  thunderstorm duration data, 502
  variability, 501
  WSI, 504
Weatherproof wire, *see* Covered conductors
Wind severity index (WSI), 504
Winding losses, *see* Loads—losses
Wire, 37; *see also* Conductor; Loads; Overhead lines
  gage, 39
  material properties, 37
  tree wire, 41
  wraps, 745, 747
Wood insulator, 705
Work-site grounds, 771, 772
WSI, *see* Wind severity index (WSI)
Wye winding, 814
  connections with floating, 230
  grounding, 814

X

XLPE, *see* Cross-linked polyethylene (XLPE)

Z

Zero reactance method, 289
Zero-sequence
  capacitance resonance, 824
  impedance, 804–805
  reactance, 803, 804
Zinc coating, 750

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