Electric Power Engineering Handbook
Second Edition

Electric Power Substations Engineering

Second Edition

Edited by

John D. McDonald

CRC Press
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Preface

The electric power substation, whether generating station or transmission and distribution, remains one of the most challenging and exciting fields of electric power engineering. Recent technological developments have had tremendous impact on all aspects of substation design and operation. The objective of *Electric Power Substations Engineering* is to provide an extensive overview of substations, as well as a reference and guide for its study. The chapters are written for the electric power-engineering professional for detailed design information, as well as for other engineering professions (e.g., mechanical, civil) who want an overview or specific information in one particular area.

The book is organized into 20 chapters to provide comprehensive information on all aspects of substations, from the initial concept of a substation to design, automation, operation, and physical and cyber security. The chapters are written as tutorials, and provide references for further reading and study. The majority of chapter authors are members of the Institute of Electrical and Electronics Engineers (IEEE) Power Engineering Society (PES) Substations Committee. They develop the standards that govern all aspects of substations. In this way, this book contains the most recent technological developments regarding industry practice as well as industry standards. This book is part of the Electrical Engineering Handbook Series published by Taylor & Francis/CRC Press. Since its inception in 1993, this series has been dedicated to the concept that when readers refer to a book on a particular topic, they should be able to find what they need to know about the subject at least 80% of the time. That has indeed been the goal of this book.

During my review of the individual chapters of this book, I was very pleased with the level of detail presented but more importantly the tutorial style of writing and use of photographs and graphics to help the reader understand the material. I thank the tremendous efforts of the 28 authors who were dedicated to do the very best job they could in writing the 20 chapters. I also thank the personnel at Taylor & Francis who have been involved in the production of this book, with a special word of thanks to Nora Konopka and Liz Spangenberger. They were a pleasure to work with and made this project a lot of fun for all of us.

John D. McDonald

Editor

John D. McDonald, P.E., is vice president, Automation for Power System Automation for KEMA, Inc. In his 32 years of experience in the electric utility industry, John has developed power application software for both supervisory control and data acquisition (SCADA)/energy management system (EMS) and SCADA/distribution management system (DMS) applications, developed distribution automation and load management systems, managed SCADA/EMS and SCADA/DMS projects, and assisted intelligent electronic device (IED) suppliers in the automation of their IEDs. John is currently assisting electric utilities in substation automation, SCADA/DMS/EMS systems, and communication protocols.

John received his BSEE and MSEE (Power Engineering) from Purdue University, and an MBA (Finance) from the University of California-Berkeley. John is a member of Eta Kappa Nu (Electrical Engineering Honorary) and Tau Beta Pi (Engineering Honorary), is a fellow of IEEE, and was awarded the IEEE Millennium Medal in 2000, the IEEE PES Excellence in Power Distribution Engineering Award in 2002, and the IEEE PES Substations Committee Distinguished Service Award in 2003. In his 20 years of working group and subcommittee leadership with the IEEE Power Engineering Society (PES) Substations Committee, John led seven working groups and task forces which published standards/tutorials in the areas of distribution SCADA, master/remote terminal unit (RTU), and RTU/IED communications.

John is president of the IEEE PES, is co-vice chair of IEEE Standards Coordinating Committee (SCC) 36, is a member of IEC Technical Committee (TC) 57 Working Groups (WGs) 3 and 10, and is the past chair of the IEEE PES Substations Committee. John is the IEEE Division VII director-elect in 2007, and the IEEE Division VII director in 2008–2009. John is a member of the advisory committee for the annual DistribuTECH Conference and is a charter member of *Electricity Today* magazine's International Editorial Advisory Board.

John teaches a SCADA/EMS course at the Georgia Institute of Technology, a SCADA/substation automation course at Iowa State University, and substation automation, distribution SCADA, and communications courses for various IEEE PES local chapters as an IEEE PES distinguished lecturer. John has published 29 papers in the areas of SCADA, SCADA/EMS, SCADA/DMS, and communications, and is a registered professional engineer (Electrical) in California, Pennsylvania, and Georgia.

John is coauthor of the book *Automating a Distribution Cooperative, from A to Z*, published by the National Rural Electric Cooperative Association Cooperative Research Network (CRN) in 1999. John was editor of the Substations Chapter, and a coauthor of the book *The Electric Power Engineering Handbook*, cosponsored by the IEEE PES and published by the CRC Press in 2000. John is editor-in-chief, and "Substation Integration and Automation" chapter author for the book *Electric Power Substations Engineering*, published by Taylor & Francis/CRC Press in 2003.

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1 How a Substation Happens

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1.1 Background

The construction of new substations and the expansion of existing facilities are commonplace projects in electric utilities. However, due to its complexity, very few utility employees are familiar with the complete process that allows these projects to be successfully completed. This chapter will attempt to highlight the major issues associated with these capital-intensive construction projects, and provide a basic understanding of the types of issues that must be addressed during this process.

There are four major types of electric substations. The first type is the switchyard at a generating station. These facilities connect the generators to the utility grid and also provide off-site power to the plant. Generator switchyards tend to be large installations that are typically engineered and constructed by the power-plant designers and are subject to planning, finance, and construction efforts different from those of routine substation projects. Because of their special nature, the creation of power-plant switchyards will not be discussed here, but the expansion and modifications of these facilities generally follow the same processes as system stations.

Another type of substation, typically known as the customer substation, functions as the main source of electric power supply for one particular business customer. The technical requirements and the business case for this type of facility depend highly on the customer's requirements, more so than on utility needs; so this type of station will also not be the primary focus of this discussion.

The third type of substation involves the transfer of bulk power across the network, and is referred to as a system station. Some of these stations provide only switching facilities (no power transformers) whereas others perform voltage conversion as well. These large stations typically serve as the end points for transmission lines originating from generating switchyards and provide the electrical power for circuits that feed transformer stations. They are integral to the long-term reliability and integrity of the electric system and enable large blocks of energy to be moved from the generators to the load centers.

Since these system stations are strategic facilities and usually very expensive to construct and maintain, these substations will be one of the major focuses of this chapter.

The fourth type of substation is the distribution station. These are the most common facilities in power electric systems and provide the distribution circuits that directly supply most electric customers. They are typically located close to the load centers, meaning that they are usually located in or near the neighborhoods that they supply, and are the stations most likely to be encountered by the customers. Due to the large number of such substations, these facilities will also be a focus of this chapter.

Depending on the type of equipment used, the substations could be

- Outdoor type with air insulated equipment
- Indoor type with air insulated equipment
- Outdoor type with gas insulated equipment
- Indoor type with gas insulated equipment
- Mixed technology substations
- Mobile substations

1.2 Need Determination

An active planning process is necessary to develop the business case for creating a substation or for making major modifications. Planners, operating and maintenance personnel, asset managers, and design engineers are among the various employees typically involved in considering such issues in substation design as load growth, system stability, system reliability, and system capacity and their evaluations determine the need for new or improved substation facilities. Customer requirements, such as new factories, etc., should be considered, as well as customer relations and complaints. In some instances, political factors also influence this process, as is the case when reliability is a major issue. At this stage, the elements of the surrounding area are defined and assessed and a required in-service date is established.

A basic outline of what is required in what area can be summarized as follows: System requirements including

- Load growth
- System stability
- System reliability
- System capacity

Customer requirements including

- Additional load
- Power quality
- Reliability
- Customer relations
- Customer complaints
- Neighborhood impact

1.3 Budgeting

Having established the broad requirements for the new station, such as voltages, capacity, number of feeders, etc., the issue of funding should then be addressed. This is typical when real-estate investigations of available sites begin, since site size and location can significantly affect the cost of the facility. Preliminary equipment layouts and engineering evaluations are also undertaken at this stage to develop ballpark costs, which then have to be evaluated in the corporate budgetary justification system.

Preliminary manpower forecasts of all disciplines involved in the engineering and construction of the substation should be undertaken, including identification of the nature and extent of any work that the utility may need to contract out. This budgeting process will involve evaluation of the project in light of corporate priorities and provide a general overview of cost and other resource requirements. Note that this process may be an annual occurrence. Any projects in which monies have yet to be spent are generally reevaluated every budget cycle.

1.4 Financing

Once the time has arrived for work to proceed on the project, the process of obtaining funding for the project must be started. Preliminary detailed designs are required to develop firm pricing. Coordination between business units is necessary to develop accurate costs and to develop a realistic schedule. This may involve detailed manpower forecasting in many areas. The resource information has to be compiled in the format necessary to be submitted to the corporate capital estimate system and internal presentations must be conducted to sell the project to all levels of management.

Sometimes it may be necessary to obtain funding to develop the capital estimate. This may be the case when the cost to develop the preliminary designs is beyond normal departmental budgets, or if unfamiliar technology is expected to be implemented. This can also occur on large, complex projects or when a major portion of the work will be contracted. It may also be necessary to obtain early partial funding in cases where expensive, long lead-time equipment may need to be purchased such as large power transformers.

1.5 Traditional and Innovative Substation Design [1]

Substation engineering is a complex multidiscipline engineering function. It could include the following engineering disciplines:

- Environmental
- Civil
- Mechanical
- Structural
- Electrical—high voltage
- Protection and controls
- Communications

Traditionally, high voltage substations are engineered based on preestablished layouts and concepts and usually conservative requirements. This approach may restrict the degree of freedom of introducing new solutions. The most that can be achieved with this approach is the incorporation of new primary and secondary technology in pre-engineered standards.

A more innovative approach is one that takes into account functional requirements such as system and customer requirements and develops alternative design solutions. System requirements include elements of rated voltage, rated frequency, existing system configuration (present and future), connected loads, lines, generation, voltage tolerances (over and under), thermal limits, short-circuit levels, frequency tolerance (over and under), stability limits, critical fault clearing time, system expansion, and interconnection. Customer requirements include environmental consideration (climatic, noise, aesthetic, spills, right-of-way), space consideration, power quality, reliability, availability, national and international applicable standards, network security, expandability, and maintainability.

Carefully selected design criteria could be developed to reflect the company philosophy. This would enable, when desired, consideration and incorporation of elements such as life cycle cost, environmental impact, initial capital investment, etc., into the design process. Design solutions could then be evaluated based on preestablished evaluation criteria that satisfy the company interests and policies.

1.6 Site Selection and Acquisition

At this stage, a footprint of the station has been developed, including the layout of the major equipment. A decision on the final location of the facility can now be made and various options can be evaluated. Final grades, roadways, storm water retention, and environmental issues are addressed at this stage, and required permits are identified and obtained. Community and political acceptance must be achieved and details of station design are negotiated in order to achieve consensus. Depending on local zoning ordinances, it may be prudent to make settlement on the property contingent upon successfully obtaining zoning approval since the site is of little value to the utility without such approval. It is not unusual for engineering, real estate, public affairs, legal, planning, operations, and customer service personnel along with various levels of management to be involved in the decisions during this phase.

The first round of permit applications can now begin. Although the zoning application is usually a local government issue, permits for grading, storm-water management, roadway access, and other environmental or safety concerns are typically handled at the state or provincial level and may be federal issues in the case of wetlands or other sensitive areas. Other federal permits may also be necessary, such as those for aircraft warning lights for any tall towers or masts in the station. Permit applications are subject to unlimited bureaucratic manipulation and typically require multiple submissions and could take many months to reach conclusion. Depending on the local ordinances, zoning approval may be automatic or may require hearings that could stretch across many months. Zoning applications with significant opposition could take years to resolve.

As a rule of thumb, the following site evaluation criteria could be used:

- Economical evaluation
- Technical evaluation
- Community acceptance

Economical evaluation should address the level of affordability, return on investment, initial capital cost, and life cycle cost.

Technical aspects that can influence the site selection process could include the following:

- Land: choose areas that minimize the need for earth movement and soil disposal.
- Water: avoid interference with the natural drainage network.
- Vegetation: choose low productivity farming areas or uncultivated land.
- Protected areas: avoid any areas or spots listed as protected areas.
- Community planning: avoid urban areas, development land, or land held in reserve for future development.
- Community involvement: engage community in the approval process.
- Topography: flat but not prone to flood or water stagnation.
- Soil: suitable for construction of roads and foundations; low soil resistivity is desirable.
- Access: easy access to and from the site for transportation of large equipment, operators, and maintenance teams.
- Line entries: establishment of line corridors (alternatives: multi-circuit pylons, UG lines).
- Pollution: risk of equipment failure and maintenance costs increase with pollution level.

To address community acceptance issues it is recommended to

- Adopt a low profile layout with rigid buses supported on insulators over solid shape steel structures.
- Locate substations in visually screened areas (hills, forest), other buildings, and trees.
- Use gas insulated switchgear (GIS).
- Use colors, lighting.
- Use underground egresses as opposed to overhead.

Other elements that may influence community acceptance are noise and oil leakages or spills.

To mitigate noise that may be emitted by station equipment, attention should be paid at station orientation with respect to the location of noise sensitive properties and use of mitigation measures such as noise barriers, sound enclosures, landscaping, and active noise cancellation.

Guidelines to address oil leakages or spills could be found in Chapter 8 as well as in Refs. [2,3].

1.7 Design, Construction, and Commissioning Process [4]

Having selected the site location, the design construction and commissioning process would broadly follow the steps shown in Fig. 1.1. Recent trends in utilities have been toward sourcing design and construction of substations through competitive bidding process to ensure capital efficiency and labor productivity.

1.7.1 Station Design

Now the final detailed designs can be developed along with all the drawings necessary for construction. The electrical equipment and all the other materials can now be ordered and detailed schedules for all disciplines negotiated. Final manpower forecasts must be developed and coordinated with other business units. It is imperative that all stakeholders be aware of the design details and understand what needs to be built and by when to meet the in-service date. Once the designs are completed and the drawings published, the remaining permits can be obtained.

The following can be used as a guide for various design elements:

Basic Layout

- Stage development diagram
- Bus configuration to meet single line requirements
- Location of major equipment and steel structures based on single line diagram
- General concept of station
- Electrical and safety clearances
- Ultimate stage

Design

Site Preparation

- Drainage and erosion, earth work, roads and access, and fencing

Foundations

- Soils, concrete design, and pile design

Structures

- Materials, finishes, and corrosion control

Buildings

- Control, metering, relaying, and annunciation buildings—types such as masonry, prefabricated, etc.
- Metalclad switchgear buildings
- GIS buildings

Mechanical Systems

- HVAC
- Sound enclosure ventilation
- Metalclad switchgear or GIS buildings ventilation

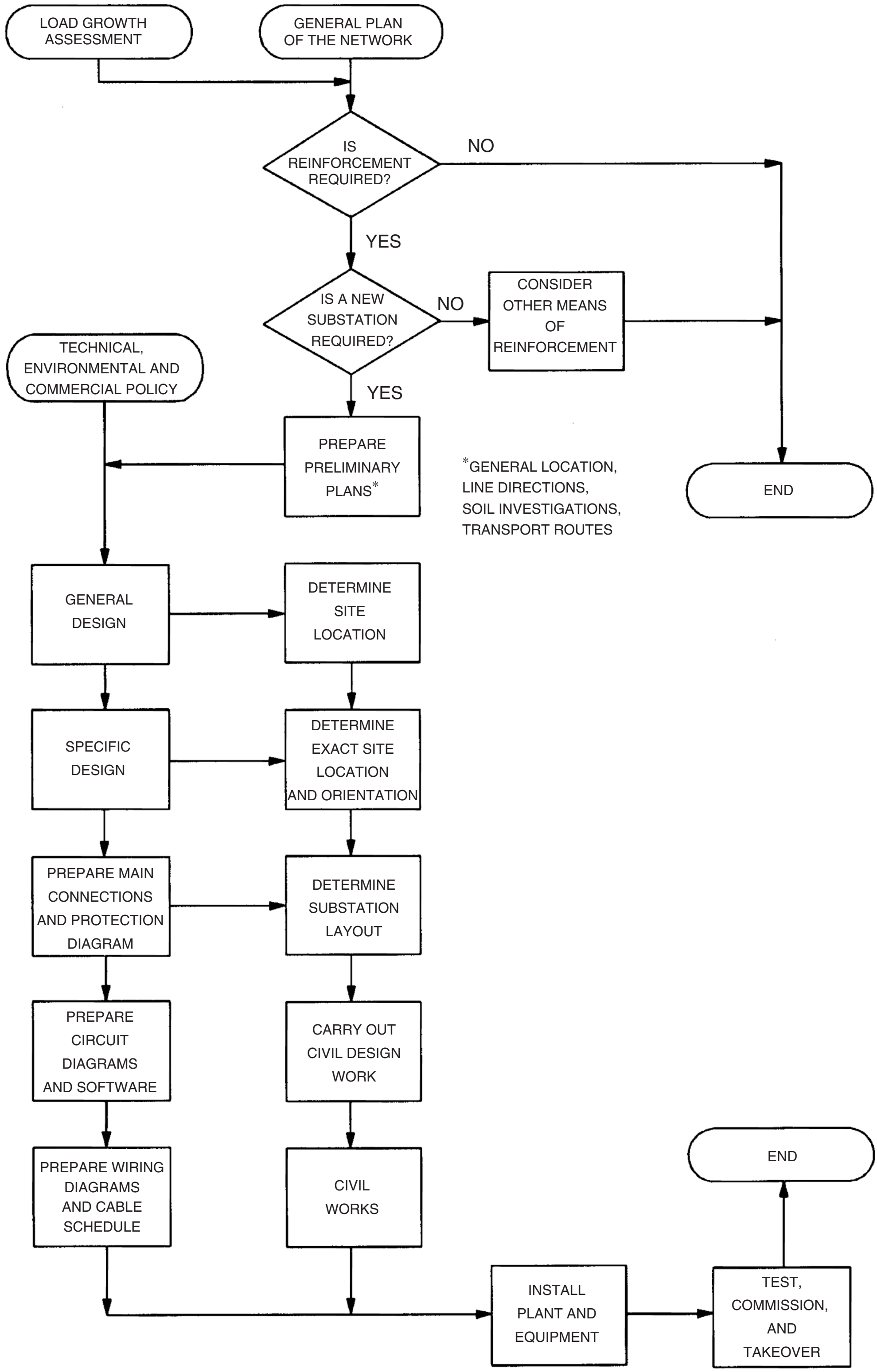

FIGURE 1.1 Establishment of a new substation.

- Fire detection and protection
- Oil sensing and spill prevention

Buswork

- Rigid buses
- Strain conductors—swing, bundle collapse
- Ampacity
- Connections
- Phase spacing
- Short circuit forces

Insulation

- Basic impulse level and switching impulse level

Station Insulators

- Porcelain post type insulators
- Resistance graded insulators
- Polymeric post insulators
- Station insulator hardware
- Selection of station insulator—TR—ANSI and CSA standard
- Pollution of insulators—pollution levels and selection of leakage distance

Suspension Insulators

- Characteristics
- Porcelain suspension insulators
- Polymeric suspension insulators
- Suspension insulators hardware
- Selection of suspension insulators
- Pollution of insulators—pollution levels and selection of leakage distance

Clearances

- Electrical clearances
- Safety clearances

Overvoltages

- Atmospheric and switching overvoltages
- Overvoltage protection—pipe and rod gaps, surge arresters
- Atmospheric overvoltage protection—lightning protection (skywires, lightning rods)

Grounding

- Function of grounding system
- Step, touch, mesh and transferred voltages
- Allowable limits of body current
- Allowable limits of step and touch voltages
- Soil resistivity
- General design guidelines

Neutral Systems

- Background of power system grounding
- Three and four wire systems
- HV and LV neutral systems
- Design of neutral systems

Station Security

- Physical security [5]
- Electronic security

1.7.2 Station Construction

With permits in hand and drawings published, the construction of the station can begin. Site logistics and housekeeping can have a significant impact on the acceptance of the facility. Parking for construction personnel, traffic routing, truck activity, trailers, fencing, and mud and dirt control along with trash and noise can be major irritations for neighbors, so attention to these details is essential for achieving community acceptance. All the civil, electrical, and electronic systems are installed at this time. Proper attention should also be paid to site security during the construction phase not only to safeguard the material and equipment, but also to protect the public.

1.7.3 Station Commissioning

Once construction is complete, testing of various systems can commence and all punch-list items addressed. To avoid duplication of testing, it is recommended to develop an inspection, testing and acceptance plan (ITAP). Elements of ITAP include

- Factory acceptance tests (FAT)
- Product verification plan (PVP)
- Site delivery acceptance test (SDAT)
- Site acceptance tests (SAT)

Final tests of the completed substation in a partially energized environment to determine acceptability and conformance to customer requirements under conditions as close as possible to normal operation conditions will finalize the in-service tests and turn-over to operations.

Environmental cleanup must be undertaken and final landscaping can be installed. Note that, depending upon the species of plants involved, it may be prudent to delay final landscaping until a more favorable season in order to ensure optimal survival of the foliage. Public relations personnel can make the residents and community leaders aware that the project is complete and the station can be made functional and turned over to the operating staff.

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2

Gas-Insulated Substations

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A gas-insulated substation (GIS) uses a superior dielectric gas, sulfur hexafluoride (SF_6), at a moderate pressure for phase to phase and phase to ground insulation. The high-voltage conductors, circuit breaker interrupters, switches, current transformers, and voltage transformers are encapsulated in SF_6 gas inside grounded metal enclosures. The atmospheric air insulation used in a conventional, air-insulated substation (AIS) requires meters of air insulation to do what SF_6 can do in centimeters. GIS can therefore be smaller than AIS by up to a factor of ten. A GIS is mostly used where space is expensive or not available. In a GIS, the active parts are protected from deterioration from exposure to atmospheric air, moisture, contamination, etc. As a result, GIS is more reliable, requires less maintenance, and will have a longer service life (more than 50 years) than AIS.

GIS was first developed in various countries between 1968 and 1972. After about 5 years of experience, the user rate increased to about 20% of new substations in countries where space was limited. In other countries with space easily available, the higher cost of GIS relative to AIS has limited its use to special cases. For example, in the U.S. only about 2% of new substations are GIS. International experience with GIS is described in a series of CIGRE papers [1–3]. The IEEE [4,5] and the IEC [6] have standards covering all aspects of the design, testing, and use of GIS. For the new user, there is a CIGRE application guide [7]. IEEE has a guide for specifications for GIS [8].

2.1 Sulfur Hexafluoride

Sulfur hexafluoride is an inert, nontoxic, colorless, odorless, tasteless, and nonflammable gas consisting of a sulfur atom surrounded by and tightly bonded to six fluorine atoms. It is about five times as dense as air. SF_6 is used in GIS at pressures from 400 to 600 kPa absolute. The pressure is chosen so that the SF_6 will not condense into a liquid at the lowest temperatures the equipment experiences. SF_6 has two to three times the insulating ability of air at the same pressure. SF_6 is about 100 times better than air for interrupting arcs. It is the universally used interrupting medium for high-voltage circuit breakers, replacing the older mediums of oil and air. SF_6 decomposes in the high temperature of an electric arc or spark, but the decomposed gas recombines back into SF_6 so well that it is not necessary to replenish the SF_6 in GIS. There are some reactive decomposition byproducts formed because of the interaction of sulfur and fluorine ions with trace amounts of moisture, air, and other contaminants. The quantities formed are very small. Molecular sieve absorbents inside the GIS enclosure eliminate these reactive byproducts over time. SF_6 is supplied in 50 kg gas cylinders in a liquid state at a pressure of about 6000 kPA for convenient storage and transport.

Gas handling systems with filters, compressors, and vacuum pumps are commercially available. Best practices and the personnel safety aspects of SF_6 gas handling are covered in international standards [9].

The SF_6 in the equipment must be dry enough to avoid condensation of moisture as a liquid on the surfaces of the solid epoxy support insulators because liquid water on the surface can cause a dielectric breakdown. However, if the moisture condenses as ice, the breakdown voltage is not affected. So dew points in the gas in the equipment need to be below about $-10°C$. For additional margin, levels of less than 1000 ppmv of moisture are usually specified and easy to obtain with careful gas handling. Absorbents inside the GIS enclosure help keep the moisture level in the gas low even though over time moisture will evolve from the internal surfaces and out of the solid dielectric materials [10].

Small conducting particles of millimeter size significantly reduce the dielectric strength of SF_6 gas. This effect becomes greater as the pressure is raised past about 600 kPA absolute [11]. The particles are moved by the electric field, possibly to the higher field regions inside the equipment or deposited along the surface of the solid epoxy support insulators—leading to dielectric breakdown at operating voltage levels. Cleanliness in assembly is therefore very important for GIS. Fortunately, during the factory and field power frequency high-voltage tests, contaminating particles can be detected as they move and cause small electric discharges (partial discharge) and acoustic signals—they can then be removed by opening the equipment. Some GIS equipment is provided with internal "particle traps" that capture the particles before they move to a location where they might cause breakdown. Most GIS assemblies are of a shape that provides some "natural" low electric-field regions where particles can rest without causing problems.

SF_6 is a strong greenhouse gas that could contribute to global warming. At an international treaty conference in Kyoto in 1997, SF_6 was listed as one of the six greenhouse gases whose emissions should be reduced. SF_6 is a very minor contributor to the total amount of greenhouse gases due to human activity, but it has a very long life in the atmosphere (half life is estimated at 3200 y), so the effect of SF_6 released to the atmosphere is effectively cumulative and permanent. The major use of SF_6 is in electrical power equipment. Fortunately, in GIS the SF_6 is contained and can be recycled. By following the present international guidelines for the use of SF_6 in electrical equipment [12], the contribution of SF_6 to global warming can be kept to less than 0.1% over a 100 y horizon. The emission rate from use in electrical equipment has been reduced over the last decade. Most of this effect has been due to simply adopting better handling and recycling practices. Standards now require GIS to leak less than 0.5% per year. The leakage rate is normally much lower. Field checks of GIS in service after many years of service indicate that a leak rate objective lower than 0.1% per year is obtainable, and is now offered by most manufacturers. Reactive, liquid (oil), and solid contaminants in used SF_6 are easily removed by filters, but inert gaseous contaminants such as oxygen and nitrogen are not easily removed. Oxygen and nitrogen are introduced during normal gas handling or by mistakes such as not evacuating all the air from the equipment before filling with SF_6. Fortunately, the purity of the SF_6 needs only be above 98% as established by international technical committees [12], so a simple field check of purity using commercially available percentage SF_6 meters will qualify the used SF_6 for reuse. For severe cases of contamination, the SF_6 manufacturers will take back the contaminated SF_6 and by putting it back into the production process in effect turn it back into "new" SF_6. Although not yet necessary, an end of life scenario for the eventual retirement of SF_6 is to incinerate the SF_6 with materials that will enable it to become part of environmentally acceptable gypsum.

The U.S. Environmental Protection Agency has a voluntary SF_6 emissions reduction program for the electric utility industry that keeps track of emissions rates, provides information on techniques to reduce emissions, and rewards utilities that have effective SF_6 emission reduction programs by high level recognition of progress. Other counties have addressed the concern similarly or even considered banning or taxing the use of SF_6 in electrical equipment. Alternatives to SF_6 exist for medium voltage electric power equipment (vacuum interrupters, clean air for insulation) but no viable alternative mediums have been identified for high-voltage electric power equipment in spite of decades of investigation. So far alternatives have had disadvantages that outweigh any advantage they may have in respect to a lower greenhouse gas effect. So for the foreseeable future, SF_6 will continue to be used for GIS where interruption of power system faults and switching is needed. For longer bus runs without any arcing (GIL), a mixture of SF_6 with nitrogen is being used to reduce the total amount of SF_6 (see Chapter 18).

2.2 Construction and Service Life

GIS is assembled from standard equipment modules (circuit breaker, current transformers, voltage transformers, disconnect and ground switches, interconnecting bus, surge arresters, and connections to the rest of the electric power system) to match the electrical one-line diagram of the substation. A cross-section view of a 242 kV GIS shows the construction and typical dimensions (Fig. 2.1).

The modules are joined using bolted flanges with an "O"-ring seal system for the enclosure and a sliding plug-in contact for the conductor. Internal parts of the GIS are supported by cast epoxy insulators. These support insulators provide a gas barrier between parts of the GIS, or are cast with holes in the epoxy to allow gas to pass from one side to the other.

Up to about 170 kV system voltage all three phases are often in one enclosure (Fig. 2.2). Above 170 kV the size of the enclosure for "three-phase enclosure" GIS becomes too large to be practical. So a "single-phase enclosure" design (Fig. 2.1) is used. There are no established performance differences between the three-phase enclosure and the single-phase enclosure GIS. Some manufacturers use the single-phase enclosure type for all voltage levels. Some users do not want the three phase to ground faults at certain locations (such as the substation at a large power plant) and will specify single-phase enclosure GIS.

Enclosures are today mostly cast or welded aluminum, but steel is also used. Steel enclosures are painted inside and outside to prevent rusting. Aluminum enclosures do not need to be painted, but may

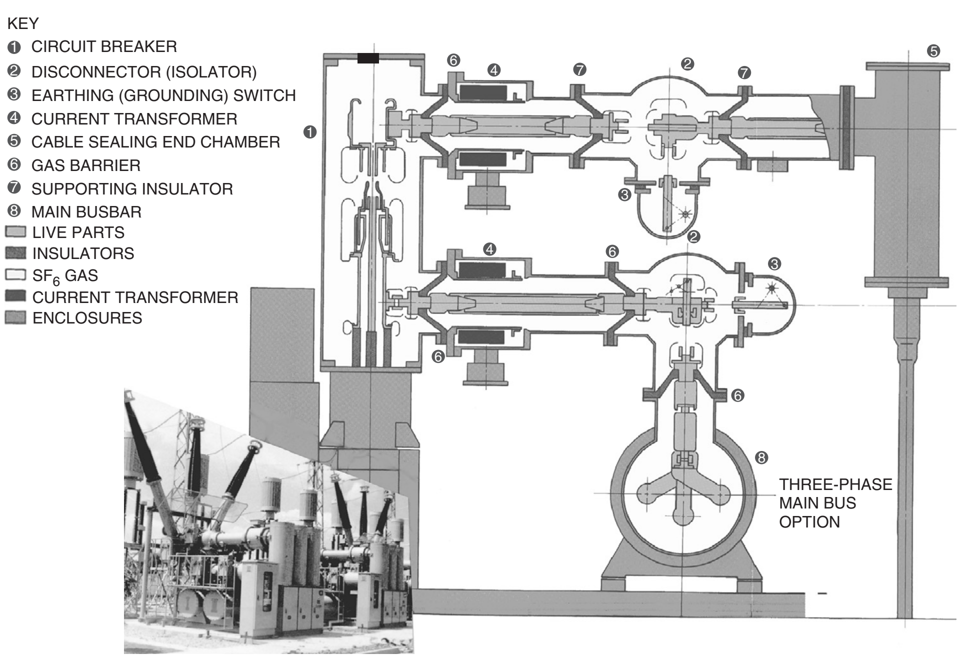


FIGURE 2.1 Single-phase enclosure GIS.

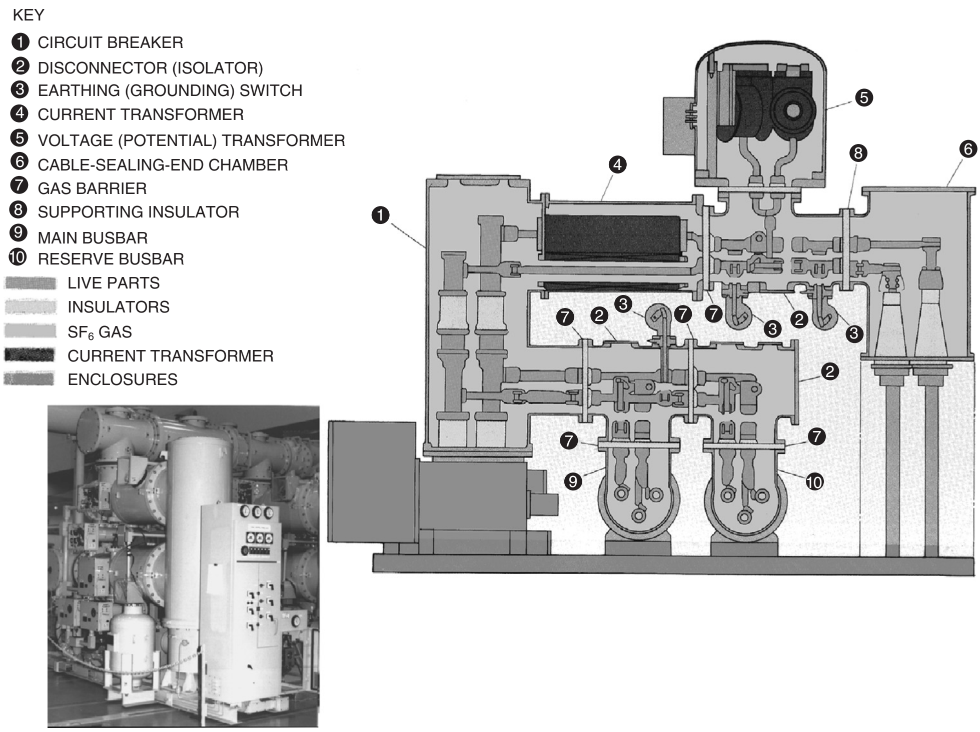


FIGURE 2.2 Three-phase enclosure GIS.

be painted for ease of cleaning, a better appearance, or to optimize heat transfer to the ambient. The choice between aluminum and steel is made on the basis of cost (steel is less expensive) and the continuous current (above about 2000 A, steel enclosures require non-magnetic inserts of stainless steel or the enclosure material is changed to all stainless steel or aluminum). Pressure vessel requirements for GIS enclosures are set by GIS standards [4,6], with the actual design, manufacture, and test following an established pressure vessel standard of the country of manufacture. Because of the moderate pressures involved, and the classification of GIS as electrical equipment, third party inspection and code stamping of the GIS enclosures are not required. The use of rupture disks as a safety measure is common although the pressure rise due to internal fault arcs in a GIS compartment of the usual size is predictable and slow enough that the protective system will interrupt the fault before a dangerous pressure is reached.

Conductors today are mostly aluminum. Copper is sometimes used for high continuous current ratings. It is usual to silver plate surfaces that transfer current. Bolted joints and sliding electrical contacts are used to join conductor sections. There are many designs for the sliding contact element. In general sliding contacts have many individually sprung copper contact fingers working in parallel. Usually the contact fingers are silver plated. A contact lubricant is used to ensure that the sliding contact surfaces do not generate particles or wear out over time. The sliding conductor contacts make assembly of the modules easy and also allow for conductor movement to accommodate differential thermal expansion of the conductor relative to the enclosure. Sliding contact assemblies are also used in circuit breakers and switches to transfer current from the moving contact to the stationary contacts.

Support insulators are made of a highly filled epoxy resin cast very carefully to prevent formation of voids or cracks during curing. Each GIS manufacturer's material formulation and insulator shape has been developed to optimize the support insulator in terms of electric-field distribution, mechanical strength, resistance to surface electric discharges, and convenience of manufacture and assembly. Post, disk, and cone-type support insulators are used. Quality assurance programs for support insulators

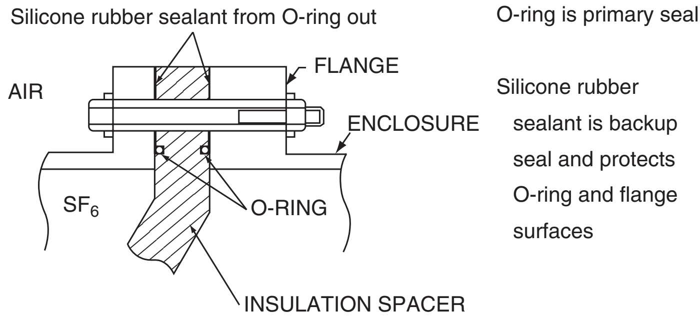


FIGURE 2.3 Gas seal for GIS enclosure.

include a high-voltage power frequency withstand test with sensitive partial discharge monitoring. Experience has shown that the electric-field stress inside the cast epoxy insulator should be below a certain level to avoid aging of the solid dielectric material. The electrical stress limit for the cast epoxy support insulator is not a severe design constraint because the dimensions of the GIS are mainly set by the lightning impulse withstand level of the gas gap and the need for the conductor to have a fairly large diameter to carry to load currents of several thousand amperes. The result is enough space between the conductor and enclosure to accommodate support insulators having low electrical stress.

Service life of GIS using the construction described above, based on more than 30 years of experience to now, can be expected to be more than 50 years. The condition of GIS examined after many years in service does not indicate any approaching limit in service life. Experience also shows no need for periodic internal inspection or maintenance. Inside the enclosure is dry, inert gas that is itself not subject to aging. There is no exposure of any of the internal materials to sunlight. Even the O-ring seals are found to be in excellent condition because there is almost always a "double seal" system with the outer seal protecting the inner—Fig. 2.3 shows one approach. This lack of aging has been found for GIS whether installed indoors or outdoors. For outdoor GIS special measures have to be taken to ensure adequate corrosion protection and tolerance of low and high ambient temperatures and solar radiation.

2.2.1 Circuit Breaker

GIS uses essentially the same dead tank SF_6 puffer circuit breakers as are used for AIS. Instead of SF_6-to-air bushings mounted on the circuit breaker enclosure, the GIS circuit breaker is directly connected to the adjacent GIS module.

2.2.2 Current Transformers

Current transformers (CTs) are inductive ring type installed either inside the GIS enclosure or outside the GIS enclosure (Fig. 2.4). The GIS conductor is the single turn primary for the CT. CTs inside the enclosure must be shielded from the electric field produced by the high-voltage conductor or high transient voltages can appear on the secondary through capacitive coupling. For CTs outside the enclosure, the enclosure itself must be provided with an insulating joint, and enclosure currents shunted around the CT. Both types of construction are in wide use.

Advanced CTs without a magnetic core (Rowgowski coil) have been developed to save space and reduce the cost of GIS. The output signal is at a low level, so it is immediately converted by an enclosure-mounted device to a digital signal. It can be transmitted over long distances using wire or fiber optics to the control and protective relays. However, most protective relays being used by utilities are not ready to accept a digital input even though the relay may be converting the conventional analog signal to digital before processing. The Rowgowski coil type of CT is linear regardless of current due to the absence of magnetic core material that would saturate at high currents.

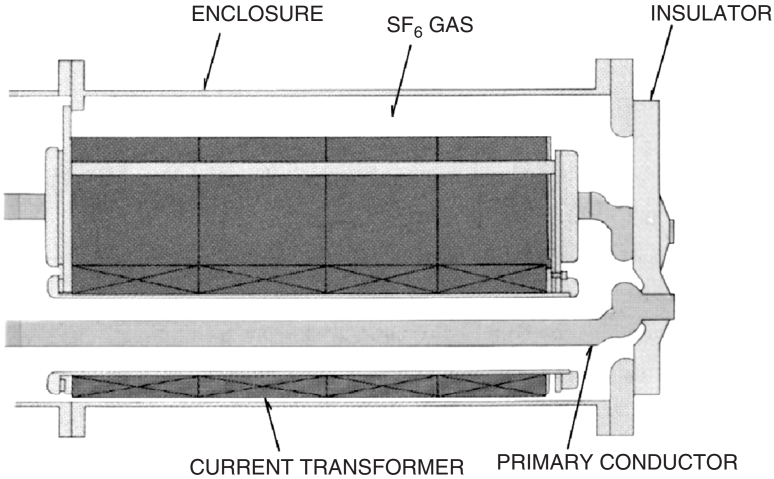


FIGURE 2.4 Current transformers for GIS.

2.2.3 Voltage Transformers

Voltage transformers (VTs) are inductive type with an iron core. The primary winding is supported on an insulating plastic film immersed in SF_6. The VT should have an electric-field shield between the primary and secondary windings to prevent capacitive coupling of transient voltages. The VT is usually a sealed unit with a gas barrier insulator. The VT is either easily removable so the GIS can be high voltage tested without damaging the VT, or the VT is provided with a disconnect switch or removable conductor link (Fig. 2.5).

Advanced voltage sensors using a simple capacitive coupling cylinder between the conductor and enclosure have been developed. In addition to size and cost advantages, these capacitive sensors do not have to be disconnected for the routing high-voltage withstand test. However, the signal level is low so it

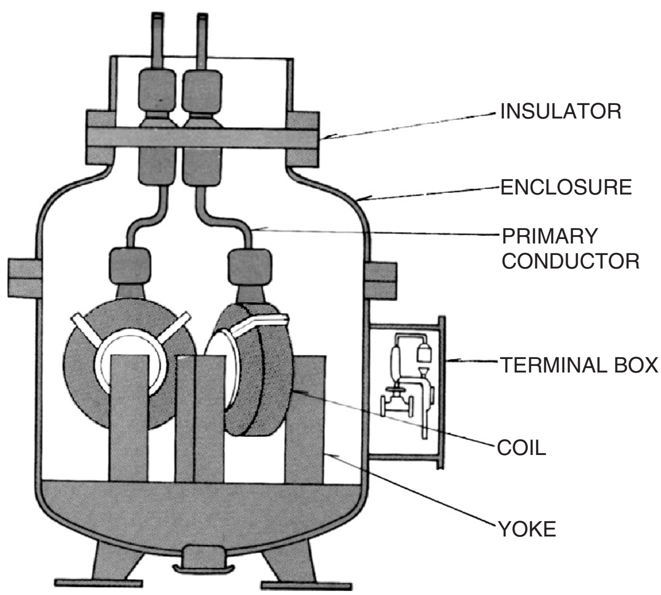


FIGURE 2.5 Voltage transformers for GIS.

is immediately converted to a digital signal, encountering the same barrier to use as the advanced CT discussed in Section 2.2.2.

2.2.4 Disconnect Switches

Disconnect switches (Fig. 2.6) have a moving contact that opens or closes a gap between stationary contacts when activated by an insulating operating rod that is itself moved by a sealed shaft coming through the enclosure wall. The stationary contacts have shields that provide the appropriate electric-field distribution to avoid too high a surface electrical stress. The moving contact velocity is relatively low (compared to a circuit breaker moving contact) and the disconnect switch can interrupt only low levels of capacitive current (for example, disconnecting a section of GIS bus) or small inductive currents (for example, transformer magnetizing current). For transformer magnetizing current interruption duty, the disconnect switch is provided with a fast acting spring operating mechanism. Load break disconnect switches have been furnished in the past, but with improvements and cost reductions of circuit breakers, it is not practical to continue to furnish load break disconnect switches—a circuit breaker should be used instead.

2.2.5 Ground Switches

Ground switches (Fig. 2.7) have a moving contact that opens or closes a gap between the high-voltage conductor and the enclosure. Sliding contacts with appropriate electric-field shields are provided at the enclosure and the conductor. A "maintenance" ground switch is operated either manually or by motor drive to close or open in several seconds. When fully closed, it can carry the rated short-circuit current for the specified time period (1 or 3 sec) without damage. A "fast acting" ground switch has a high-speed drive, usually a spring, and contact materials that withstand arcing so it can be closed twice onto an energized conductor without significant damage to itself or adjacent parts. Fast acting ground

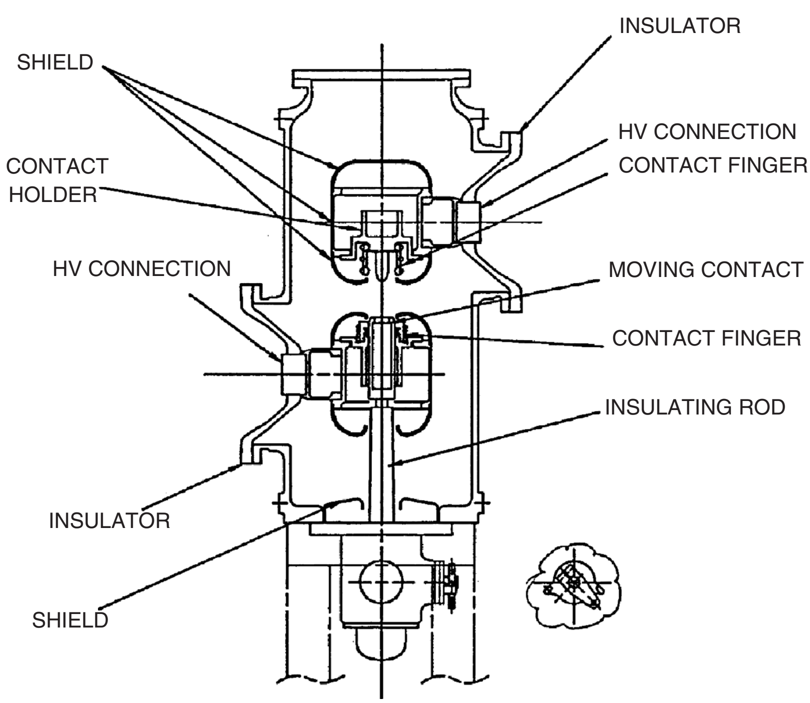


FIGURE 2.6 Disconnect switches for GIS.

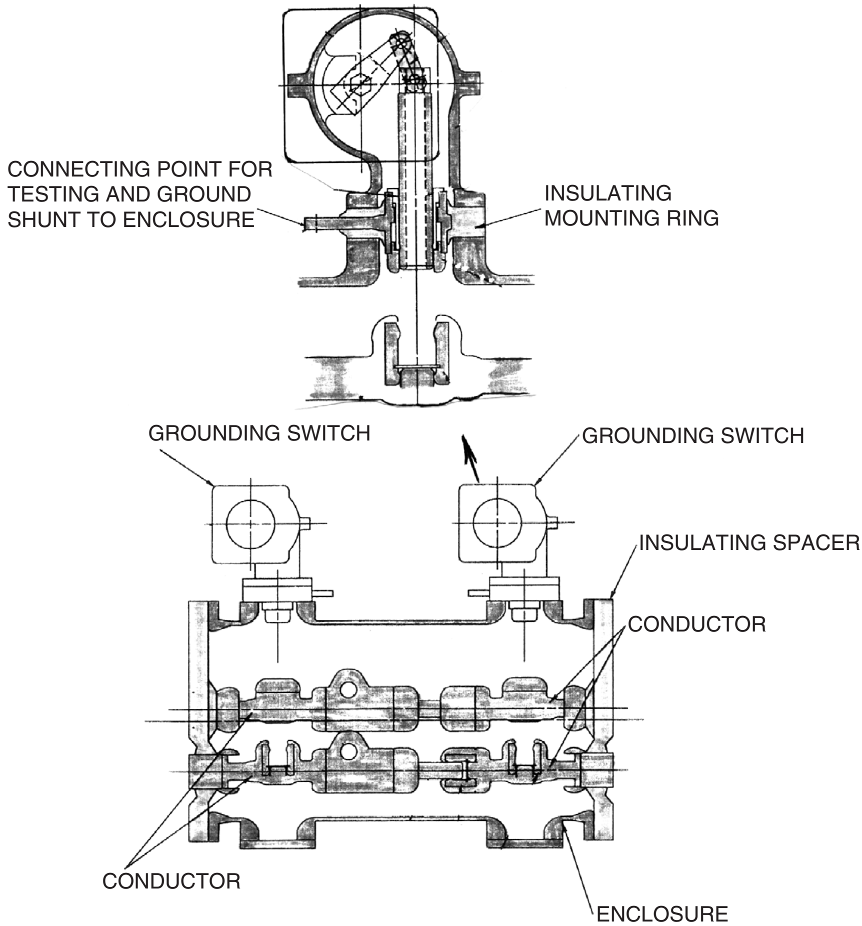


FIGURE 2.7 Ground switches for GIS.

switches are frequently used at the connection point of the GIS to the rest of the electric power network, not only in case the connected line is energized, but also because the fast acting ground switch is better able to handle discharge of trapped charge.

Ground switches are almost always provided with an insulating mount or an insulating bushing for the ground connection. In normal operation the insulating element is bypassed with a bolted shunt to the GIS enclosure. During installation or maintenance, with the ground switch closed, the shunt can be removed and the ground switch used as a connection from test equipment to the GIS conductor. Voltage and current testing of the internal parts of the GIS can then be done without removing SF_6 gas or opening the enclosure. A typical test is measurement of contact resistance using two ground switches (Fig. 2.8).

2.2.6 Interconnecting Bus

To connect GIS modules that are not directly connected to each other, SF_6 bus consisting of an inner conductor and outer enclosure is used. Support insulators, sliding electrical contacts and flanged enclosure joints are usually the same as for the GIS modules, and the length of a bus section is normally limited by the allowable span between conductor contacts and support insulators to about 6 m. Specialized bus designs with section lengths of 20 m have been developed and are applied both with GIS and as separate transmission links (see Chapter 18 on GIL).

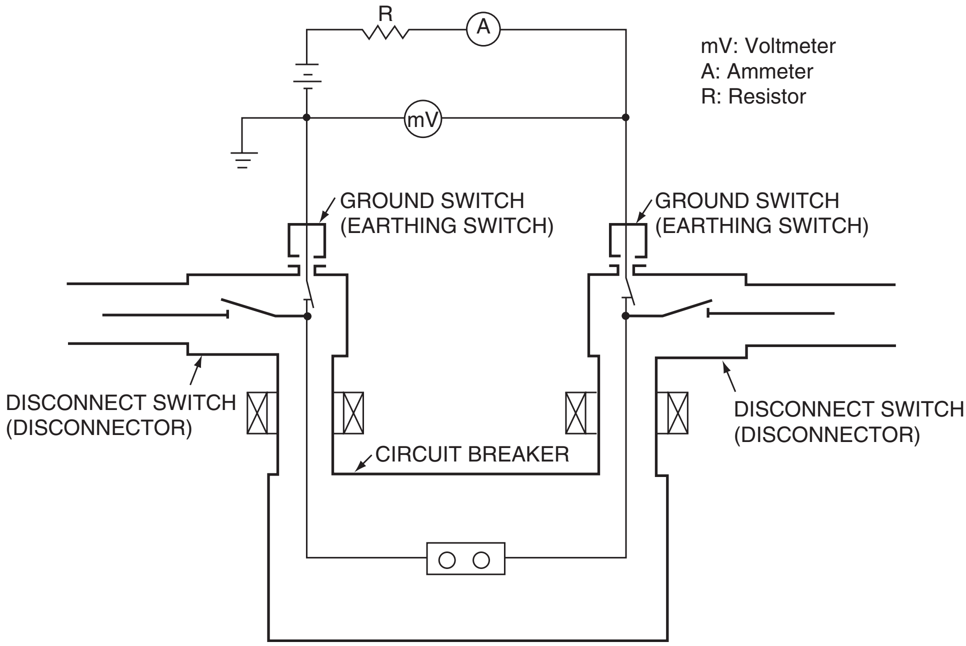


FIGURE 2.8 Contact resistance measured using ground switch.

2.2.7 Air Connection

SF_6-to-air bushings (Fig. 2.9) are made by attaching a hollow insulating cylinder to a flange on the end of a GIS enclosure. The insulating cylinder contains pressurized SF_6 on the inside and is suitable for exposure to atmospheric air on the outside. The conductor continues up through the center of the insulating cylinder to a metal end plate. The outside of the end plate has provisions for bolting on an air-insulated conductor. The insulating cylinder has a smooth interior. Sheds on the outside improve the performance in air under wet or contaminated conditions. Electric-field distribution is controlled by internal metal shields. Higher voltage SF_6-to-air bushings also use external shields. The SF_6 gas inside the bushing is usually the same pressure as the rest of the GIS. The insulating cylinder has most often been porcelain in the past, but today many are a composite consisting of fiberglass epoxy inner cylinder with an external weathershed of silicone rubber. The composite bushing has better contamination resistance and is inherently safer because it will not fracture as will porcelain.

2.2.8 Power Cable Connections

Power cables connecting to a GIS are provided with a cable termination kit that is installed on the cable to provide a physical barrier between the cable dielectric and the SF_6 gas in the GIS (Fig. 2.10). The cable termination kit also provides a suitable electric-field distribution at the end of the cable. Because the cable termination will be in SF_6 gas, the length is short and sheds are not needed. The cable conductor is connected with bolted or compression connectors to the end plate or cylinder of the cable termination kit. On the GIS side, a removable link or plug in contact transfers current from the cable to the GIS conductor. For high-voltage testing of the GIS or the cable, the cable is disconnected from the GIS by removing the conductor link or plug in contact. The GIS enclosure around the cable termination usually has an access port. This port can also be used for attaching a test bushing.

For solid dielectric power cables up to system voltage of 170 kV "plug-in" termination kits are available. These have the advantage of allowing the GIS cable termination to have one part of the plug-in termination factory installed so the GIS cable termination compartment can be sealed and

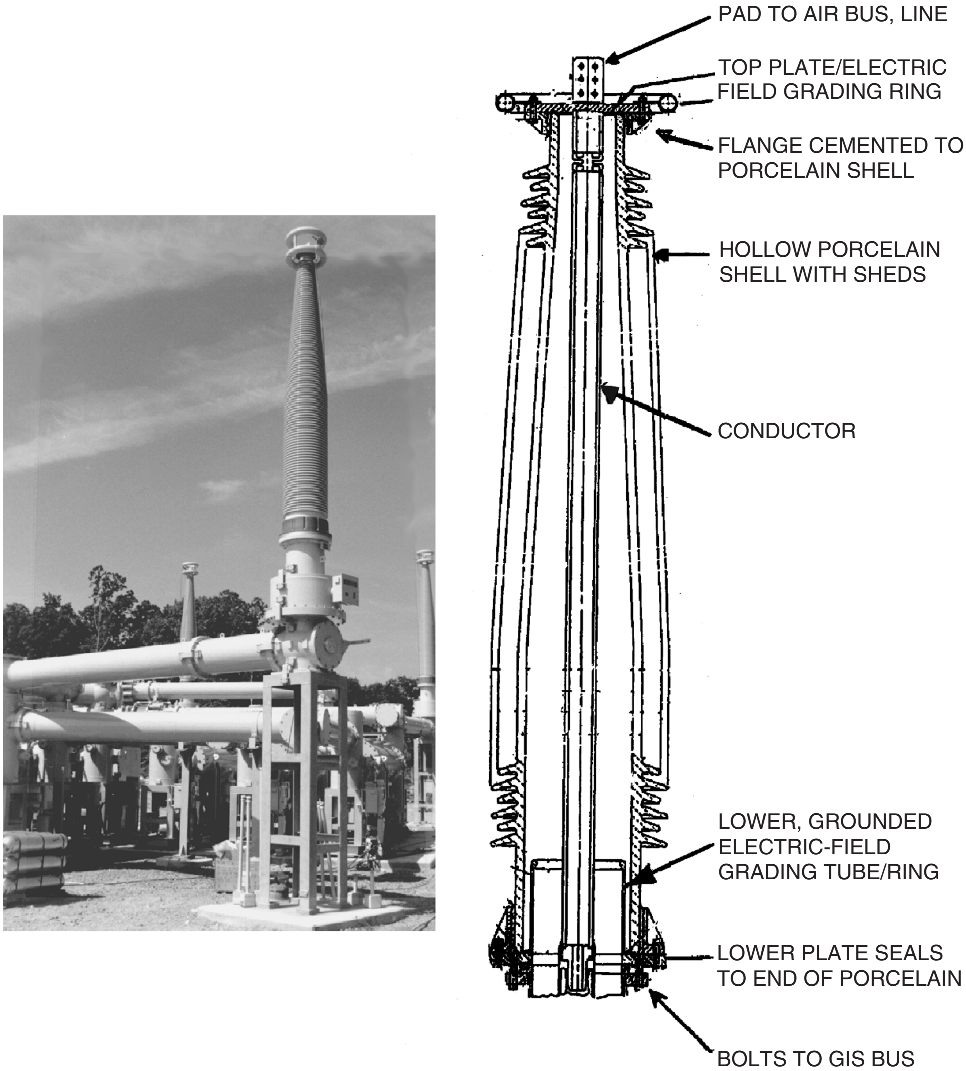


FIGURE 2.9 SF_6-to-air bushing.

tested at the factory. In the field, the power cable with the mating termination part can be installed on the cable as convenient and then plugged into the termination part on the GIS. For the test, the cable can be unplugged—however, power cables are difficult to bend and may be directly buried. In these cases a disconnect link is still required in the GIS termination closure.

2.2.9 Direct Transformer Connections

To connect a GIS directly to a transformer, a special SF_6-to-oil bushing that mounts on the transformer is used (Fig. 2.11). The bushing is connected under oil on one end to the transformer's high-voltage leads. The other end is SF_6 and has a removable link or sliding contact for connection to the GIS conductor. The bushing may be an oil-paper condenser type or, more commonly today, a solid insulation type. Because leakage of SF_6 into the transformer oil must be prevented, most SF_6-to-oil bushings have a center section that allows any SF_6 leakage to go to the atmosphere rather than into the transformer. For testing, the SF_6 end of the bushing is disconnected from the GIS conductor after

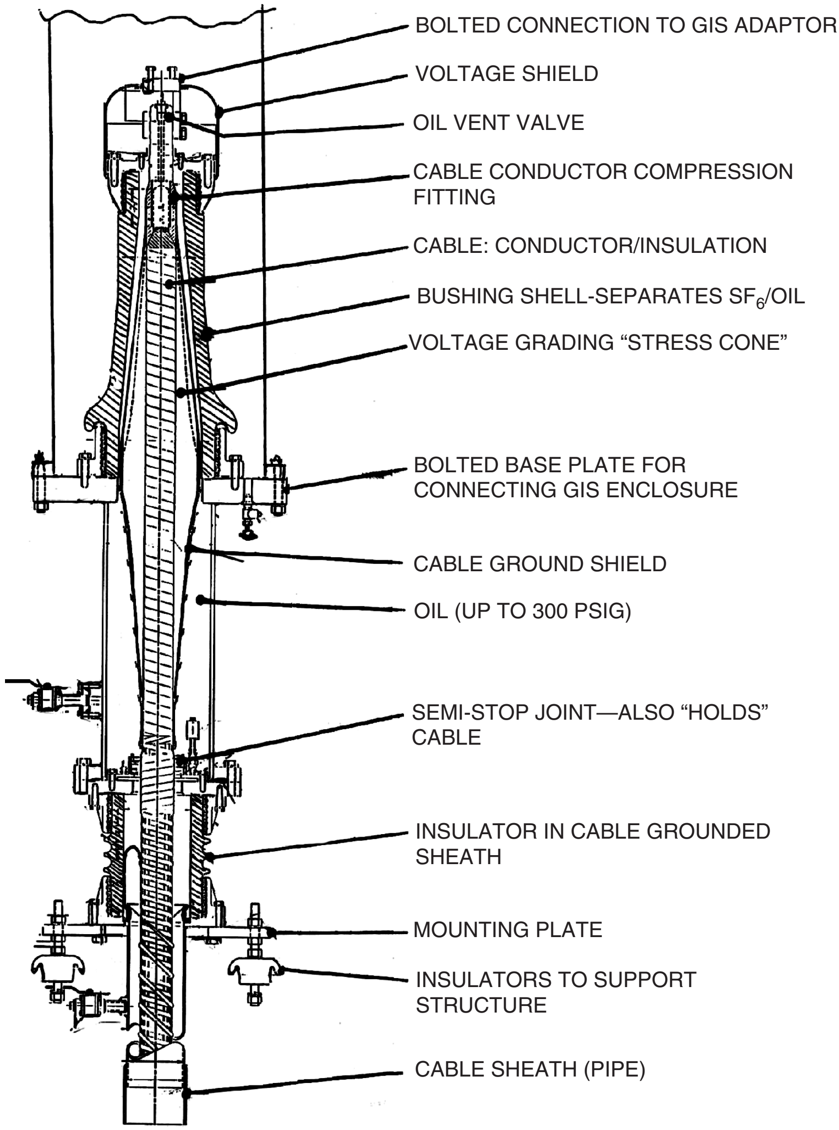


FIGURE 2.10 Power cable connection.

gaining access through an opening in the GIS enclosure. The GIS enclosure of the transformer can also be used for attaching a test bushing.

2.2.10 Surge Arrester

Zinc oxide surge-arrester elements suitable for immersion in SF_6 are supported by an insulating cylinder inside a GIS enclosure section to make a surge arrester for overvoltage control (Fig. 2.12). Because the GIS conductors are inside in a grounded metal enclosure, the only way for lightning impulse voltages to enter is through the connection of the GIS to the rest of the electrical system. Cable and direct transformer connections are not subject to lightning strikes, so only at SF_6-to-air bushing connections is ligtning a concern. Air-insulated surge arresters in parallel with the SF_6-to-air bushings usually provide adequate protection of the GIS from lightning impulse voltages at a much lower cost than

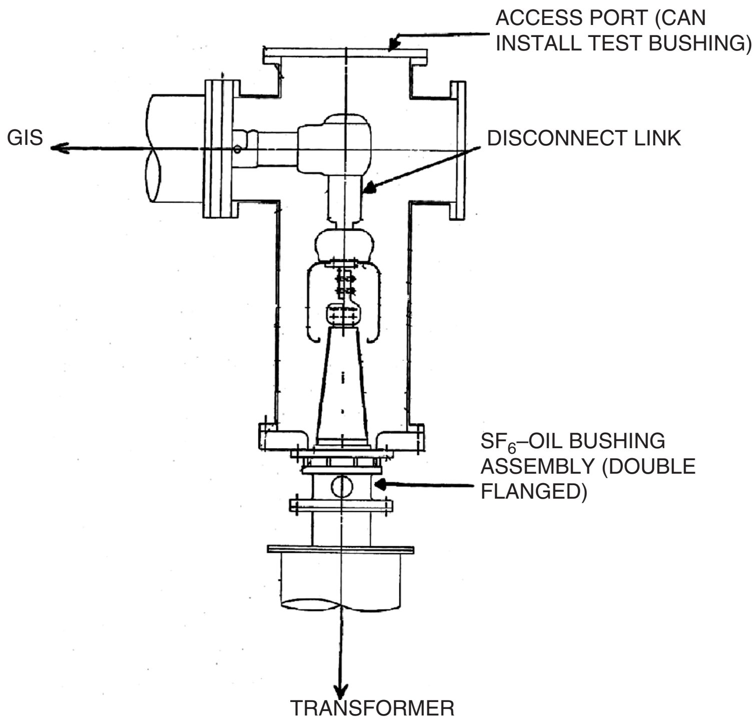


FIGURE 2.11 Direct SF_6 bus connection to transformer.

SF_6 insulated arresters. Switching surges are seldom a concern in GIS because with SF_6 insulation the withstand voltages for switching surges are not much less than the lightning impulse voltage withstand. In AIS, there is a significant decrease in withstand voltage for switching surges compared to lightning impulse because the longer time-span of the switching surge allows time for the discharge to completely

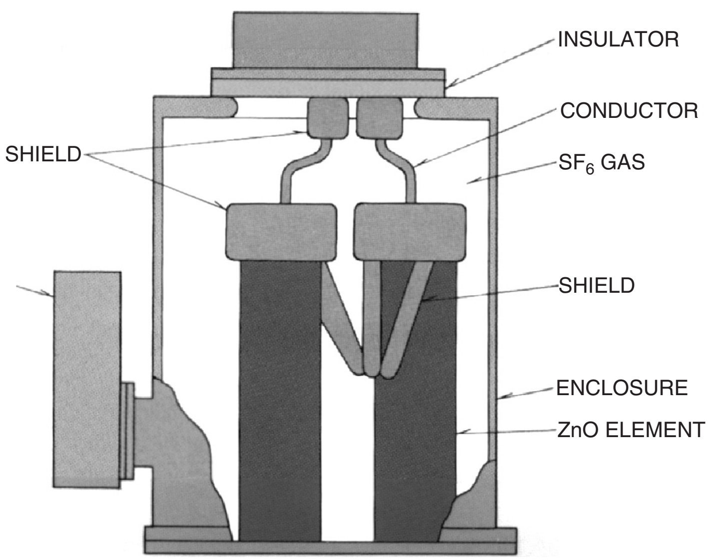


FIGURE 2.12 Surge arrester for GIS.

bridge the long insulating distances in air. In the GIS, the short insulation distances can be bridged in the short time-span of a lightning impulse; so the longer time-span of a switching surge does not significantly decrease the breakdown voltage. Insulation coordination studies usually show there is not a need for surge arresters in a GIS; however, many users specify surge arresters at transformers and cable connections as the most conservative approach.

2.2.11 Control System

For ease of operation and convenience in wiring the GIS back to the substation control room, a local control cabinet (LCC) is usually provided for each circuit breaker position (Fig. 2.13). The control and power wires for all the operating mechanisms, auxiliary switches, alarms, heaters, CTs, and VTs are brought from the GIS equipment modules to the LCC using shielded multiconductor control cables. In addition to providing terminals for all the GIS wiring, the LCC has a mimic diagram of the part of the GIS being controlled. Associated with the mimic diagram are control switches and position indicators for the circuit breaker and switches. Annunciation of alarms is also usually provided in the LCC. Electrical interlocking and some other control functions can be conveniently implemented in the LCC. Although the LCC is an extra expense, with no equivalent in the typical AIS, it is so well established and popular that elimination to reduce costs has been rare. The LCC does have the advantage of providing a very clear division of responsibility between the GIS manufacturer and user in terms of scope of equipment supply.

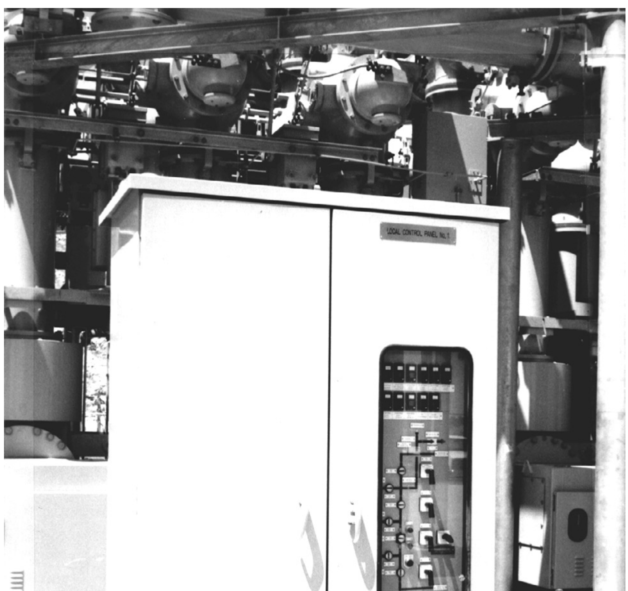


FIGURE 2.13 Local control cabinet for GIS.

Switching and circuit breaker operation in a GIS produces internal surge voltages with a very fast rise time of the order of nanoseconds and peak voltage level of about 2 per unit. These "very fast transient" voltages are not a problem inside the GIS because the duration of this type of surge voltage is very short—much shorter than the lightning impulse voltage. However, a portion of the very fast transient voltages will emerge from the inside of the GIS at any places where there is a discontinuity of the metal enclosure—for example at insulating enclosure joints for external CTs or at the SF_6-to-air bushings. The resulting "transient ground rise voltage" on the outside of the enclosure may cause some small sparks across the insulating enclosure joint or to adjacent grounded parts—these may alarm nearby personnel but are not harmful to a person because the energy content is very low. However, if these very fast transient voltages enter the control wires, they could cause misoperation of control devices. Solid-state controls can be particularly affected. The solution is thorough shielding and grounding of the control wires. For this reason, in a GIS the control cable shield should be grounded at both the equipment and the LCC ends using either coaxial ground bushings or short connections to the cabinet walls at the location where the control cable first enters the cabinet.

2.2.12 Gas Monitor System

The insulating and interrupting capability of the SF_6 gas depends on the density of the SF_6 gas being at a minimum level established by design tests. The pressure of the SF_6 gas varies with temperature, so a mechanical or electronic temperature compensated pressure switch is used to monitor the equivalent of gas density (Fig. 2.14). GIS is filled with SF_6 to a density far enough above the minimum density for full dielectric and interrupting capability so that from 5 to 20% of the SF_6 gas can be lost before the performance of the GIS deteriorates. The density alarms provide a warning of gas being lost, and can be used to operate the circuit breakers and switches to put a GIS that is losing gas into a condition selected by the user. Because it is much easier to measure pressure than density, the gas monitor system may be a pressure gage. A chart is provided to convert pressure and temperature measurements into density. Microprocessor based measurement systems are available that provide pressure, temperature, density, and even percentage of proper SF_6 content. These can also calculate the rate at which SF_6 is being lost. However, they are significantly more expensive than the mechanical temperature compensated pressure switches, so they are supplied only when requested by the user.

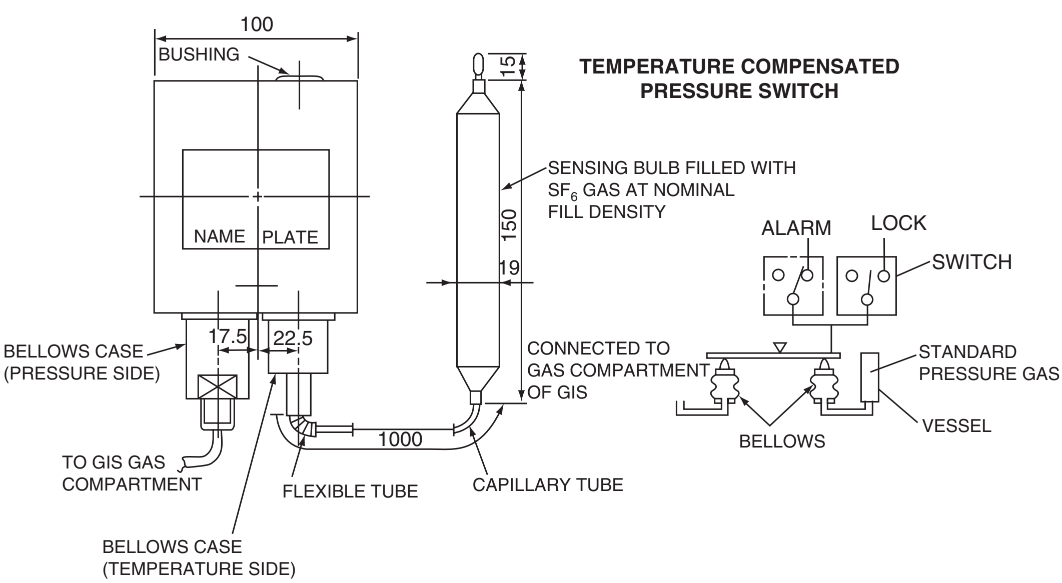


FIGURE 2.14 SF_6 density monitor for GIS.

2.2.13 Gas Compartments and Zones

A GIS is divided by gas barrier insulators into gas compartments for gas handling purposes. Due to the arcing that takes place in the circuit breaker, it is usually its own gas compartment. Gas handling systems are available to easily process and store about 1000 kg of SF_6 at one time, but the length of time needed to do this is longer than most GIS users will accept. GIS is therefore divided into relatively small gas compartments of less than several hundred kilograms. These small compartments may be connected with external bypass piping to create a larger gas zone for density monitoring. The electrical functions of the GIS are all on a three-phase basis, so there is no electrical reason to not connect the parallel phases of a single-phase enclosure type of GIS into one gas zone for monitoring. Reasons for not connecting together many gas compartments into large gas zones include a concern with a fault in one gas compartment causing contamination in adjacent compartments and the greater amount of SF_6 lost before a gas-loss alarm. It is also easier to locate a leak if the alarms correspond to small gas zones—on the other hand, a larger gas zone will, for the same size leak, give more time to add SF_6 between the first alarm and second alarm. Each GIS manufacturer has a standard approach to gas compartments and gas zones, but of course will modify the approach to satisfy the concerns of individual GIS users.

2.2.14 Electrical and Physical Arrangement

For any electrical one-line diagram there are usually several possible physical arrangements. The shape of the site for the GIS and the nature of connecting lines and cables should be considered. Figure 2.15 compares a natural physical arrangement for a breaker and a half GIS with a "linear" arrangement.

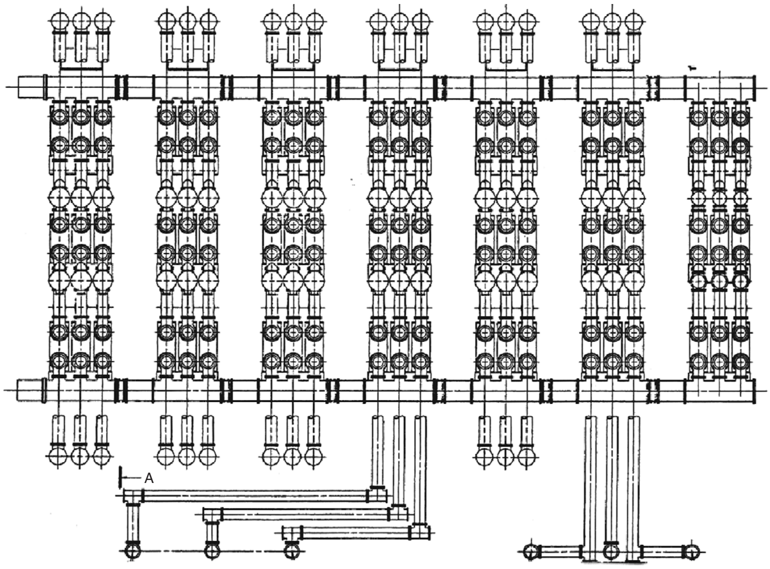
Most GIS designs were developed initially for a double bus, single break arrangement (Fig. 2.2). This widely used approach provides good reliability, simple operation, easy protective relaying, excellent economy, and a small footprint. By integrating several functions into each GIS module, the cost of the double bus, single breaker arrangement can be significantly reduced. An example is shown in Fig. 2.16. Disconnect and ground switches are combined into a "three position switch" and made a part of each bus module connecting adjacent circuit breaker positions. The cable connection module includes the cable termination, disconnect switches, ground switches, a VT, and surge arresters.

2.2.15 Grounding

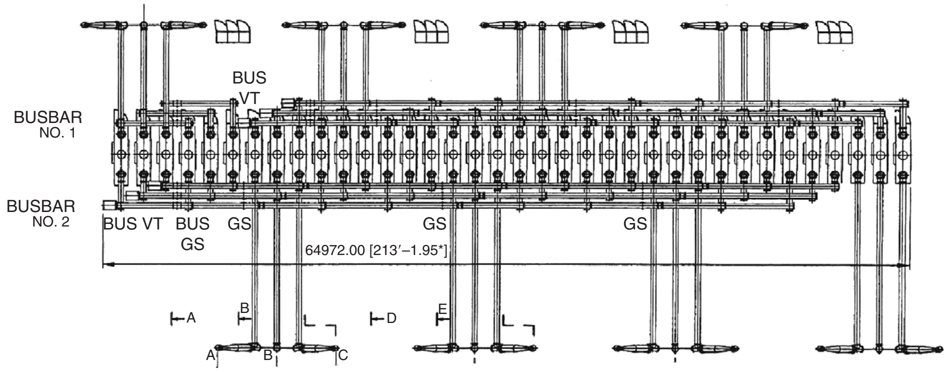
The individual metal enclosure sections of the GIS modules are made electrically continuous either by the flanges enclosure joint being a good electrical contact in itself or with external shunts bolted to the flanges or to grounding pads on the enclosure. Although some early single-phase enclosure GIS were "single point grounded" to prevent circulating currents from flowing in the enclosures, today the universal practice is to use "multipoint grounding" even though this leads to some electrical losses in the enclosures due to circulating currents. The three enclosures of a single-phase GIS should be bonded to each other at the ends of the GIS to encourage circulating currents to flow—these circulating enclosure currents act to cancel the magnetic field that would otherwise exist outside the enclosure due to the conductor current. Three-phase enclosure GIS does not have circulating currents, does have eddy currents in the enclosure, and should also be multipoint grounded. With multipoint grounding and the many resulting parallel paths for the current from an internal fault to flow to the substation ground grid, it is easy to keep the touch and step voltages for a GIS to the safe levels prescribed in IEEE 80.

2.2.16 Testing

Test requirements for circuit breakers, CTs, VTs, and surge arresters are not specific for GIS and will not be covered in detail here. Representative GIS assemblies having all of the parts of the GIS except for the circuit breaker are design tested to show the GIS can withstand the rated lightning impulse voltage, switching impulse voltage, power frequency overvoltage, continuous current, and short-circuit current.



NATURAL—EACH BAY BETWEEN MAIN BUSBARS HAS THREE CIRCUIT BREAKERS



LINEAR—CIRCUIT BREAKERS ARE SIDE BY SIDE

FIGURE 2.15 One-and-one-half circuit breaker layouts.

Standards specify the test levels and how the tests must be done. Production tests of the factory assembled GIS (including the circuit breaker) cover power frequency withstand voltage, conductor circuit resistance, leak checks, operational checks, and CT polarity checks. Components such as support insulators, VTs, and CTs are tested in accord with the specific requirements for these items before assembly into the GIS. Field tests repeat the factory tests. The power frequency withstand voltage test is most important as a check of the cleanliness of the inside of the GIS in regard to contaminating conducting particles, as explained in Section 2.1. Checking of interlocks is also very important. Other field tests may be done if the GIS is a very critical part of the electric power system—for example, a surge voltage test may be requested.

2.2.17 Installation

GIS is usually installed on a monolithic concrete pad or the floor of a building. The GIS is most often rigidly attached by bolting or welding the GIS support frames to embedded steel plates of beams. Chemical drill anchors can also be used. Expansion drill anchors are not recommended because dynamic

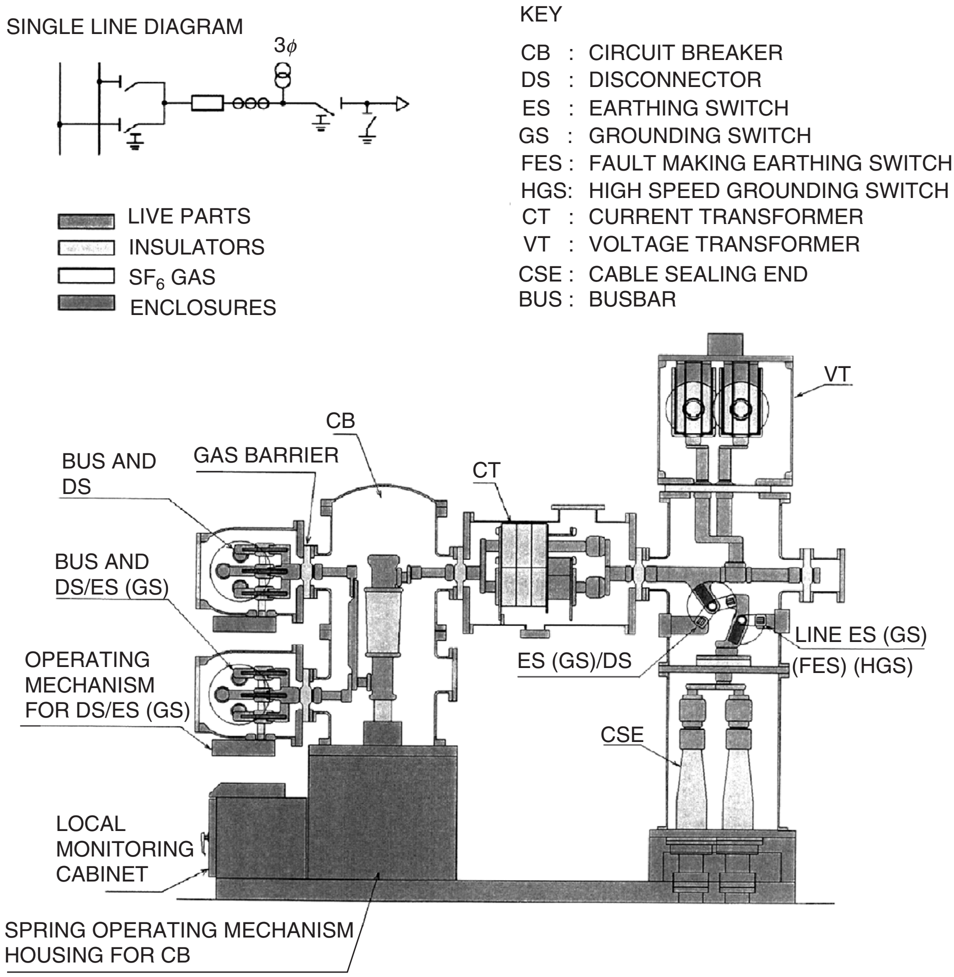


FIGURE 2.16 Integrated (combined function) GIS.

loads when the circuit breaker operates may loosen expansion anchors. Large GIS installations may need bus expansion joints between various sections of the GIS to adjust to the fitup in the field and, in some cases, provide for thermal expansion of the GIS. The GIS modules are shipped in the largest practical assemblies; at the lower voltage level two or more circuit breaker positions can be delivered fully assembled. The physical assembly of the GIS modules to each other using the bolted flanged enclosure joints and conductor contacts goes very quickly. More time is used for evacuation of air from gas compartments that have been opened, filling with SF_6 gas and control system wiring. The field tests are then done. For high-voltage GIS shipped as many separate modules, installation and test take about 2 weeks per circuit breaker position. Lower voltage systems shipped as complete bays, and mostly factory wired, can be installed more quickly.

2.2.18 Operation and Interlocks

Operation of a GIS in terms of providing monitoring, control, and protection of the power system as a whole is the same as that for an AIS except that internal faults are not self-clearing, so reclosing should not be used for faults internal to the GIS. Special care should be taken for disconnect and ground switch operation, because if these are opened with load current flowing, or closed into load or fault current, the arcing between the switch moving and stationary contacts will usually cause a phase to phase fault in three-phase enclosure GIS or to a phase to ground fault in single-phase enclosure GIS. The internal fault will cause severe damage inside the GIS. A GIS switch cannot be as easily or quickly replaced as an AIS switch. There will also be a pressure rise in the GIS gas compartment as the arc heats the gas. In extreme cases, the internal arc will cause a rupture disk to operate or may even cause a burn-through of the enclosure. The resulting release of hot decomposed SF_6 gas may cause serious injury to nearby personnel. For both the sake of the GIS and the safety of personnel, secure interlocks are provided so that the circuit breaker must be open before an associated disconnect switch can be opened or closed, and the disconnect switch must be open before the associated ground switch can be closed or opened.

2.2.19 Maintenance

Experience has shown that the internal parts of the GIS are so well protected inside the metal enclosure that they do not age, and as a result of proper material selection and lubricants, there is negligible wear on the switch contacts. Only the circuit breaker arcing contacts and the Teflon nozzle of the interrupter experience wear proportional to the number of operations and the level of the load or fault currents being interrupted. The contacts and nozzle materials combined with the short interrupting time of modern circuit breakers provide typically for thousands of load current interruption operations and tens of full rated fault current interruptions before there is any need for inspection or replacement.

Except for circuit breakers in special use such as a pumped storage plant, most circuit breakers will not be operated enough to ever require internal inspection. So most GIS will not need to be opened for maintenance. The external operating mechanisms and gas monitor systems should be visually inspected, with the frequency of inspection determined by experience.

Replacement of certain early models of GIS has been necessary in isolated cases due to either inherent failure modes or persistent corrosion causing SF_6 leakage problems. These early models may no longer be in production, and in extreme cases the manufacturer is no longer in business. If space is available, a new GIS (or even AIS) may be built adjacent to the GIS being replaced and connections to the power system shifted over into the new GIS. If space is not available, the GIS can be replaced one breaker position at a time using custom designed temporary interface bus sections between the old GIS and the new.

2.3 Economics of GIS

The equipment cost of GIS is naturally higher than that of AIS due to the grounded metal enclosure, the provision of an LCC, and the high degree of factory assembly. A GIS is less expensive to install than an AIS. The site development costs for a GIS will be much lower than for an AIS because of the much smaller area required for the GIS. The site development advantage of GIS increases as the system voltage increases because high-voltage AIS takes very large areas because of the long insulating distances in atmospheric air. Cost comparisons in the early days of GIS projected that, on a total installed cost basis, GIS costs would equal AIS costs at 345 kV. For higher voltages, GIS was expected to cost less than AIS. However, the cost of AIS has been reduced significantly by technical and manufacturing advances (especially for circuit breakers) over the last 30 years, but GIS equipment has not shown significant cost reductions. So although GIS has been a well-established technology for a long time, with a proven high reliability and almost no need for maintenance, it is presently perceived as costing too much and only applicable in special cases where space is the most important factor. Currently, GIS costs are being reduced by integrating functions as described in Section 2.2.14. As digital control systems become common in substations, the costly electromagnetic CTs and VTs of a GIS will be replaced by less expensive sensors such as optical VTs and Rogowski coil CTs. These less expensive sensors are also much smaller, reducing the size of the GIS, allowing more bays of GIS to be shipped fully assembled. Installation and site development costs are correspondingly lower. The GIS space advantage over AIS increases. An approach termed "mixed technology switchgear" (or hybrid GIS) that uses GIS breakers, switches, CTs, and VTs with interconnections between the breaker positions and connections to other equipment using air-insulated conductors is a recent development that promises to reduce the cost of the GIS at some sacrifice in space savings. This approach is especially suitable for the expansion of an existing substation without enlarging the area for the substation.

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3

Air-Insulated Substations—Bus/Switching Configurations

Michael J. Bio

3.1 Introduction

Various factors affect the reliability of an electrical substation or switchyard facility, one of which is the arrangement of switching devices and buses. The following are the six types of arrangements commonly used:

1. Single bus
2. Double bus–double breaker
3. Main and transfer (inspection) bus
4. Double bus–single breaker
5. Ring bus
6. Breaker-and-a-half

Additional parameters to be considered when evaluating the configuration of a substation or a switchyard are maintenance, operational flexibility, relay protection, cost, and also line connections to the facility. This chapter will review each of the six basic configurations and compare how the arrangement of switching devices and buses of each impacts reliability and these parameters.

3.2 Single Bus Arrangement

This is the simplest bus arrangement, a single bus and all connections directly to one bus.

Reliability of the single bus configuration is low: even with proper relay protection, a single bus failure on the main bus or between the main bus and circuit breakers will cause an outage of the entire facility.

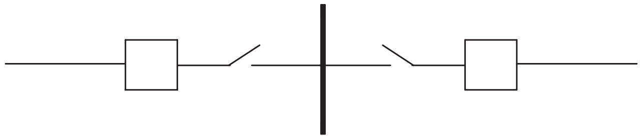

FIGURE 3.1 Single bus arrangement.

With respect to maintenance of switching devices, an outage of the line they are connected to is required. Furthermore, for a bus outage the entire facility must be de-energized. This requires standby generation or switching loads to adjacent substations, if available, to minimize outages of loads supplied from this type of facility.

Cost of a single bus arrangement is relatively low, but also is the operational flexibility; for example, transfer of loads from one circuit to another would require additional switching devices outside the substation.

Line connections to a single bus arrangement are normally straight forward, since all lines are connected to the same main bus. Therefore, lines can be connected on the main bus in areas closest to the direction of the departing line, thus mitigating lines crossing outside the substation.

Due to the low reliability, significant efforts when performing maintenance, and low operational flexibility, application of the single bus configuration should be limited to facilities with low load levels and low availability requirements.

Since single bus arrangement is normally just the initial stage of a substation development, when laying out the substation a designer should consider the ultimate configuration of the substation, such as where future supply lines, transformers, and bus sections will be added. As loads increase, substation reliability and operational abilities can be improved with step additions to the facility, for example, a bus tie breaker to minimize load dropped due to bus outages.

3.3 Double Bus–Double Breaker Arrangement

The double bus–double breaker arrangement involves two breakers and two buses for each circuit.

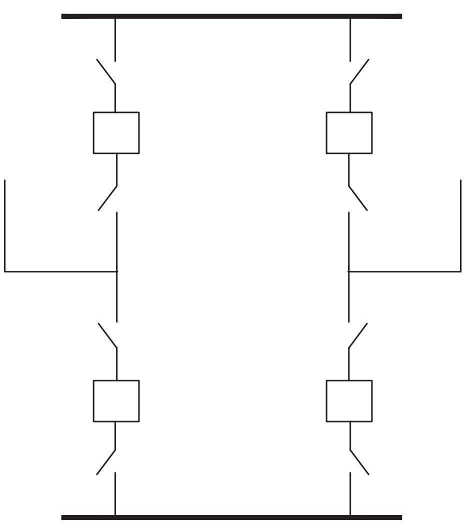

FIGURE 3.2 Double breaker-double bus arrangement.

With two breakers and two buses per circuit, a single bus failure can be isolated without interrupting any circuits or loads. Furthermore, a circuit failure of one circuit will not interrupt other circuits or buses. Therefore, reliability of this arrangement is extremely high.

Maintenance of switching devices in this arrangement is very easy, since switching devices can be taken out-of-service as needed and circuits can continue to operate with partial line relay protection and some line switching devices in-service, i.e., one of the two circuit breakers.

Obviously, with double the amount of switching devices and buses, cost will be substantially increased relative to other more simple bus configurations. In addition, relaying is more complicated and more land is required, especially for low-profile substation configurations.

External line connections to a double breaker–double bus substation normally do not cause conflicts with each other, but may require substantial land area adjacent to the facility as this type of station expands.

This arrangement allows for operational flexibility; certain lines could be fed from one bus section by switching existing devices.

This bus configuration is applicable for loads requiring a high degree of reliability and minimum interruption time. The double breaker–double bus configuration is expandable to various configurations, for example, a ring bus or breaker-and-a-half configurations, which will be discussed later.

3.4 Main and Transfer Bus Arrangement

The main and transfer bus configuration connects all circuits between the main bus and a transfer bus (sometimes referred to as an inspection bus). Some arrangements include a bus tie breaker and others simply utilize switches for the tie between the two buses.

This configuration is similar to the single bus arrangement; in that during normal operations, all circuits are connected to the main bus. So the operating reliability is low; a main bus fault will de-energize all circuits.

However, the transfer bus is used to improve the maintenance process by moving the line of the circuit breaker to be maintained to the transfer bus. Some systems are operated with the transfer bus normally de-energized. When a circuit breaker needs to be maintained, the transfer bus is energized through the tie breaker. Then the switch, nearest the transfer bus, on the circuit to be maintained is closed and its breaker and associated isolation switches are opened. Thus transferring the line of the circuit breaker to be maintained to the bus tie breaker and avoiding interruption to the circuit load. Without a bus tie breaker and only bus tie switches, there are two options. The first option is by transferring the circuit to be maintained to one of the remaining circuits by closing that circuit's switch (nearest to the transfer bus) and carrying both circuit loads on the one breaker. This arrangement most likely will require special relay settings for the circuit breaker to carry the transferred load. The second option is by transferring the circuit to be maintained directly to the main bus with no relay protection from the substation. Obviously in the latter arrangement, relay protection (recloser or fuse) immediately outside the substation should be considered to minimize faults on the maintained line circuit from causing extensive station outages.

The cost of the main and transfer bus arrangement is more than the single bus arrangement because of the added transfer bus and switching devices. In addition, if a low-profile configuration is used, land requirements are substantially more.

Connections of lines to the station should not be very complicated. If a bus tie breaker is not installed, consideration as to normal line loading is important for transfers during maintenance. If lines are normally operated at or close to their capability, loads will need to be transferred or temporary generators provided similar to the single bus arrangement maintenance scenario.

The main and transfer bus arrangement is an initial stage configuration, since a single main bus failure can cause an outage of the entire station. As load levels at the station rise, consideration of a main bus tie breaker should be made to minimize the amount of load dropped for a single contingency.

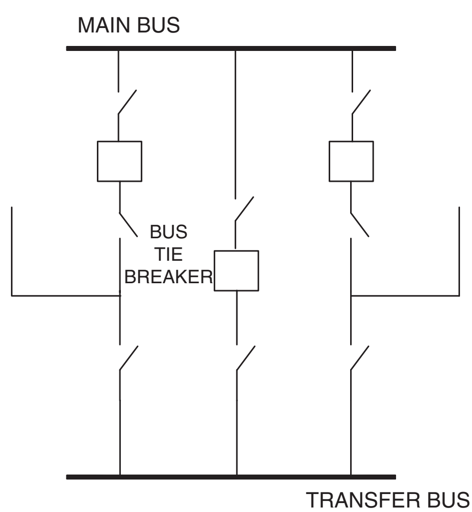

FIGURE 3.3 Main and transfer bus arrangement.

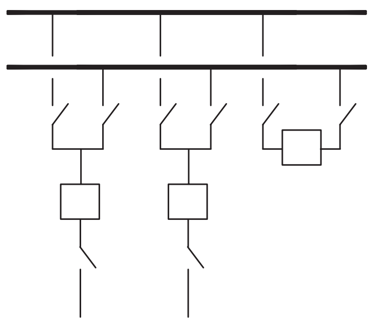

FIGURE 3.4 Double bus, single breaker arrangement.

Another operational capability of this configuration is that the main bus can be taken out-of-service without an outage to the circuits by supplying from the transfer bus, but obviously, relay protection (recloser or fuse) immediately outside the substation should be considered to minimize faults on any of the line circuit from causing station outages.

Application of this type of configuration should be limited to low reliability requirement situations.

3.5 Double Bus–Single Breaker Arrangement

The double bus–single breaker arrangement connects each circuit to two buses, and there is a tie breaker between the buses. With the tie breaker operated normally closed, it allows each circuit to be supplied from either bus via its switches. Thus providing increased operating flexibility and improved reliability. For example, a fault on one bus will not impact the other bus. Operating the bus tie breaker normally open eliminates the advantages of the system and changes the configuration to a two single bus arrangement.

Relay protection for this arrangement will be complex with the flexibility of transferring each circuit to either bus. Operating procedures would need to be detailed to allow for various operating arrangements, with checks to ensure the in-service arrangements are correct. A bus tie breaker failure will cause an outage of the entire station.

The double bus–single breaker arrangement with two buses and a tie breaker provides for some ease in maintenance, especially for bus maintenance, but maintenance of the line circuit breakers would still require switching and outages as described above for the single bus arrangement circuits.

The cost of this arrangement would be more than the single bus arrangement with the added bus and switching devices. Once again, low-profile configuration of this arrangement would require more area. In addition, bus and circuit crossings within the substation are more likely.

Application of this arrangement is best suited where load transfer and improved operating reliability are important. Though adding a transfer bus to improve maintenance could be considered, it would involve additional area and switching devices, which could increase the cost of the station.

3.6 Ring Bus Arrangement

As the name implies, all breakers are arranged in a ring with circuits connected between two breakers. From a reliability standpoint, this arrangement affords increased reliability to the circuits, since with properly operating relay protection, a fault on one bus section will only interrupt the circuit on that bus section and a fault on a circuit will not affect any other device.

Protective relaying for a ring bus will involve more complicated design and, potentially, more relays to protect a single circuit. Keep in mind that bus and switching devices in a ring bus must all have the same ampacity, since current flow will change depending on the switching device's operating position.

From a maintenance point of view, the ring bus provides good flexibility. A breaker can be maintained without transferring or dropping load, since one of the two breakers can remain in-service and provide line protection while the other is being maintained.

Similarly, operating a ring bus facility gives the operator good flexibility since one circuit or bus section can be isolated without impacting the loads on another circuit.

Cost of the ring bus arrangement can be more expensive than a single bus, main bus and transfer, and the double bus–single breaker schemes since two breakers are required for each circuit, even though one is shared.

The ring bus arrangement is applicable to loads where reliability and availability of the circuit is a high priority. There are some disadvantages of this arrangement: (a) a "stuck breaker" event could cause an outage of the entire substation depending on the number of breakers in the ring, (b) expansion of the ring bus configuration can be limited due to the number of circuits that are physically feasible in this arrangement, and (c) circuits into a ring bus to maintain a reliable configuration can cause extensive bus and line work. For example, to ensure service reliability, a source circuit and a load circuit should always be next to one another. Two source circuits adjacent to each other in a stuck breaker event could eliminate all sources to the station. Therefore, a low-profile ring bus can command a lot of area.

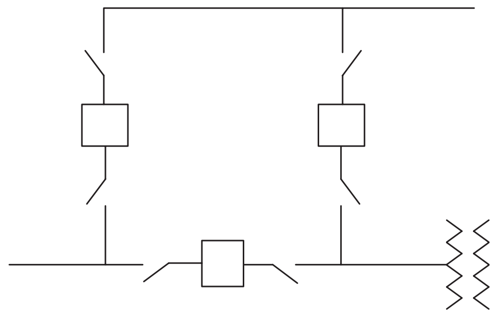

FIGURE 3.5 Ring bus arrangement.

3.7 Breaker-and-a-Half Arrangement

The breaker-and-a-half scheme is configured with a circuit between two breakers in a three-breaker line-up with two buses; thus, one-and-a-half breakers per circuit. In many cases, this is the next development stage of a ring bus arrangement.

Similar to the ring bus, this configuration provides good reliability; with proper operating relay protection, a single circuit failure will not interrupt any other circuits. Furthermore, a bus section fault, unlike the ring bus, will not interrupt any circuit loads.

Maintenance as well is facilitated by this arrangement, since an entire bus and adjacent breakers can be maintained without transferring or dropping loads.

Relay protection is similar to the ring bus, and due to the additional devices, is more complex and costly than most of the previously reviewed arrangements.

The breaker-and-a-half arrangement can be expanded as needed. By detailed planning of the ultimate substation expansion with this configuration, line conflicts outside the substation can be minimized.

Cost of this configuration is commensurate with the number of circuits, but based on the good reliability, operating flexibility, and ease of maintenance, the price can be justified.

Obviously, the area required for this type of arrangement is significant, and the higher the voltage, the more clearances required and area needed.

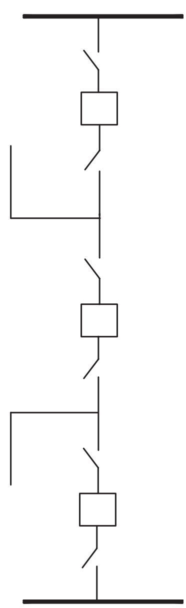

FIGURE 3.6 Breaker-and-a-half arrangement.

3.8 Comparison of Configurations

As a summary to the discussion above, Table 3.1 provides a quick reference to the key features of each configuration discussed with a relative cost comparison. The single bus

TABLE 3.1 Bus/Switching Configuration Comparison Table

Configuration	Reliability/Operation	Cost	Available Area
Single Bus	Least reliable—single failure can cause a complete outage. Limited operating flexibility	Least cost (1.0)—fewer components	Least area—fewer components
Double Bus–Double Breaker	Highly reliable—duplicated devices; single circuit or bus fault isolates only that component. Greater operating and maintenance flexibility	High cost (2.17)—duplicated devices and more material	Greater area—more devices and more material
Main and Transfer Bus	Least reliable—reliability is similar to the single bus arrangement, but operating and maintenance flexibility improved with the transfer bus	Moderate cost (2.06)—more devices and material required than the single bus	Low area—high-profile configuration is preferred to minimize land use
Double Bus–Single Breaker	Moderately reliable—with bus tie breaker, bus sections and line circuits are isolated. Good operating flexibility	High cost (2.15)—more devices and material	Greater area—more devices and more material
Ring Bus	High reliability—single circuit or bus section fault isolated. Operation and maintenance flexibility good	Moderate cost (1.62)—additional components and materials	Moderate area—dependent on the extent of the substation development
Breaker-and-a-Half	Highly reliable—Bus faults will not impact any circuits, and circuit faults isolate only that circuit. Operation and maintenance flexibility best with this arrangement	Moderate cost (1.69)—cost is reasonable based on improved reliability and operational flexibility	Greater area—more components. Area increases substantially with higher voltage levels

arrangement is considered the base, or 1 per unit cost with all others expressed as a factor of the single bus arrangement cost. Parameters considered in preparing the estimated cost were: (a) each configuration was estimated with only two circuits, (b) 138 kV was the voltage level for all arrangements, (c) estimates were based on only the bus, switches, and breakers, with no dead end structures, fences, land, or other equipment and materials, and (d) all were designed as low-profile stations.

Obviously, the approach used here is only a starting point for evaluating the type of substation or switching station to build. Once a type station is determined based on reliability, operational flexibility, land availability, and relative cost, a complete and thorough evaluation should take place. In this evaluation additional factors need be considered, such as, site development cost, ultimate number of feeders, land required, soil conditions, environmental impact, high profile versus low profile, ease of egress from substation with line circuits, etc. As the number of circuits increases, the relative difference in cost shown in the table may no longer be valid. These types of studies can require a significant amount of time and cost, but the end result will provide a good understanding of exactly what to expect of the ultimate station cost and configuration.

4

High-Voltage Switching Equipment

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4.1 Introduction

The design of the high-voltage substation must include consideration for the safe operation and maintenance of the equipment. Switching equipment is used to provide isolation, no-load switching (including line charging current interrupting, loop splitting, and magnetizing current interrupting), load switching, and interruption of fault currents. The magnitude and duration of the load currents and the fault currents will be significant in the selection of the equipment used.

System operations and maintenance must also be considered when equipment is selected. One significant choice is the decision of single-phase or three-phase operation. High-voltage power systems are generally operated as a three-phase system, and the imbalance that will occur when operating equipment in a single-phase mode must be considered.

4.2 Ambient Conditions

Air-insulated high-voltage electrical equipment is generally covered by standards based on assumed ambient temperatures and altitudes. Ambient temperatures are generally rated over a range from $-40°C$ to $+40°C$ for equipment that is air insulated and dependent on ambient cooling. Altitudes above 1000 m (3300 ft) may require derating.

At higher altitudes, air density decreases; hence the dielectric strength of air is also reduced and derating of the equipment is recommended. Operating clearances (strike distances) must be increased to compensate for the reduction in the dielectric strength of the ambient air. Also, current ratings generally decrease at higher elevations due to the decreased density of the ambient air, which is the cooling medium used for dissipation of the heat generated by the load losses associated with load current levels; however, the continuous current derating is slight in relation to the dielectric derating; in most cases it is negligible, and in many cases is offset by the cooler temperature of the ambient air typically found at these higher elevations.

4.3 Disconnect Switches

A disconnect switch is a mechanical device that conducts electrical current and provides an open point in a circuit for isolation of one of the following devices:

- Circuit breaker
- Circuit switcher
- Power transformer
- Capacitor bank
- Reactor
- Other substation equipment

The three most important functions disconnect switches must perform are to open and close reliably when called upon to do so, to carry current continuously without overheating, and to remain in the closed position under fault current conditions. Disconnect switches are normally used to provide a point of visual isolation of the substation equipment for maintenance. Typically a disconnect switch would be installed on each side of a piece of substation equipment to provide a visible confirmation that the power conductors have been opened for personnel safety. Once the switches are operated to the open position, portable safety grounds can be attached to the de-energized equipment for worker protection. Either in place of portable grounds or in addition to portable grounds (as a means of redundant safety), switches can be equipped with grounding blades to perform the safety grounding function. The principal drawback of the use of grounding blades is that they provide a safety ground in a specific, nonchangeable location, whereas portable safety grounds can be located at whatever position is desired to achieve a ground point for personnel safety. A very common application of fixed position grounding blades is for use with a capacitor bank, with the grounding blades performing the function of bleeding off the capacitor bank's trapped charge.

Disconnect switches are designed to continuously carry load currents and momentarily carry short-circuit currents for a specified duration (typically defined in seconds or cycles depending upon the magnitude of the short-circuit current). They are designed for no-load switching, opening, or closing circuits where negligible currents are made or interrupted (including capacitive current [line charging current] and resistive or inductive current [magnetizing current]), or when there is no significant voltage across the open terminals of the switch (loop splitting [parallel switching]). They are relatively slow-speed operating devices and therefore are not designed for interruption of any significant magnitude current arcs. Disconnect switches are also installed to bypass breakers or other equipment for maintenance and can be used for bus sectionalizing. Interlocking equipment is available to prevent operating sequence errors, which could cause substation equipment damage, by inhibiting operation of the disconnect switch until the load current has been interrupted by the appropriate equipment. This interlocking equipment takes three basic forms:

- Mechanical cam-action type (see Fig. 4.1)—used to interlock a disconnect switch and its integral grounding blades to prevent the disconnect switch from being closed when the grounding blades are closed and to prevent the grounding blades from being closed when the disconnect switch is closed.
- Key type (see Fig. 4.2)—a mechanical plunger extension and retraction only or electromechanical equipment consisting of a mechanical plunger and either electrical auxiliary switch contacts or an electrical solenoid. It is used in a variety of applications including, but not limited to, interlocking a disconnect switch and its integral grounding blades, interlocking the grounding blades on one disconnect switch with a physically separate disconnect switch in the same circuit, or interlocking

FIGURE 4.1 Mechanical cam-action type interlock.

FIGURE 4.2 Key type interlock.

a disconnect switch with a circuit breaker (to ensure that the circuit breaker is open before the disconnect switch is allowed to open).

- Solenoid type (see Fig. 4.3)—most commonly used to ensure that the circuit breaker is open before the disconnect switch is allowed to open.

Single-phase or three-phase operation is possible for some disconnect switches. Operating mechanisms are normally installed to permit opening and closing of the three-phase disconnect switch by an operator standing at ground level. Common manual operating mechanisms include a swing handle (see Fig. 4.4) or a gear crank (see Fig. 4.5). Other manual operating mechanisms, which are less common, include a reciprocating or pump type handle or a handwheel. The choice of which manual operating mechanism to use is made based upon the required amount of applied force necessary to permit operation of the disconnect switch. A general guideline is that disconnect switches rated 69 kV and below or 1200-A continuous current and below are typically furnished with a swing handle operating mechanism, whereas disconnect switches rated 115 kV and above or 1600-A continuous current and above are typically furnished with a gear crank operating mechanism. This convention can vary based upon the type of disconnect switch used, as different types of disconnect switches have varying operating effort requirements. Motor-operating mechanisms (see Fig. 4.6) are also available and are applied when remote switching is necessary or desired and when the disconnect switch's function is integrated into a comprehensive system monitoring and performance scheme such as a Supervisory Control and Data Acquisition (SCADA) system. These motor-operating mechanisms can be powered either via a substation battery source or via the input from an auxiliary AC source. Some motor-operating mechanisms have their own internal batteries that can be fed from an auxiliary AC source via an AC to DC trickle charger, thus providing multiple stored operations in the event of loss of auxiliary AC source supply. These stored energy motor operators (see Fig. 4.7) are ideally suited for substations that do not have a control building to house substation batteries and for line installations where it is undesirable or economically infeasible to supply a DC battery source external to the motor operator. Remote terminal units (RTUs) are commonly used to communicate with these stored energy motor operators, providing the remote electrical input signal that actuates the motor operator.

Disconnect switches can be mounted in a variety of positions, with the most common positions being horizontal upright (see Fig. 4.8), vertical (see Fig. 4.9), and underhung (see Fig. 4.10). A disconnect

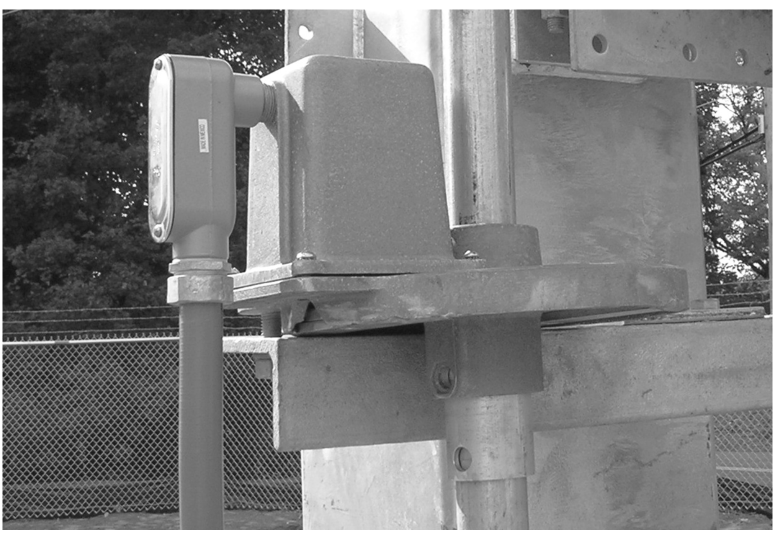

FIGURE 4.3 Solenoid type interlock.

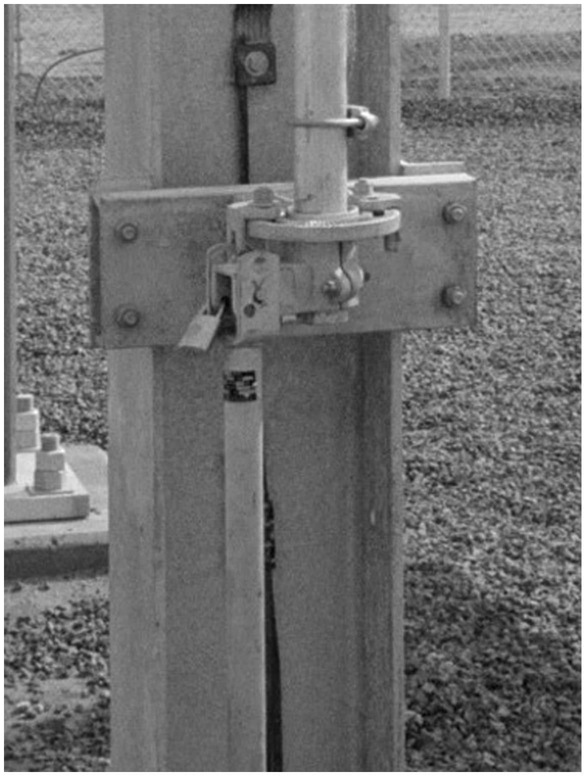

FIGURE 4.4 Swing handle operator for disconnect switch.

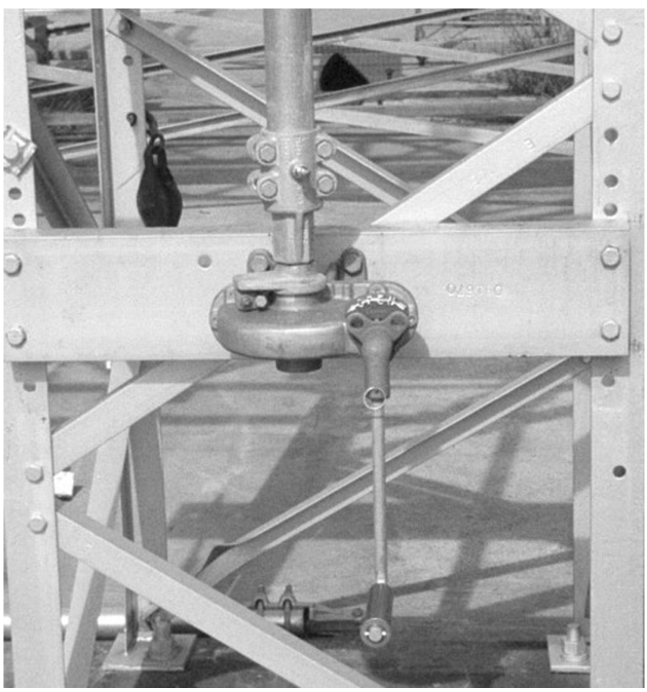

FIGURE 4.5 Gear Crank operator for disconnect switch.

FIGURE 4.6 Motor operator for disconnect switch.

FIGURE 4.7 Stored energy motor operator for disconnect switch.

FIGURE 4.8 Horizontally upright mounted disconnect switch.

switch's operation can be designed for vertical or horizontal operating of its switch blades. Several configurations are available, including

- Vertical break (see Fig. 4.11)
- Double end break (also sometimes called double side break) (see Fig. 4.12)
- Double end break "Vee" (also sometimes called double side break "Vee") (see Fig. 4.13)
- Center break (see Fig. 4.14)
- Center break "Vee" (see Fig. 4.15)

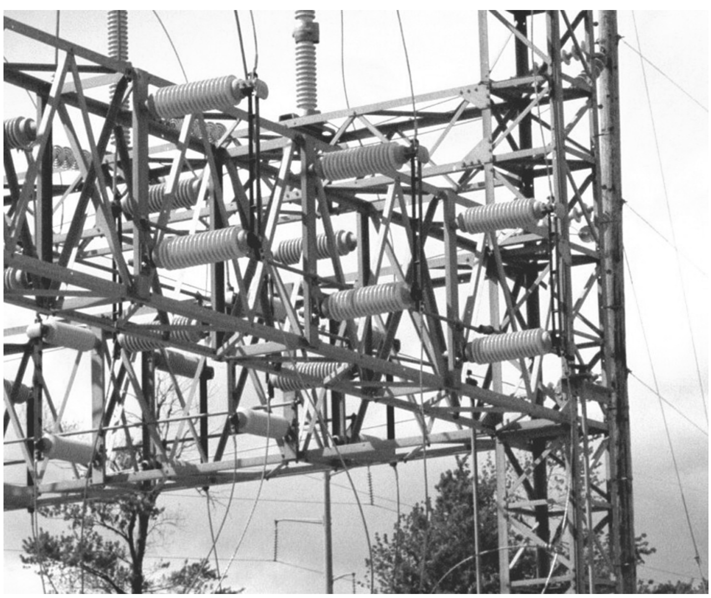

FIGURE 4.9 Vertically mounted disconnect switch.

FIGURE 4.10 Underhung mounted disconnect switch.

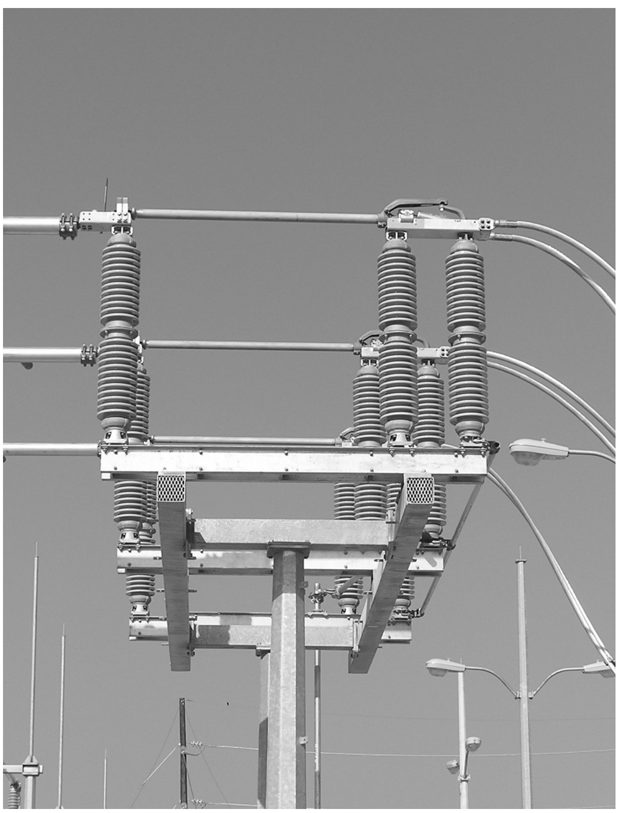

FIGURE 4.11 Vertical break disconnect switch.

FIGURE 4.12 Double end break (double side break) disconnect switch.

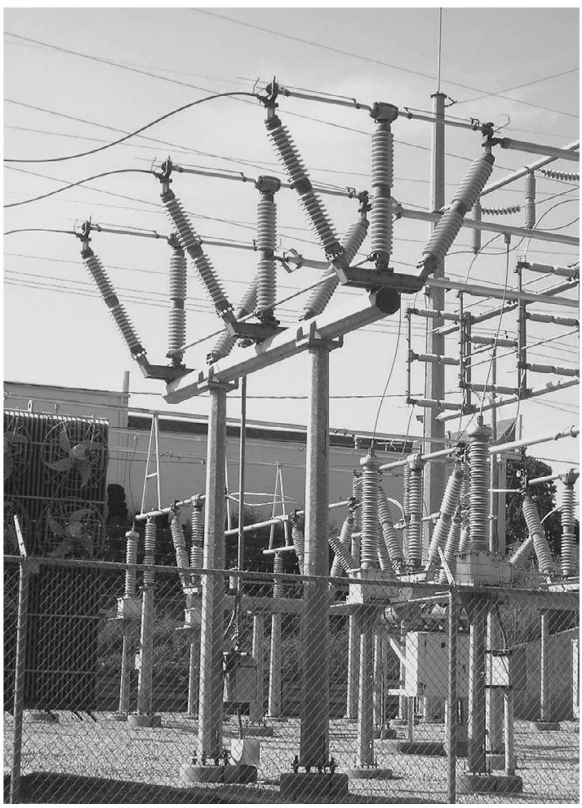

FIGURE 4.13 Double end break "Vee" (double side break "Vee") disconnect switch.

FIGURE 4.14 Center break disconnect switch.

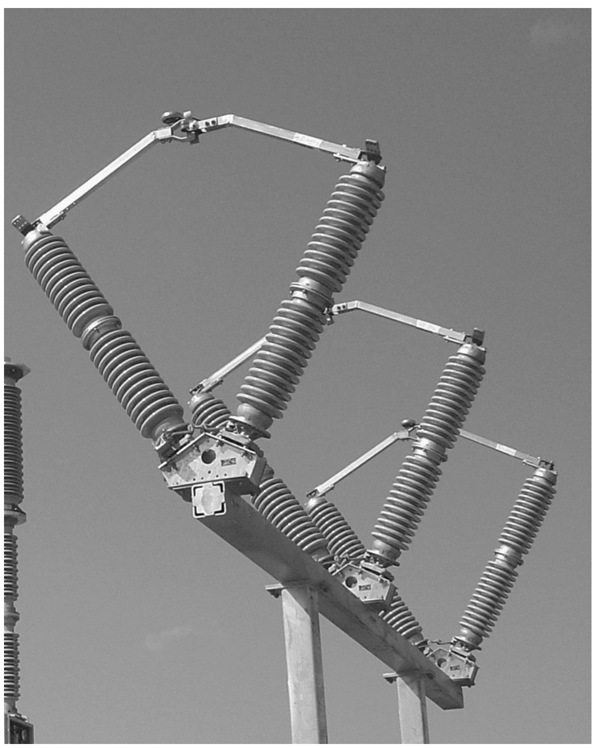

FIGURE 4.15 Center break "Vee" disconnect switch.

FIGURE 4.16 Single side break disconnect switch.

- Single side break (see Fig. 4.16)
- Vertical reach (also sometimes called pantograph, semipantograph, or knee-type switches) (see Fig. 4.17)
- Grounding (see Fig. 4.18)
- Hookstick (see Fig. 4.19)

Each of these switch types has specific features that lend themselves to certain types of applications.

Vertical break switches are the most widely used disconnect switch design, are the most versatile disconnect switch design, can be installed on minimum phase spacing, are excellent for applications in ice environments due to their rotating blade design, and are excellent for installations in high fault current locations due to their contact design (see Fig. 4.20).

Double end break switches can be installed on minimum phase spacing—the same phase spacing as for vertical break switches (due to the disconnect switch blades being disconnected from both the source

FIGURE 4.17 Vertical reach (pantograph) disconnect switch.

FIGURE 4.18 Grounding switch.

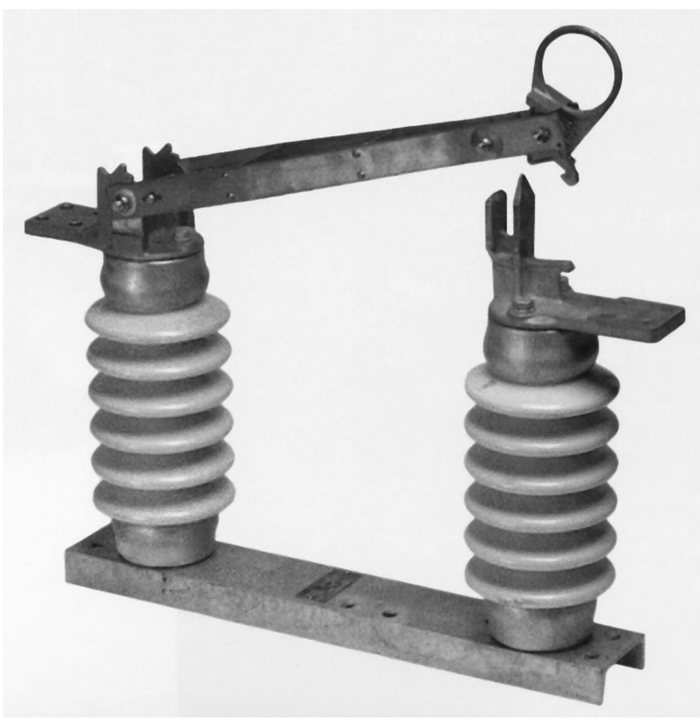

FIGURE 4.19 Hookstick operated disconnect switch.

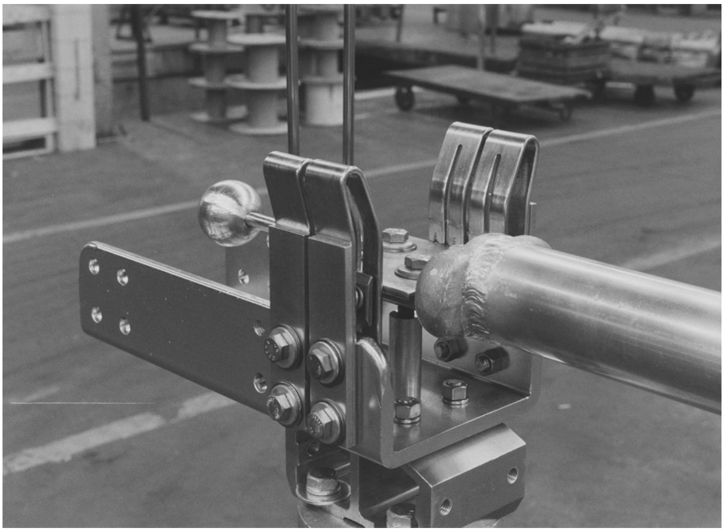

FIGURE 4.20 Contact design of vertical break disconnect switch.

and the load when in the open position (see Fig. 4.21), can be installed in minimum overhead clearance locations (something that vertical break switch designs cannot do), do not require a counterbalance for the blades as the blades do not have to be lifted during operation (many vertical break switches utilize a counterbalance spring to control the blade movement during opening and closing operations and to reduce the operating effort required), are excellent for applications in ice environments due to their rotating blade design (even better, in fact, than vertical break switches are for this application due to the

FIGURE 4.21 Double end break disconnect switch in open position.

FIGURE 4.22 Double end break "Vee" disconnect switch on single horizontal member, two column structure.

contact configuration of the double end break switch versus the vertical break switch), are excellent for installations in high fault current locations due to their contact design, and have the advantage of being able to interrupt significantly more line charging current or magnetizing current than any single break type switch can due to their two break per phase design.

Double end break "Vee" switches share all of the same characteristics as the conventional double end break switches but with the additional feature advantage of consuming the smallest amount of substation space of any three-phase switch type as they can be installed on a single horizontal beam structure with one, two (see Fig. 4.22), or three vertical columns (the quantity of which is determined by the kilovolt (kV) rating of the switch and other site-specific conditions such as seismic considerations).

Center break switches can be installed in minimum overhead clearance locations but require greater phase spacing than vertical break, double end break, or double end break "Vee" switches do (as center break switches have one of the two blades per phase energized when in the open position); require only six insulators per three-phase switch (versus the nine insulators per three-phase switch required for vertical break, double end break, and double end break "Vee" switches); do not require a counterbalance for the blades as the blades do not have to be lifted during operation; and are the best available three-phase switch design for vertical mounting (see Fig. 4.23) as the two blades per phase self-counterbalance each other during opening and closing operations via the synchronizing pipe linkage.

Center break "Vee" switches share all of the same characteristics as the conventional center break switches but with the additional feature advantage of consuming a smaller amount of substation space as they can be installed on a single horizontal beam structure with one, two, or three vertical columns (the quantity of which is determined by the kV rating of the switch and other site-specific conditions such as seismic considerations).

Single side break switches can be installed in minimum overhead clearance locations but may require greater phase spacing than vertical break, double end break, or double end break "Vee" switches do; require only six insulators per three-phase switch (versus the nine insulators per three-phase switch required for vertical break, double end break, and double end break "Vee" switches); and do not require a counterbalance for the blades as the blades do not have to be lifted during operation.

Vertical reach switches are used most commonly in extra high-voltage (EHV) applications, typically for 345, 500, and 765 kV installations. The U.S. utility industry uses few of the vertical reach switches, but this switch design is fairly common in Europe and in other parts of the world.

Grounding switches can be furnished as an integral attachment to any of the previously mentioned disconnect switch types (see Fig. 4.24), or can be furnished as a stand-alone device (i.e., not attached as

FIGURE 4.23 Vertically mounted center break disconnect switch.

an integral component of a disconnect switch) (see Fig. 4.18). Grounding switches are commonly applied to perform safety grounding of disconnect switches, buses, and capacitor banks. As previously mentioned, when grounding switches are used, there is an interlocking scheme of some type normally employed to assure proper sequence of operations.

FIGURE 4.24 Grounding switch integrally attached to vertical break disconnect switch.

Hookstick switches are single-phase devices that provide isolation, bypassing (typically of a regulator, a recloser, or a current transformer), transferring (i.e., feeding a load from an alternate source), or grounding.

For all types of disconnect switches previously mentioned, phase spacing is usually adjusted to satisfy the spacing of the bus system installed in the substation. In order to attain proper electrical performance, the standards establish minimum metal-to-metal clearances to be maintained for a given switch type and kV rating.

Prior to about 1970 almost all switches had copper live part construction and met a standard that allows a 30°C temperature rise when the switch is energized and carrying its full nameplate current value. Subsequent to 1970, many switch designs of aluminum live part construction were created and a new governing standard that allows a 53°C temperature rise when the switch is energized and carrying its full nameplate current value came into existence. International standards allow a 65°C temperature rise when switches are energized and carrying their full nameplate current value. When it comes to the temperature rise capability of a switch, cooler is better as it means the switch has more inherent built-in current carrying capability; so a 30°C rise switch is more capable than a 53°C rise switch or a 65°C rise switch, and a 53°C rise switch is more capable than a 65°C rise switch.

4.4 Load Break Switches

A load break switch is a disconnect switch that has been equipped to provide breaking and making of specified currents. This is accomplished by the addition of equipment that changes what the last points of metal-to-metal contact upon opening and the first points of metal-to-metal contact upon closing are, that increases the speed at which the last points of metal-to-metal contact part in air, or that confine the arcing to a chamber which contains a dielectric medium capable of interrupting the arc safely and reliably.

Arcing horns (see Fig. 4.25) are the equipment added to disconnect switches to allow them to interrupt very small amounts of charging or magnetizing current. The capability of arcing horns to

FIGURE 4.25 Arcing horns on a vertical break switch.

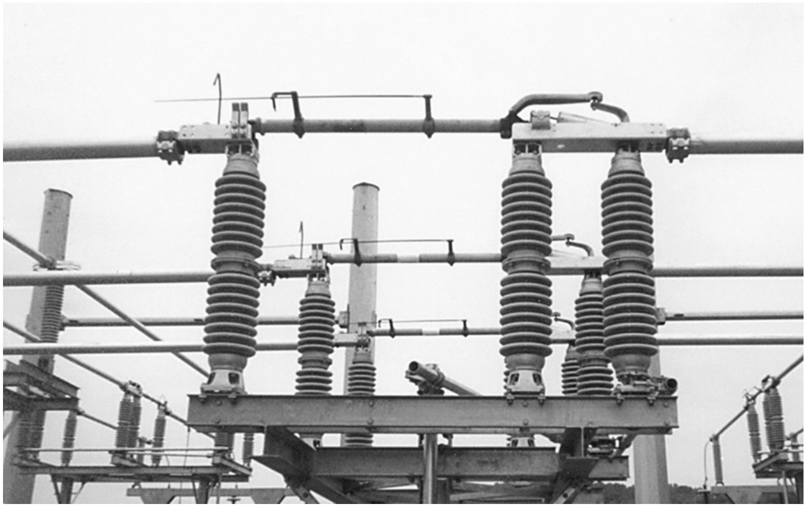

FIGURE 4.26 High-speed arcing horns on a vertical break switch.

perform current interruption is a function of arcing horn material (typically copper or stainless steel), switch break type (vertical break, double end break, double end break Vee, center break, center break Vee, or single side break), phase spacing, switch mounting position (horizontal upright, vertical, or underhung), and other factors. These "standard" arcing horns can be used on any kV-rated switch. Standard arcing horns do not have load breaking capability and should not be used to perform a load breaking function as damage to the disconnect switch will result. Also, standard arcing horns have no loop splitting rating.

High-speed arcing horns (see Fig. 4.26) (sometimes called whip horns, quick breaks, buggy whips, or quick break whips) are the equipment added to disconnect switches to allow them to interrupt small amounts of charging or magnetizing current. The capability of these quick break whip horns is a function of arcing horn material (typically stainless steel or beryllium copper) and tip speed of the whip horn at the point when it separates from the fixed catcher on the jaw contact assembly of the switch. Quick break whip type arcing horns are suitable for use on disconnect switches rated 161 kV and below, as above 161 kV quick break whip type arcing horns can produce visible or audible corona. Whip type arcing horns do not have load breaking capability and should not be used to perform a load breaking function as damage to the disconnect switch will result. Also, whip type arcing horns have no loop splitting rating.

If the need for interrupting loop currents, load currents, or large amounts of line charging current exists, then a disconnect switch can be outfitted with an interrupter (using either sulfur hexafluoride [SF_6] gas or vacuum as the interrupting medium) capable of performing these interrupting duties. Most commonly, the type of disconnect switch outfitted with these load/line/loop interrupters is a vertical break switch, although single side break switches are sometimes used. At 30 kV and below, center break switches and center break Vee switches can also be equipped with load/line/loop interrupters to perform these functions. While SF_6 gas load/line/loop interrupters (see Fig. 4.27) are single gap type for all kV ratings (requiring no voltage division across multiple gaps per phase to achieve successful interruption), vacuum load/line/loop interrupters are multigap type for system voltages above 30 kV. At 34.5 and 46 kV, two vacuum bottles per phase are required; at 69 kV, three vacuum bottles per phase (see Fig. 4.28); at 115 kV, five vacuum bottles per phase; at 138 kV, six vacuum bottles per phase; at 161 kV, seven vacuum bottles per phase; and at 230 kV, eight vacuum bottles per phase are necessary. An additional difference between vacuum interrupters and SF_6 interrupters is that SF_6 interrupters provide visual indication of the presence of adequate dielectric for successful interruption (see Fig. 4.29),

FIGURE 4.27 Load break switch with SF_6 interrupters.

a feature not available on vacuum interrupters. This visual indication is a significant feature in the area of personnel safety, particularly on load break switches that may be manually operated.

In order to decide which of these attachments (arcing horns, quick break whips, or load/line/loop interrupters) is required for a given installation, it is necessary to be able to determine the amount of

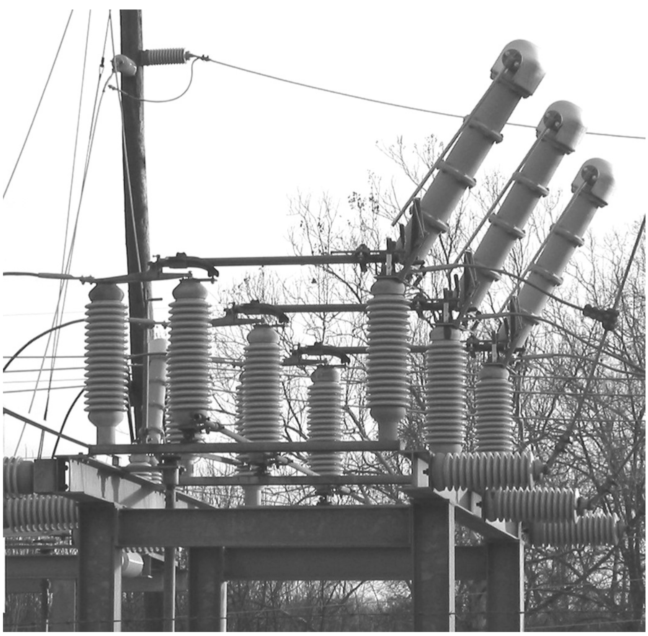

FIGURE 4.28 Load break switch with multi-bottle vacuum interrupters.

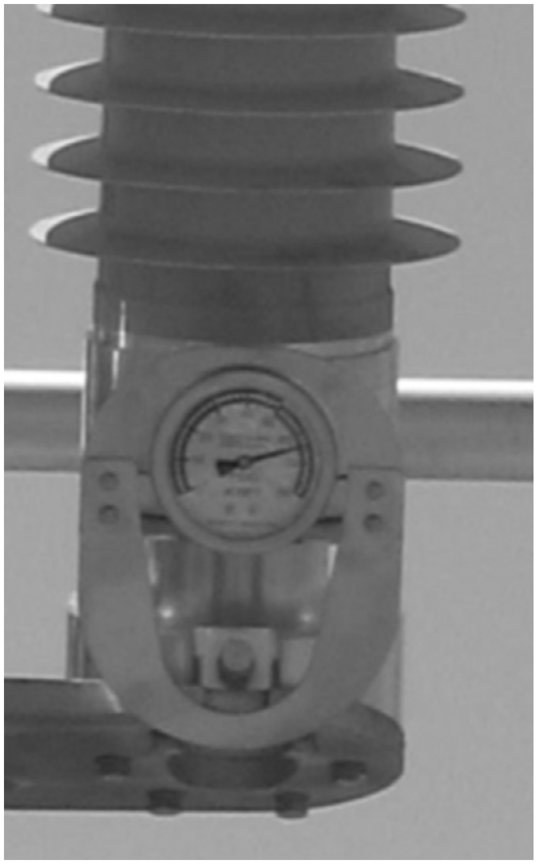

FIGURE 4.29 SF_6 interrupter's pressure indicator.

charging current and/or magnetizing current that exists. ANSI C37.32-2002, Annex A provides a conservative rule of thumb regarding the calculation of the amount of available line charging current at a given kV rating as a function of miles of line as indicated below:

- 15 kV 0.06 A/mile of line
- 23 kV 0.10 A/mile of line
- 34.5 kV 0.14 A/mile of line
- 46 kV 0.17 A/mile of line
- 69 kV 0.28 A/mile of line
- 115 kV 0.44 A/mile of line
- 138 kV 0.52 A/mile of line
- 161 kV 0.61 A/mile of line
- 230 kV 0.87 A/mile of line
- 345 kV 1.31 A/mile of line

Many factors influence the amount of available line charging current, including the following:

- Phase spacing
- Phase-to-ground distance
- Atmospheric conditions (humidity, airborne contaminants, etc.)

- Adjacent lines on the same right of way (especially if of a different kV)
- Distance to adjacent lines
- An overbuild or underbuild on the same transmission towers (especially if of a different kV)
- Distance to overbuild or underbuild lines
- Conductor configuration (phase over phase, phase opposite phase, phase by phase [side by side], delta upright, delta inverted, etc.)

If it is desired to be more precise in the determination of the amount of available line charging current, exact values for a given installation can be calculated by analyzing all of the applicable system components and parameters of influence in lieu of using the rules of thumb shown above.

When determining the amount of available magnetizing current at a given site, a conservative estimate is 1% of the full-load rating of the power transformer. For almost all power transformers the actual value of magnetizing current is only a fraction of this amount; so if a more precise value is desired, the power transformer manufacturer can be consulted to obtain the specific value of magnetizing current for a given transformer. Just as there are a variety of factors that influence the amount of line charging current present in a given installation, so too are there various factors that affect the amount of available magnetizing current. These factors include, but are not limited to, transformer core design, transformer core material, transformer coil design, and transformer coil material.

4.5 High-Speed Grounding Switches

Automatic high-speed grounding switches are applied for protection of power transformers when the cost of supplying other protective equipment is deemed unjustifiable and the amount of system disturbance that the high-speed grounding switch creates is judged acceptable. The switches are generally actuated by discharging a spring mechanism to provide the "high-speed" operation. The grounding switch operates to provide a deliberate ground fault on one phase of the high-voltage bus supplying the power transformer, disrupting the normally balanced 120° phase shifted three-phase system by effectively removing one phase and causing the other two phases to become 180° phase shifted relative to each other. This system imbalance is remotely detected by protective relaying equipment that operates the transmission line breakers at the remote end of the line supplying the power transformer, tripping the circuit open to clear the fault. This scheme also imposes a voltage interruption to all other loads connected between the remote circuit breakers and the power transformer as well as a transient spike to the protected power transformer, effectively shortening the transformer's useful life. Frequently, a system utilizing a high-speed ground switch also includes the use of a motor operated disconnect switch and a relay system to sense bus voltage. The relay system's logic allows operation of the motor operated disconnect switch when there is no voltage on the transmission line to provide automatic isolation of the faulted power transformer and to allow reclosing operations of the remote breakers to restore service to the transmission line and to all other loads fed by this line.

The grounding switch scheme is dependent on the ability of the source transmission line relay protection scheme to recognize and clear the fault by opening the remote circuit breaker. Clearing times are necessarily longer since the fault levels are not normally within the levels appropriate for an instantaneous trip response. The lengthening of the trip time also imposes additional stress on the equipment being protected and should be considered when selecting this method for power transformer protection. High-speed grounding switches are usually considered when relative fault levels are low so that the risk of significant damage to the power transformer due to the extended trip times is mitigated.

4.6 Power Fuses

Power fuses are a generally accepted means of protecting small power transformers (i.e., power transformers of 15 MVA and smaller (see Fig. 4.30), capacitor banks, potential transformers and/or

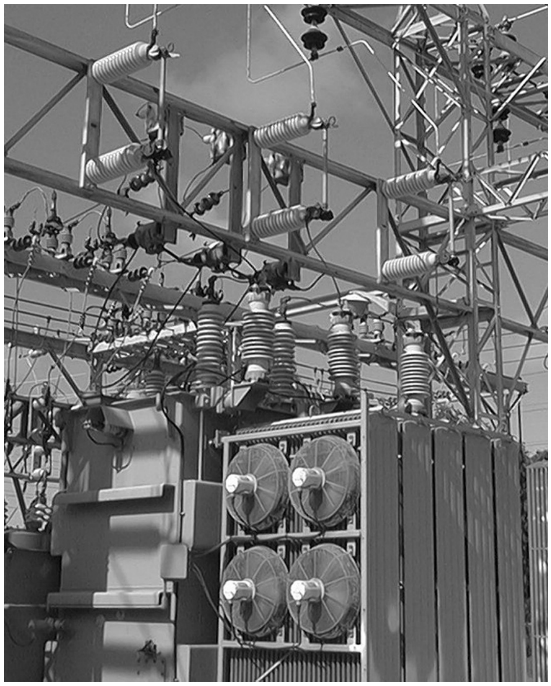

FIGURE 4.30 Power fuses protecting a power transformer.

station service transformers. The primary purpose of a power fuse is to provide interruption of permanent faults. Power fuses are an economical alternative to circuit switcher or circuit breaker protection. Fuse protection is generally limited to voltages from 15 to 69 kV, but has been applied for protection of equipment as large as 161 kV.

To provide the greatest protective margin, it is necessary to use the smallest fuse rating possible. The advantage of close fusing is the ability of the fuse unit to provide backup protection for some secondary faults. For the common delta-wye connected transformer, a fusing ratio of 1.0 would provide backup protection for a phase-to-ground fault as low as 230% of the secondary full-load rating. Fusing ratio is defined as the ratio of the fuse rating to the transformer full-load current rating. With low fusing ratios, the fuse may also provide backup protection for line-to-ground faults remote to the substation on the distribution, subtransmission, or transmission network.

Fuse ratings also must consider other parameters than the full-load current of the transformer being protected. Coordination with other overcurrent devices, accommodation of peak overloadings, and severe duty may require increased ratings of the fuse unit. The general purpose of the power transformer fuse is to accommodate, not interrupt, peak loads. Fuse ratings must consider the possibility of nuisance trips if the rating is selected too low for all possible operating conditions.

The concern of unbalanced voltages in a three-phase system must be considered when selecting fusing. The possibility of one or two fuses blowing must be reviewed. Unbalanced voltages can cause tank heating in three-phase power transformers and overheating and damage to three-phase motor loads. The potential for ferroresonance must be considered for some transformer configurations when using fusing.

Fuses are available in a number of time-to-melt and time-to-clear curves (standard, fast, medium, slow, and very slow) to provide coordination with other system protective equipment. Fuses are not voltage critical; they may be applied at any voltage equal to or less than their rated voltage. Fuses may not require additional structures, as they are generally mounted on the incoming line structure (see Fig. 4.31)

FIGURE 4.31 Incoming line structure mounted power fuses.

and result in space savings in the substation layout. Power fuses are available in four mounting configurations—vertical, underhung, 45° underhung, and horizontal upright—with the vast majority of all power fuse installations being vertically mounted units (see Fig. 4.32).

FIGURE 4.32 Vertically mounted power fuses.

4.7 Circuit Switchers

Circuit switchers have been developed to overcome some of the limitations of fusing for substation power transformers. Circuit switchers have SF_6 gas interrupters and are designed to provide three-phase interruption (solving the unbalanced voltage considerations) and to provide protection for transient overvoltages and overloads at a competitive cost between the costs of power fuses and circuit breakers. Additionally they can provide protection from power transformer faults based on differential, sudden pressure, and overcurrent relay schemes as well as critical operating constraints such as for low oil level, high oil or winding temperature, pressure relief device operation, etc.

The earliest circuit switchers were designed and supplied as a combination of a circuit breaking interrupter and an in-series isolating disconnect switch. These earliest models (see Fig. 4.33) had multiple interrupter gaps per phase on above 69 kV interrupters and grading resistors, thus the necessity for the in-series disconnect switch. Later models have been designed with improved interrupters that have reduced the number of gaps required for successful performance to a single gap per phase, thus eliminating the necessity of the disconnect switch blade in series with the interrupter. Circuit switchers are now available in vertical interrupter design (see Fig. 4.34) or horizontal interrupter design configurations with (see Fig. 4.35) or without (see Fig. 4.36) an integral disconnect switch. The earliest circuit switchers had a 4 kA symmetrical primary fault current interrupting capability, but subsequent design improvements over the years have produced circuit switchers capable of 8, 10, 12, 16, 20, 25, 31.5, and 40 kA symmetrical primary fault current interrupting, with the highest of these interrupting values being on par with circuit breaker capabilities. The interrupting speeds of circuit switchers have also been improved from their initial 8 cycle interrupting time to 6 to 5 to 3 cycles, with the 3 cycle offering the

FIGURE 4.33 Multiple interrupter gap per phase circuit switcher.

FIGURE 4.34 Vertical interrupter circuit switcher without integral disconnect switch.

same speed as the most commonly available circuit breaker interrupting time. Different model types, configurations, and vintages have different interrupting ratings and interrupting speeds. Circuit switchers have been developed and furnished for applications involving protection of power transformers, lines, cables, capacitor banks, and line connected or tertiary connected shunt reactors. Circuit switchers can also be employed in specialty applications such as series capacitor bypassing and for load/line/loop interrupting applications where fault-closing capability is required (as fault-closing capability is not a feature inherent in disconnect switch mounted load/line/loop interrupters or in the disconnect switches these interrupters are mounted on).

4.8 Circuit Breakers

A circuit breaker is defined as “a mechanical switching device capable of making, carrying, and breaking currents under normal circuit conditions and also making, carrying, and breaking for a specified time, and breaking currents under specified abnormal conditions such as a short circuit” (IEEE Standard C.37.100-1992.).

Circuit breakers are generally classified according to the interrupting medium used to cool and elongate the electrical arc permitting interruption. The types of circuit breakers are

- Air magnetic
- Vacuum (see Fig. 4.37)
- Air blast

FIGURE 4.35 Horizontal interrupter circuit switcher with integral vertical break disconnect switch.

- Oil (bulk oil [see Figs. 4.38 and 4.39] and minimum oil)
- SF_6 gas (see Figs. 4.40 and 4.41)

Air magnetic circuit breakers are limited to older switchgear and have generally been replaced by vacuum or SF_6 gas for switchgear applications. Vacuum is used for switchgear applications and for some outdoor breakers, generally 38 kV class and below.

Air blast breakers, used for EHVs ($\geq$345 kV), are no longer manufactured and have been replaced by breakers using SF_6 technology.

Oil circuit breakers have been widely used in the utility industry in the past but have been replaced by other breaker technologies for newer installations. Two designs exist: bulk oil (dead tank) designs dominant in the U.S., and minimum oil (live tank) designs prevalent in some other parts of the world. Bulk oil circuit breakers were designed as single tank (see Fig. 4.38) or three tank (see Fig. 4.39) devices, with 69 kV and below ratings available in either single tank or three tank configurations and 115 kV and above ratings being three tank designs. Oil circuit breakers were large and required significant foundations to support the weight and impact loads occurring during operation. Environmental concerns and regulations forced the necessity of oil containment pools; whereas the ongoing maintenance costs of the oil circuit breakers coupled with the development and widespread use of the SF_6 gas circuit breakers have led to the selection of the SF_6 gas circuit breaker in lieu of the oil circuit breaker for new installations and the retiring from service of old oil circuit breakers in favor of SF_6 gas circuit breakers in many existing installations.

FIGURE 4.36 Horizontal interrupter circuit switcher without integral disconnect switch.

Oil circuit breaker development had been relatively static for many years. The design of the interrupter employs the arc caused when the contacts are parted and the breaker starts to operate. The electrical arc generates hydrogen gas due to the decomposition of the insulating mineral oil. The interrupter is designed to use the gas as a cooling mechanism to cool the arc and also to use the pressure to elongate the arc through a grid (arc chutes) allowing extinguishing of the arc when the current passes through zero.

Vacuum circuit breakers use an interrupter that is a small cylinder enclosing the moving contacts under a hard vacuum. When the contacts part, an arc is formed from contact erosion. The arc products are immediately forced to and deposited on a metallic shield surrounding the contacts. Without anything to sustain the arc, it is quickly extinguished.

Vacuum circuit breakers are widely employed for metal clad switchgear up to 38 kV class. The small size of the vacuum breaker allows vertically stacked installations of vacuum breakers in a two-high configuration within one vertical section of switchgear, permitting significant savings in space and material compared to earlier designs employing air magnetic technology. When used in outdoor circuit breaker designs, the vacuum cylinder is housed in a metal cabinet or oil filled tank for dead tank construction popular in the U.S. market.

FIGURE 4.37 Vacuum circuit breaker.

FIGURE 4.38 Single tank bulk oil circuit breaker.

Gas circuit breakers employ SF_6 as an interrupting and insulating medium. In "single puffer" mechanisms the interrupter is designed to compress the gas during the opening stroke and use the compressed gas as a transfer mechanism to cool the arc and also use the pressure to elongate the arc through a grid (arc chutes), allowing extinguishing of the arc when the current passes through zero. In other designs the arc heats the SF_6 gas and the resulting pressure is used for elongating and interrupting the arc. Some older dual pressure SF_6 breakers employed a pump to provide the high-pressure SF_6 gas for arc interruption.

Gas circuit breakers typically operate at pressures between 6 and 7 atm. The dielectric strength and interrupting performance of SF_6 gas reduce significantly at lower pressures, normally as a result of lower ambient temperatures. For cold temperature applications (ambient temperatures as cold as $-40°C$) dead tank gas circuit breakers are commonly supplied with tank heaters to keep the gas in vapor form rather than allowing it to liquefy, as liquefied SF_6 significantly derates the breaker's capability. For

FIGURE 4.39 Three tank bulk oil circuit breaker.

extreme cold temperature applications (ambient temperatures between −40°C and −50°C) the SF_6 gas is typically mixed with another gas, either nitrogen (N_2) or carbon tetrafluoride (CF_4), to prevent liquefaction of the SF_6 gas. The selection of which gas to mix with the SF_6 is based upon a given site's defining critical criteria, either dielectric strength or interrupting rating. An SF_6–N_2 mixture derates the interrupting capability of the breaker but maintains most of the dielectric strength of the device, whereas an SF_6–CF_4 mixture derates the dielectric strength of the breaker but maintains most of the interrupting rating of the device. Unfortunately, for extreme cold temperature applications of gas circuit breakers there is no gas or gas mixture that maintains both full dielectric strength and full interrupting rating performance. For any temperature application, monitoring the density of the SF_6 gas is critical to the proper and reliable performance of gas circuit breakers. Most dead tank SF_6 gas circuit breakers have a density switch and a two-stage alarm system. Stage one (commonly known as the alarm stage) sends a signal to a remote monitoring location that the gas circuit breaker is experiencing a gas leak, while stage two sends a signal that the gas leak has caused the breaker to reach a gas level that can no longer assure proper operation of the breaker in the event of a fault current condition that must be cleared. Once the breaker reaches stage two (commonly known as the lockout stage), the breaker will either trip open and block any reclosing signal until the low-pressure condition is resolved or will block trip in the closed position and remain closed, ignoring any signal to trip, until the low-pressure condition is resolved. The selection of which of these two options, trip and block close or block trip, is desired is specified by the user and is preset by the breaker manufacturer.

Circuit breakers are available as live tank, dead tank, or grounded tank designs. Dead tank means interruption takes place in a grounded enclosure and current transformers are located on both sides of the break (interrupter contacts). Interrupter maintenance is at ground level and seismic withstand is improved versus live tank designs. Bushings (more accurately described as gas-filled weathersheds, because, unlike the condenser bushings found on bulk oil circuit breakers, gas breakers do not have true bushings) are used for line and load connections that permit installation of bushing current

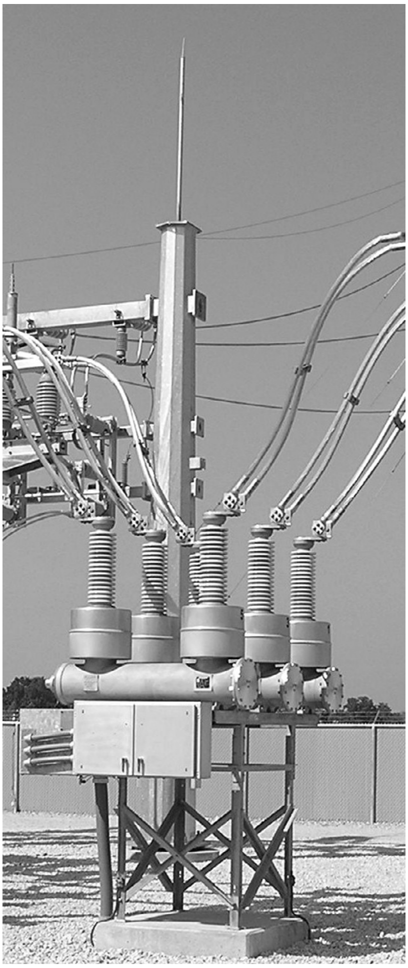

FIGURE 4.40 SF_6 gas dead tank circuit breaker.

FIGURE 4.41 SF_6 gas dead tank circuit breaker.

transformers for relaying and metering at a nominal cost. The dead tank breaker does require additional insulating oil or gas (i.e., more insulating oil or gas than just the amount required to perform successful interruption and to maintain adequate dielectric strength) to provide the insulation between the interrupter and the grounded tank enclosure.

Live tank means interruption takes place in an enclosure that is at line potential. Live tank circuit breakers consist of an interrupter chamber that is mounted on insulators and is at line potential. This approach allows a modular design as interrupters can be connected in series to operate at higher voltage levels. Operation of the contacts is usually through an insulated operating rod or rotation of a porcelain insulator assembly via an operating mechanism at ground level. This design minimizes the quantity of oil or gas required as no additional quantity is required for insulation of a grounded tank enclosure. The live tank design also readily adapts to the addition of pre-insertion resistors or grading capacitors when they are required. Seismic capability requires special consideration due to the high center of gravity of the live tank breaker design, and live tank circuit breakers require separate, structure mounted, free standing current transformers.

Grounded tank means interruption takes place in an enclosure that is partially at line potential and partially at ground potential. Although the grounded tank breaker's current transformers are on the same side of the break (interrupter contacts) the grounded tank breaker relays just like a dead tank breaker. The grounded tank breaker design came about as a result of the installation of a live tank breaker interrupter into a dead tank breaker configuration.

Interrupting times are usually quoted in cycles and are defined as the maximum possible delay between energizing the trip circuit at rated control voltage and the interruption of the circuit by the main contacts of all three poles. This applies to all currents from 25 to 100% of the rated short-circuit current.

Circuit breaker ratings must be examined closely. Voltage and interrupting ratings are stated at a maximum operating voltage rating, i.e., 38 kV rating for a breaker applied on a nominal 34.5 kV circuit. The breakers have an operating range designated as K factor per IEEE C37.06, Table 3 in the appendix. For a 72.5 kV breaker, the voltage range is 1.21 meaning that the breaker is capable of its full interrupting rating down to a voltage of 60 kV.

Breaker ratings need to be checked for some specific applications. Applications requiring reclosing operation should be reviewed to be sure that the duty cycle of the circuit breaker is not being exceeded. Some applications for out of phase switching or back-to-back switching of capacitor banks also require review and may require specific duty/special purpose/definite purpose circuit breakers to ensure proper operation during fault interruption.

5

High-Voltage Power Electronic Substations

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The preceding sections on gas-insulated substations (GIS), air-insulated substations (AIS), and high-voltage switching equipment apply in principle also to the AC circuits in high-voltage power electronic substations. This section focuses on the specifics of power electronics as applied in substations for power transmission purposes.

The dramatic development of power electronics in the past decades has led to significant progress in electric power transmission technology, resulting in special types of transmission systems, which require special kinds of substations. The most important high-voltage power electronic substations are converter stations, above all for high-voltage direct current (HVDC) transmission systems, and controllers for flexible AC transmission systems (FACTS).

High-voltage power electronic substations consist essentially of the main power electronic equipment, i.e., converter valves and FACTS controllers with their dedicated cooling systems. Furthermore, in addition to the familiar components of conventional substations covered in the preceding sections, there are also converter transformers and reactive power compensation equipment, including harmonic filters, buildings, and auxiliaries.

Most high-voltage power electronic substations are air insulated, although some use combinations of air and gas insulation. Typically, passive harmonic filters and reactive power compensation equipment are air insulated and outdoors, whereas power electronic equipment (converter valves, FACTS controllers), control and protection electronics, active filters, and most communication and auxiliary systems are air insulated, but indoors.

Basic community considerations, grounding, lightning protection, seismic protection, and general fire protection requirements apply as with other substations. In addition, high-voltage power electronic substations may emit electric and acoustic noise and therefore require special shielding. Extra fire-protection is applied as a special precaution because of the high power density in the electronic circuits, although the individual components of today are mostly nonflammable and the materials used for insulation or barriers within the power electronic equipment are flame retardant.

International technical societies like IEEE, IEC, and CIGRE continue to develop technical standards, disseminate information, maintain statistics, and facilitate the exchange of know-how in this high-tech power engineering field. Within the IEEE, the group that deals with high-voltage power electronic substations is the IEEE Power Engineering Society (PES) Substations Committee, High Voltage Power Electronics Stations Subcommittee. On the Internet, it can be reached through the IEEE site (www.ieee.org).

5.1 Converter Stations (HVDC)

Power converters make possible the exchange of power between systems with different constant or variable frequencies. The most common converter stations are AC–DC converters for HVDC transmission. HVDC offers frequency- and phase-independent short- or long-distance overhead or underground bulk power transmission with fast controllability. Two basic types of HVDC converter stations exist: back-to-back AC–DC–AC converter stations and long-distance DC transmission terminal stations.

Back-to-back converters are used to transmit power between nonsynchronous AC systems. Such connections exist, for example, between the western and eastern grids of North America, with the ERCOT system of Texas, with the grid of Quebec, and between the 50-Hz and 60-Hz grids in South America and Japan. With these back-to-back HVDC converters, the DC voltage and current ratings are chosen to yield optimum converter costs. This aspect results in relatively low DC voltages, up to about 200 kV, at power ratings up to several hundred megawatts. Figure 5.1 shows the schematic diagram of an HVDC back-to-back converter station with a DC smoothing reactor and reactive power compensation elements (including AC harmonic filters) on both AC buses. The term back-to-back indicates that rectifier (AC to DC) and inverter (DC to AC) are located in the same station.

Long-distance DC transmission terminal stations terminate DC overhead lines or cables and link them to AC buses and systems. Their converter voltages are governed by transmission efficiency considerations and can exceed 1 million V ($\pm$500 kV) with power ratings up to several thousands of megawatts. Typically, in large HVDC terminals, the two poles of a bipolar system can be operated independently, so that in case of component or equipment failures on one pole, power transmission with a part of the total rating can still be maintained. Figure 5.2 shows the schematic diagram of one such bipolar HVDC sea cable link with two 250-MW converter poles and 250-kV DC cables.

Most HVDC converters of today are line-commutated 12-pulse converters. Figure 5.3 shows a typical 12-pulse bridge circuit using delta and wye transformer windings, which eliminate some of the harmonics typical for a 6-pulse Graetz bridge converter. The harmonic currents remaining are absorbed by adequately designed AC harmonic filters that prevent these currents from entering the power systems.

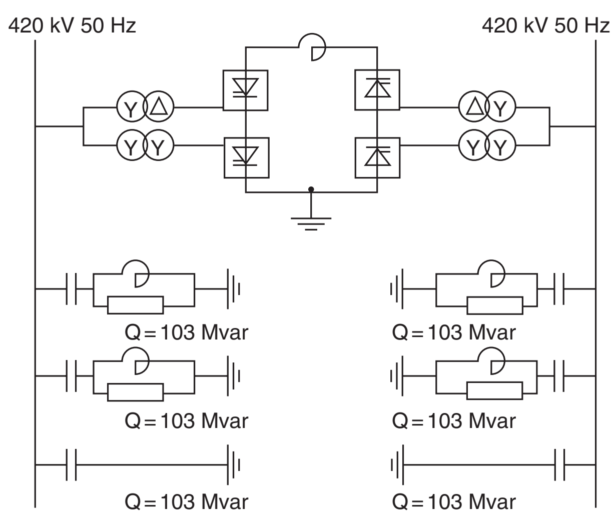

FIGURE 5.1 Schematic diagram of an HVDC back-to-back converter station, rated 600 MW.

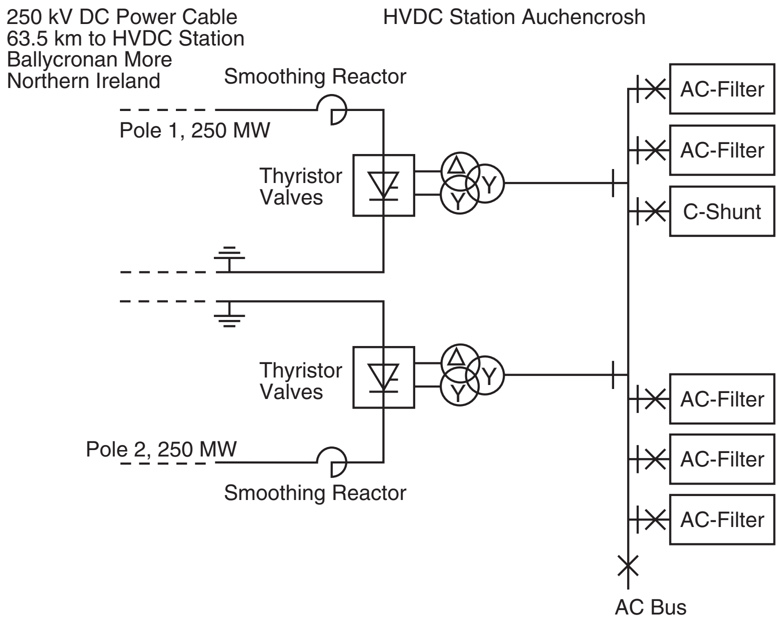

FIGURE 5.2 Schematic diagram of the Auchencrosh terminal station of the Scotland-Ireland HVDC cable transmission.

At the same time, these AC filters meet most or all of the reactive power demand of the converters. Converter stations connected to DC lines often need DC harmonic filters as well. Traditionally, passive filters have been used, consisting of passive components like capacitors, reactors, and resistors. More recently, because of their superior performance, active (electronic) AC and DC harmonic filters [1–5]—as a supplement to passive filters—using insulated gate bipolar transistors (IGBTs) have been successfully implemented in some HVDC projects. IGBTs have also led to the recent development of self-commutated converters, also called voltage-sourced converters [6–8]. They do not need reactive power from the grid and require less harmonic filtering.

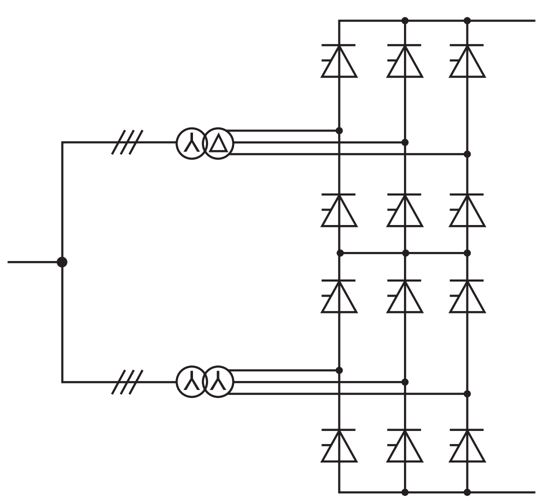

FIGURE 5.3 Transformers and valves in a 12-pulse converter bridge.

The AC system or systems to which a converter station is connected significantly impact its design in many ways. This is true for harmonic filters, reactive power compensation devices, fault duties, and insulation coordination. Weak AC systems (i.e., with low short-circuit ratios) represent special challenges for the design of HVDC converters [9]. Some stations include temporary overvoltage limiting devices consisting of MOV (metal oxide varistors) arresters with forced cooling for permanent connection, or using fast insertion switches [10].

HVDC systems, long-distance transmissions in particular, require extensive voltage insulation coordination, which cannot be limited to the converter stations themselves. It is necessary to consider the configuration, parameters, and behavior of the AC grids on both sides of the HVDC, as well as the DC line connecting the two stations. Internal insulation of equipment such as transformers and bushings must take into account the voltage gradient distribution in solid and mixed dielectrics. The main insulation of a converter transformer has to withstand combined AC and DC voltage stresses. Substation clearances and creepage distances must be adequate. Standards for indoor and outdoor clearances and creepage distances are being promulgated [11]. DC electric fields are static in nature, thus enhancing the pollution of exposed surfaces. This pollution, particularly in combination with water, can adversely influence the voltage-withstand capability and voltage distribution of the insulating surfaces. In converter stations, therefore, it is often necessary to engage in adequate cleaning practices of the insulators and bushings, to apply protective greases, and to protect them with booster sheds. Insulation problems with extra-high-voltage DC bushings continue to be a matter of concern and study [12,13].

A specific issue with long-distance DC transmission is the use of ground return. Used during contingencies, ground (and sea) return can increase the economy and availability of HVDC transmission. The necessary electrodes are usually located at some distance from the station, with a neutral line leading to them. The related neutral bus, switching devices, and protection systems form part of the station. Electrode design depends on the soil or water conditions [14,15]. The National Electric Safety Code (NESC) does not allow the use of earth as a permanent return conductor. Monopolar HVDC operation in ground-return mode is permitted only under emergencies and for a limited time. Also environmental issues are often raised in connection with HVDC submarine cables using sea water as a return path. This has led to the recent concept of metallic return path provided by a separate low-voltage cable. The IEEE-PES is working to introduce changes to the NESC to better meet the needs of HVDC transmission while addressing potential side effects to other systems.

Mechanical switching devices on the DC side of a typical bipolar long-distance converter station comprise metallic return transfer breakers (MRTB) and ground return transfer switches (GRTS). No true DC breakers exist, and DC fault currents are best and most swiftly interrupted by the converters themselves. MRTBs with limited DC current interrupting capability have been developed [16]. They include commutation circuits, i.e., parallel reactor/capacitor (L/C) resonance circuits that create artificial current zeroes across the breaker contacts. The conventional grid-connecting equipment in the AC switchyard of a converter station is covered in the preceding sections. In addition, reactive power compensation and harmonic filter equipment are connected to the AC buses of the converter station. Circuit breakers used for switching these shunt capacitors and filters must be specially designed for capacitive switching. A back-to-back converter station does not need any mechanical DC switching device.

Figures 5.4 through 5.7 show photos of different converter stations. The back-to-back station shown in Fig. 5.4 is one of several asynchronous links between the western and eastern North American power grids. The photo shows the control building (next to the communication tower), the valve hall attached to it, the converter transformers on both sides, the AC filter circuits (near the centerline), and the AC buses (at the outer left and right) with the major reactive power compensation and temporary overvoltage (TOV) suppression equipment that was used in this low-short-circuit-ratio installation. The valve groups shown in Fig. 5.5 are arranged back to back, i.e., across the aisle in the same room.

Figure 5.6 shows the valve hall of a ±500-kV long-distance transmission system, with valves suspended from the ceiling for better seismic-withstand capability. The converter station shown in Fig. 5.7 is the south terminal of the Nelson River ±500-kV HVDC transmission system in Manitoba,

FIGURE 5.4 A 200 MW HVDC back-to-back converter station at Sidney, Nebraska. (Photo courtesy of Siemens.)

Canada. It consists of two bipoles commissioned in stages from 1973 to 1985. The DC yard and line connections can be seen on the left side of the picture, while the 230-kV AC yard with harmonic filters and converter transformers is on the right side. In total, the station is rated at 3854 MW.

5.2 FACTS Controllers

The acronym FACTS stands for flexible AC transmission systems. These systems add some of the virtues of DC, i.e., phase independence and fast controllability, to AC transmission by means of electronic controllers. Such controllers can be shunt or series connected or both. They represent variable reactances or AC voltage sources. They can provide load flow control and, by virtue of their fast controllability, damping of power swings or prevention of subsynchronous resonance (SSR).

Typical ratings of FACTS controllers range from about 30 to several hundred MVAr. Normally they are integrated in AC substations. Like HVDC converters, they require controls, cooling systems, harmonic filters, transformers, and related civil works.

Static VAr compensators (SVC) are the most common shunt-connected controllers. They are, in effect, variable reactances. SVCs have been used successfully for many years, either for load (flicker) compensation of large industrial loads (e.g., arc furnaces) or for transmission compensation in utility systems. Figure 5.8 shows a schematic one-line diagram of an SVC, with one thyristor-controlled reactor, two thyristor-switched capacitors, and one harmonic filter. The thyristor controller and switches provide fast control of the overall SVC reactance between its capacitive and inductive design limits. Due to the network impedance, this capability translates into dynamic bus voltage control. As a consequence, the SVC can improve transmission stability and increase power transmission limits across a given path. Harmonic filter and capacitor banks, reactors (normally air core), step-down transformers, breakers and disconnect switches on the high-voltage side, as well as heavy-duty buswork on the medium-voltage side, characterize most SVC stations. A building or an e-house with medium-voltage wall bushings contains the power electronic (thyristor) controllers. The related cooler is usually located nearby.

A new type of controlled shunt compensator, a static compensator called STATCOM, uses voltage-sourced converters with high-power gate-turn-off thyristors (GTO), or IGBT [17,18]. Figure 5.9 shows the related one-line diagram. STATCOM is the electronic equivalent of the classical (rotating)

FIGURE 5.5 600 MW HVDC back-to-back converter valves. (Photo courtesy of Siemens.)

synchronous condenser, and one application of STATCOM is the replacement of old synchronous condensers. The need for high control speed and low maintenance can support this choice. Where the STATCOM's lack of inertia is a problem, it can be overcome by a sufficiently large DC capacitor. STATCOM requires fewer harmonic filters and capacitors than an SVC, and no reactors at all. This makes the footprint of a STATCOM station significantly more compact than that of the more conventional SVC.

Like the classical fixed series capacitors (SC), thyristor-controlled series capacitors (TCSC) [19,20] are normally located on insulated platforms, one per phase, at phase potential. Whereas the fixed SC compensates a fixed portion of the line inductance, TCSC's effective capacitance and compensation level can be varied statically and dynamically. The variability is accomplished by a thyristor-controlled reactor connected in parallel with the main capacitor. This circuit and the related main protection and switching components are shown in Fig. 5.10. The thyristors are located in weatherproof housings on the platforms. Communication links exist between the platforms and ground. Liquid cooling is provided through ground-to-platform pipes made of insulating material. Auxiliary platform power, where

FIGURE 5.6 Valve hall of a ± 500 kV, 1200 MW long-distance HVDC converter station. (Photo courtesy of Siemens.)

needed, is extracted from the line current via current transformers (CTs). Like most conventional SCs, TCSCs are typically integrated into existing substations. Upgrading an existing SC to TCSC is generally possible. A new development in series compensation is the thyristor-protected series compensator (TPSC). The circuit is basically the same as for TCSC, but without any controllable reactor and forced

FIGURE 5.7 Dorsey terminal of the Nelson River HVDC transmission system. (Photo courtesy of Manitoba Hydro.)

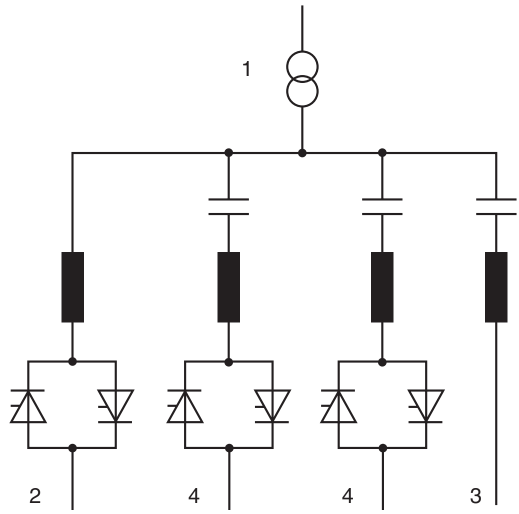

FIGURE 5.8 One-line diagram of a Static VAr compensator (SVC). 1, Transformer; 2, thyristor-controlled reactor (TCR); 3, fixed connected capacitor/filter bank; 4, thyristor-switched capacitor (TSC) bank.

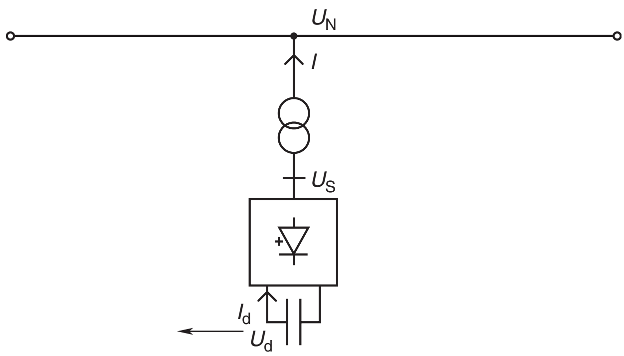

FIGURE 5.9 One-line diagram of a voltage sourced static compensator (STATCOM).

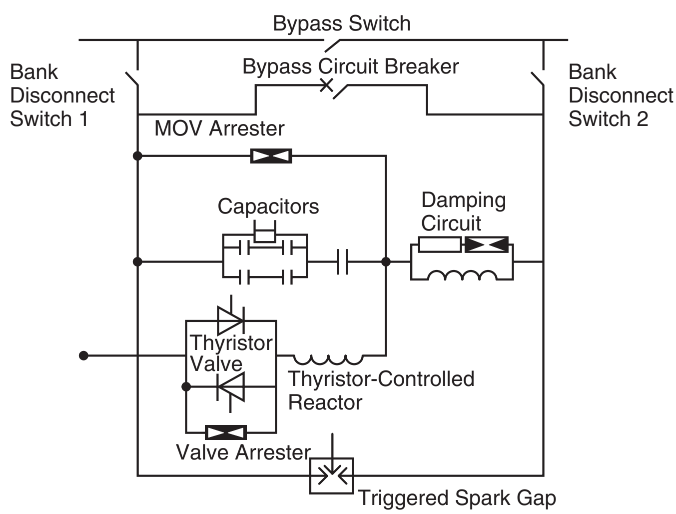

FIGURE 5.10 Schematic diagram of one phase of the Serra da Mesa (Brazil) thyristor-controlled series capacitors (TCSC).

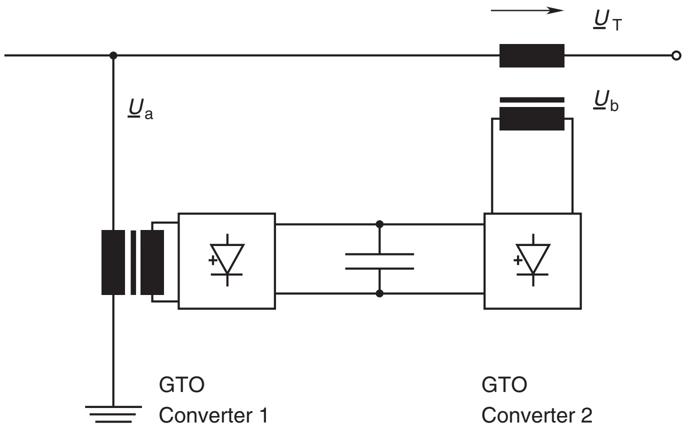

FIGURE 5.11 One-line diagram of a unified power flow controller (UPFC).

thyristor cooling. The thyristors of a TPSC are used only as a bypass switch to protect the capacitors against overvoltage, thereby avoiding large MOV arrester banks with relatively long cool-off intervals.

While SVC and STATCOM controllers are shunt devices, and TCSCs are series devices, the so-called unified power flow controller (UPFC) is a combination of both [21]. Figure 5.11 shows the basic circuit. The UPFC uses a shunt-connected transformer and a transformer with series-connected line windings, both interconnected to a DC capacitor via related voltage-source-converter circuitry within the control building. A more recent FACTS station project [22–24] involves similar shunt and series elements as the UPFC, and this can be reconfigured to meet changing system requirements. This configuration is called a convertible static compensator (CSC).

The ease with which FACTS stations can be reconfigured or even relocated is an important factor and can influence the substation design [25,26]. Changes in generation and load patterns can make such flexibility desirable.

Figures 5.12 through 5.17 show photos of FACTS substations. Figure 5.12 shows a 500-kV AC feeder (on the left side), the transformers (three single-phase units plus one spare), the medium-voltage bus,

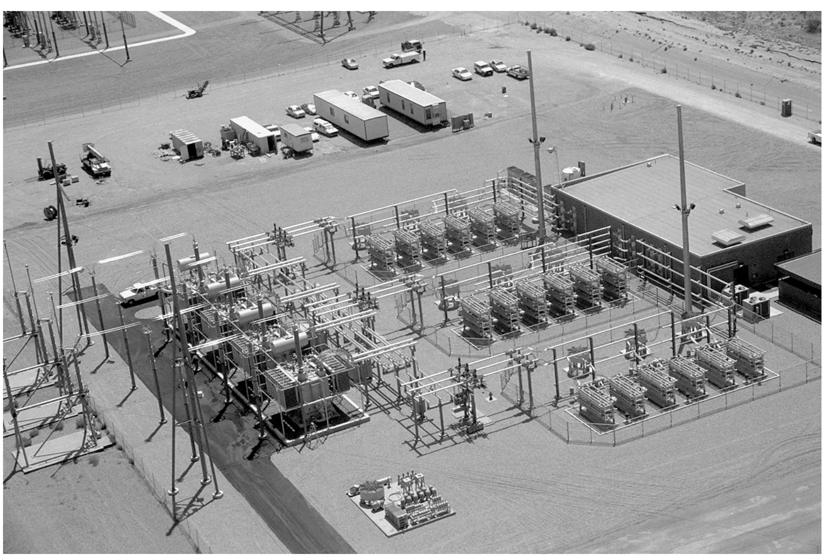

FIGURE 5.12 500 kV, 400 MVAr SVC at Adelanto, California. (Photo courtesy of Siemens.)

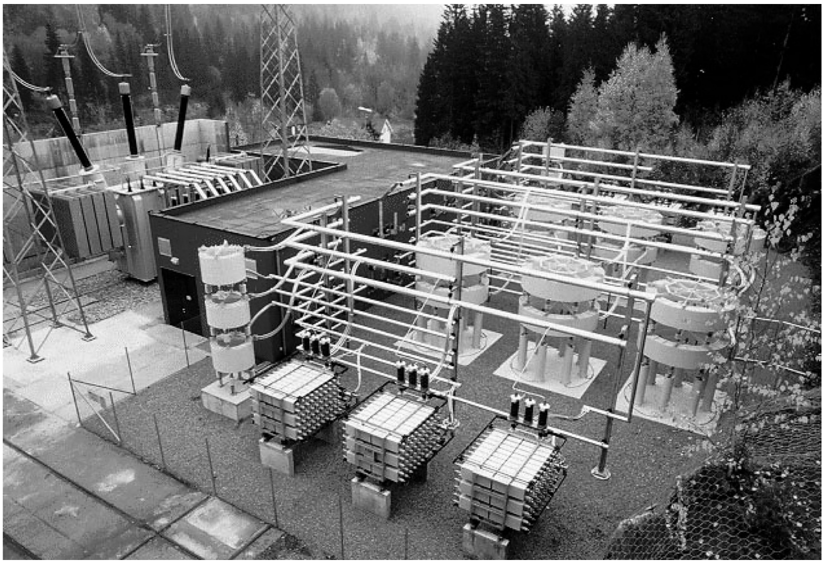

FIGURE 5.13 420 kV, ±160 MVAr SVC at Sylling, Norway. (Photo courtesy of ABB.)

and three thyristor-switched capacitor (TSC) banks, as well as the building that houses the thyristor switches and controls.

The SVC shown in Fig. 5.13 is connected to the 420-kV Norwegian AC grid southwest of Oslo. It uses thyristor-controlled reactors (TCR) and TSCs, two each, which are visible together with the 9.3-kV high-current buswork on the right side of the building. Figures 5.14 and 5.15 show photos of two 500-kV TCSC installations in the U.S. and Brazil, respectively. In both, the platform-mounted valve housings are clearly visible. Slatt (U.S.) has six equal TCSC modules per phase, with two valves combined in each of the three housings per bank. At Serra da Mesa (Brazil), each platform has one single valve housing.

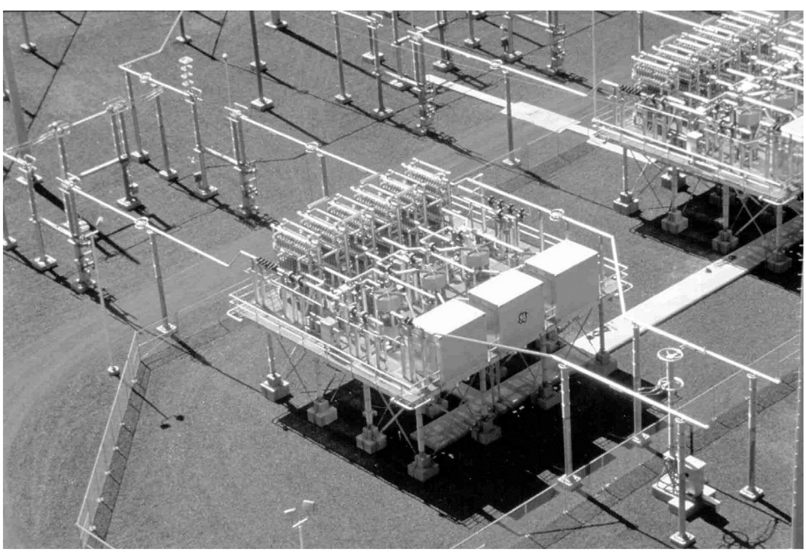

FIGURE 5.14 Aerial view of BPA's Slatt, Oregono, 500 kV TCSC. (Photo courtesy of GE.)

FIGURE 5.15 TCSC Serra da Mesa, FURNAS, Brazil, 500 kV, 107 MVAr, $(1 \ldots 3) \times 13.17$ W. (Photo courtesy of Siemens.)

Figure 5.16 shows an SVC being relocated. The controls and valves are in container-like housings, which allow for faster relocation. Figure 5.17 shows the world's first UPFC, connected to AEP's Inez substation in eastern Kentucky. The main components are identified and clearly recognizable. Figure 5.18 depicts a CSC system at the 345-kV Marcy substation in New York state.

FIGURE 5.16 Static VAr compensator is relocated where the system needs it. (Photo courtesy of ALSTOM T&D Power Electronic Systems.)

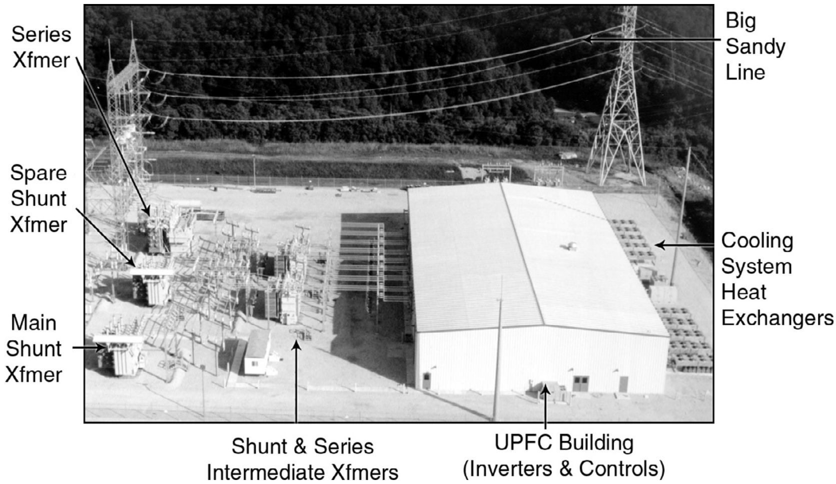

FIGURE 5.17 UPFC at Inez substation. (Photo courtesy of American Electric Power.)

5.3 Control and Protection System

Today's state-of-the-art HVDC and FACTS controls—fully digitized and processor-based—allow steady-state, quasi steady-state, dynamic, and transient control actions and provide important equipment and system protection functions. Fault monitoring and sequence-of-event recording devices are used in most power electronics stations. Typically, these stations are remotely controlled and offer full local controllability as well. Man–machine interfaces are highly computerized, with extensive

FIGURE 5.18 Convertible static compensator (CSC) at NYPA's 345 kV Marcy, New York substation. (Photo courtesy of New York Power Authority.)

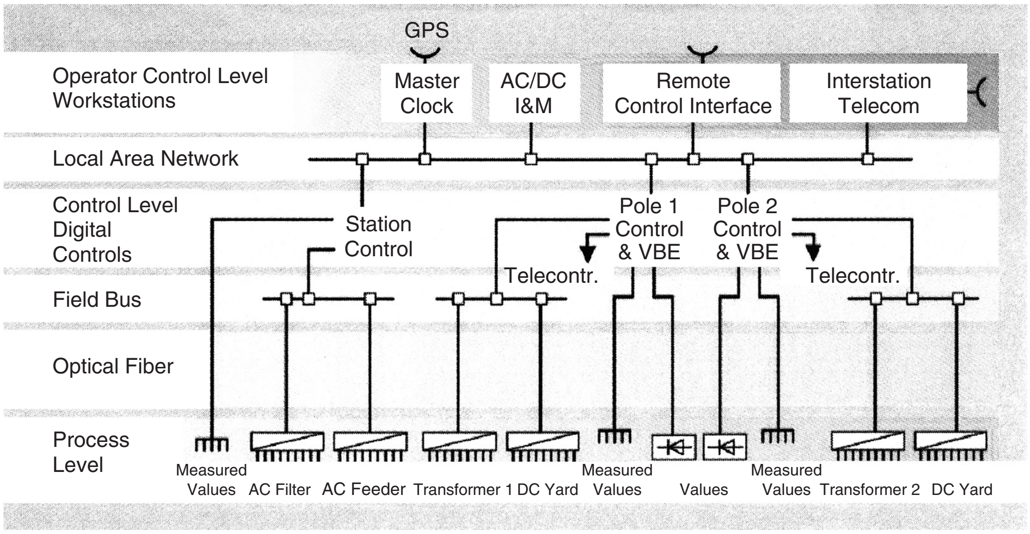

FIGURE 5.19 HVDC control hierarchy, one station.

supervision and control via monitor and keyboard. All of these functions exist in addition to the basic substation secondary systems described in Chapters 6 and 7.

HVDC control and protection algorithms are usually rather complex. Real power, reactive power, AC bus frequency and voltage, startup and shutdown sequences, contingency and fault-recovery sequences, remedial action schemes, modulation schemes for system oscillation and SSR damping, and loss of communication are some of the significant control parameters and conditions. Fast dynamic performance is standard. Special voltage vs. current (v/i) control characteristics are used for converters in multiterminal HVDC systems to allow safe operation even under loss of interstation communication. Furthermore, HVDC controls provide equipment and system protection, including thyristor overcurrent, thyristor overheating, and DC line fault protection. Control and protection reliability are enhanced through redundant and fault-tolerant design. HVDC stations can often be operated from different control centers.

Figure 5.19 illustrates the basic control levels and hierarchy used in one terminal of a bipolar HVDC long-distance transmission scheme. Valve control at process level is based on phase-angle control, i.e., gating of thyristors (or other semiconductors) precisely timed with respect to the related AC phase voltages. The phase angles determine the converter DC voltages and, per Ohm's law, DC currents and load flow.

Figure 5.20 shows the local control interface of a back-to-back HVDC converter station used for power transmission between nonsynchronous grids. Figure 5.21 shows a photo taken during the functional testing of the control and protection hardware against a real-time simulator for a major long-distance HVDC scheme. Figure 5.22 shows a typical control monitor screen layout displaying a bipolar HVDC system overview.

The protection zones of one pole of an HVDC converter station are shown in Fig. 5.23. Each protection zone is covered by at least two independent protective units—the primary protective unit and the secondary (backup) protective unit. Protection systems are separated from the control software and hardware. Some control actions are initiated by the protection scheme via signals to the control system.

The control and protection schemes of FACTS stations are tailored to the related circuits and tasks. Industrial SVCs have open-loop, direct, load-compensation control. In transmission systems, FACTS controllers are designed to provide closed-loop steady-state and dynamic control of reactive power and bus voltage, as well as some degree of load flow control, with modulation loops for stability and SSR mitigation. In addition, the controls include equipment and system protection functions.

FIGURE 5.20 Local control desk of a 600 MW back-to-back converter station. (Photo courtesy of Siemens.)

With SVC and TCSC, the phase-angle control determines the effective shunt and series reactance, respectively. This fast reactance control, in turn, has the steady-state and dynamic effects listed above. STATCOM control is a phase-angle-based inverter AC voltage output control. The AC output is essentially in phase with the system voltage. The amplitude determines whether the STATCOM acts in a capacitive or inductive mode.

Most controllers included here have the potential to provide power system damping, i.e., to improve system stability. By the same token, if not properly designed, they may add to or even create system undamping, especially SSR. It is imperative to include proper attention to SSR in the control design and functional testing of power electronic stations, especially in the vicinity of existing or planned turbo-generators.

FIGURE 5.21 Controls for a ± 500 kV, 1800 MW HVDC; function test. (Photo courtesy of Siemens.)

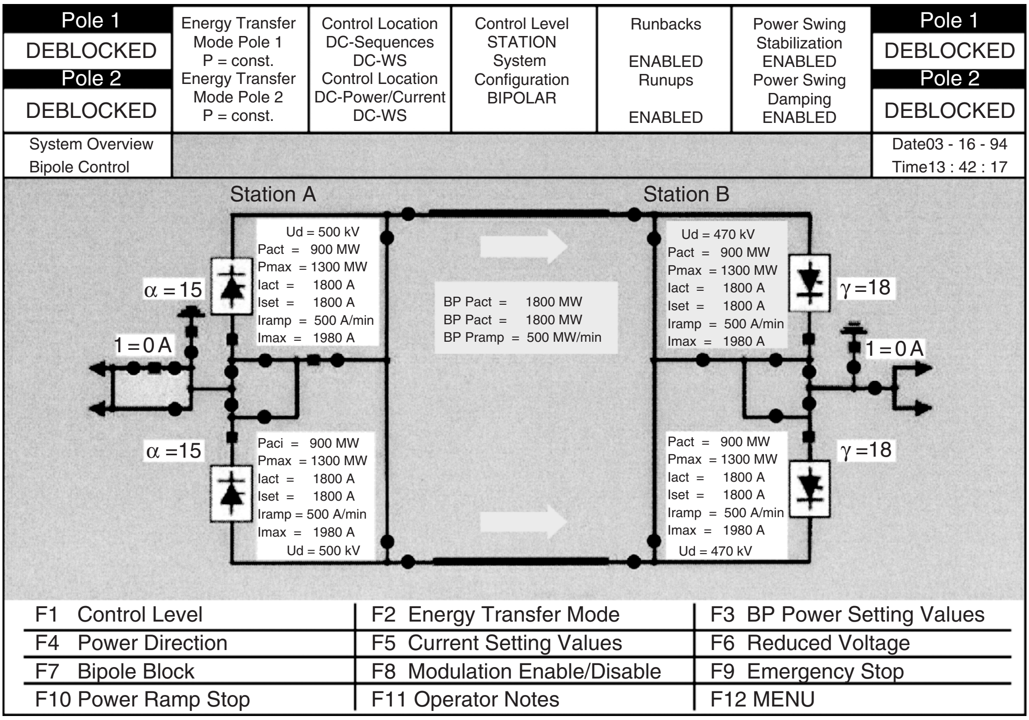

FIGURE 5.22 Operator workstation, typical screen layout for a bipolar HVDC system overview.

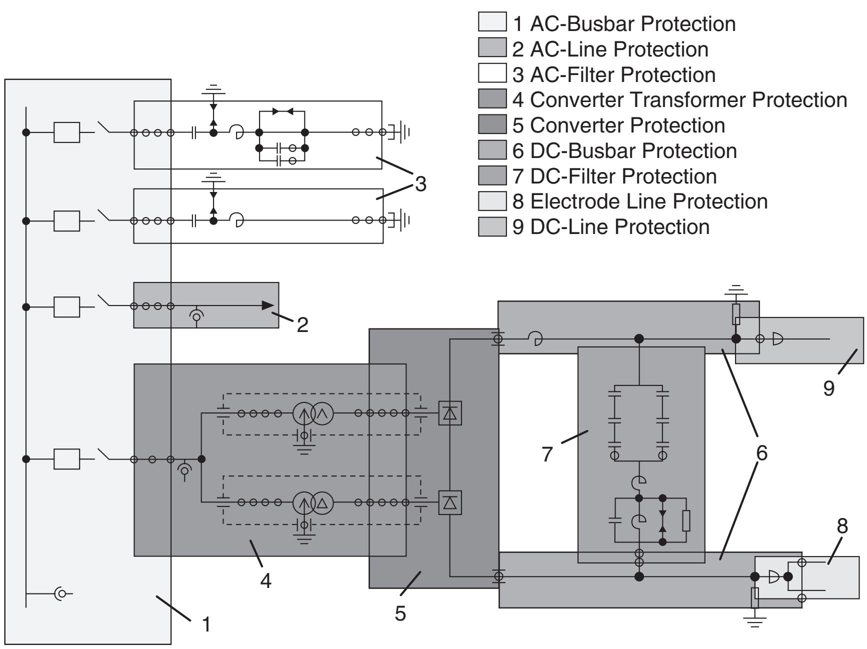

FIGURE 5.23 HVDC converter station protection zones (one pole).

Principally, the control and protection systems described above comprise the following distinctive hardware and software subsystems:

- Valve firing and monitoring circuits
- Main (closed-loop) control
- Open-loop control (sequences, interlocks, etc.)
- Protective functions
- Monitoring and alarms
- Diagnostic functions
- Operator interface and communications
- Data handling

5.4 Losses and Cooling

Valve losses in high-voltage power electronic substations are comparable in magnitude to those of the associated transformers. Typical HVDC converter efficiency exceeds 99%. This means that the losses in each terminal of a 1000-MW long-distance transmission system can approach 10 MW. Those of a 200-MW back-to-back station (both conversions AC–DC–AC in the same station) can be approximately 4 MW. The valves' share would be about 5 and 2 MW, respectively. Deionized water circulated in a closed loop is generally used as primary valve coolant. Various types of dry or evaporative secondary coolers dissipate the heat, usually into the surrounding air.

As opposed to the relatively broad distribution of losses in transformers, power electronic valve equipment includes areas of extreme loss density. Almost all losses occur in semiconductor wafers and snubber resistors. This loss density and the location of the converter valves inside a building make special cooling techniques necessary.

Standard procedures to determine and evaluate high-voltage power electronic substation losses, HVDC converter station losses in particular, have been developed [27].

5.5 Civil Works

High-voltage power electronic substations are special because of the valve rooms and buildings required for converters and controls, respectively. Insulation clearance requirements can lead to very large valve rooms (halls). The valves are connected to the yard through wall bushings. Converter transformers are often placed adjacent to the valve building, with the valve-side bushings penetrating through the walls in order to save space.

The valves require controlled air temperature, humidity, and cleanness inside the valve room. Although the major part of the valve losses is handled by the valve cooling system, a fraction of the same is dissipated into the valve room and adds to its air-conditioning or ventilation load. The periodic fast switching of electronic converter and controller valves causes a wide spectrum of harmonic currents and electromagnetic fields, as well as significant audible noise. Therefore, valve rooms are usually shielded electrically with wire meshes in the walls and windows. Electric interference with radio, television, and communication systems can usually be controlled with power-line carrier filters and harmonic filters.

Sources of audible noise in a converter station include the transformers, capacitors, reactors, and coolers. To comply with the contractually specified audible noise limits within the building (e.g., in the control room) and outdoors (in the yard, at the substation fence), low-noise equipment, noise-damping walls, barriers, and special arrangement of equipment in the yard may be necessary. The theory of audible noise propagation is well understood [28], and analytical tools for audible noise design are available [29]. Specified noise limits can thus be met, but doing so may have an impact on total station layout and cost. Of course, national and local building codes also apply. In addition to the actual valve room and control building, power electronic substations typically include rooms for coolant pumps and water treatment, for auxiliary power distribution systems, air-conditioning systems, battery rooms, and communication rooms.

Extreme electric power flow densities in the valves create a certain risk of fire. Valve fires with more or less severe consequences have occurred in the past [30]. Improved designs as well as the exclusive use of flame-retardant materials in the valve, coordinated with special fire detection and protection devices, reduce this risk to a minimum [31]. The converter transformers have fire walls in between and dedicated sprinkler systems around them as effective fire-fighting equipment.

Many high-voltage power electronic stations have spare transformers to minimize interruption times following a transformer failure. This leads to specific arrangements and bus configurations or extended concrete foundations and rail systems in some HVDC converter stations.

Some HVDC schemes use outdoor valves with individual housings. They avoid the cost of large valve buildings at the expense of more complicated valve maintenance. TCSC stations also have similar valve housings on insulated platforms together with the capacitor banks and other equipment.

5.6 Reliability and Availability

Power electronic systems in substations have reached levels of reliability and availability comparable with all the other substation components. System availability is influenced by forced outages due to component failures and by scheduled outages for preventive maintenance or other purposes. By means of built-in redundancy, detailed monitoring, self-supervision of the systems, segmentation and automatic switch-over strategies, together with consistent quality control and a prudent operation and maintenance philosophy, almost any level of availability is achievable. The stations are usually designed for unmanned operation. The different subsystems are subjected to an automatic internal control routine, which logs and evaluates any deviations or abnormalities and relays them to remote control centers for eventual actions if necessary. Any guaranteed level of availability is based on built-in redundancies in key subsystem components. With redundant thyristors in the valves, spare converter transformers at each station, a completely redundant control and protection system, available spare parts for other important subsystems, maintenance equipment, and trained maintenance personnel at hand, an overall availability level as high as 99% can be attained, and the average number of annual forced outages can be kept below five.

The outage time for preventive maintenance of the substation depends mainly on a utility's practices and philosophy. Most of the substation equipment, including control and protection, can be overhauled in coordination with the valve maintenance, so that no additional interruption of service is necessary. Merely a week annually is needed per converter station of an HVDC link.

Because of their enormous significance in the high-voltage power transmission field, HVDC converters enjoy the highest level of scrutiny, systematic monitoring, and standardized international reporting of reliability design and performance. CIGRE has developed a reporting system [32] and publishes biannual HVDC station reliability reports [33]. At least one publication discusses the importance of substation operation and maintenance practices on actual reliability [34]. The IEEE has issued a guide for HVDC converter reliability [35]. Other high-voltage power electronic technologies have benefited from these efforts as well. Reliability, availability, and maintainability (RAM) have become frequent terms used in major high-voltage power electronic substation specifications [36] and contracts.

High-voltage power electronic systems warrant detailed specifications to assure successful implementation. In addition to applicable industry and owner standards for conventional substations and equipment, many specific conditions and requirements need to be defined for high-voltage power electronic substations. To facilitate the introduction of advanced power electronic technologies in substations, the IEEE and IEC have developed and continue to develop applicable standard specifications [37,38].

Operation and maintenance training are important for the success of high-voltage power electronic substation projects. A substantial part of this training is best performed on site during commissioning. The IEEE and other organizations have, to a large degree, standardized high-voltage power electronic component and substation testing and commissioning procedures [39–41]. Real-time digital system simulators have become a major tool for the off-site function tests of all controls, thus reducing the amount of actual on-site testing. Nonetheless, staged fault tests are still performed with power electronic substations including, for example, with the Kayenta TCSC [42].

5.7 Future Trends

For interconnecting asynchronous AC networks and for transmission of bulk energy over long distances, HVDC systems remain economically, technically, and environmentally the preferred solution at least in the near future. One can expect continued growth of power electronics applications in transmission systems. Innovations such as the voltage-sourced converter [43] or the capacitor-commutated converter [44], active filters, outdoor valves [45], or the transformerless converter [46] may reduce the complexity and size of HVDC converter stations [47]. Voltage-sourced converter technology combined with innovative DC cables may make converter stations economically viable also at lower power levels (up to 300 MW).

New and more economical FACTS technologies may be introduced. Self-commutated converters and active filters will change the footprint of high-voltage power electronic substations. STATCOMs may eventually replace rotating synchronous condensers. TCSCs or UPFCs may replace phase-shifting transformers to some degree. New developments such as electronic transformer tap changers, semiconductor breakers, electronic fault-current limiters, and arresters may even affect the "conventional" parts of the substation. As a result, the high-voltage power electronic substations of the future will be more common, more effective, more compact, easier to relocate, and found in a wider variety of settings.

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6

Interface between Automation and the Substation

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An electric utility substation automation (SA) system depends on the interface between the substation and its associated equipment to provide and maintain the high level of confidence demanded for power system operation and control. It must also serve the needs of other corporate users to a level that justifies its existence. This chapter describes typical functions provided in utility SA systems and some important aspects of the interface between substation equipment and the automation system components.

6.1 Physical Challenges

6.1.1 Components of a Substation Automation System

The electric utility SA system uses any number of devices integrated into a functional array by a communications technology for the purpose of monitoring, controlling, and configuring the substation.

SA systems incorporate microprocessor-based intelligent electronic devices (IEDs), which provide inputs and outputs to the system while performing some primary control or processing service. Common IEDs are protective relays, load survey and/or operator indicating meters, revenue meters, programmable logic controllers (PLCs), and power equipment controllers of various descriptions. Other devices may also be present, dedicated to specific functions for the SA system. These may include transducers, position sensors, and clusters of interposing relays. Dedicated devices often use a controller (SA controller) or interface equipment such as a conventional remote terminal unit (RTU) as a means to connect into the SA system. The SA system typically has one or more communications connections to the outside world.

Common communications connections include utility operations centers, maintenance offices, and/or engineering centers. A substation display or users station, connected to or part of a substation host computer, may also be present. Most SA systems connect to a traditional SCADA system master station serving the real-time needs for operating the utility network from one or more operations center. SA systems may also incorporate a variation of SCADA RTU for this purpose or the RTU function may appear in a SA controller or substation host computer. Other utility users usually connect to the system through a bridge, gateway, or network processor. The components described here are illustrated in Fig. 6.1.

6.1.2 Locating Interfaces

The SA system interfaces to control station equipment through interposing relays and to measuring circuits through meters, protective relays, transducers, and other measuring devices as indicated in Fig. 6.1. These interfaces may be associated with, and integral to an IED, or dedicated interface devices for a specific automation purpose. The interfaces may be distributed throughout the station or centralized within one or two cabinets. Finding space to locate the interfaces can be a challenge depending on available panel space and layout of station control centers. Small substations can be more challenging than large ones. Choices for locating interfaces also depend on how much of the substation will be modified for automation and the budget allocated for modification. Individual utilities rely on engineering and economic judgment for guidance in selecting a design.

The centralized interface simplifies installing a SA system in an existing substation since the placement of the interface equipment affects only one or two panels housing the new SA controller, substation host,

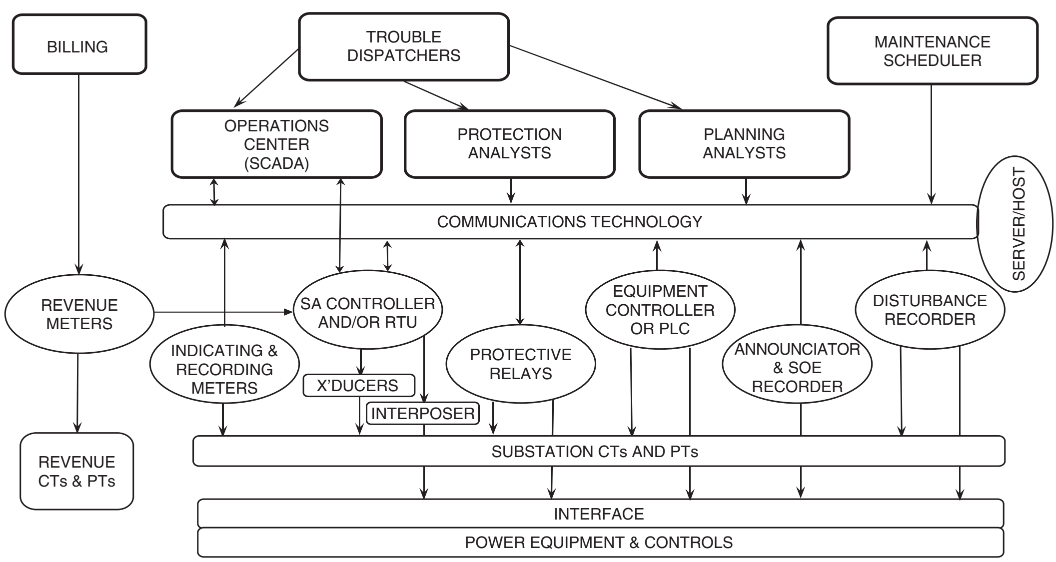

FIGURE 6.1 Power station SA system functional diagram.

HMI, discrete interface, and new IED equipment. However, cabling will be required from each controlled and monitored equipment panel which meets station panel wiring standards for insulation, separations, conductor sizing, and interconnection termination. Centralizing the SA system–station equipment interface has the potential to adversely affect the security of the station, as many control and instrument transformer circuits become concentrated in a single panel or cabinet and can be seriously compromised by fire and invite mishaps from human error. This practice has been widely used for installing earlier SCADA systems where all the interfaces centered around the SCADA RTU and often drives the configuration of an upgrade from SCADA to automation.

Placing the interface equipment on each monitored or controlled panel is much less compromising, but may be more costly and difficult to design. Each interface placement must be individually located, and more panels are affected. If a low-energy interface (less than 50 V) is used, a substantial savings in cable cost may be realized since interconnections between the SA controller and the interface devices may be made with less expensive cable and hardware. Low-energy interconnections can lessen the impact on the cabling system of the substation, reducing the likelihood that additional cable trays, wireways, and ducts will be needed.

The distributed approach is more logical when the SA system incorporates protective relay IEDs; panel-mounted indicating meters or control function PLCs. Protection engineers usually insist on separating protection devices into logical groups based on substation configuration for security. Similar concerns often dictate the placement of indicating meters and PLCs. Many utilities have abandoned the "time honored" operator "bench board" in substations in favor of distributing the operator control and indication hardware throughout the substation. The interface to the SA system becomes that of the IED on the substation side and a communications channel on the SA side. Depending on the communications capability of the IEDs, the SA interface can be as simple as a shielded, twisted pair cable routed between IEDs and the SA controllers. The communications interface can also be complex where multiple short haul RS-232 connections to a communications controller are required. "High-end" IEDs often have Ethernet network capability that will integrate with complex networks. These pathways may also utilize optical fiber systems and unshielded twisted pair (UTP) Ethernet cabling or even coaxial cable or some combination thereof.

As the cabling distances within the substation increase, system installation costs increase, particularly if additional cable trays, conduit, or ducts are required. Using SA communications technology and IEDs can often reduce interconnection cost. Distributing multiple, small, SA "hubs" throughout the substation can reduce cabling to that needed for a communications link to the SA controller. Likewise, these hubs can be electrically isolated using fiber optic technology for improved security and reliability. More complex SA systems use multiple communications systems to maintain availability should a channel be compromised.

6.1.3 Environment

The environment of a substation is another challenge for SA equipment. Substation control buildings are seldom heated or air-conditioned. Ambient temperatures may range from well below freezing to above 100°F (40°C). Metal clad switchgear substations can reach ambient temperatures in excess of 140°F (50°C) even in temperate climates. Temperature changes stress the stability of measuring components in IEDs, RTUs, and transducers. Good temperature stability is important in SA system equipment and needs to be defined in the equipment purchase specifications. IEEE Standard 1613 defines environmental requirements for SA system communications components. Designers of SA systems for substations need to pay careful attention to the temperature specifications of the equipment selected for SA. In many environments, self-contained heating or air conditioning is advisable.

When equipment is installed in outdoor enclosures, not only is the temperature-cycling problem aggravated, moisture from precipitation and condensation become troublesome. Outdoor enclosures usually need heaters to control their temperature to prevent condensation. The placement of heaters should be reviewed carefully when designing an enclosure, as they can aggravate temperature stability and even create hot spots within the cabinet that can damage components and shorten life span. Heaters near the power batteries help improve low-temperature performance but adversely affect battery life span at high ambient temperatures. Obviously, keeping incident precipitation out of the enclosure is very important. Drip shields and gutters around the door seals will reduce moisture penetration. Venting the cabinet helps limit the possible build up of explosive gasses from battery charging but may pose a problem with the admittance of moisture. Incident solar radiation shields may also be required to keep enclosure temperature manageable. Specifications that identify the need for wide temperature range components, coated circuit boards, and corrosion-resistant hardware are part of specifying and selecting SA equipment for outdoor installation.

Environmental factors also include airborne contamination from dust, dirt, and corrosive atmospheres found at some substation sites. Special noncorrosive cabinets and air filters may be required for protection against the elements. Insects and wildlife also need to be kept out of equipment cabinets. In some regions seismic requirements are important enough to be given special consideration.

6.1.4 Electrical Environment

The electrical environment of a substation is severe. High levels of electrical noise and transients are generated by the operation of power equipment and their controls. Operating high-voltage disconnect switches can generate transients that couple onto station current, potential and control wiring entering or leaving the switch yard and get distributed throughout the facility. Operating station controls for circuit breakers, capacitors, and tap changers can also generate transients that can be found throughout the station on battery power and station service wiring. EHV stations also have high electrostatic field intensities that couple to station wiring. Finally, ground rise during faults or switching can damage electronic equipment in stations. IEEE Standard 1613 defines testing for SA system components for electrical environment. IEEE C37.90-2000 defines electrical environmental testing requirements for protective devices.

Effective grounding is critical to controlling the effects of substation electrical noise on electronic devices. IEDs need a solid ground system to make their internal suppression effective. Ground systems should be radial to a single point with signal and protective grounds separated. Signal grounds require large conductors for "surge" grounds. They must be as short as possible and establish a single ground point for logical groupings of equipment. These measures help to suppress the introduction of noise and transients into measuring circuits. A discussion of this topic is usually found in the IED manufacturer's instruction book and their advice should be heeded.

The effects of electrical noise can be controlled with surge suppression, shielded and twisted pair cabling, as well as careful cable-separation practices. Surges can be suppressed with capacitors, metal oxide varistors (MOVs), and semiconducting over voltage "Transorbs" applied to substation instrument transformer and control wiring. IEDs qualified under IEEE C37.90-2000 include surge suppression within the device to maintain a "surge fence." However, surge suppression can create reliability problems as well. Surge suppressors must have sufficient energy-absorbing capacity and be coordinated so that all suppressors clamp around the same voltage. Otherwise, the lowest dissipation, lowest voltage suppressor will become sacrificial. Multiple failures of transient suppressors can short circuit important station signals to ground, leading to blown VT fuses, shorted CTs, and shorted control wiring; even false tripping. At a minimum, as the lowest energy, lowest clamp voltage devices fail; the effectiveness of the suppression plan degrades, making the devices suspect damage and misoperation.

While every installation has a unique noise environment, some testing can help prevent noise problems from becoming unmanageable. IEEE surge withstand capability test C37.90-2000 for protective devices and IEEE 1613 for automation devices address the transients generated by operating high-voltage disconnect switches and the operation of electromechanical control devices. These tests can be applied to devices in a laboratory or on the factory floor. They should be included when specifying station interface equipment. Insulation resistance and high potential test are also sometimes useful and are standard requirements for substation devices for many utilities.

6.2 Measurements

Electric utility SA systems gather power system performance parameters (i.e., volts, amperes, watts, and vars) for system generators, transmission lines, transformer banks, station buses, and distribution feeders. Energy output and usage measurements (i.e., kilowatt-hours and kilovar-hours) are also important for the exchange of financial transactions. Other measurements such as transformer temperatures, insulating gas pressures, fuel tank levels for on-site generation, or head level for hydro generators might also be included in the system's suite of measurements. Often, transformer tap positions, regulator positions, or other multiple position measurements are also handled as if they were measurements. These values enter the SA system through IEDs, transducers, and sensors of many descriptions.

IEDs, meters, and transducers measure electrical parameters (watts, vars, volts, amps) with instrument transformers shown in Fig. 6.2. They convert instrument transformer outputs to digitized values for a communications method or DC voltages or currents that can be readily digitized by a traditional SCADA RTU or SA controller.

Whether a measurement is derived from the direct digital conversion of AC input signals by an IED or from a transducer analog with an external digitizing process, the results are functionally the same. However, IEDs that perform signal processing and digital conversion directly as part of their primary function use supplementary algorithms to process measurements. Transducers use analog signal processing technology to reach their results. IEDs use a communications channel for passing digitized data to the SA controller instead of conventional analog signals and an external device to digitize them.

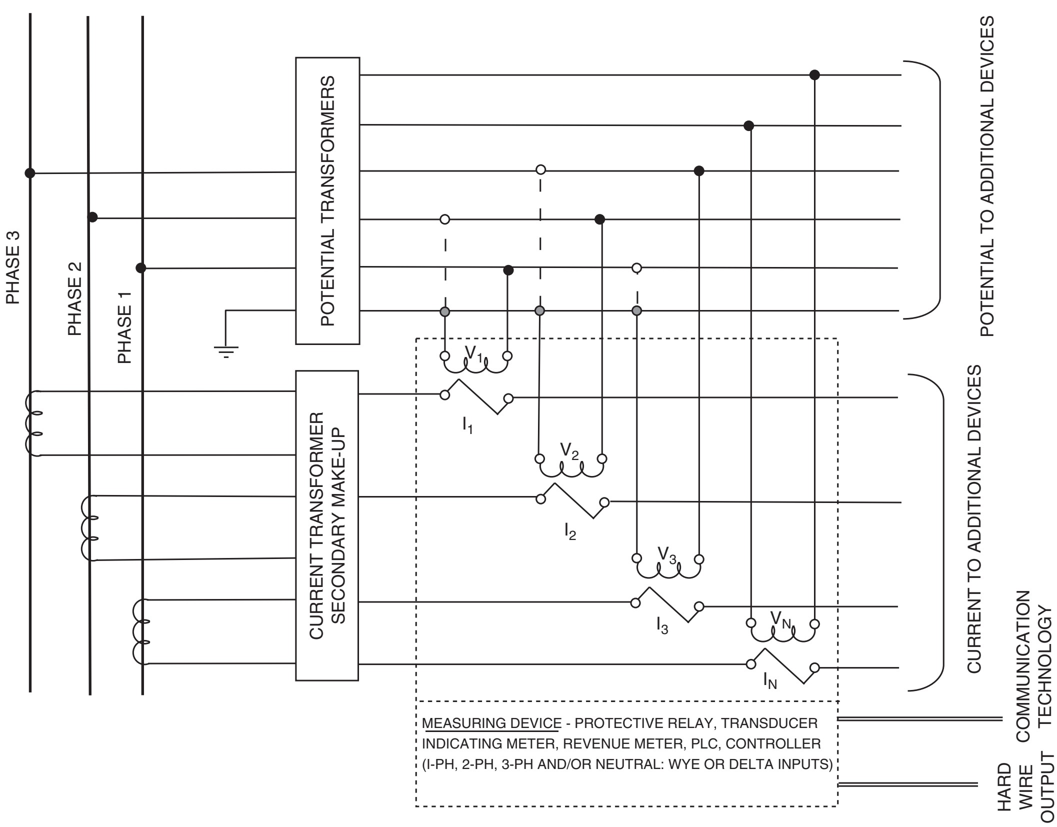

FIGURE 6.2 SA system electrical measuring interface.

6.2.1 What Measurements Are Needed

The suite of measurements included in the SA system serve many users with differing requirements. It is important to assess those requirements when specifying measuring devices and designing their placement, as all IED measurements are not functionally equal and may not serve specific users. For example, it is improbable that measurements made by a protective relay will serve the needs for measuring energy interchange accounting unless the device has been qualified under the requisite revenue measuring standards. Other examples where measurement performance differences are important might not be as obvious but can have significant impact on the usability of the data collected and the results from including that data in a process. Another case in point, planners prefer measurements that are averaged with an algorithm that mimics the heating of conductors, not instantaneous "snap-shot" or averaged instantaneous values.

Likewise, the placement of sensors for the IED's primary function may not be the correct location for the measurement required. For example, the measurements made by a recloser control made on the secondary side of a power transformer or at a feeder will not suffice when the required measurement should be made at the primary of the transformer. Notably, the recloser measurement includes both real and reactive power losses of the transformer that would not be present in a measurement made on the primary. Voltage sensors can be on the adjacent bus separated from the measurement current sensors by a section breaker or reactor and will give erroneous measurement. There are many subtleties to sensor placement for measurements as well as their connected relationship.

The task of defining the requirements for measurements belongs to the user of the measurement. System users need to specify the specific set of measurements they require. Along with those measurements they should supply the details of where those measurements must be made within the electrical network. They need to specify the accuracy requirements and the applicable standards that must be applied to those measurements. Users must also define the performance parameters such as latency and refresh rates that are discussed in more detail in the following sections. The system designer needs to have these requirements in hand before rendering the system design. Without the specifics the designer must guess at what will be sufficient. Unfortunately, many systems are constructed without this step taking place and the results bring dissatisfaction to the user, discredit to the designer, and added cost to correct problems.

6.2.2 Performance Requirements

In the planning stages of a SA system the economic value of the data to be acquired needs to be weighed against the cost to measure it. A balance must be struck to achieve the data quality required to suit the users and functions of the system. This affects the conceptual design of the measuring interface and provides input to the performance specifications for IEDs and transducers as well as the measuring practices applied. This step is important. Specifying a higher performance measuring system than required raises the overall system cost. Conversely, constructing a low-performance system adds costs when the measuring system must be upgraded. The tendency to select specific IEDs for the measuring system without accessing the actual measuring technology can lead to disappointing performance.

The electrical relationship between measurements and the placement of available instrument transformer sources deserves careful attention to insure satisfactory performance. Many design compromises can be made when installing SA monitoring in an existing power station because of the availability of measuring sensors. This is especially true when using protective relays as load-monitoring data sources (IEDs). Protection engineers often ignore current omissions or contributions at a measuring point, as they may not materially affect fault measurements. These variances are often intolerable for power flow measurements. Measuring source placement may also result in measurements that include or exclude reactive contributions of a series or shunt reactor or capacitor. Measurements could also include unwanted reactive component contributions of a transformer bank. Measurements might also become erroneous when a section breaker is open if the potential source is on an adjacent bus. Power system charging current and unbalances also influence measurement accuracy, especially at low load levels. Some placement issues are illustrated in Fig. 6.3. The compromises are endless and each produces an unusual operating condition in some state. When deficiencies are recognized, the changes to correct them can be very costly, especially, if instrument transformers must be installed, moved, or replaced to correct the problem.

The overall accuracy of measured measurements is affected by a number of factors. These include instrument transformer errors, IED or transducer performance and analog to digital (A/D) conversion. Accuracy is not predictable based solely on the IED, transducer, or A/D converter specifications. Significant measuring errors often result from instrument transformer performance, and errors induced in the scaling and digitizing process. IEEE Standard C57.13 describes instrument transformer specifications.

Revenue metering accuracy is usually required for monitoring power interchange at interconnection points and where the measurements feed economic area interchange and dispatch systems. High accuracy, revenue metering grade, instrument transformers, and 0.25% accuracy class IEDs or transducers can produce consistent real power measurements with accuracy of 1% or better at 0.5 to l.0 power factor, and reactive power measurements with accuracy of 1% or better at 0 to 0.5 power factors. Note that real power measurements at low power factors and reactive power measurements at high power factors are difficult to make accurately.

When a SA system provides information for internal power flow telemetering, revenue grade instrument transformers are not usually available. SA IEDs and transducers must often share lesser accuracy instrument transformers provided for protective relaying or load monitoring. Overall accuracy under these conditions can easily decrease to 2–3% for real power, voltage, and current measurements and 5% or greater for reactive power.

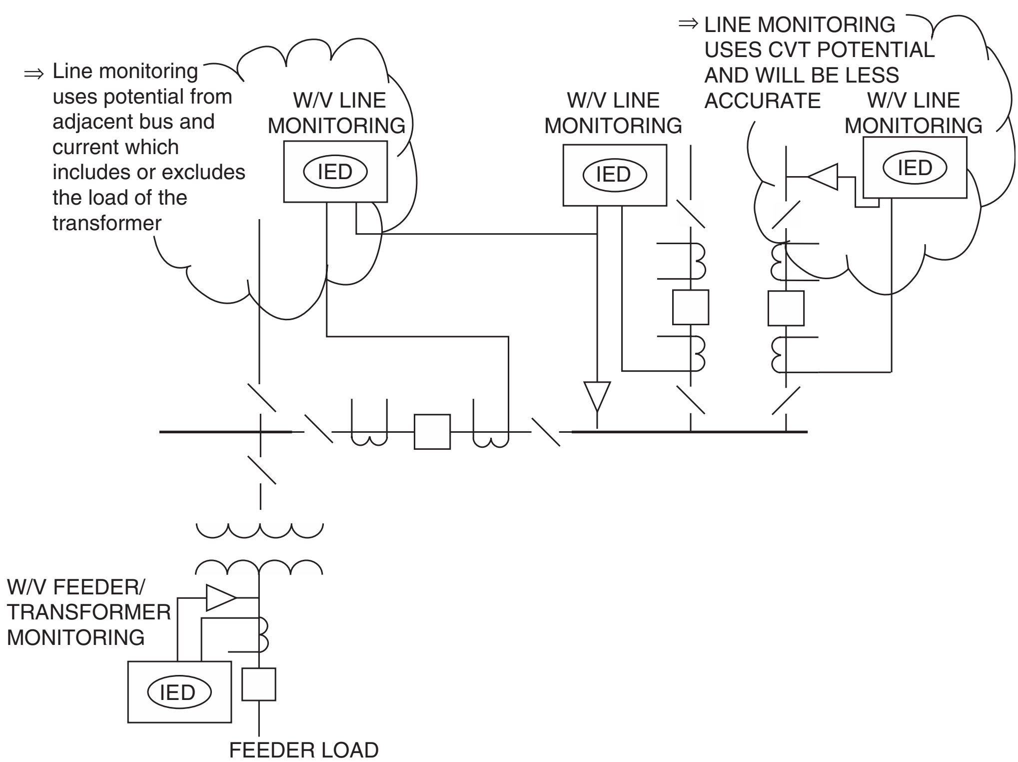

FIGURE 6.3 Measurement sensor placement.

6.2.3 Characteristics of Digitized Measurements

The processing of analog AC voltages and currents into digitized measurements for a SA system adds some significant characteristics to the result. Processing analog DC signals into digitized measurements adds many of the same characteristics. As measurements pass through the SA system more characteristics are added that can have a significant impact on their end use.

In the analog environment, a signal may have any value within its range. In the digital environment, signals may have only discrete values within their range. The set of values is imparted by the analog to digital conversion process. The increments within the digital value set are determined by the minimum resolution of the A/D converter and number of states into which it can resolve. For discussion, consider an A/D converter whose minimum resolution is 1.0 mV and whose range is 4095 increments (4.095 V). The increment figure is usually expressed in the converter's basic binary format, in this case, 12 bits. In order to perform its conversion each input it converts must be scaled so that the overall range of the input falls within the range of 0–4.095 V. If the input can assume values that are both positive and negative, then the converter range is spilt by offsetting the converter range by one half (2.047 V) giving the effective range of positive and negative 2.047 V. The minimum resolution of a measurement processed by this converter is then the full scale of the input divided by the number of states, 4095 for unipolar and 2047 for bipolar. For example, if a bus voltage of 13,200 V were to be converted the full-scale range of 15,000 would be a reasonable choice. The minimum resolution of this measurement is then 15,000/4095 or 3.66 V. A display that showed values to the nearest volt, or less, is thus misleading since the value displayed cannot be resolved to 1.0 V or less but only to 3.66 V. If the measurements in this example are assumed to be bipolar, as would be direct input AC signals, then the minimum resolution for the voltage measurement is 7.32 V.

The minimum resolution of any digitized measurement significantly impacts usability of that measurement in any process or calculation in which it appears. The minimum resolution can be improved by adding resolution to the A/D converter, such as using a 16-bit converter that has 65,535 states. In the above example the minimum resolution becomes 15,000/32768 or 0.46 V. The higher resolution converter is more expensive and may or may not be economically required. Minimum resolution also affects the dynamic range of a measurement. For the 12-bit converter that range is approximately 2000/1 and 32,000/1 for the 16-bit converter. More realistically, the dynamic range for a 12-bit converter is 200/1 and 3200/1 for a 16-bit converter. However, more characteristics control the usable range of the measurement.

The problem with representing large numbers is more complex with power measurements. Once power levels reach into the megawatt region the numbers are so large they cannot be transported easily in a 16-bit format with the unit of watts. Scaling these larger numbers becomes imperative and as a result the resolution of smaller numbers suffers. Scaling is discussed later in this chapter.

A/D converters have their accuracy specifications stated at full scale but generally do not state their expected performance at midrange or at the lower end of their range where it is common for electrical measurements to reside during much of their life. In addition, converters which are offset to midrange to allow conversion of inputs, which are bipolar or are AC suffer difficulty measuring inputs that are near zero (converter midrange). These measurements often have an offset of several times their minimum resolution increment and declining accuracy in this portion of their range. Figure 6.4 illustrates an accuracy band for converted measurements as a function of range. Converters may also introduce fluctuations around their measured value on the order of several times their minimum increment. This "bounce," as it is called, gives annoying changes to the observed measurement that makes the lower significant digits of a measurement unusable.

IEDs and automation controllers frequently have software and self-calibration components to help minimize the effects of converter performance on measurements. This software may correct for offsets and drift as well as filter out or average some of the bounce. It is important to define the performance requirements across the range of measurements to be encountered by the system before selecting a measurement technology. Note that some performance limitations can be mitigated by carefully selecting the scaling applied to measurements so as to avoid measurements made at the low end of the converter range.

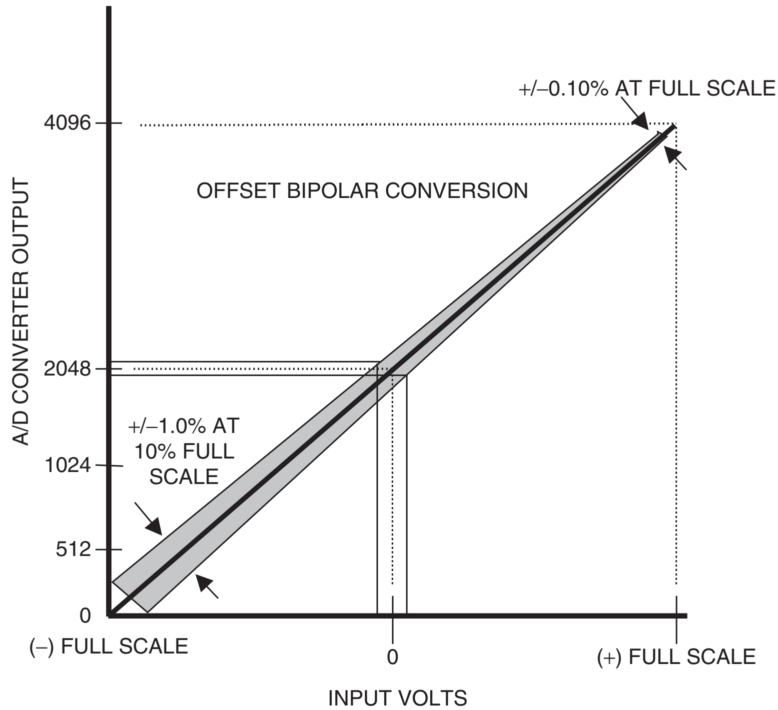

FIGURE 6.4 A/D conversion accuracy.

There are two other important characteristics of digitized measurements to be considered in the design of an automation system, which are not directly related to the conversion process. These are more aligned with how the system handles measurements than how they are made. These are latency and time skew.

Latency is the time from which inputs presented at a measuring device are measured and available to the user, whether the user is a human or a software program that requires it. Contributors to latency include:

- The time required to process the inputs into measurements and make them available to the measuring device's communications process
- The time to move the measurement from the measuring device's communications process across the network to the user's communications process
- The time for the user's communications process to make the measurement available to the user

While we would expect the inputs at a measuring device to be measured and available at its communications port on demand that may not be the case. Many IEDs and automation controllers have functions, which take precedence to processing measurements and moving them out to the communications process. This is especially true of protection devices where the protective functions take precedence over any other function when it senses possible fault processing requirements. In some devices, there can be a delay in the order of seconds incurred in refreshing the measurements stored in the communications process memory with new values. Until the communications process has new values, it will send old values on request or when its scheduled report occurs. Where latency is an unknown it can be measured by continuously requesting a measurement and observing the time required to see a step change on a measurement input in the returned value. For some devices, this time delay is variable and not easily predicted.

There may be multiple users of measurements made in an automation system. Each user has a pathway to retrieve their measurements based on one or more communications technologies and links. Users can expect latency in their measurements to result from these components that often differ between users based on the differences in the technology, pathways, and links. That suggests that each user needs to define the acceptable latency as part of their performance definitions.

Communications technology can have a profound impact on latency. Different communications technologies and channels have different base speeds at which they transport data. Contributing characteristics include basic communications bit rate, channel speed, message handling procedures, and protocol characteristics. Simple systems poll for measurements on a predictable schedule that suggests that user measurements are transported in one or two poll cycles. During the poll cycle the delays are directly predicted from the channel and procedural characteristics.

More complex systems may have less predictable message handling characteristics or intermediary devices that are temporary residences of measurements while they move along the pathway. Intermediaries may re-format and re-scale measurements for users and divergent pathways and technologies. For example, a user pathway may include a moderately high-speed technology from the measuring device to the first intermediary and a store and forward technology for the link to user via a remote server or host. Thus the first part of the journey may take one-tenth of seconds to complete and the additional hops might take minutes. This emphasizes the importance for users to define their expectations and requirements. This latency may be variable depending on the technology and loading factors and could be difficult to predict or measure.

The last contributor to latency is the time for the measurement to be available to the user at its final destinations. Moving the values to the user host does not fully define the time required for the value to be available to the user. The destination host may introduce delays while it processes the values and places them in the resting place for user access. This time may also be a variable based on the activity level of the host. The host may simply buffer new data until it has time to process it and drop it in its database. Delays can also occur as the values are retrieved and presented to the user.

Latency can have substantial impacts on the users of automation measurements. Users need to specify what latency is tolerable and specify a means to detect when that requirement is not being met to the extent that the added delays affect their process.

Time skew can be important to many data users that are looking at a broad set of values. Time skew is the time difference between a measurement in a data set and any other measurement of that set. The data set might include measurements taken within a single substation or a subset thereof. However, a data set may include measurements made across a wide geographic area, which might include multiple substations, generating stations, and even multiple utilities taken to perform generation dispatch and system security. Clearly the user (or applications program) cannot simply assume all values in the data set are taken precisely at the same time instant unless some special provisions have been made to assure that happens. Part of the performance requirement definition is to determine what an acceptable time skew is for each user data set. As with other characteristics, different users will have different requirements. The data transport scheme used to move the values to the user plays a very significant role in determining and controlling time skew.

Some systems have provisions to assure time skew is minimized. A simple method to minimize time skew samples measurements at a specific time by "freezing and holding" them and saves them until they can be retrieved without taxing the communications link. While it is more common to apply this method to sets of energy interchange measurements (kilowatt-hours or kilovar-hours) across interconnections and generating sources, the same principle can be used for other data sets. "Freeze and hold" schemes rely on a system-wide broadcast command or a high-accuracy clock to synchronize sampling the measurements. An updated version of this concept uses a high-accuracy time source such as a GPS to synchronize sampling. The sample data set then has a time tag attached so that the user knows when the sample set was taken. This concept is being applied to the measurement of voltage phase angles across large areas to measure and predict stability.

6.2.4 Instrument Transformers

Electrical measurements on a high-voltage transmission or distribution network cannot be made practically or safely with direct contact to the power carrying conductors. Instead, the voltages and currents must be brought down to a safe and usable level that can be input into measuring instruments. This is the task of an instrument transformer. They provide replica voltages and currents scaled to more manageable levels. They also bring their replicas to a safe ground potential reference. The most common output range is 0–150 V for voltages and 0–5.0 A for currents based on their nominal inputs. Other ranges are used as well. The majority of these devices are iron core transformers. However, other sensor technologies can perform this function that are discussed further in this section.

6.2.4.1 Current Transformers

Current transformers (CTs) of all sizes and types find their way into substations to provide the current replicas for metering, controls, and protective relaying. Some will perform well for SA applications and some may be marginal. CT performance is characterized by turns ratio, turns ratio error (ratio correction factor), saturation voltage, phase angle error, and rated secondary circuit load (burden). CTs are often installed around power equipment bushings, as shown in Fig. 6.5. They are the most common types found in medium- and high-voltage equipment. Bushing CTs are toroidal, having a single primary turn (the power conductor), which passes through their center. The current transformation ratio results from the number of turns wound on the core to make up the primary and secondary. Lower voltage CTs are often a "wound" construction with both a multiturn primary and secondary winding around their "E-form" or "shell form" core. Their ratio is the number of secondary turns divided by the number of primary turns. CT secondary windings are often tapped to provide multiple turns ratios. The core cross-sectional area, diameter, and magnetic properties determine the CT's performance. As the CT is operated over its nominal current ranges, its deviations from specified turns ratio are characterized by its ratio correction curve sometimes provided by the manufacturer. At low currents, the exciting current of the iron core causes ratio errors that are predominant until sufficient primary magnetic flux overcomes the effects of core magnetizing. Thus, watt or var measurements made at very low load may be substantially in error both from ratio error and phase shift. Exciting current errors are a function of individual CT construction. They are generally higher for protection CTs than revenue metering CTs by design.

FIGURE 6.5 Bushing current transformer installation.

Revenue metering CTs are designed with core cross sections chosen to minimize exciting current effects and their cores are allowed to saturate at fault currents. Protection CTs use larger cores as high current saturation must be avoided for the CT to faithfully reproduce high currents for fault sensing. The exciting current of the larger core at low primary current is not considered important for protection but can be a problem for measuring low currents. Core size and magnetic properties determine the ability of CTs to develop voltage to drive secondary current through the circuit load impedance (burden). This is an important consideration when adding SA IEDs or transducers to existing metering CT circuits, as added burden can affect accuracy. The added burden of SA devices is less likely to create metering problems with protection CTs at load levels, but could have undesirable effects on protective relaying at fault levels. In either case, CT burdens are an important consideration in the design. Experience with both protection and metering CTs wound on modern high silicon steel cores has shown, however, that both perform comparably once the operating current sufficiently exceeds the exciting current if secondary burden is kept low.

CT secondary windings are generally uncommitted. They can be connected in any number of configurations so long as they have a safety ground connection to prevent the windings from drifting toward the primary voltage. It is common practice to connect CTs in parallel so that their current contribution can be summed to produce a new current such as one representing a line current where the line has two circuit breaker connections such as in a “breaker-and-a-half” configuration.

CTs are an expensive piece of equipment and replacing them to meet new measuring performance requirements is usually cost prohibitive. However, new technology has developed, which makes it possible for an IED to compensate for CT performance limitations. This technology allows the IED to “learn” the properties of the CT and correct for ratio and phase angle errors over the CT’s operating range. Thus, a CT designed to feed protection devices can be used to feed revenue measuring IEDs and meet the requirements of IEEE Standard C57.13.

Occasions arise where it is necessary to obtain current from more than one source by summing currents with auxiliary CTs. There are also occasions where auxiliary CTs are needed to change the overall ratio or shift phase relationships from a source from a wye to a delta or vice versa to suit a particular measuring scheme. These requirements can be met satisfactorily only if the auxiliaries used are adequate. If the core size is too small to drive the added circuit burden, the auxiliaries will introduce excessive ratio and phase angle errors that will degrade measurement accuracy. Using auxiliary transformer must be approached with caution.

6.2.4.2 Voltage Sources

The most common voltage sources for power system measurements are either wound transformer (voltage transformers) or capacitive divider devices (capacitor voltage transformers [CVTs] or bushing voltage devices). Some new applications of resistor dividers and magneto-optic technologies are also becoming available. All provide scaled replicas of their primary high voltage. They are characterized by their ratio, load capability (burden), and phase angle response. Wound voltage transformers (VTs) provide the best performance with ratio and phase angle errors suitable for revenue measurements. Even protection-type voltage transformers can provide revenue metering performance if the burden is carefully controlled. VTs are usually capable of supplying large secondary circuit loads without degradation, provided their secondary wiring is of adequate size. For SA purposes, VTs are unaffected by changes in temperature and only marginally affected by changes in load. They are the preferred source for measuring voltages. VTs operating at 69 KV and above are almost always connected with their primary windings connected phase to ground. At lower voltages, VTs can be purchased with primary windings that can be connected either phase to ground or phase to phase. VT secondary windings are generally uncommitted and can be connected with wye, delta, or in a number of different configurations so long as they have a suitable ground reference.

CVTs use a series stack of capacitors, connected as a voltage divider to ground, along with a low-voltage transformer to obtain a secondary voltage replica. They have internal reactive components that are adjusted to compensate for the phase angle and ratio errors. CVTs are less expensive than wound transformers and can approximate wound transformer performance under controlled conditions. While revenue grade CVTs are available, CVTs are less stable and less accurate than wound VTs. Older CVTs may be too unstable to perform satisfactorily. Secondary load and ambient temperature can affect CVTs. CVTs must be individually calibrated in the field to bring their ratio and phase angle errors within specifications and must be recalibrated whenever the load is changed. Older CVTs can change ratio up to $\pm5\%$ with significant phase angle changes as well resulting from ambient temperature variation. In all, CVTs are a reluctant choice for SA system measuring. When CVTs are the only choice consideration should be given to using modern devices for better performance and a periodic calibration program to maintain their performance at satisfactory levels.

Bushing capacitor voltage devices (BCVDs) use a tap made in the capacitive grading of a high-voltage bushing to provide the voltages replica. They can supply only very limited secondary load and are very load sensitive. They can also be very temperature sensitive. As with CVTs, if BCVDs are the only choice, they should be individually calibrated and periodically checked.

6.2.5 New Measuring Technology

There are new technologies appearing in the market that are not based on the iron core transformer. Each of these technologies has its particular application. Table 6.1 lists some of these technologies and their particular characteristic of interest.

6.2.6 Substation Wiring Practices

VTs and CTs are the interfaces between the power system and the substation. Their primary connections must meet all the applicable standards for loadability, safety, and reliability. Utilities have generally adopted a set of practices for secondary wiring that meets their individual needs. Generally VT secondaries are wired with #12 AWG conductors, or larger, depending on the distance they must run. CTs are generally wired with #10 AWG or larger conductors, also depending on the length of the wire run. Where secondary cable distance or instrument transformer burden is a problem, utilities often specify multiple parallel conductors. Once inside the substation control center, wiring practices differ between utilities but #12 AWG conductors are usually specified. Instrument transformer wiring is generally 600-V class insulation. Utilities generally have standards that dictate acceptable terminal blocks and wire terminals as well as how these devices are to be used.

6.2.7 Measuring Devices

The integrated substation has changed the way measurements for automation are made significantly. Early SCADA and monitoring systems relied on transducers to convert CT and VT signals to something that could be handled by a SCADA RTU or monitoring equipment. While this technology still has many valid applications, it is increasingly common practice to collect measurements from IEDs in the substation via a communications channel. Where IEDs and the communications channel can meet the performance requirements of the system, transducers and separate conversion devices become redundant, thus savings can be accrued by deleting them from the measuring plan.

TABLE 6.1 Characteristic of New Technology Measurement Sensors

Air core current transformers	Wide operating range without saturation
Regowsky coils	Wide operating range without saturation, can be embedded in insulators
Hall effect sensor	Can be embedded in line post insulators
Magneto-optic	Very high accuracy, dynamic range, reduced size and weight
Resistor divider	Low cost

6.2.7.1 Transducers

Transducers measure power system parameters by sampling instrument transformer secondaries. They provide scaled, low-energy signals that represent power system measurements that the SA interface controller can easily accept. Transducers also isolate and buffer the SA interface controller from the power system and substation environments. Transducer outputs are DC voltages or currents in the range of a few tens of volts or milliamperes. A SCADA RTU or other such device processes and transmits digitized transducer signals. In older systems a few transducer signals were sometimes transmitted to a central location using analog technology.

Transducers measuring power system electrical measurements are designed to be compatible with instrument transformer outputs. Voltage inputs are based around 120 or 115 VAC and current inputs accept 0–5 A. Many transducers can operate at levels above their normal ranges with little degradation in accuracy provided their output limits are not exceeded. Transducer input circuits share the same instrument transformers as the station metering and protection systems; thus, they must conform to the same wiring standards as any switchboard component. Special termination standards also apply in many utilities. Test switches for “in-service” testing are often provided to make it possible to test transducers without shutting down power equipment. Most transducers require an external power source to supply their power requirements. The reliability of these sources is crucial to maintaining data available.

Transducer outputs are voltage or current sources specified to supply a rated voltage or current into a specific load. For example, full output may correspond to 10 V at up to 10 mA output current or 1.0 mA into a maximum 10 kΩ load resistance, up to 10 V maximum. Some over-range capability is provided in transducers so long as the maximum current or voltage capability is not exceeded. The over-range may vary from 20 to 100%, depending on the transducer; however, accuracy is usually not specified for the over-range area.

Transducer outputs are usually wired with shielded, twisted pair cable to minimize stray signal pickup. In practice, #18 AWG conductors or smaller are satisfactory, but individual utility practices differ. It is common to allow transducer output circuits to remain isolated from ground to reduce their susceptibility to transient damage, although some SA controller suppliers require a common ground for all signals, to accommodate semiconductor multiplexers. Some transducers may also have a ground reference associated with their outputs. Double grounds, where transducer and controller both have ground references, can cause major reliability problems. Practices also differ somewhat on shield grounding with some shields utilities grounding at both ends, but are more common to ground shields at the SA controller end only. When these signals must cross a switchyard, however, it is a good practice to not only provide the shielded, twisted pairs, but to also provide a heavy gauge overall cable shield. This shield should be grounded where it leaves a station control house to enter a switchyard and where it re-enters another control house. These grounds are terminated to the station ground mass, and not the SA analog grounds bus.

6.2.7.2 Intelligent Electronic Devices as Analog Data Sources

Technological advancements have made it practical to use electronic substation meters, protective relays, and even reclosers and regulators as sources for measurement. IED measurements are converted directly to digital form and passed to the SA system via a communications channel while the IED performs its primary function. In order to use IEDs effectively it is necessary to assure that the performance characteristics of the IED fit the requirements of the system. Some IEDs designed for protection functions, where they must accurately measure fault currents, do not measure low load accurately. Others, where measuring is part of a control function, may lack overload capability or have insufficient resolution. Sampling rates and averaging techniques will affect the quality of data and should be evaluated as part of the system product selection process. With reclosers and regulators the measuring CTs and VTs are often contained within the equipment. They may not be accurate enough to meet the measuring standards set for the SA system. Regulators may only have a single phase CT and VT, which limits their accuracy for measuring three-phase loads. These issues challenge the SA system integrator to deliver a quality system.

The IED communications channel becomes an important data highway and needs attention to security, reliability and most of all, throughput. A communication interface is needed in the SA system to retrieve and convert the data to meet the requirement of the data users.

6.2.8 Scaling Measured Values

In a SA system, the transition of power system measurements to database or display values is a process that entails several steps of scaling, each with its own dynamic range and scaling constants. Current and voltage transformers first scale power system parameters to replicas, then an IED or transducer scales them again. In the process an analog to digital conversion occurs as well. Each of these steps has its own proportionality constant which, when combined, relates the digital coding of the data value to the primary measurements. At the data receiver or master station, coded values are operated on by one or more constants to convert the data to user-acceptable values for processes, databases, and displays. In some system architectures data values must be re-scaled in the process of protocol conversion. Here, an additional scaling process manipulates the data value coding and may add or truncate bits to suit the conversion format.

SA system measuring performance can be severely affected by data value scaling. Optimally, under normal power system conditions, each IED or transducer should be operating in its most linear range and utilize as much A/D conversion range as possible. Scaling should take into account the minimum, normal, and maximum value for the measurement, even under abnormal or emergency conditions. Optimum scaling balances the expected value at maximum, the current and voltage transformer ratios, the IED or transducer range, and the A/D range, to utilize as much of the IED or transducer output and A/D range as possible under normal power system conditions without driving the conversion over its full scale at maximum value. This practice minimizes the quantizing error of the A/D conversion process and provides the best measurement resolution. Some measurements with excessive dynamic ranges may even need to be duplicated at different scaling in order to meet the performance required.

Some IEDs perform scaling locally such as for user displays and present scaled measurements at their communication ports. Under some circumstance, the pre-scaled measurements can be difficult to use in a SA system particularly when a protocol conversion must take place that cannot handle large numbers. A solution to this problem is to set the IED scaling to unity and apply all the scale factors at the data receivers. The practical restraints imposed when applying SA to an existing substation using available instrument transformer ratios will compromise scaling within A/D or IED ranges.

6.2.9 Integrated Energy Measurements—Pulse Accumulators

Energy transfer measurements are derived from integrating instantaneous values over an arbitrary time period, usually 15 min values for 1 h. The most common of these is watt-hours, although var-hours and amp-squared-hours are not uncommon. They are usually associated with energy interchange over interconnecting tie lines, generator output, at the boundary between a transmission provider and distribution utility or the load of major customers. In most instances, they originate from a revenue measuring package, which includes revenue grade instrument transformers and one or more watt-hour and var-hour meters. Most utilities provide remote and/or automatic reading through the utility meter reading system. They also can be interfaced to a SA system.

Integrated energy transfer values are traditionally recorded by counting the revolutions of the disk on an electromechanical watt-hour meter. Newer technology makes this concept obsolete but the integrated interchange value continues as a mainstay of energy interchange between utilities and customers. In the old technology a set of contacts opens and closes in direct relation to the disk rotation, either mechanically from a cam driven by the meter disk shaft or through the use of opto-electronics and a light beam interrupted by or reflected off the disk. These contacts may be standard form “A,” form “B,” form “C,” or a form “K,” which is peculiar to watt-hour meters. Modern revenue meters often mimic this feature, as do some transducers. Each contact transfer (pulse) represents an increment of energy transfer as measured by a watt-hour meter. Pulses are accumulated over a period of time in a register and then the total is recorded on command from a clock.

When applied to SA systems, energy transfer measurements are processed by metering IEDs, pulse accumulators (PAs) in an RTU, or SA controllers. The PA receives contact closures from the metering package and accumulates them in a register. On command, the pulse count is frozen, then reported to an appropriate data user. The register is sometimes reset to zero to begin the cycle for the next period. This command is synchronized to a master clock, and all "frozen" accumulator measurements are reported some time later when time permits. Some RTUs can freeze and store their PAs from an internal or local external clock should the master "freeze-and-read command" be absent. These may be internally "time tagged" for transmission when commanded by the master station. High-end meter IEDs retain interval accumulator reads in memory that can be retrieved by the utility automatic meter reading system. They may share multiple ports and supply data to the SA system. Other options may include the capability to arithmetically process several demand measurements to derive a resultant. Software to "de-bounce" the demand contacts is also sometimes available.

Integrated energy transfer telemetering is almost always provided on tie lines between bordering utilities and at the transmission—distribution or generation—transmission boundaries. The location of the measuring point is usually specified in the interconnection agreement contract, along with a procedure to insure metering accuracy. Some utilities agree to share a common metering point at one end of a tie and electronically transfer the interchange reading to the bordering utility. Others insist on having their own duplicate metering, sometimes specified to be a "back-up" service. When a tie is metered at both ends, it is important to verify that the metering installations are within expected agreement. Even with high-accuracy metering, however, some disagreement can be expected, and this is often a source of friction between utilities.

6.3 State (Status) Monitoring

State indications are an important function of SA systems. Any system indication that can be resolved into a small number of discrete states can be handled as state (status or binary) indication. These are items where the monitored device can assume states like "on or off," "open or closed," "in or out," but states in between are unimportant or not probable. Examples include power circuit breakers, circuit switchers, reclosers, motor-operated disconnect switches, pumps, battery chargers, and a variety of other "on–off" functions in a substation. Multiple on–off states are sometimes grouped to describe stepping or sequential devices. In some cases, status points might be used to convey a digital value such as a register where each point is one bit of the register.

Status points may be provided with status change memory so that changes occurring between data reports are observable. State changes may also be "time tagging" to provide sequence of events. State changes can also be counted in a register and be reported in several different formats. Many status indications originate from auxiliary switch contacts that are mechanically actuated by the monitored device. Interposing relay contacts are also used for status points where the interposer is driven from auxiliary switches on the monitored equipment. This practice is common depending on the utility and the availability of spare contacts. Interposing relays are also used to limit the exposure of status point wiring to the switchyard environment. Many IEDs provide state indication from internal electronic switches that function as contacts.

6.3.1 Contact Performance

The mechanical behavior of either relay or auxiliary switch contacts can complicate state monitoring. Contacts may electrically open and close several times as the moving contact bounces against a stationary contact when making the transition (mechanically bounce). Many transitions can occur before the contacts finally settling into their final position. The system input point may interpret the bouncing contact as multiple operations of the primary device. A number of techniques are used to minimize the effects of bouncing contacts. Some systems rely on "C" form contacts for status indications so that status changes are recognized only when one contact closes proceeded by the opening of its companion. Contact changes occurring on one contact only are ignored. "C" contact arrangements are more immune to noise pulses. Another technique to deal with bouncing is to wait for a period of time after the first input change before re-sampling the input, giving the contact a chance to bounce into its final state.

Event recording with high-speed resolution is particularly sensitive to contact bounce as each transition is recorded in the log. When the primary device is subject to pumping or bouncing induced from its mechanical characteristics, it may be difficult to prevent excessive status change reporting. When interposing devices are used event contacts can also experience unwanted delays that can confuse interpretation of event timing sequences. While this may not be avoidable, it is important to know the response time of all event devices so that event sequences can be correctly interpreted.

IEDs often have de-bounce algorithms in their software to filter contact bouncing. These algorithms allow the user to "tune" the de-bouncing to be tolerant of bouncing contacts. However tempting the "tuning" out the bouncing might be, tuning might cover a serious equipment problem that is the root cause.

6.3.2 Ambiguity

State monitoring can be subject to a certain degree of ambiguity. Where a monitored device is represented by a single input, a change of state is inferred when that input changes. However, the single input does not really indicate that the state has changed but that the previous state is no longer valid. Designers need to consider the consequences of this ambiguity. Devices that have significant impact if their state is misrepresented should have two inputs so that two changes must occur that are complimentary to better insure the state of the end device is known. Some designers flag the instances where the two input configurations assume a state where inputs are ambiguous as alarm points.

It is also possible to inject ambiguous state indications into a system by operating practices of the devices. For example, if a circuit breaker is being test operated its indication points may be observed by the system as valid changes that result in log entries or alarm indications. Likewise, a device may show an incorrect state when it has been removed from service as when a circuit breaker or switcher has its control power disconnected or is "racked" into an inoperative or disconnected position in switchgear. Ambiguity may also result from the loss of power to the monitoring device. Loss of a communications link or a software restart on an intermediary device can also introduce ambiguity.

As much as it is possible, it is important to insure users of state data that the data are not misrepresenting reality. The consequences of ambiguous data should be evaluated as part of any system design.

6.3.3 Wetting Sources

Status points are usually monitored from isolated, "dry," contacts and the monitoring power (wetting) is supplied from the input point. Voltage signals from a station control circuits can also be monitored by SA controllers and interpreted as status signals. Equipment suppliers can provide a variety of status point input options. When selecting between options the choice balances circuit isolation against design convenience. The availability of spare isolated contacts often becomes an issue when making design choices. Voltage signals may eliminate the need for spare contacts, but can require circuits from various parts of the station and from different control circuits be brought to a common termination location. This compromises circuit isolation within the station and raises the possibility of test personnel causing circuit misoperation. Usually, switchboard wiring standards would be required for this type of installation, which could increase costs. Voltage inputs are often fused with small fuses at the source to minimize the risk the exposed wiring will compromise the control circuits.

In installations using isolated dry contacts, the wetting voltage is sourced from the station battery, a SA controller, IED supply, or on some occasions, station AC service. Each monitored control circuit must then provide an isolated contact for status monitoring. Isolating circuits at each control panel improves the overall security of the installation. It is common for many status points to share a common supply, either station battery or a low-voltage supply provided for this purpose. When status points are powered from the station battery, the monitored contacts have full control voltages appearing across their surfaces and thus can be expected to be more immune to open circuit failures from contact surface contamination. Switchboard wiring standards would be required for this type of installation. An alternative source for status points is a low-voltage wetting supply. Wiring for low-voltage sourced status points may not need to be switchboard standard in this application, which may realize some economies. Usually, shielded, twisted pairs are used with low-voltage status points to minimize noise effects. Concern over contact reliability due to the lower "wetting" voltage can be partially overcome by using contacts that are closed when the device is in its normal position, thereby maintaining a loop current through the contact. Some SA systems provide a means to detect wetting supply failure for improved reliability. Where multiple IEDs are status point sources it can be difficult to detect a lost wetting supply. Likewise, where there are multiple points per IED and multiple IED sources, it can be challenging to maintain isolation.

In either approach, the status point loop current is determined by the monitoring device design. Generally, the loop current is 1.0 to 20 mA. Filter networks and/or software filtering is usually provided to reduce noise effects and false changes resulting from bouncing contacts.

6.3.4 Wiring Practices

When wiring status points, it is important to ensure that the cable runs radially between the monitor and the monitored device. Circuits where status circuit loops are not parallel pairs are subject to induced currents that can cause false status changes. Circular loops most often occur when existing spare cable conductors in multiple cables are used or when using a common return connection for several status points. Designers should be wary of this practice. The resistance of status loops can also be an important consideration. Shielded, twisted pairs make the best interconnection for status points, but this type of cable is not always readily available in switchboard standard sizes and insulation for use in control battery-powered status circuits.

Finally, it is important to provide for testing status circuits. Test switches or jumper locations for simulating open or closed status circuits are needed as well as a means for isolating the circuit for testing.

6.4 Control Functions

The control functions of electric utility SA systems permit routine and emergency switching, local and remote operating capability for station equipment, and action by programmed logic. SA controls are most often provided for circuit breakers, reclosers, and switchers. Control for voltage regulators, tap-changing transformers, motor-operated disconnects, valves, or even peaking units through a SA system is also common.

A variety of different control outputs are available from IEDs and SA controllers, which can provide both momentary timed control outputs and latching-type interposing. Latching is commonly associated with blocking of automatic breaker reclosing or voltage controllers for capacitor switching. A typical interface application for controlling a circuit breaker is shown in Fig. 6.6.

6.4.1 Interposing Relays

Power station controls often require high power levels and operate in circuits powered from 48, 125, or 250-VDC station batteries or from 120 or 240-VAC station service. Control circuits often must switch 10

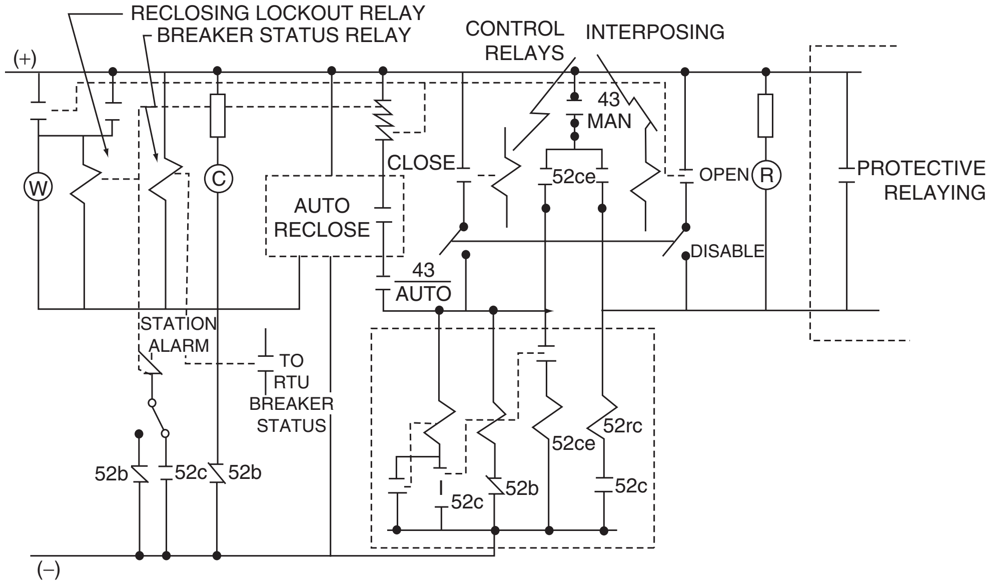

FIGURE 6.6 Schematic diagram of a breaker control interface.

or 20 A to affect their action that imposes constraints on the interposing devices. The interposing between a SA controller or IED and station controls commonly use large electromechanical relays. Their coils are driven by the SA control system through static or pilot duty relay drivers and their contacts switch the station control circuits. Interposing relays are often specified with 25 A, 240 VAC contact rating to insure adequate interrupting duty. Smaller interposing relays are also used, however, often with only 10 or 3 A contacts, where control circuits allow. When controlling DC circuits, the large relays may be required, not because of the current requirements, but to provide the long contact travel needed to interrupt the arc associated with interrupting an inductive DC circuit. Note that most relays, which would be considered for the interposing function, do not carry DC interrupting ratings. "Magnetic blowout" contacts, contacts fitted with small permanent magnets, which lengthen the interruption arc to aid in extinguishing it, may also be used to improve interrupting duty. They are polarity sensitive, however, and work only if correctly wired. Correct current flow direction must be observed.

Many SA controllers and IEDs require the use of surge suppression to protect their control output contacts. A fast switching diode may be used across the driven coil to commute the coil collapse transient when the coil is de-energized. As the magnetic field of the device coil collapses on de-energization, the coil voltage polarity reverses and the collapsing field generates a back electric and magnetic field (EMF) in an attempt to sustain the coil current. The diode conducts the back EMF and prevents the build up of high voltage across the coil. The technique is very effective. It requires the diode to handle the steady-state current of the coil and be able to withstand at least three times the steady-state voltage. However, control circuits that have a high capacitive impedance component often experience ringing transients that simple diodes do not commute. Rather, the simple diode causes the transient to be offset and allows it to continue ringing. These applications require clamping for both the discharge and oscillatory transients where Zener diodes are better suited. Failure of a suppression diode in the shorted mode will disable the device and cause a short circuit to the control driver, although some utilities use a series resistor with the diode to reduce this reliability problem. Some designers select the diode to be "sacrificial" so that if it fails, it is vaporized to become an open circuit instead of a short.

Other transient suppressors that are effective for ringing transients include Transorbs and MOV. Transorbs behave like back to back zener diodes and clamp the voltage across their terminals to a specified voltage. They are reasonably fast. MOVs are very similar but the suppression takes place as the voltages across them cause the metal oxide layers to break down and they are not as fast. Both Transorbs and MOVs have energy ratings in joules. They must be selected to withstand the energy of the device coil. In many applications, designers choose to clamp the transients to ground with Transorbs and MOVs rather than clamping them across the coil. In this configuration, the ground path must be of low impedance for the suppression to be effective. Where multiple suppressors are used, it is important to insure surge suppressors are coordinated so that they clamp around the same voltage and have similar switching and dissipation characteristics. Without coordination, the smallest, lowest voltage device will become sacrificial and become a common point of failure.

6.4.2 Control Circuit Designs

Many station control circuits can be designed so that the interrupting duty problem for interposing devices is minimized thereby allowing smaller interposers to be used. These circuits are designed so that once they are initiated, some other contact in the circuit interrupts control current in preference to the initiating device. The control logic is such that the initiating contact is bypassed once control action begins, and remains bypassed until control action is completed. The initiating circuit current is then interrupted, or at least greatly reduced, by a device in another portion of the control circuit. This eliminates the need for the interposing relay to interrupt heavy control circuit current. This is typical of modern circuit breaker closing circuits, motor-operated disconnects, and many circuit switchers. Other controls that "self-complete" are breaker tripping circuits, where the tripping current is interrupted by the breaker auxiliary switch contacts long before the initiating contact opens. This is not true of circuit breaker closing circuits, however. Closing circuits usually must interrupt the coil current of the "anti-pump" elements in the circuit that can be highly inductive.

Re-designing control circuits often simplifies the application of control. The need for large interposing relay contacts can be eliminated in many cases by simple modifications to the controlled circuit to make them "self completing." An example of this would be the addition of any auxiliary control relay to a breaker control circuit, which maintains the closing circuit until the breaker has fully closed and provides antipumping should it trip free. This type of revision is often desirable, anyway, if a partially completed control action could result in some equipment malfunction.

Control circuits may also be revised to limit control circuit response to prevent more than one action from taking place while under supervisory control. This includes preventing a circuit breaker from "pumping" if it were closed into a fault or failed to latch. Another example is to limit tap changer travel to move only one tap per initiation. Many designers try to insure that a device cannot give simultaneous complementary control signals such as giving a circuit breaker a close and trip signal at the same time. This can be important in controlling stand-by or peaking generator where the control circuits might not be designed with remote control in mind.

6.4.3 Latching Devices

It is often necessary to modify control circuit behavior when SA control is used to operate station equipment. Control mode changes that would ordinarily accompany a local operator performing manual operation must also occur when action occurs through SA control. Many of these require latched interposing relays that modify control behavior when supervisory control is exercised, and can be reset through SA or local control. The disabling of automatic circuit breaker reclosing when a breaker is opened through supervisory control action is an example. Automatic reclosing must also be restored and/or reset when a breaker is closed through supervisory control. This concept also applies to automatic capacitor switcher controls that must be disabled when supervisory control is used and can be restored to automatic control through local or supervisory control.

These types of control modifications generally require a latching-type interposing design. Solenoid-operated control switches have become available which can directly replace a manual switch on a switchboard and can closely mimic manual control action. These can be controlled through supervisory control, and can frequently provide the proper control behavior.

6.4.4 Intelligent Electronic Devices for Control

IEDs often have control capability accessible through their communications ports. Protective relays, panel meters, recloser controls, and regulators are common devices with control capability. They offer the opportunity to control substation equipment without a traditional RTU and/or interposing relay cluster for the interface, sometimes without even any control circuit additions. Instead, the control interface is embedded in the IED. When using embedded control interfaces the SA system designer needs to assess the security and capability of the interface provided. These functional requirements for a control interface should not change just because the interface devices are within an IED. External interposing may be required to meet circuit loads or interrupting duty.

When controlling equipment with IEDs over a communications channel, the integrity of the channel and the security of the messaging system become important factors. Not all IEDs have select-before-operate capability common to RTUs and SCADA systems. Their protocols may also not have efficient error detection that could lead to misoperation. In addition, the requirements to have supervisory control disabled for test and maintenance should not impact the IED's primary function.

Utilities are showing increasing interest in using PLCs in substations. PLCs have broad application in any number of industrial control applications and have a wide variety of input/output modules, processors, and communications options available. They are also well supported with development tools and have a programming language standard, IEC-61131-3, which proposes to offer significant portability to PLC user's software. In substation applications designers need to be wary of the stresses that operating DC controls may impose on PLC I/O modules. PLCs also may require special power supply considerations to work reliably in the substation environment. Still, PLCs are a flexible platform for logic applications such as interlocking and process control applications such as voltage regulation and load shedding.

6.5 Communications Networks Inside the Substation

SA systems are based on IEDs that share information and functionality by virtue of their communications capability. The communications interconnections may use hard copper, optical fiber, wireless, or a combination of these. The communications network is the glue that binds the system together. The communications pathways may vary in complexity depending on the end goals of the system. Ultimately, the internal network passes information and functionality around the substation and upward to the utility enterprise. Links to the enterprise may take a number of different forms and will not be discussed in this chapter.

6.5.1 Point to Point Networks

The communications link from an IED to the SA system may be a simple point to point connection where the IED connects directly to a SA controller. Many IEDs connect point to point to a multiported controller or data concentrator, which serves as the SA system communications hub. In early integrations, these connections were simple RS-232 serial pathways similar to those between a computer and a modem. RS-232 does not support multiple devices on a pathway. Some IEDs will not communicate on a party line since they do not support addressing and have only primitive message control. RS-232 is typically used for short distance, only 50 feet. Most RS-232 connections are also solid device to device. Isolating RS-232 pathways requires special hardware. Often, utilities use point to point optical fiber links to connect RS-232 ports together to insure isolation.

6.5.2 Point to Multipoint Networks

Most automation systems rely on point to multipoint connections for IEDs. IEDs that share a common protocol often support a "party line" communications pathway where they share a channel. A SA controller may use this as a "master–slave" communications bus where the SA controller controls the traffic on the channel. All devices on a common bus must be addressable so that only one device communicates at a time. The SA controller communicates to each device one at a time so as to prevent communications collisions.

RS-485 is the most common point to multipoint bus. It is a shielded, twisted copper pair, terminated at each end of the bus with a termination resistor equal to the characteristic impedance of the bus cable. RS-485 buses support 32 devices on the channel. Channel length is typically 4000 ft maximum length. The longer the bus the more likely communications error will occur because of reflections on the transmission line; therefore the longer the bus the slower it normally runs. RS-485 may run as fast as 1.0 megabits per second although most operate closer to 19.2 kbps or slower. The RS-485 bus must be linear, end to end. Stubs or taps will cause reflections and are not permitted. RS-485 devices are wired in a "daisy chain" arrangement. RS-422 is similar to RS-485 except it is two pairs: one outbound and one inbound. This is in contrast to RS-485 where messages flow in both directions as the channel is turned around when each device takes control of the bus while transmitting.

6.5.3 Peer to Peer Networks

There is a growing trend in IEDs communications to support peer to peer messaging. Here, each device has equal access to the communications bus and can message any other device. This is substantially different than a master–slave environment even where multiple masters are supported. A peer to peer network must provide a means to prevent message collisions, or to detect them and mitigate the collision.

PLC communications and some other control systems use a token passing scheme to give control to devices along the bus. This is often called "token ring." A permissive message (the token) is passed from device to device along the communications bus that gives the device authority to transmit messages. Different schemes control the amount of access time each "pass" allows. While the device has the "token," it may transmit messages to any other device on the bus. These busses may be RS-485 or higher speed coaxial cable arrangements. When the token is lost or a device fails, the bus must restart. Therefore, token ring schemes must have a mechanism to recapture order.

Another way to share a common bus as peers is to use a carrier sense multiple access with collision detection (CSMA/CD) scheme. Ethernet, IEEE Standard 802.x is such a scheme. Ethernet is widely used in the information technology environment and is finding its way into substations. Ethernet can be coaxial cable or twisted pair cabling. UTP cable, Category V (CAT V), is widely used for high-speed Ethernet local area networks (LANs). Some utilities are extending their wide area networks (WANs) to substations where it becomes both an enterprise pathway and a pathway for SCADA and automation. Some utilities are using LANs within the substation to connect IEDs together. A growing number of IEDs support Ethernet communication over LANs. Where IEDs cannot support Ethernet, some suppliers offer network interface modules (NIMs) to make the transition. A number of different communications protocols are appearing on substation LANs, embedded in a general purpose networking protocol such as TCP/IP (Internet Protocol).

While Ethernet can be a device to multiple device network like RS-485, it is more common to wire devices to a hub or router. Each device has a "home run" connection to the hub. In the hub the outbound path of each device connects to inbound path of all other devices. All devices hear a message from one device. Hubs can also acquire intelligence and perform a switching service. A switched hub passes outbound messages only to the intended recipient. That allows more messages to pass through without busying all devices with the task of figuring out for whom the message is intended. Switched hubs also mitigate collisions such that individual devices can expect its channel to be collision free. Switched hubs can also add delays in message passing, as the hub must examine every message address and direct it to the addressee's port. Routers connect segments of LANs and WANs together to get messages in the right place and to provide security and access control. Hubs and routers require operating power and therefore must be provided with a high reliability power source in order to function during interruptions in the substation.

6.5.4 Optical Fiber Systems

Optical fiber is an excellent media for communicating within the substation. It isolates devices electrically because it is nonconducting. This is very important because high levels of radiated electromagnetic fields and transient voltages are present in the substation environment.

Optical fiber can be used in place of copper cable runs to make point to point connections. A fiber media converter is required to make the transition from the electrical media to the fiber. They are available in many different configurations. The most common are Ethernet and RS-232 to fiber but they are also available for RS-485 and RS-422. Fiber is ideal for connecting devices in different substation buildings or out in the switchyard. Figure 6.7 illustrates a SCADA system distributed throughout a substation connected together with a fiber network.

6.5.4.1 Fiber Loops

Low-speed fiber communications pathways are often provided to link multiple substation IEDs together on a common channel. The IEDs could be recloser controls, PLCs, or even protective relays distributed throughout the switchyard. While fiber is a point to point connection, fiber modems are available that provide a repeater function. Messages pass through the modem, in the RX port and out the TX port, to form a loop as illustrated in the Fig. 6.8. When an IED responds to a message, it breaks the loop and sends its message on toward the head of the loop. The fiber cabling is routed around to all devices to make up the loop. However, a break in the loop will make all IEDs inaccessible. Another approach to this architecture is to use bi-directional modems that have two paths around the loop. This technique is immune to single-fiber breaks. It is also easy to service.

Some utilities implement bi-directional loops to reach multiple small substations close to an access point to save building multiple access points. When the access point is a wire line that requires isolations, the savings can be substantial. Also, the devices may not be accessible except through a power cable duct system such as urban areas that are served by low-voltage networks. Here the extra cost of the bi-directional fiber loop is often warranted.

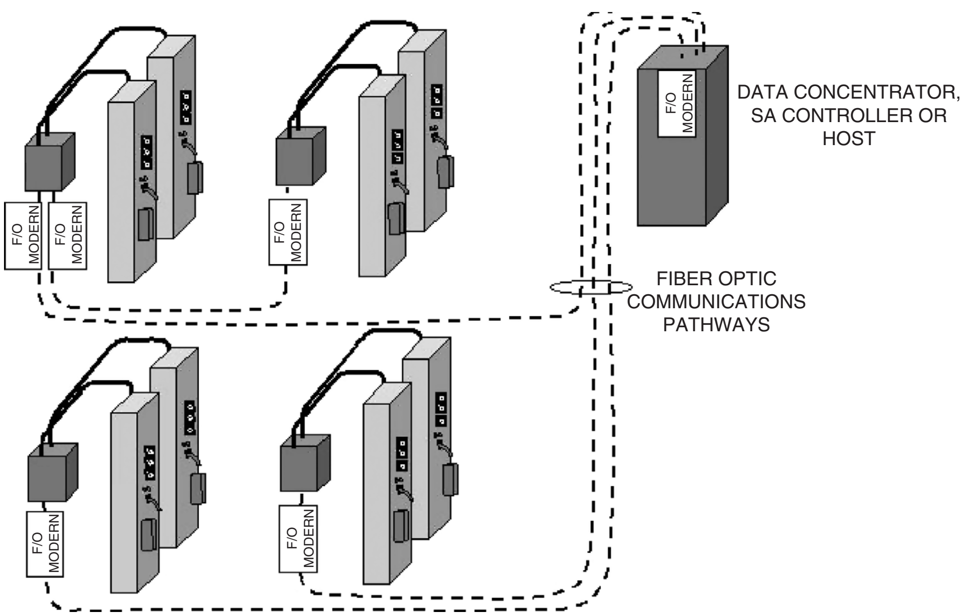

FIGURE 6.7 A fiber optic network for distributed SCADA and automation.

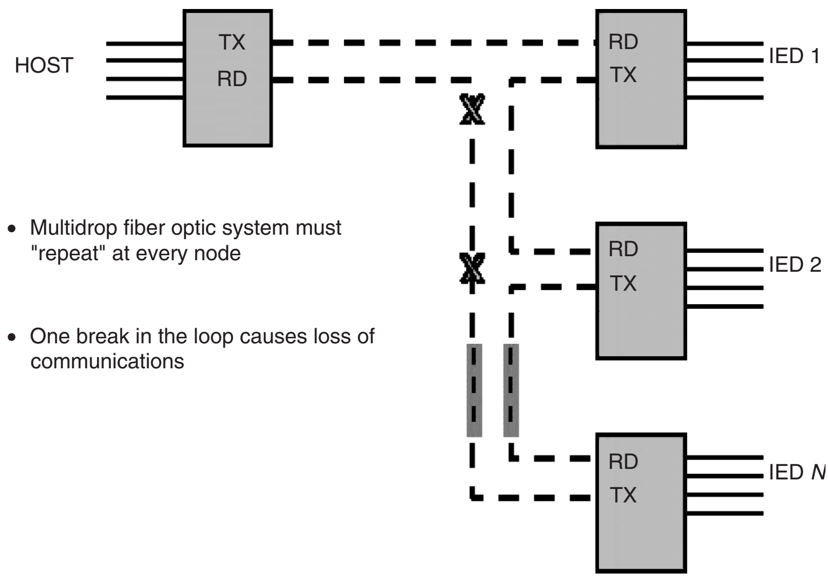

FIGURE 6.8 Fiber optic loop.

6.5.4.2 Fiber Stars

Loop topology does not always fit substation applications. Some substation layouts better fit a “star” configuration where all the fiber runs are home runs to a single point. To deal with star topologies there are alternatives. The simplest is to use multistrand fiber cables and make a loop with butt splices at the central point. While the cable runs can all be home runs the actual configuration is a loop. However, there are star configuration fiber modems available, which eliminate the need for creating loops. This modem supports multiple F/O ports and combines them to single port. Typically, the master port is an RS-232 connection where outgoing messages on the RS-232 port are sent to all outgoing optical ports and returning messages are funneled from the incoming optical ports to the receive side of the RS-232 port. Another solution is to make the modems at the central point all RS-485 where the messages can be distributed along a short RS-485 bus.

6.5.4.3 Message Limitations

In the above discussion there are two limitations imposed by the media. First, there is no provision for message contention and collision detection. Therefore, the messaging protocol must be master slave or the modems must deal with the possibility of collisions. Unsolicited reporting will not work because of the lack of collision detection. In fiber loop topologies, outgoing message will be injected into the loop at the head device and travel the full circumference of the loop and reappear as a received message to the sender. This can be confusing to some communications devices at the head end. That device must be able to ignore its own messages.

6.5.4.4 Ethernet Over Fiber

As IEDs become network ready and substation SCADA installations take a more network-oriented topology, fiber optic links for Ethernet will have increasing application in substations. Just as with slower speed fiber connections, Ethernet over fiber is great for isolating devices and regions in the substation. There are media converters and fiber ready routers, hubs, and switches readily available for these applications. Because Ethernet has a collision detection system the requirement to control messaging via a master–slave environment is unnecessary. The routers and switches take care of that problem. The star configuration is also easily supported with a multiport fiber router.

6.5.5 Communications between Facilities

Some utilities have leveraged their right of ways into optical fiber communications systems. Fiber optic (F/O) technology is very wide band and therefore capable of huge data throughputs of which SCADA and automation messaging might represent only a tiny fraction of the available capacity.

Utilities have taken different paths in dealing with F/O opportunities. Some have chosen to leverage the value of their existing right of way by building their own F/O communications networks and leasing services to others. Still other utilities have leased just the right of way to a telecommunications provider for income or F/O access for their own use. Using a piece of the F/O highway for SCADA or automation is an opportunity. But, if the highway needs to be extended to reach the substation, the cost can get high.

Typical F/O systems are based around high-capacity SONET communications technology. Telecommunications people see these pathways as high-utilization assets and tend to try to add as many services to the network as possible. SCADA and automation communications can certainly be part of such a network. Some industry experts believe that the power system operations communications, SCADA, ought to reside on its own network for security and not share the close proximity to corporate traffic that is part of an F/O network.

F/O technology has another application that is very valuable for SCADA and automation. Because F/O is nonconductive, it is a perfect medium for connecting communicating devices that may not share a solid ground plane. This is typical of substation equipment. These applications do not need the high bandwidth properties and use simple low-speed F/O modems. F/O cable is also low cost. This allows devices in outbuildings to be safely interconnected. It is also an excellent method to isolate radio equipment from substation devices to lessen the opportunity for lightening collected by radios to damage substation devices.

6.5.6 Communications Network Reliability

The more the functionality of the SA system is distributed to IEDs, the more critical the communications network becomes. The network design can easily acquire single points of failure sensitivities that can cripple the entire system and even affect substation functions. System designers need to make a risk assessment of their proposed communication architecture to assure users it can meet their expectations for reliability. Designers may need to duplicate critical components and pathways to meet their goals. They may also choose to segment IEDs into parallel networks to maintain high reliability. It may be appropriate to separate critical IEDs from those that are not as critical. Still, designers need to look after details such as power sources, cable separation, panel assignments, and pathway routes to maintain adequate performance.

6.6 Testing Automation Systems

Testing assures the quality and readiness of substation equipment. A SA system will require testing at several points along its life span. It is important to make allowances for testing within the standard practices of the utility. While testing practices are part of the utility "culture," designing the testing facilities for SA system with enough flexibility to allow for culture change in the future will be beneficial. Surely, testing can have a great impact on the availability of the automation system and under some circumstance, the availability of substation power equipment and substation reliability. Testing can be a big contributor to operation and maintenance (O & M) cost.

6.6.1 Test Facilities

SA systems integrate IEDs whose primary function may be protection, operator interface, equipment control, and even power interchange measurement for monetary exchange. A good test plan allows for the automation functions to be isolated from the substation while the primary functions of the IEDs remain in operation.

6.6.1.1 Control

It is necessary to test automation control to confirm control point mapping to operator interfaces and databases. This is also necessary for programmed control algorithms. Utilities want to be sure that the right equipment operates when called upon. Having the wrong equipment operate, or nothing at all operate, will severely hamper confidence in the system. Since any number of substation IEDs may be configured to control equipment, test methods must be devised to facilitate testing without detrimental impact on the operation of the substation. Disconnect points and operation indicators may be needed for this purpose. For example, if a breaker failure relay is also the control interface for local and remote control of its associated circuit breaker, then it should be possible to test the control functions without having to shut the breaker down because it would be without breaker failure protection. If the breaker control portion of the breaker failure relay can be disabled without disabling its protective function then testing may be straightforward. However, some utilities solve this problem by disabling all the breaker failure outputs and allowing the circuit breaker to remain in service without protection for short periods of time while control is being tested. Other utilities rely on a redundant device to provide protection while one device is disabled for testing. These choices are made based on the utility's experience and comfort level. Work rules sometimes dictate testing practices.

While being able to disable control output is necessary, it is also important to be able to verify the control output has occurred when it is stimulated. With IEDs, it is often not possible to view the control output device since it is buried within the IED. It may be useful to install indicators to show the output device is active. Otherwise, at least a temporary indicating device is needed to verify that control has taken place. At least once during commissioning, every control interface should operate its connected power equipment to assure that interface actually works.

6.6.1.2 Status Points

Status point mapping must also be tested. Status points appear on operator interface displays, logs of various forms and may be data sources for programmed logic or user algorithms. They are important for knowing the state of substation equipment. Any number of IEDs may supply state information to an automation system. Initially, it is recommended that the source equipment for status points be exercised so that the potential for contact bounce to cause false indications is evaluated. Simulating contact state changes at the IED input by shorting or opening the input circuits is often used for succeeding tests. Disconnect points make that task easier and safer.

As with control points, some care must be exercised when simulating status points. Status changes will be shown on operator interfaces and entered into logs. Operators will have to know to disregard them and cleanse the logs after testing is completed. Since the IED monitors the status point for its own function, the IED may need to be disabled during status point testing. If the automation system has programmed logic processes running it is possible that status changes will propagate to into the algorithms and cause unwanted actions to take place. These processes need to be disabled or protected from the test data.

6.6.1.3 Measurements

Measurements may also come from many different substations IEDs. They feed operator interfaces, databases, and logs. They may also feed programmed logic processes. Initially, measuring IEDs need to have their measurements checked for reasonability. Reasonability tests include making sure the sign of the measurement is as expected in relation to the power system and that the data values accurately represent the measurements. Utilities rarely calibrate measuring IEDs as they once did transducers, but reasonability testing should target uncovering scaling errors and incorrectly set CT and PT ratios. Most utilities provide disconnect and shorting switches (test switches) so that measuring IEDs can have test sources connected to them. That allows known voltage and currents to be applied and the results checked against the expected value. Test switches can be useful in the future if the accuracy of the IEDs falls into question. They also simplify replacing the IED without shutting down equipment if it fails in service.

Some IEDs allow the user to substitute test values in place of "live" measurements. Setting test values can greatly simplify checking the mapping of values through the system. By choosing a "signature" value, it is easy to discern test from live values as they appear on screens and logs. This feature is also useful for checking alarm limits and for testing programmed logic.

During testing of measuring IEDs, some care must be exercised to prevent test data from causing operator concerns. Test data will appear on operator interface displays. It may trigger alarm messages and make log entries. These must be cleansed from logs after testing is completed. Since measuring IEDs may feed data to programmed logic processes it is important to disable such processes during testing to prevent unwanted actions. Any substituted values need to be returned to live measurements at the end of testing as well.

6.6.1.4 Programmed Logic

Many SA systems include programmed logic as a component of the system. Programmed logic obtains data from substation IEDs and provides some output to the substation. Output often includes control of equipment such as voltage regulation, reactive control, or even switching. Programmed logic is also used to provide interlocks to prevent potentially harmful actions from taking place. These algorithms must be tested to insure they function as planned. This task can be formidable. It requires data inputs are provided and the outputs checked against expected result. A simulation mode in the logic host can be helpful in this task. Some utilities use a simulator to monitor this input data as the source IEDs are tested. This verifies the point mapping and scaling. They may also use a simulator to monitor the result of the process based on the inputs. Simulators are valuable tools for testing programmed logic. Many programs are so complex that they cannot be fully tested with simulated data, therefore their results may not be verifiable. Some utilities allow their programmed logic to run off of live data with a monitor watching the results for a test period following commissioning to be sure the program is acceptable.

6.6.2 Commissioning Test Plan

Commissioning a SA system requires a carefully thought out test plan. There needs to be collaboration between users, integrators, suppliers, developers, and constructors. Many times, the commissioning test plan is an extension of the factory acceptance test (FAT), assuming a FAT was performed. Normally the FAT does not have enough of the substation pieces to be comprehensive therefore the real "proof test" will be at commissioning. Once the test plan is in place it should be rigorously adhered to. Changes to the commissioning test plan should be documented and accepted by all parties. Just as in the FAT, a record of deviations from expected results should be documented and later remedied.

A key to a commissioning test plan is to make sure every input and output that is mapped in the system is tested and verified. Many times this cannot be repeated once the system is in service.

6.6.3 In-Service Testing

Once an automation system is in service it will become more difficult to thoroughly test. Individual IEDs may be replaced or updated without a complete end to end check because of access restriction to portions of the system. Utilities often feel exchanging "like for like" is not particularly risky. However, this assumes the new device has been thoroughly tested to insure it matches the device being replaced. Often the same configuration file for the old device is used to program the new device hence further reducing the risk. Some utilities purchase an automation simulator to further test new additions and replacements.

However, new versions of IEDs, databases, and communications software should make the utility wary of potential problems. It is not unusual for new software to include bugs that had previously been corrected as well as new problems in what were previously stable features. Utilities must decide to what level they feel new software versions need to be tested. A thorough simulator and bench test is in order before beginning to deploy new software in the field. It is important to know what versions of software are resident in each IED and the system host. Keeping track of the version changes and resulting problems may lead to significant insights.

Utilities must expect to deal with in-service support issues that are common to integrated systems.

6.7 Summary

The addition of SA systems control impacts station security and deserves a great deal of consideration. It should be recognized that SA control can concentrate station controls in a small area and can increase the vulnerability of station control to human error and accident. This deserves careful attention to the control interface design for SA systems. The security of the equipment installed must insure freedom from false operation, and the design of operating and testing procedures must recognize these risks and minimize them.

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IEEE Standard C37.90.1-2002 IEEE Standard for Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus.

IEEE Standard 1613–2003 IEEE Standard Environmental and Testing Requirements for Communications Networking Devices in Electric Power Substations.

IEEE Standard C37.1-1994 IEEE Standard Definition, Specification, and Analysis of Systems Used for Supervisory Control, Data Acquisition, and Automatic Control (Current edition 2.0, 2003–10).

7

Substation Integration and Automation

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7.1 Introduction

Electric utility deregulation, economic pressures forcing downsizing, and the marketplace pressures of potential takeovers have forced utilities to examine their operational and organizational practices. Utilities are realizing that they must shift their focus to customer service. Customer service requirements all point to one key element: information—the right amount of information to the right person or computer within the right amount of time. The flow of information requires data communication over extended networks of systems and users. In fact, utilities are among the largest users of data and are the largest users of real-time information.

The advent of industry deregulation has placed greater emphasis on the availability of information, the analysis of this information, and the subsequent decision making to optimize system operation in a competitive environment. The intelligent electronic devices (IEDs) being implemented in today's substations contain valuable information, both operational and nonoperational, needed by many user groups within the utility. The challenge facing utilities is determining a standard integration architecture that can meet the utility's specific needs, can extract the desired operational and nonoperational information, and can deliver this information to the users who have applications to analyze the information.

7.2 Definitions and Terminology

Substation integration and automation can be broken down into five levels, as seen in Table 7.1. The lowest level is the power system equipment, such as transformers and circuit breakers. The middle three levels are IED implementation, IED integration, and substation automation (SA) applications. All electric utilities are implementing IEDs in their substations. The focus today is the integration of the IEDs. Once this is done, the focus will shift to what automation applications should run at the substation level. The highest level is the utility enterprise, and there are multiple functional data paths from the substation to the utility enterprise, as seen in Table 7.2.

Since the substation integration and automation technology is fairly new, there are no industry-standard definitions, except for the definition of an IED. The industry-standard definition of an IED is given below, as well as definitions for IED integration, SA, conventional remote terminal units (RTUs), data concentrator, operational data, and nonoperational data.

IED: Any device incorporating one or more processors with the capability to receive or send data or control from or to an external source (e.g., electronic multifunction meters, digital relays, controllers) [2,10].

IED integration: Integration of protection, control, and data acquisition functions into a minimal number of platforms to reduce capital and operating costs, reduce panel and control room space, and eliminate redundant equipment and databases.

SA: Deployment of substation and feeder operating functions and applications ranging from supervisory control and data acquisition (SCADA) and alarm processing to integrated volt/VAR control in order to optimize the management of capital assets and enhance operation and maintenance efficiencies with minimal human intervention.

Conventional RTU: Designed primarily for hardwired input/output (I/O) and has little or no capability to talk to downstream IEDs.

Data concentrator: Designed primarily for IED integration and may also have limited capability for hardwired I/O.

Operational data: Also called SCADA data, and are instantaneous values of power system analog and status points (e.g., volts, amps, MW, MVAR, circuit breaker status, switch position). The operational data is conveyed to the SCADA master station at the scan rate of the SCADA system (e.g., 10 sec for analog points, 2 sec for generation analog points, 2 sec for status points), using the SCADA system's communication protocol (e.g., DNP3 [distributed network protocol]). This data is time critical and is used to monitor and control the power system (e.g., opening circuit breakers, changing tap settings, equipment failure indication, etc.).

Nonoperational data: Consists of files and waveforms (e.g., event summaries, oscillographic event reports, or sequential event records) in addition to SCADA-like points (e.g., status and analog points) that have a logical state or a numerical value. This data is not needed by the SCADA dispatchers to monitor and control the power system. File data is transmitted intermittently, either on demand or event

TABLE 7.1 Five-Layer Architecture for Substation Integration and Automation

Utility Enterprise Connection
Substation Automation Applications
IED Integration via Data Concentrator/Substation Host Processor
IED Implementation
Power System Equipment (Transformers, Breakers)

triggered. Though it is not considered time critical, it is valuable data to receive within a short period of time. This data is the most challenging to obtain because it typically requires the IED supplier's proprietary ASCII commands for extraction.

7.3 Open Systems

An open system is a computer system that embodies supplier-independent standards so that software can be applied on many different platforms and can interoperate with other applications on local and remote systems. An open system is an evolutionary means for a substation control system that is based on the use of nonproprietary, standard software and hardware interfaces. Open systems enable future upgrades available from multiple suppliers at lower costs to be integrated with relative ease and low risk.

The concept of open systems applies to substation integration and automation. It is important to learn about the different de jure (legal) and de facto (actual) standards and then apply them so as to eliminate proprietary approaches. An open-systems approach allows the incremental upgrade of the automation system without the need for complete replacement, as happened in the past with proprietary systems. There is no longer a need to rely on one supplier for complete implementation. Systems and IEDs from competing suppliers are able to interchange and share information. The benefits of open systems include longer expected system life, investment protection, upgradeability and expandability, and readily available third-party components.

7.4 Architecture Functional Data Paths

There are three primary functional data paths from the substation to the utility enterprise, as seen in Table 7.2. The most common data path is conveying the operational data (e.g., volts, amps) to the utility's SCADA system every 2–4 sec. This information is critical for the utility's dispatchers to monitor and control the power system. The most challenging data path is conveying the nonoperational data to the utility's data warehouse. The challenges associated with this data path include the characteristics of the data (not necessarily points but, rather, files and waveforms), the periodicity of data transfer (not continuous but, rather, on demand), and the protocols used to obtain the data from the IEDs (not standard but, rather, IED supplier's proprietary protocols). Another challenge is whether the data are pushed from the substation into the data warehouse or pulled from the data warehouse or both. The third data path is remote access to an IED by "passing through" or "looping through" the substation integration architecture and isolating a particular IED in the substation.

7.5 Substation Integration and Automation System Functional Architecture

The functional architecture diagram in Fig. 7.1 shows the three functional data paths from the substation to the utility enterprise, as well as the SCADA system and the data warehouse. The operational data

TABLE 7.2 Three Functional Data Paths from Substation to Utility Enterprise

<table>
<tr><td colspan="3">Utility Enterprise</td></tr>
<tr><td>Operational Data to SCADA System</td><td>Nonoperational Data to Data Warehouse</td><td>Remote Access to IED</td></tr>
<tr><td colspan="3">Substation Automation Applications</td></tr>
<tr><td colspan="3">IED Integration</td></tr>
<tr><td colspan="3">IED Implementation</td></tr>
<tr><td colspan="3">Power System Equipment (Transformers, Breakers)</td></tr>
</table>

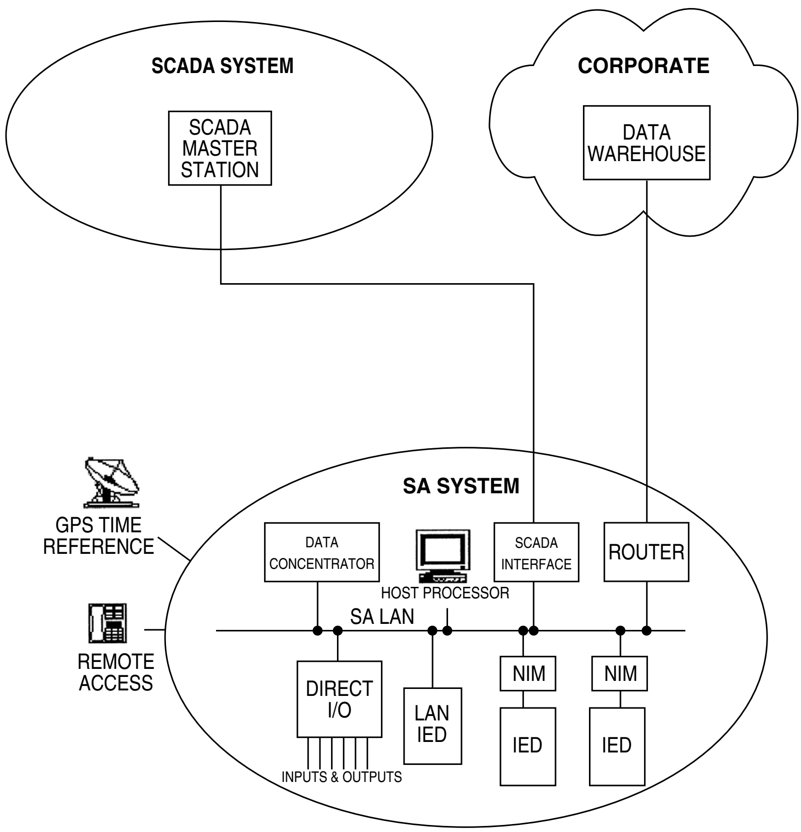

FIGURE 7.1 SA system functional architecture diagram.

path to the SCADA system utilizes the communication protocol presently supported by the SCADA system. The nonoperational data path to the data warehouse conveys the IED nonoperational data from the SA system to the data warehouse, either being pulled by a data warehouse application from the SA system or being pushed from the SA system to the data warehouse based on an event trigger or time. The remote access path to the substation utilizes a dial-in telephone connection. The global positioning system (GPS) satellite clock time reference is shown, providing a time reference for the SA system and IEDs in the substation. The host processor provides the graphical user interface and the historical information system for archiving operational and nonoperational data. The SCADA interface knows which SA system points are sent to the SCADA system, as well as the SCADA system protocol. The local area network (LAN)-enabled IEDs can be directly connected to the SA LAN. The non-LAN-enabled IEDs require a network interface module (NIM) for protocol and physical interface conversion. The IEDs can have various applications, such as equipment condition monitoring (ECM) and relaying, as well as direct (or hardwired) I/O.

7.6 New vs. Existing Substations

The design of new substations has the advantage of starting with a blank sheet of paper. The new substation will typically have many IEDs for different functions, and the majority of operational data for the SCADA system will come from these IEDs. The IEDs will be integrated with digital two-way communications. The small amount of direct I/O (hardwired) can be acquired using programmable logic controllers (PLCs). Typically, there are no conventional RTUs in new substations. The RTU functionality is addressed using IEDs and PLCs and an integration network using digital communications.

In existing substations there are several alternative approaches, depending on whether the substation has a conventional RTU installed. The utility has three choices for their existing conventional substation RTUs: integrate RTU with IEDs; integrate RTU as another substation IED; and retire RTU and use IEDs and PLCs, as with a new substation. First, many utilities have integrated IEDs with existing conventional RTUs, provided the RTUs support communications with downstream devices and support IED communication protocols. This integration approach works well for the operational data path, but it does not support the nonoperational and remote access data paths. The latter two data paths must be done outside of the conventional RTU. Second, if the utility desires to keep their conventional RTU, the preferred approach is to integrate the RTU in the substation integration architecture as another IED. In this way, the RTU can be easily retired when the RTU hardwired direct I/O transitions to come primarily from the IEDs. Third, the RTUs may be old and difficult to support and the SA project might be a good time to retire these older RTUs. The hardwired direct I/O from these RTUs would then come from the IEDs and PLCs, as with a new substation.

7.7 Equipment Condition Monitoring

Many electric utilities have employed ECM to maintain electric equipment in top operating condition while minimizing the number of interruptions. With ECM, equipment-operating parameters are automatically tracked to detect the emergence of various abnormal operating conditions. This allows substation operations personnel to take timely action when needed to improve reliability and extend equipment life. This approach is applied most frequently to substation transformers and high-voltage electric supply circuit breakers to minimize the maintenance costs of these devices, to improve their availability, and to extend their useful life.

Equipment availability and reliability can be improved by reducing the amount of off-line maintenance and testing required and by reducing the number of equipment failures. To be truly effective, ECM should be part of an overall condition-based maintenance strategy that has been properly designed and integrated into the regular maintenance program.

ECM IEDs are being implemented by many utilities. In most implementations, the communication link to the IED is via a dial-up telephone line. To facilitate integrating these IEDs into the substation architecture, the ECM IEDs must support at least one of today's widely used IED protocols: Modbus, Modbus Plus, DNP3, or IEC 870-5-101 or 104. In addition, a migration path to IEC 61850 is desired. If the ECM IEDs can be integrated into the substation architecture, the operational data will have a path to the SCADA system, and the nonoperational data will have a path to the utility's data warehouse. In this way, the users and systems throughout the utility that needs this information will have access to it. Once the information is brought out of the substation and into the SCADA system and data warehouse, users can share the information in the utility. The "private" databases that result in islands of automation will go away. Therefore, the goal of every utility is to integrate these ECM IEDs into a standard substation integration architecture so that both operational and nonoperational information from the IEDs can be shared by utility users.

7.8 Substation Integration and Automation Technical Issues

There are many technical issues in substation integration and automation. These issues are discussed in this section in the following areas: system responsibilities, system architecture, substation host processor, substation LAN requirements, substation LAN protocols, user interface, communication interfaces, and the data warehouse.

7.8.1 System Responsibilities

The system must interface with all of the IEDs in the substation. This includes polling the IEDs for readings and event notifications. The data from all the IEDs must be sent to the utility enterprise to

FIGURE 7.2 Substation automation system.

populate the data warehouse or be sent to an appropriate location for storage of the substation data. The system processes data and control requests from users and from the data warehouse. The system must isolate the supplier from the IEDs by providing a generic interface to the IEDs. In other words, there should be a standard interface regardless of the IED supplier. The system should be updated with a report-by-exception scheme, where status-point changes are reported only when they change state between scans, and analog-point changes are reported only when they exceed their significant deadband. This reduces the load on the communication channel. In some systems, the data are reported in an unsolicited response mode. When the end device has something to report, it does not have to wait for a poll request from a master (master to slave). The device initiates the communication by grabbing the communication channel and transmitting its information.

Current substation integration and automation systems perform protocol translation, converting all the IED protocols from the various IED suppliers. Even with the protocol standardization efforts going on in the industry, there will always be legacy protocols that will require protocol translation.

The system must manage the IEDs and devices in the substation. The system must be aware of the address of each IED, alternate communication paths, and IEDs that may be utilized to accomplish a specific function. The system must know the status of all connected IEDs at all times.

The system provides data exchange and control support for the data warehouse. It should use a standard messaging service in the interface (standard protocol). The interface should be independent of any IED protocol and should use a report-by-exception scheme to reduce channel loading.

The system must provide an environment to support user applications. These user applications can be internally written by the utility, or they can be purchased from a third party and integrated into the substation integration and automation system. Figure 7.2 is a photograph of a SA system.

7.8.2 System Architecture

The types of data and control that the system will be expected to facilitate are dependent on the choice of IEDs and devices in the system. This must be addressed on a substation-by-substation basis.

The primary requirement is that the analog readings be obtained in a way that provides an accurate representation of their values.

The data concentrator stores all analog and status information available at the substation. This information is required for both operational and nonoperational reasons (e.g., fault–event logs and oscillography). There are three levels of data exchange and requirements associated with the substation integration and automation system.

7.8.2.1 Level 1—Field Devices

Each electronic device (relay, meter, PLC, etc.) has internal memory to store some or all of the following data: analog values, status changes, sequence of events, and power quality. These data are typically stored in a first in first out (FIFO) queue and vary in the number of events, etc., maintained.

7.8.2.2 Level 2—Substation Data Concentrator

The substation data concentrator should poll each device (both electronic and other) for analog values and status changes at data collection rates consistent with the utility's SCADA system (e.g., status points every 2 sec, tie-line and generator analogs every 2 sec, and remaining analog values every 2–10 sec). The substation data concentrator should maintain a local database.

7.8.2.3 Level 3—SCADA System, Data Warehouse

All data required for operational purposes should be communicated to the SCADA system via a communication link from the data concentrator, as seen in Fig. 7.1. All data required for non-operational purposes should be communicated to the data warehouse via a communication link from the data concentrator, as seen in Fig. 7.1. Figure 7.3 shows an example of a SCADA system dispatch center.

A data warehouse is necessary to support a mainframe or client–server architecture of data exchange between the system and corporate users over the corporate wide area network (WAN). This setup provides users with up-to-date information and eliminates the need to wait for access using a single line

FIGURE 7.3 SCADA system dispatch center.

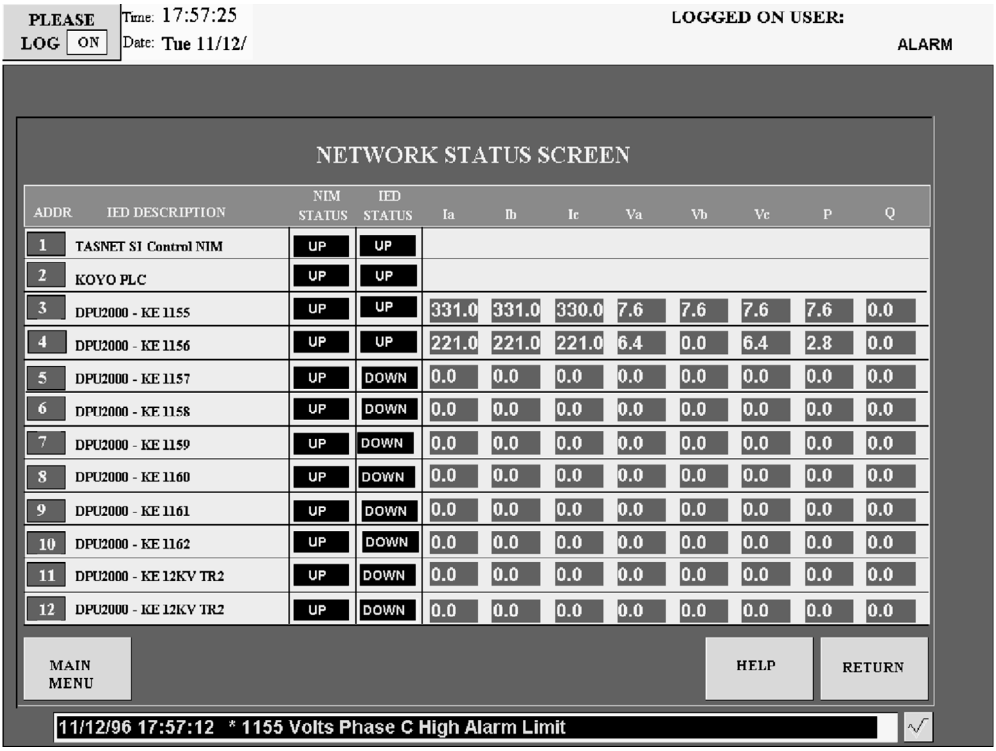

FIGURE 7.4 Network status display.

of communications to the system, such as telephone dial-up through a modem. Figure 7.4 is a screenshot showing a network status display.

7.8.3 Substation Host Processor

The substation host processor must be based on industry standards and strong networking ability, such as Ethernet, TCP/IP, UNIX, Windows 2000 or XP, Linux, etc. It must also support an open architecture, with no proprietary interfaces or products. An industry-accepted relational database (RDB) with structured query language (SQL) capability and enterprise-wide computing must be supported. The RDB supplier must provide replication capabilities to support a redundant or backup database. A full-graphics user interface (bit or pixel addressable) should be provided with Windows-type capability. There should be interfaces to Windows-type applications (i.e., Excel, Access, etc.). The substation host processor should be flexible, expandable, and transportable to multiple hardware platforms (IBM, Dell, Sun, HP, etc.). Should the host processor be single or redundant or distributed? For a smaller distribution substation, the host processor can be a single processor. For a large transmission substation, there may be redundant processors to provide automatic backup in case of failure. Suppliers who offer a distributed processor system with levels of redundancy may be a more cost-effective option for the larger substations. PLCs can be used as controllers, running special application programs at the substation level, coded in ladder logic. Smaller secondary substations will have IEDs but may not have a host processor, instead using a data concentrator for IED integration. This setup lacks a user interface and historical data collection. The IED data from these secondary substations are sent upstream to a larger primary substation that contains a complete substation integration and automation system. Figures 7.5 and 7.6 illustrate primary and secondary integration and automation systems, respectively.

FIGURE 7.5 Primary substation integration and automation system.

7.8.4 Substation Local Area Network (LAN)

7.8.4.1 LAN Requirements

The substation LAN must meet industry standards to allow interoperability and the use of plug-and-play devices. Open-architecture principles should be followed, including the use of industry standard protocols (e.g., IEEE 802.x [Ethernet]). The LAN technology employed must be applicable to the substation environment and facilitate interfacing to process-level equipment (IEDs, PLCs) while providing immunity and isolation to substation noise.

The LAN must have enough throughput and bandwidth to support integrated data acquisition, control, and protection requirements. Should the LAN utilize deterministic protocol technologies, such as token ring and token bus schemes? Response times for data transfer must be deterministic and repeatable. (Deterministic: pertaining to a process, model, or variable whose outcome, result, or value does not depend on chance [10].)

The LAN should support peer-to-peer communications capability for high-speed protection functions as well as file-transfer support for IED configuration and PLC programs. (Peer-to-peer: communication between two or more network nodes in which either node can initiate sessions and is able to poll or answer to polls [10].) Priority data transfer would allow low-priority data such as configuration files to be downloaded without affecting time-critical data transfers. The IED and peripheral interface should be a common bus for all I/O. If the LAN is compatible with the substation computer (e.g., Ethernet), a front-end processor may not be needed. There are stringent speed requirements for interlocking and intertripping data transfer, which the LAN must support. The LAN must be able to support switches, and support routers for the utility enterprise WAN interface. Test equipment for the LAN must be readily available and economical. Implementation of the LAN technology must be

FIGURE 7.6 Secondary substation integration and automation system.

competitive to drive the cost down. For example, Ethernet is more widely used than FDDI, and therefore Ethernet interface equipment costs less. Figure 7.7 illustrates the configuration of a SA system.

7.8.4.2 LAN Protocols

A substation LAN is a communications network, typically high speed, and within the substation and extending into the switchyard. The LAN provides the ability to quickly transfer measurements, indications, control adjustments, and configuration and historic data between intelligent devices at the site. The benefits achievable using this architecture include: a reduction in the amount and complexity of the cabling currently required between devices; an increase in the available communications bandwidth to support faster updates and more advanced functions such as virtual connection, file transfer, peer-to-peer communications, and plug-and-play capabilities; and the less tangible benefits of an open LAN architecture, which include laying the foundation for future upgrades, access to third-party equipment, and increased interoperability.

The EPRI-sponsored Utility Substation Communication Initiative performed benchmark and simulation testing of different LAN technologies for the substation in late 1996. The initial substation configuration tested included 47 IEDs with these data types: analog, accumulator, control and events, and fault records. The response requirements were 4 msec for a protection event, 111 transactions/sec for SCADA traffic, and 600 sec to transmit a fault record. The communication profiles tested were FMS/Profibus at 12 Mbps, MMS/Trim7/Ethernet at 10 and 100 Mbps, and switched Ethernet. Initially, the testing was done with four test-bed nodes using four 133-MHz Pentium computers. The four nodes simulated 47 devices in the substation. Analysis of the preliminary results from this testing resulted in a more extensive follow-up test done with 20 nodes using 20 133-MHz Pentium computers.

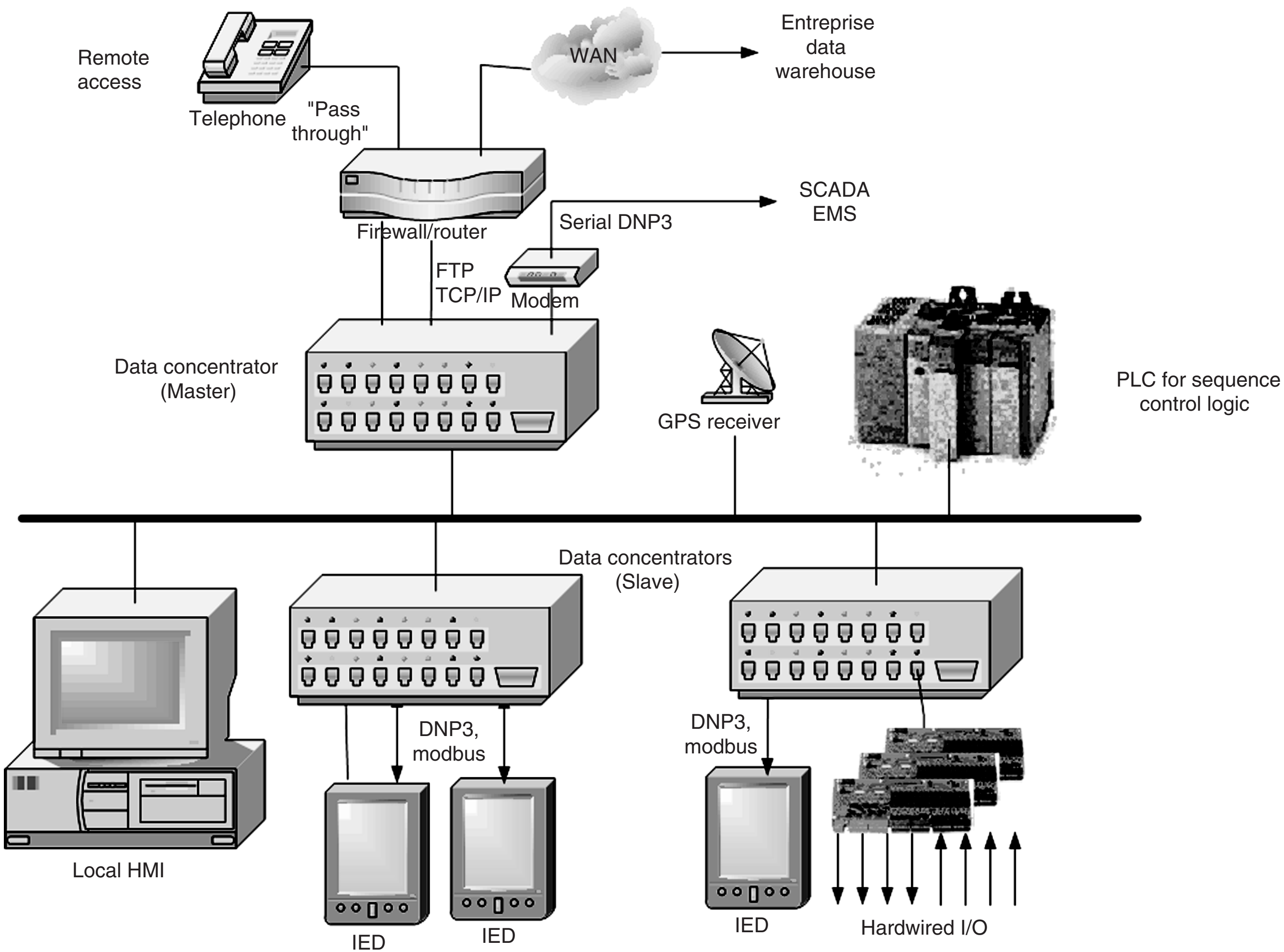

FIGURE 7.7 Configuration of substation automation system.

The 20 nodes simulated a large substation issuing four trip signals each to simulate 80 trip signals from 80 different IEDs.

The tests determined that FMS/Profibus at 12 Mbps (fast FMS implementation) could not meet the trip-time requirements for protective devices. However, MMS/Ethernet did meet the requirements. In addition, it was found that varying the SCADA load did not impact transaction performance. Moreover, the transmission of oscillographic data and SCADA data did not impact transaction times.

7.8.5 User Interface

The user interface in the substation must be an intuitive design to ensure effective use of the system with minimal confusion. An efficient display hierarchy will allow all essential activities to be performed from a few displays. It is critical to minimize or, better yet, eliminate the need for typing. There should be a common look and feel established for all displays. A library of standard symbols [2, Table 9, p. 37] should be used to represent substation power apparatus on graphical displays. In fact, this library should be established and used in all substations and coordinated with other systems in the utility, such as the distribution SCADA system, the energy management system (EMS), the geographic information system (GIS), the trouble call management system, etc. The field personnel, or the users of the system, should be involved in determining what information should be on the different displays. Multiple databases should be avoided, such as a database for an IED associated with a third-party user–interface software package (e.g., U.S. Data FactoryLink, BJ Systems RealFlex, Intellution, Wonderware, etc.).

The substation one-line displays may be similar in appearance to the displays on a distribution management system or an EMS. Figure 7.8 shows a typical substation one-line display. The functionality of an analog panel meter is typically integrated in the user interface of the SA system. The metered values can be viewed in a variety of formats. Alarm displays can have tabular and graphical display

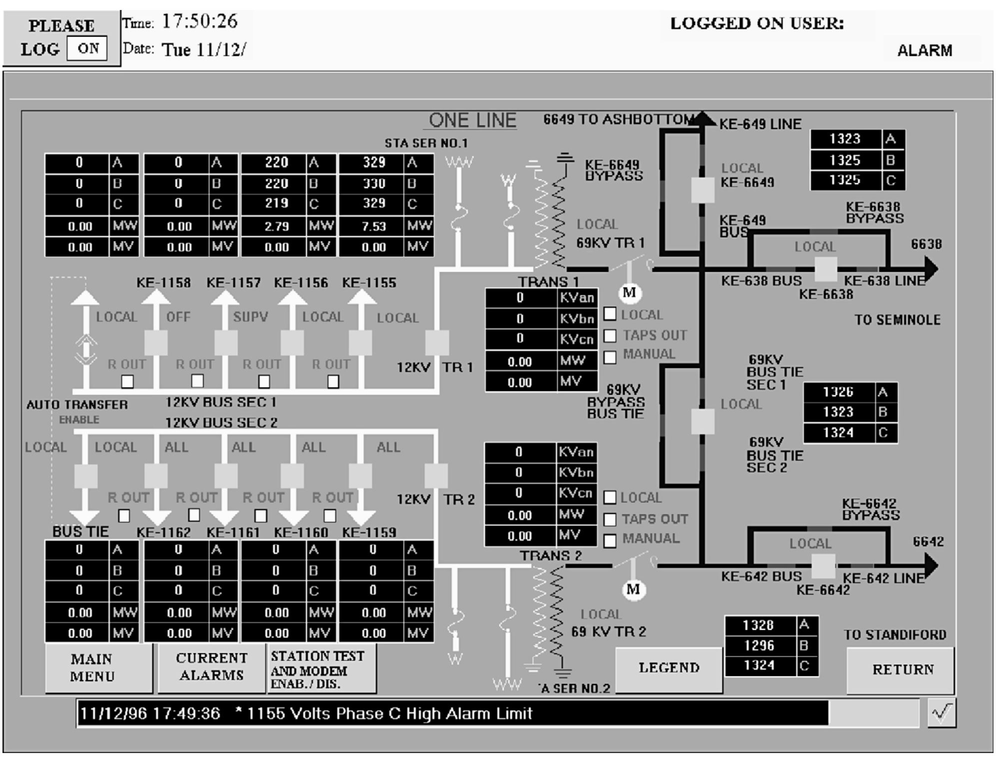

FIGURE 7.8 Substation one-line display.

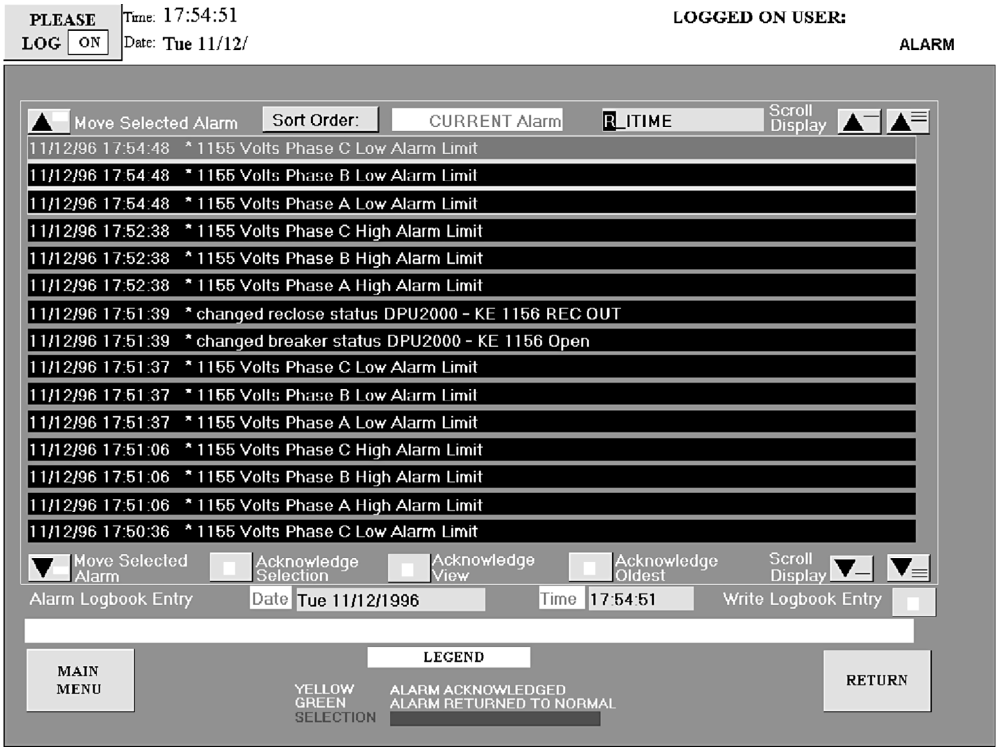

FIGURE 7.9 Substation alarm display.

formats. There should be a convenient means to obtain detailed information about the alarm condition. Figure 7.9 shows a typical substation alarm display.

There are two types of logs in the substation. The substation integration and automation system has the capability of logging any information in the system at a specified periodicity. It can log alarms and events with time tags. In other words, any information the system has can be included in a log. A manual log is also in the substation for documenting all activities performed in the substation. The information in the manual log can be included in the system, but it would have to be entered into the system using the keyboard, and typing is not something field personnel normally want to do.

7.8.6 Communication Interfaces

There are interfaces to substation IEDs to acquire data, determine the operating status of each IED, support all communication protocols used by the IEDs, and support standard protocols being developed. There may be an interface to the EMS that allows system operators to monitor and control each substation and the EMS to receive data from the substation integration and automation system at different periodicities. There may be an interface to the distribution management system with the same capabilities as the EMS interface. There may also be an interface to a capacitor control system that allows (a) control of switched capacitor banks located on feeders emanating from the substation, (b) monitoring of VARs on all three phases for the decision to switch the capacitor bank, and (c) verification that the capacitor bank did switch. There is always an interface for remote access capabilities—providing authorized access to the system via dial-in telephone or a secure network connection—to obtain data and alarms, execute diagnostic programs, and retrieve results of diagnostic programs. Lastly, there is an interface to a time-standard source. A time reference unit (TRU) is typically provided at each substation for outputting time signals to the substation integration and automation system IEDs, controllers, and host computers. The GPS time standard is used and synchronized to GPS satellite time. The GPS system includes an alphanumeric display for displaying time, satellite tracking status, and other setup parameters.

7.8.7 Data Warehouse

The data warehouse enables users to access substation data while maintaining a firewall to protect substation control and operation functions. (A firewall protects a trusted network from an outside, "untrusted" network—a difficult job to do quickly and efficiently, since the firewall must inspect each network communication and decide whether to allow it to cross over to the trusted network [18].) Both operational and nonoperational data (e.g., fault–event logs, oscillographic data) are needed in the data warehouse. The utility must determine who will use the SA system data, the nature of their application, the type of data needed, how often the data are needed, and the frequency of update required for each user. Examples of user groups within a utility are operations, planning, engineering, SCADA, protection, distribution automation, metering, substation maintenance, and information technology.

The data warehouse is a server or group of servers that retrieve data from the local data marts, which typically are linked to systems such as SCADA, SA, power plant distributed control systems, maintenance management, outage management, and customer information systems. The data warehouse accesses and stores these points and files centrally and integrates the data sets into unique information that is delivered to, or accessed when needed by, specific user groups in engineering, operations, and maintenance.

Few utilities have included data marts in their automation plans, primarily due to the lack of knowledge of the technology's availability. Compounding this situation is the complexity involved in retrieving and integrating disparate data sets from various local data warehouses. The problem is that most utilities implement a variety of automated systems, and while SCADA systems operate today with more standardized data transfer communication protocols, the IEDs in all other automated systems use proprietary ASCII commands to retrieve their nonoperational data. This means that a data warehouse must be highly customized to communicate with each manufacturer's IED.

Leveraging data warehouse technology requires the proper implementation of integration and automation early in the project planning cycle. The mistake too many utilities make is viewing integration and automation strictly as the installation of computerized monitoring and control devices in the substation. The crucial but often missing step is the integration of these devices and systems to the utility enterprise, focusing outside the substation as well as inside the substation. Without enterprise integration, the data warehouse concept fails to deliver the promised benefits.

7.9 Protocol Fundamentals

A communication protocol allows communication between two devices. The devices must have the same protocol (and version) implemented. Any protocol differences will result in communication errors.

If the communication devices and protocols are from the same supplier, i.e., where a supplier has developed a unique protocol to utilize all the capabilities of the two devices, it is unlikely the devices will have trouble communicating. By using a unique protocol of one supplier, a utility can maximize the device's functionality and see a greater return on its investment. However, the unique protocol will constrain the utility to one supplier for support and for purchase of future devices.

If the communication devices are from the same supplier but the protocol is an industry standard protocol supported by the device supplier, the devices should not have trouble communicating. The device supplier has designed its devices to operate with the standard protocol and communicate with other devices using the same protocol and version. By using a standard protocol, the utility can purchase equipment from any supplier that supports the protocol and can therefore comparison-shop for the best prices.

Industry standard protocols typically require more overhead than a supplier's unique protocol. Standard protocols often require a high-speed channel than a supplier's unique protocol for the same efficiency or information throughput. However, high-speed communication channels are more prevalent today and can provide adequate efficiency when using industry standard protocols. IEC 61850 is designed to operate efficiently over 10 Mbps switched, 100 Mbps shared, or switched Ethernet. If a utility is considering IEC 61850 as its protocol of choice, a prerequisite should be installation of high-speed communications. If the utility's plan is to continue with a communication infrastructure operating at 1200–9600 bps, the better choice for an industry standard protocol would be DNP3.

A utility may not be able to utilize all of a device's functionality using an industry standard protocol. If a device was designed before the industry standard protocol, the protocol may not thoroughly support the device's functionality. If the device was designed after the industry standard protocol was developed, the device should have been designed to work with the standard protocol such that all of the device's functionality is available.

The substation integration and automation architecture must allow devices from different suppliers to communicate (interoperate) using an industry standard protocol. Using an industry standard protocol, where suppliers have designed their devices to achieve full functionality with the protocol, a utility has the flexibility to choose the best devices for each application. Though devices from different suppliers can operate and communicate under the standard protocol, each device may have capabilities not supported by another device. There is also risk that the implementations of the industry standard protocol by the two suppliers in each device may have differences. Factory testing will verify that the functions of one device are supported by the protocol of the other device and vice versa. If differences or incompatibilities are found, they can be corrected during factory testing.

7.10 Protocol Considerations

There are two capabilities a utility considers for an IED. The primary capability of an IED is its stand-alone capabilities, such as protecting the power system for a relay IED. The secondary capability of an IED is its integration capabilities, such as its physical interface (e.g., RS-232, RS-485, Ethernet) and its communication protocol (e.g., DNP3, Modbus, IEC 870-5-101 or 104).

Utilities typically specify the IEDs they want to use in the substation rather than giving a supplier a turnkey contract to provide only that supplier's IEDs in the substation. However, utilities typically choose an IED based on its stand-alone capabilities, without considering the IED's integration capabilities. Once the IEDs are installed, the utility may find it difficult to migrate to an integrated system if the IEDs were purchased with the supplier's proprietary protocol and with an undesirable physical interface (e.g., RS-485 purchased when Ethernet is desired). When purchasing IEDs the utility must consider both the stand-alone capabilities and the integration capabilities, even if the IEDs will not be integrated in the near future.

The most common IED communication protocols are Modbus, Modbus Plus, DNP3, or IEC 870-5-101 or 104. IEC 61850 is becoming commercially available in North America from more IED suppliers, and it is being implemented in more utility substations. However, the implementations may not be optimal if the IEC 61850 functionality is not built into the IED itself. In such cases, the supplier develops a separate box for the IEC 61850 functionality apart from the IED itself, and this typically results in poor performance because of data latency due to the additional box. The utility must be cautious when ordering an IED for use in a system using a protocol other than the supplier's (often proprietary) target protocol, since some IED functionality may be lost. The most common IED networking technology today in substations is serial communications, either RS-232 or RS-485. As more and more IEDs become available with Ethernet ports, the IED networking technology in the substation will be primarily Ethernet.

7.10.1 Utility Communications Architecture (UCA)

The use of international protocol standards is now recognized throughout the electric utility industry as a key to successful integration of the various parts of the electric utility enterprise. Efforts to standardize the protocols that facilitate substation integration and automation have taken place within the framework provided by the Electric Power Research Institute's (EPRI) utility communications architecture (UCA).

UCA is a standards-based approach to utility data communications that provides for wide-scale integration from the utility enterprise level (as well as between utilities) down to the customer interface, including distribution, transmission, power plant, control center, and corporate information systems. The UCA Version 1.0 specification was issued in December 1991 as part of EPRI Project RP2949, Integration of Utility Communication Systems. Although this specification supplied a great deal of functionality, industry adoption was limited, due in part to a lack of detailed specifications about how the specified protocols would actually be used by applications. For example, the manufacturing messaging specification (MMS) ISO/IEC 9506 protocol was specified for real-time data exchange at many levels within a utility. Unfortunately, the protocol did not have specific mappings to MMS for exchanging power system data and schedules or for communicating directly with substation or distribution feeder devices. The result was a continuation in interoperability problems.

The UCA (MMS) forum was started in May 1992 to address these UCA application issues. Six working groups were established to consider issues of MMS application in power plants, control centers, customer interface, SA, distribution feeder automation, and profile issues. The MMS forum served as a mechanism for utilities and suppliers to build the technical agreements necessary to achieve a wide range of interoperability using UCA MMS. Out of these efforts came the notion of defining standard power system objects and mapping them onto the services and data types supported by MMS and the other underlying standard protocols. This heavily influenced the definition of the UCA Version 2.0 specification issued in late 1996, which endorsed ten different protocol profiles, including transmission control protocol/Internet protocol (TCP/IP) and intercontrol center communication protocol (ICCP), as well as a new set of common application service models for real-time device access.

The EPRI UCA/Substation Automation Project began in the early 1990s to produce industry consensus regarding substation integrated control, protection and data acquisition, and interoperability of substation devices from different manufacturers. The Substation Protocol Reference Specification recommended three of the ten UCA2 profiles for use in SA. Future efforts in this project were integrated with the efforts in the Utility Substations Initiative described below.

In mid-1996 American Electric Power hosted the first Utility Substations Initiative meeting as a continuation of the EPRI UCA/Substation Automation Project. Approximately 40 utilities and 25 suppliers participated, having formed supplier–utility teams to define the supplier IED functionality and to implement a standard IED protocol (UCA2 profile) and LAN protocol (Ethernet).

Generic object models for substation and feeder equipment (GOMSFE) were developed to facilitate suppliers in implementing the UCA/Substation Automation Project's substation and feeder elements of the power system object model. New IED products with this functionality are commercially available. The Utility Substations Initiative met three times each year, in January, May, and September, immediately following the IEEE PES Power System Relaying Committee (PSRC) meetings and in conjunction with the UCA Users Group meetings. Every other meeting included a supplier interoperability demonstration. The demonstration in September 2002 involved approximately 20 suppliers with products interconnected by a fiber Ethernet LAN interoperating with the UCA2 MMS protocol, the GOMSFE device object models, and Ethernet networks.

The UCA International Users Group is a nonprofit organization whose members are utilities, suppliers, and users of communications for utility automation. The mission of the UCA International Users Group is to enable utility integration through the deployment of open standards by providing a forum in which the various stakeholders in the utility industry can cooperatively work together as members of a common organization. The group's goals are to

- influence, select, and endorse open and public standards appropriate to the utility market based on the needs of the membership;
- specify, develop, and accredit product or system-testing programs that facilitate the field interoperability of products and systems based upon these standards; and
- implement educational and promotional activities that increase awareness and deployment of these standards in the utility industry.

The UCA International Users Group was first formed in 2001 and presently has 72 corporate members, including 36 suppliers, 23 electric utilities, and 13 consultants and other organizations. The UCA International Users Group organization consists of a board of directors, with the executive committee and technical committee reporting to the board. The executive committee has three committees reporting to it: marketing, liaison, and membership. The technical committee has a number of subcommittees reporting to it, including substation, communications, products, object models (IEC 61850/GOMSFE), and test procedures. The Web site for the UCA International Users Group is www.ucausersgroup.org. The UCA International Users Group met at the IEEE PES Substations Committee Annual Meeting April 27–30, 2003, in Sun Valley, Idaho. This meeting included a supplier interoperability demonstration, with 20 suppliers demonstrating the implementation of the UCA2 MMS protocol and Ethernet networking technology into their IEDs and products, and interoperating with the other suppliers' equipment.

7.10.2 Merger of UCA with IEC 61850

In 2001, the developers of 61850 and UCA agreed to merge the standards and get to one international standard, a critical objective for both standards projects. Subparts of 61850 sections document the use of MMS and the fit of GOMSFE. A messaging mechanism compatible with UCA GOOSE provides a mechanism for sharing of analog values as well as status reports among peer IEDs on the LAN using IEC 61850. A subset of this having only status point exchange, as in UCA GOOSE, is called GSSE. This allows UCA devices to talk to 61850 clients.

Even if a product is updated to 61850, it will likely only have certain features implemented. The IED buyer must work carefully with suppliers to ensure that the selected products can interoperate with respect to functions that are important to substation design. Suppliers should be asked about existing working demonstrations of compatibility, and listing of functions that are not available or are impaired (e.g., excessive throughput time delays) in mixed-vendor networks. Without doubt, many suppliers must respond to such questions today with development roadmaps and firmware upgrade strategies, rather than working products. The track record and commitment of the supplier must be investigated and judged.

7.10.3 International Electrotechnical Commission (IEC) 61850

The continuing development of UCA2/MMS has ceased as suppliers refocus on implementing IEC 61850 versions of this LAN-based automation design. Meanwhile, supplier–utility demonstration projects of UCA2/MMS are now in service, with most activity pertaining to monitoring the performance of the installed demonstration systems. There are very few SA systems in service today in North America (other than the vendor–utility demonstration projects) that utilize UCA2/MMS. The trial installations include significant amounts of custom relay and IED programming and adaptation to make the sophisticated new technology work in its first practical installations.

IEC 61850 has absorbed features of UCA and largely includes UCA capabilities as a subset. Critical portions of the IEC 61850 standard documents are undergoing continuing development. All critical base sections have been issued by IEC as official international standards. The vendors who are implementing the standard in products are interacting with the IEC TC 57 Working Group to resolve design problems and issues.

EPRI has reduced its involvement in the promotion and support of this technology, and the development effort is now focused on supplier implementation of IEC 61850. North American relay manufacturers are creating 61850 compatible products with varying degrees of aggressiveness—they must balance their investments in this with those for other widely used or demanded protocols such as DNP on Ethernet. The market for 61850 relays in North America is prospective and debated, and will depend largely on willingness of a significant number of utilities to step forward and commit to implementations when products are available. European relay manufacturers have presented a firm commitment to 61850, which is justified by their likely ability to sell this new technology in the areas of the world where they are traditionally strong.

Some suppliers have developed separate interface devices that serve as an IEC 61850 gateway, enabling their relays to integrate with IEC 61850–based networks. This approach is not recommended in any situation where latency of data or response speed is important. Past experience indicates that gateways of this type can introduce significant latency, which utilities have found to be unacceptable. For any new device that is considered for interfacing legacy IEDs in 61850 installations, it will be critical to have specifications and supplier commitment to achieve low latency that meets the application need.

7.10.4 Distributed Network Protocol (DNP)

The development of the DNP was a comprehensive effort to achieve open, standards-based interoperability between substation computers, RTUs, IEDs, and master stations (except intermaster station communications) for the electric utility industry. DNP is based on the standards of the IEC TC 57, WG 03. DNP has been designed to be as close to compliant as possible to the standards as they existed at the time of development with the addition of functionality not identified in Europe but needed for current and future North American applications (e.g., limited transport-layer functions to support 2K block transfers for IEDs as well as radio frequency [RF] and fiber support). The present version of DNP is DNP3, which is defined in three distinct levels. Level 1 has the least functionality (for simple IEDs) and Level 3 has the most functionality (for SCADA master station-communication front-end processors).

The short-term benefits of using DNP are interoperability between multisupplier devices; fewer protocols to support in the field; reduced software costs; no protocol translators needed; shorter delivery schedules; less testing, maintenance, and training; improved documentation; independent conformance testing; and support by independent user group and third-party sources (e.g., test sets, source code). In the long term, further benefits can be derived from using DNP, including easy system expansion; long product life; more value-added products from suppliers; faster adoption of new technology; and major operations savings.

DNP was developed by Harris, Distributed Automation Products, in Calgary, Alberta, Canada. In November 1993, responsibility for defining further DNP specifications and ownership of the DNP specifications was turned over to the DNP User Group, a group composed of utilities and suppliers who are utilizing the protocol. The DNP User Group is a forum of over 300 users and implementers of the DNP3 protocol worldwide. The major objectives of the user group are to maintain control of the protocol and determine the direction in which the protocol will migrate; to review and add new features, functions, and enhancements to the protocol; to encourage suppliers and utilities to adopt the DNP3 protocol as a standard; to define recommended protocol subsets; to develop test procedures and verification programs; and to support implementer interaction and information exchange. The DNP User Group has an annual general meeting in North America, usually in conjunction with the DistribuTECH Conference in January or February. The Web site for DNP and the DNP User Group is www.dnp.org. The DNP User Group Technical Committee is an open volunteer organization of industry and technical experts from around the world. This committee evaluates suggested modifications or additions to the protocol and then amends the protocol description as directed by the user group members.

7.11 Choosing the Right Protocol

There are several factors to consider when choosing the right protocol for your application. First, determine the system area you are most concerned with, e.g., the protocol from a SCADA master station to the SCADA RTUs, a protocol from substation IEDs to an RTU or a PLC, or a LAN in the substation. Second, determine the timing of your installation, e.g., 6 months, 18–24 months, or 3–5 years. In some application areas, technology is changing so quickly that the timing of your installation can have a great impact on your protocol choice. If you are implementing new IEDs in the substation and need them to be in service in 6 months, you could narrow your protocol choices to DNP3, Modbus, Modbus Plus, or IEC 870-5-101 or 104. These protocols are used extensively in IEDs today. If you choose an IED that is commercially available with IEC 61850 capabilities today, then you can choose IEC 61850 as your protocol and networking functionality.

If your time frame is 1–2 years, you should consider IEC 61850 as the protocol. Monitor the results of the IEC 61850 utility demonstration projects. These projects have implemented new supplier IED products that are using IEC 61850 functionality for the IED communication protocol, Ethernet as the substation local area network, and GSSE protection messaging on the Ethernet LANs.

If your time frame is near term (6–9 months), make protocol choices from suppliers who are participating in the industry initiatives and are incorporating this technology into their product's migration paths. This will help protect your investment from becoming obsolete by allowing incremental upgrades to new technologies.

7.12 Communication Protocol Application Areas

There are various protocol choices depending on the protocol application area of your system. Protocol choices vary with the different application areas, which are in different stages of protocol development and levels of industry efforts. The status of development efforts for different applications will help determine realistic plans and schedules for your specific projects.

7.12.1 Within the Substation

The need for a standard IED protocol dates back to the late 1980s. IED suppliers acknowledge that their expertise is in the IED itself—not in two-way communications capability, the communications protocol, or added IED functionality from a remote user. Though the industry made some effort to add communications capability to the IEDs, each IED supplier was concerned that any increased functionality would compromise performance and drive the IED cost so high that no utility would buy it. Therefore, the industry vowed to keep costs competitive and performance high as standardization was incorporated into the IED.

The IED suppliers' lack of experience in two-way communications and communication protocols resulted in crude, primitive protocols and, in some cases, no individual addressability and improper error checking (no select-before-operate for control). Each IED required its own communication channel, but only limited channels, if any, were available from RTUs. SCADA system and RTU suppliers were pressured to develop the capability to communicate with IEDs purchased by the utilities. Each RTU and IED interface required not only a new protocol but also a proprietary protocol not used by any other IED.

It was at this point that the Data Acquisition, Processing and Control Systems Subcommittee of the IEEE PES Substations Committee recognized the need for a standard IED protocol. The subcommittee formed a task force to examine existing protocols and determine, based on two sets of screening criteria, the two best candidates. IEEE Standard 1379, Trial Use Recommended Practice for Data Communications between Intelligent Electronic Devices and Remote Terminal Units in a Substation, was published in March 1998. This document did not establish a new communication protocol. To quickly achieve industry acceptance and use, it instead provided a specific implementation of two existing communication protocols in the public domain, DNP3 and IEC 870-5-101. The document was updated and published again in 2000.

For IED communications, if your implementation time frame is 6–9 months, select from protocols that already exist—DNP3, Modbus, Modbus Plus, or IEC 870-5-101 or 104. However, if the implementation time frame is 1 year or more, consider IEC 61850 functionality. Regardless of your time frame, evaluate each supplier's product migration plans. Try to determine if the system will allow migration from today's IED with DNP3 to tomorrow's IED with IEC 61850 functionality without replacing the entire IED. This will leave open the option of migrating the IEDs in the substation to IEC

61850 in an incremental manner, thus avoiding wholesale replacement. If you choose an IED that is commercially available with IEC 61850 functionality today, then you will want to use MMS as your IED protocol.

7.12.2 Substation-to-Utility Enterprise

This is the area of traditional SCADA communication protocols. The Data Acquisition, Processing and Control Systems Subcommittee of the IEEE PES Substations Committee began developing a recommended practice in the early 1980s in an attempt to standardize master/remote communications practices. At that time, each SCADA system supplier had developed a proprietary protocol based on technology of the time. These proprietary protocols exhibited varied message structures, terminal-to-data circuit terminating equipment (DCE) and DCE-to-channel interfaces, and error detection and recovery schemes. The IEEE Recommended Practice for Master/Remote Supervisory Control and Data Acquisition (SCADA) Communications (IEEE Std. 999-1992) addressed this nonuniformity among the protocols, provided definitions and terminology for protocols, and simplified the interfacing of more than one supplier's RTUs to a master station.

The major standardization effort undertaken in this application area has taken place in Europe as part of the IEC standards-making process. The effort resulted in the development of the IEC 870-5 protocol, which was slightly modified by GE (Canada) to create DNP. This protocol incorporated a pseudo transport layer, allowing it to support multiple master stations. The goal of DNP was to define a generic standards-based (IEC 870-5) protocol for use between IEDs and data concentrators within the substation, as well as between the substation and the SCADA system control center. Success led to the creation of the supplier-sponsored DNP User Group that currently maintains full control over the protocol and its future direction. DNP3 has become a de facto standard in the electric power industry and is widely supported by suppliers of test tools, protocol libraries, and services.

7.13 Summary

As we look to the future, it seems the time between the present and the future is shrinking. When a PC bought today is made obsolete in 6 months by a new model with twice the performance at less cost, how can you protect the investments in technology you make today? Obviously, there is no way you can keep up on a continuous basis with all the technology developments in all areas. You must rely on others to keep you informed, and whom you select to keep you informed is critical. With every purchase, you must evaluate not only the supplier's present products, but also its future product development plans. Does the supplier continuously enhance and upgrade products? Is the supplier developing new products to meet future needs? Do existing products have a migration path to enhanced and new products? Selecting the right supplier will ensure you stay informed about new and future industry developments and trends and will allow you to access new technologies that will improve your current operation.

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8

Oil Containment[1]

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Containment and control of oil spills at electric supply substations is a concern for most electric utilities. The environmental impact of oil spills and their cleanup is governed by several federal, state, and local regulations, necessitating increased attention in substations to the need for secondary oil containment, and a Spill Prevention Control and Countermeasure (SPCC) plan. Beyond the threat to the environment, cleanup costs associated with oil spills could be significant, and the adverse community response to any spill is becoming increasingly unacceptable.

The probability of an oil spill occurring in a substation is very low. However, certain substations, due to their proximity to navigable waters or designated wetlands, the quantity of oil on site, surrounding topography, soil characteristics, etc., have or will have a higher potential for discharging harmful quantities of oil into the environment. At minimum, a SPCC plan will probably be required at these locations, and installation of secondary oil-containment facilities might be the right approach to mitigate the problem.

Before an adequate spill prevention plan is prepared and a containment system is devised, the engineer must first be thoroughly aware of the requirements included in the federal, state, and local regulations.

The federal requirements of the U.S. for discharge, control, and countermeasure plans for oil spills are contained in the Code of Federal Regulations, Title 40 (40CFR), Parts 110 and 112. The above regulations only apply if the facility meets the following conditions:

1. Facilities with above-ground storage capacities greater than 2500 l (approximately 660 gal) in a single container or 5000 l (approximately 1320 gal) in aggregate storage, *or*
2. Facilities with a total storage capacity greater than 159,000 l (approximately 42,000 gal) of buried oil storage, *or*
3. *Any* facility which has spilled more than 3786 l (1000 gal) of oil in a single event or spilled oil in two events occurring within a 12-month period, and

[1]Sections of this chapter reprinted from IEEE Std. 980–1994 (R2001), *IEEE Guide for Containment and Control of Oil Spills in Substations*, 1995, Institute of Electrical and Electronics Engineers, Inc. (IEEE). The IEEE disclaims any responsibility or liability resulting from the placement and use in the described manner. Information is reprinted with permission of the IEEE.

4. Facilities which, due to their location, could reasonably be expected to discharge oil into or upon the navigable waters of the U.S. or its adjoining shorelines.

In other countries, applicable governmental regulations will cover the above requirements.

8.1 Oil-Filled Equipment in Substation (IEEE, 1994)

A number of electrical apparatus installed in substations are filled with oil that provides the necessary insulation characteristics and assures their required performance. Electrical faults in this power equipment can produce arcing and excessive temperatures that may vaporize insulating oil, creating excessive pressure that may rupture the electrical equipment tanks. In addition, operator errors, sabotage, or faulty equipment may also be responsible for oil releases.

The initial cause of an oil release or fire in electrical apparatus may not always be avoidable, but the extent of damage and the consequences for such an incident can be minimized or prevented by adequate planning in prevention and control.

Described below are various sources of oil spills within substations. Spills from any of these devices are possible. The user must evaluate the quantity of oil present, the potential impact of a spill, and the need for oil containment associated with each oil-filled device.

8.1.1 Large Oil-Filled Equipment

Power transformers, oil-filled reactors, large regulators, and circuit breakers are the greatest potential source of major oil spills in substations, since they typically contain the largest quantity of oil.

Power transformers, reactors, and regulators may contain anywhere from a few hundred to 100,000 l or more of oil (500 to approximately 30,000 gal), with 7500–38,000 l (approximately 2000–10,000 gal) being typical. Substations usually contain one to four power transformers, but may have more.

The higher voltage oil circuit breakers may have three independent tanks, each containing 400–15,000 l (approximately 100–4000 gal) of oil, depending on their rating. However, most circuit breaker tanks contain less than 4500 l (approximately 1200 gal) of oil. Substations may have 10–20 or more oil circuit breakers.

8.1.2 Cables

Substation pumping facilities and cable terminations (potheads) that maintain oil pressure in pipe-type cable installations are another source of oil spills. Depending on its length and rating, a pipe-type cable system may contain anywhere from 5000 l (approximately 1500 gal) up to 38,000 l (approximately 10,000 gal) or more of oil.

8.1.3 Mobile Equipment

Although mobile equipment and emergency facilities may be used infrequently, consideration should be given to the quantity of oil contained and associated risk of oil spill. Mobile equipment may contain up to 30,000 l (approximately 7500 gal) of oil.

8.1.4 Oil-Handling Equipment

Oil filling of transformers, circuit breakers, cables, etc. occurs when the equipment is initially installed. In addition, periodic reprocessing or replacement of the oil may be necessary to ensure that proper insulation qualities are maintained. Oil pumps, temporary storage facilities, hoses, etc. are brought in to accomplish this task. Although oil processing and handling activities are less common, spills from these devices can still occur.

8.1.5 Oil Storage Tanks

Some consideration must be given to the presence of bulk oil storage tanks (either above-ground or below-ground) in substations as these oil tanks could be responsible for an oil spill of significant magnitude. Also, the resulting applicability of the 40CFR, Part 112 rules for these storage tanks could require increased secondary oil containment for the entire substation facility. The user may want to reconsider storage of bulk oil at substation sites.

8.1.6 Other Sources

Station service, voltage, and current transformers, as well as smaller voltage regulators, oil circuit reclosers, capacitor banks, and other pieces of electrical equipment typically found in substations, contain small amounts of insulating oil, usually less than the 2500 l (approximately 660 gal) minimum for a single container.

8.1.7 Spill Risk Assessment

The risk of an oil spill caused by an electric equipment failure is dependent on many factors, including:

- Engineering and operating practices (i.e., electrical fault protection, loading practices, switching operations, testing, and maintenance).
- Quantities of oil contained within apparatus.
- Station layout (i.e., spatial arrangement, proximity to property lines, streams, and other bodies of water).
- Station topography and site preparation (i.e., slope, soil conditions, ground cover).
- Rate of flow of discharged oil.

Each facility must be evaluated to select the safeguards commensurate with the risk of a potential oil spill.

The engineer must first consider whether the quantities of oil contained in the station exceed the quantities of oil specified in the Regulations, and secondly, the likelihood of the oil reaching navigable waters if an oil spill or rupture occurs. If no likelihood exists, no SPCC plan is required.

SPCC plans must be prepared for each piece of portable equipment and mobile substations. These plans have to be general enough that the plan may be used at any and all substations or facility location.

Both the frequency and magnitude of oil spills in substations can be considered to be very low. The probability of an oil spill at any particular location depends on the number and volume of oil containers, and other site-specific conditions.

Based on the applicability of the latest regulatory requirements, or when an unacceptable level of oil spills has been experienced, it is recommended that a program be put in place to mitigate the problems. Typical criteria for implementing oil spill containment and control programs incorporate regulatory requirements, corporate policy, frequency and duration of occurrences, cost of occurrences, safety hazards, severity of damage, equipment type, potential impact on nearby customers, substation location, and quality-of-service requirements (IEEE, 1994).

The decision to install secondary containment at new substations (or to retrofit existing substations) is usually based on predetermined criteria. A 1992 IEEE survey addressed the factors used to determine where oil spill containment and control programs are needed. Based on the survey, the criteria in Table 8.1 are considered when evaluating the need for secondary oil containment.

The same 1992 IEEE survey provided no clear-cut limit for the proximity to navigable waters. Relatively, equal support was reported for several choices over the range of 45–450 m (150–1500 feet).

Rarely is all of the equipment within a given substation provided with secondary containment. Table 8.2 lists the 1992 IEEE survey results identifying the equipment for which secondary oil containment is provided.

TABLE 8.1 Secondary Oil-Containment Evaluation Criteria

Criteria	Utilities Responding that Apply this Criteria
Volume of oil in individual device	88%
Proximity to navigable waters	86%
Total volume of oil in substation	62%
Potential contamination of groundwater	61%
Soil characteristics of the station	42%
Location of substation (urban, rural, remote)	39%
Emergency response time if a spill occurs	30%
Failure probability of the equipment	21%
Age of station or equipment	10%

Source: IEEE, 1994.

Whatever the criteria, each substation has to be evaluated by considering the criteria to determine candidate substations for oil-containment systems (both new and retrofit). Substations with planned equipment change-outs and located in environmentally sensitive areas have to be considered for retrofits at the time of the change-out.

8.2 Containment Selection Consideration (IEEE, 1994)

Containment selection criteria have to be applied in the process of deciding the containment option to install in a given substation. Criteria to be considered include: operating history of the equipment, environmental sensitivity of the area, the solution's cost-benefit ratio, applicable governmental regulations, and community acceptance.

The anticipated cost of implementing the containment measures must be compared to the anticipated benefit. However, cost alone can no longer be considered a valid reason for not implementing containment and/or control measures, because any contamination of navigable waters may be prohibited by government regulations.

Economic aspects can be considered when determining which containment system or control method to employ. Factors such as proximity to waterways, volume of oil, response time following a spill, etc., can allow for the use of less effective methods at some locations.

Due to the dynamic nature of environmental regulations, some methods described in this section of the handbook could come in conflict with governmental regulations or overlapping jurisdictions.

TABLE 8.2 Secondary Oil-Containment Equipment Criteria

Equipment	Utilities Responding that Provide Secondary Containment
Power transformers	86%
Above-ground oil storage tanks	77%
Station service transformers	44%
Oil circuit breakers	43%
Three-phase regulators	34%
Below-ground oil storage tanks	28%
Shunt reactors	26%
Oil-filling equipment	22%
Oil-filled cables and terminal stations	22%
Single-phase regulators	19%
Oil circuit reclosers	15%

Source: IEEE, 1994.

Therefore, determination of which containment system or control method to use must include research into applicable laws and regulations.

Community acceptance of the oil spill containment and control methods is also to be considered. Company policies, community acceptance, customer relations, etc. may dictate certain considerations. The impact on adjacent property owners must be addressed and, if needed, a demonstration of performance experiences could be made available.

8.3 Oil Spill Prevention Techniques

Upon an engineering determination that an oil spill prevention system is needed, the engineer must weigh the advantages and disadvantages that each oil retention system may have at the facility in question. The oil retention system chosen must balance the cost and sophistication of the system to the risk of the damage to the surrounding environment. The risks, and thus the safeguards, will depend on items such as soil, terrain, relative closeness to waterways, and potential size of discharge. Each of the systems that are described below may be considered based on their relative merits to the facility under consideration. Thus, one system will not always be the best choice for all situations and circumstances.

8.3.1 Containment Systems

The utility has to weigh the advantages and disadvantages that each oil retention system may have at the facility in question. Some of the systems that could be considered based on their relative merits to the facility under consideration are presented in the next paragraphs.

8.3.1.1 Yard Surfacing and Underlying Soil

100 to 150 mm (4 to 6 in.) of rock gravel surfacing are normally required in all electrical facility yards. This design feature benefits the operation and maintenance of the facility by providing proper site drainage, reducing step and touch potentials during short-circuit faults, eliminating weed growth, improving yard working conditions, and enhancing station aesthetics. In addition to these advantages, this gravel will aid in fire control and in reducing potential oil spill cleanup costs and penalties that may arise from federal and state environmental laws and regulations.

Yard surfacing is not to be designed to be the primary or only method of oil containment within the substation, but rather has to be considered as a backup or bonus in limiting the flow of oil in the event that the primary system does not function as anticipated.

Soil underlying power facilities usually consists of a non-homogeneous mass that varies in composition, porosity, and physical properties with depth.

Soils and their permeability characteristics have been adapted from typical references and can be generalized as in the following Table 8.3.

8.3.1.2 Substation Ditching

One of the simplest methods of providing total substation oil spill control is the construction of a ditch entirely around the outside periphery of the station. The ditch has to be of adequate size as to contain all surface run-offs due to rain and insulating oil. These ditches may be periodically drained by the use of valves.

TABLE 8.3 Soil Permeability Characteristics

Permeability (cm/sec)	Degree of Permeability	Type of Soil
Over 10^{-1}	High	Stone, gravel, and coarse- to medium-grained sand
10^{-1} to 10^{-3}	Medium	Medium-grained sand to uniform, fine-grained sand
10^{-3} to 10^{-6}	Low	Uniform, fine-grained sand to silty sand or sandy clay
Less than 10^{-6}	Practically impermeable	Silty sand or sandy clay to clay

Source: IEEE, 1994.

8.3.1.3 Collecting Ponds with Traps

In this system, the complete design consists of a *collection pit* surrounding the protected equipment, drains connecting the collection pits to an open *containment pit* and an oil trap which is sometimes referred to as a skimming unit and the discharge drain. Figure 8.1 (IEEE, 1994) presents the general concept of such a containment solution. The collection pit surrounding the equipment is filled with rocks and designed only deep enough to extinguish burning oil. The bottom of this pit is sloped for good drainage to the drainpipe leading to an open containment pit. This latter pit is sized to handle all the oil of the largest piece of equipment in the station. To maintain a dry system in the collecting units, the invert of the intake pipe to the containment pit must be at least the maximum elevation of the oil level. In areas of the country subject to freezing temperatures, it is recommended that the trap (skimmer) be encased in concrete, or other similar means available, to eliminate heaving due to ice action.

8.3.1.4 Oil Containment Equipment Pits

Probably one of the most reliable but most expensive methods of preventing oil spills and insuring that oil will be contained on the substation property is by placing all major substation equipment on or in containment pits. This method of oil retention provides a permanent means of oil containment. These containment pits will confine the spilled oil to relatively small areas that in most cases will greatly reduce the cleanup costs.

One of the most important issues related to an equipment pit is to prevent escape of spilled oil into underlying soil layers. Pits with liners or sealers may be used as part of an oil containment system capable of retaining any discharged oil for an extended period of time. Any containment pit must be constructed with materials having medium to high permeability (above 10^{-3} cm/sec) and be sealed in order to prevent migration of spilled oil into underlying soil layers and groundwater. These surfaces may be sealed and/or lined with any of the following materials:

1. Plastic or rubber—Plastic or rubber liners may be purchased in various thickness and sizes. It is recommended that a liner be selected that is resistant to mechanical injury which may occur due

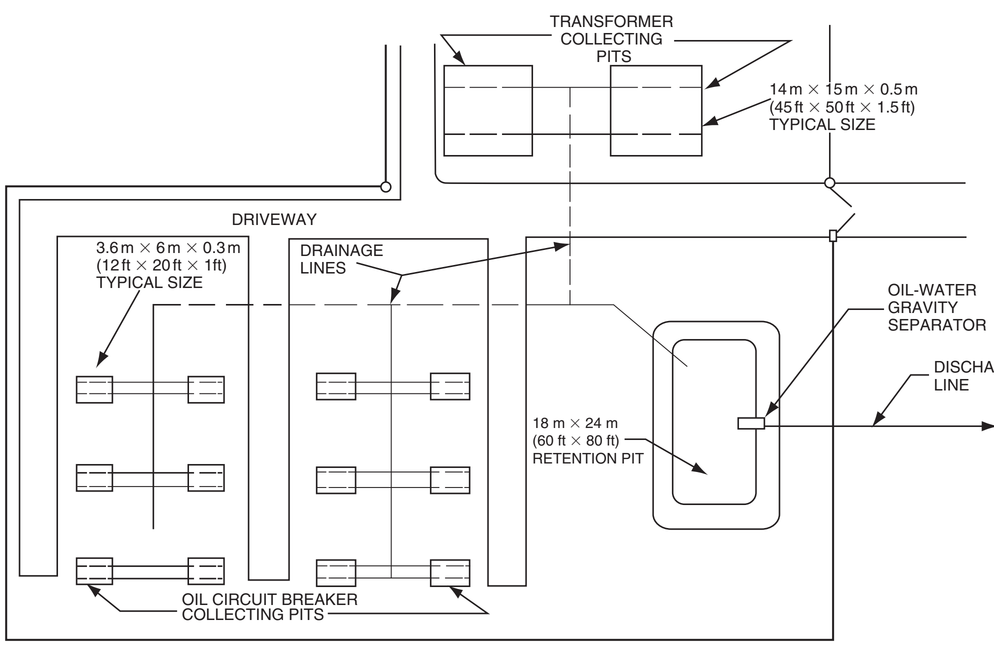

FIGURE 8.1 Typical containment system with retention and collection pits.

to construction and installation, equipment, chemical attacks on surrounding media, and oil products.

2. Bentonite (clay)—Clay and Bentonite may also be used to seal electrical facility yards and containment pits. These materials can be placed directly in 100 to 150 mm (4 to 6 in.) layers or may be mixed with the existing subsoil to obtain an overall soil permeability of less than 10^{-3} cm/sec.
3. Spray-on fiberglass—Spray-on fiberglass is one of the most expensive pit liners available, but in some cases, the costs may be justifiable in areas which are environmentally sensitive. This material offers very good mechanical strength properties and provides excellent oil retention.
4. Reinforced concrete—100 to 150 mm (4 to 6 in.) of reinforced concrete may also be used as a pit liner. This material has an advantage over other types of liners in that it is readily available at the site at the time of initial construction of the facility. Concrete has some disadvantages in that initial preparation is more expensive and materials are not as easily workable as some of the other materials.

If materials other than those listed above are used for an oil containment liner, careful consideration must be given to selecting materials, which will not dissolve or become soft with prolonged contact with oil, such as asphalt.

8.3.1.5 Fire Quenching Considerations (IEEE, 1994)

In places where the oil-filled device is installed in an open pit (not filled with stone), an eventual oil spill associated with fire will result in a pool fire around the affected piece of equipment. If a major fire occurs, the equipment will likely be destroyed. Most utilities address this concern by employing active or passive quenching systems, or drain the oil to a remote pit. Active systems include foam or water spray deluge systems.

Of the passive fire quenching measures, pits filled with crushed stone are the most effective. The stone-filled pit provides a fire quenching capability designed to extinguish flames in the event that a piece of oil-filled equipment catches on fire. An important point is that in sizing a stone-filled collecting or retention pit, the final oil level elevation (assuming a total discharge) has to be situated approximately 300 mm (12 in) below the top elevation of the stone.

All the materials used in construction of a containment pit have to be capable of withstanding the higher temperatures associated with an oil fire without melting. If any part of the containment (i.e., discharge pipes from containment to a sump) melts, the oil will be unable to drain away from the burning equipment, and the melted materials may pose an environmental hazard.

8.3.1.6 Volume Requirements

Before a substation oil-containment system can be designed, the volume of oil to be contained must be known. Since the probability of an oil spill occurring at a substation is very low, the probability of simultaneous spills is extremely low. Therefore, it would be unreasonable and expensive to design a containment system to hold the sum total of all of the oil contained in the numerous oil-filled pieces of equipment normally installed in a substation. In general, it is recommended that an oil-containment system be sized to contain the volume of oil in the single largest oil-filled piece of equipment, plus any accumulated water from sources such as rainwater, melted snow, and water spray discharge from fire protection systems. Interconnection of two or more pits to share the discharged oil volume may provide an opportunity to reduce the size requirements for each individual pit.

Typically, equipment containment pits are designed to extend 1.5–3 m (5–10 ft) beyond the edge of the tank in order to capture a majority of the leaking oil. A larger pit size is required to capture all of the oil contained in an arcing stream from a small puncture at the bottom of the tank (such as from a bullet hole). However, the low probability of the event and economic considerations govern the 1.5–3 m (5–10 ft) design criteria. For all of the oil to be contained, the pit or berm has to extend 7.5 m (25 ft) or more beyond the tank and radiators.

The volume of the pit surrounding each piece of equipment has to be sufficient to contain the spilled oil in the air voids between the aggregate of gravel fill or stone. A gravel gradation with a nominal size of 19–50 mm (3/4 to 2 in.) which results in a void volume between 30 and 40% of the pit volume is generally being used. The theoretical maximum amount of oil that can be contained in 1 ft^3 or 1 m^3 of stone is given by the following formulae:

$$\text{Oil Volume [gal]} = \frac{\text{void volume of stone [\%]}}{100 \times 0.1337\ \text{ft}^3} \tag{8.1}$$

$$\text{Oil Volume [l]} = \frac{\text{void volume of stone [\%]}}{100 \times 0.001\ \text{m}^3} \tag{8.2}$$

where

1 gallon $= 0.1337\ \text{ft}^3$
1 liter $= 0.001\ \text{m}^3 = 1\ \text{dm}^3$

If the pits are not to be automatically drained of rainwater, then an additional allowance must be made for precipitation. The additional space required would depend on the precipitation for that area and the frequency at which the facility is periodically inspected. It is generally recommended that the pits have sufficient space to contain the amount of rainfall for this period plus a 20% safety margin.

Expected rain and snow accumulations can be determined from local weather records. A severe rainstorm is often considered to be the worst-case event when determining the maximum volume of short-term water accumulation (for design purposes). From data reported in a 1992 IEEE survey, the storm water event design criteria employed ranged from 50 to 200 mm (2 to 8 in.) of rainfall within a short period of time (1–24 h). Generally accepted design criteria is assuming a one in a 25-year storm event.

The area directly surrounding the pit must be graded to slope away from the pit to avoid filling the pit with water in times of rain.

8.3.1.7 Typical Equipment Containment Solutions

Figure 8.2 illustrates one method of pit construction that allows the equipment to be installed partially below ground. The sump pump can be manually operated during periods of heavy rain or automatically operated. If automatic operation is preferred, special precautions must be included to insure that oil is not pumped from the pits. This can be accomplished with either an oil-sensing probe or by having all major equipment provided with oil-limit switches (an option available from equipment suppliers). These limit switches are located just below the *minimum* top oil line in the equipment and will open when the oil level drops below this point.

A typical above-grade pit and/or berm, as shown in Fig. 8.3, has maintenance disadvantages but can be constructed relatively easily after the equipment is in place at new and existing electrical facilities. These pits may be emptied manually by gate valves or pumps depending on the facility terrain and layout, or automatically implemented by the use of equipment oil limit switches and dc-operated valves or sump pumps.

Another method of pit construction is shown in Fig. 8.4. The figure shows all-concrete containment pits installed around transformers. The sump and the control panel for the oil pump (located inside the sump) are visible and are located outside the containments. Underground piping provides the connection between the two adjacent containments and the sump. The containments are filled with fire-quenching stones.

8.3.2 Discharge Control Systems (IEEE, 1994)

An adequate and effective station drainage system is an essential part of any oil-containment design. Drains, swales, culverts, catch basins, etc., provide measures to ensure that water is diverted away from the substation. In addition, the liquid accumulated in the collecting pits or sumps of various electrical

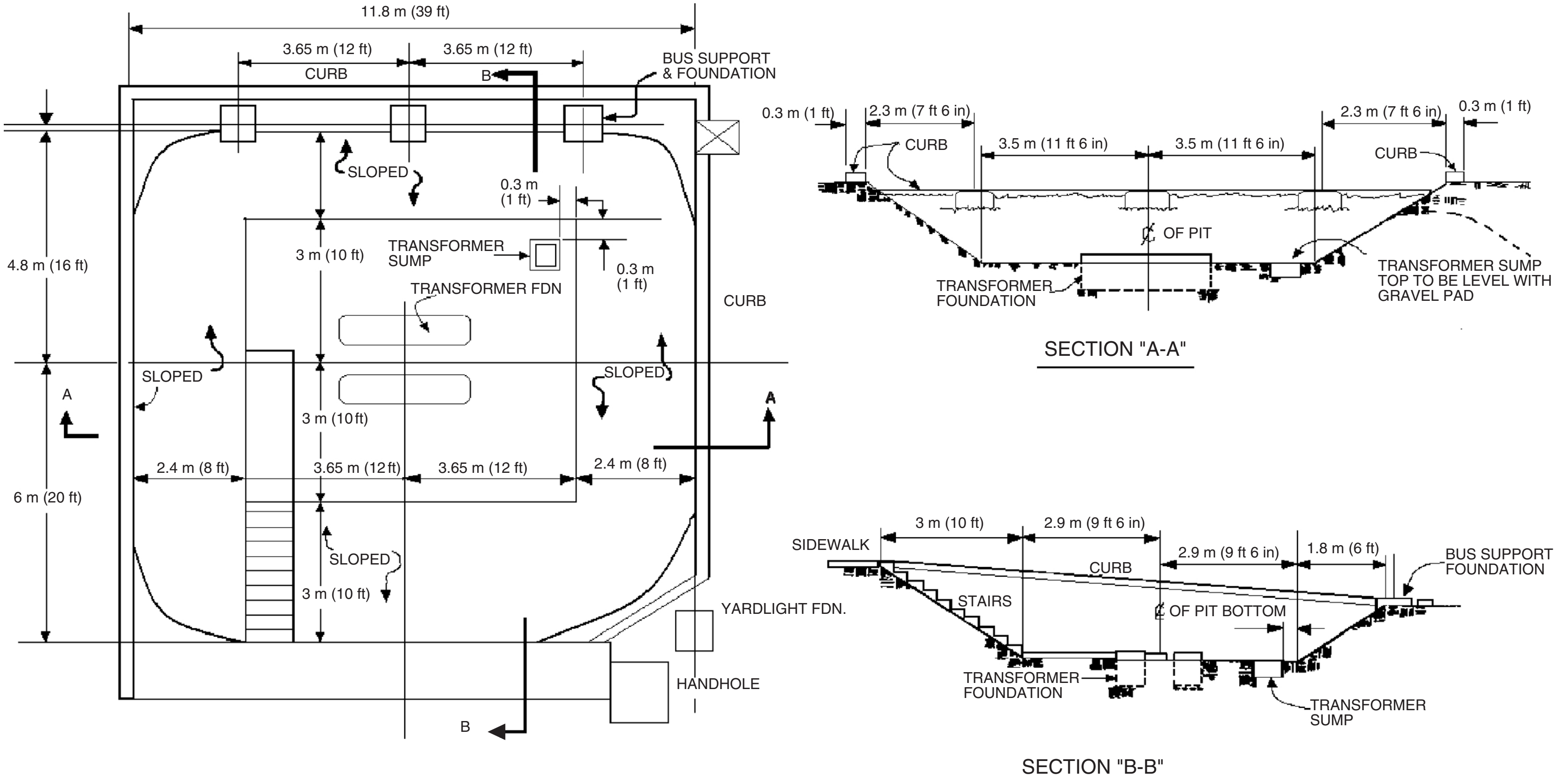

FIGURE 8.2 Typical below-grade containment pit.

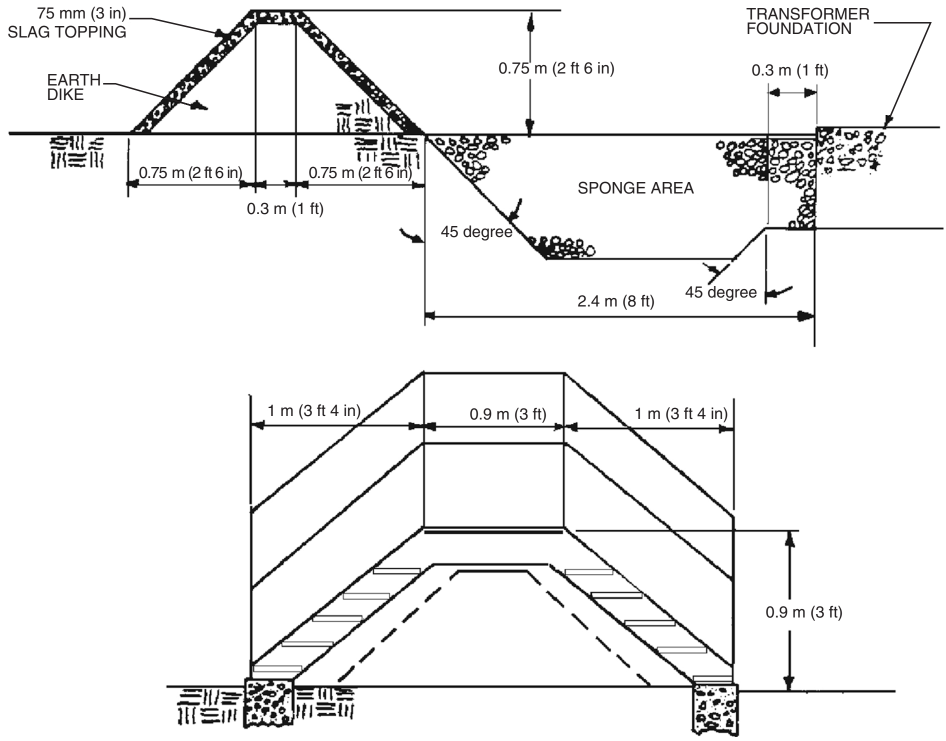

FIGURE 8.3 Typical above-grade berm/pit.

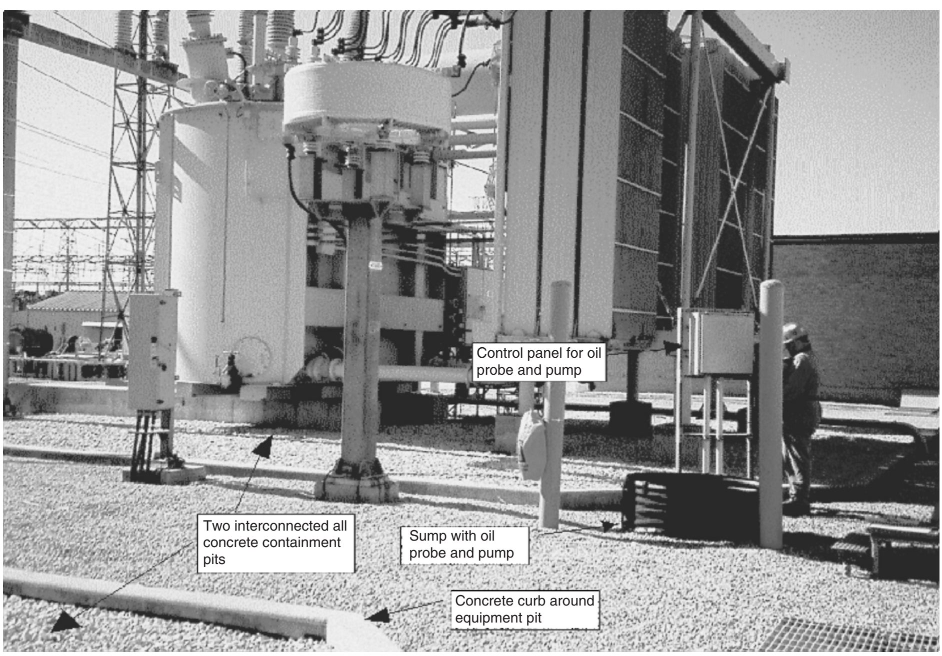

FIGURE 8.4 All-concrete containment pits.

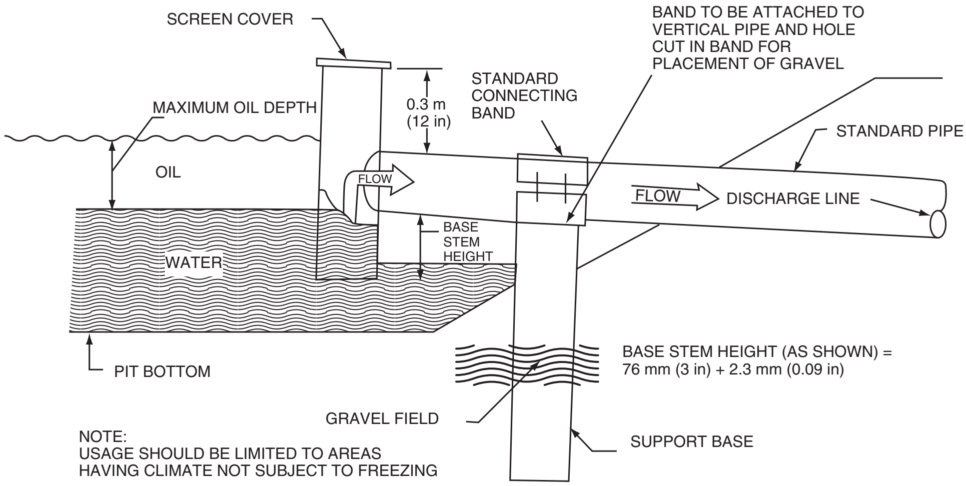

FIGURE 8.5 Oil-water gravity separator.

equipment, or in the retention pit has to be discharged. This liquid consists mainly of water (rainwater, melted snow or ice, water spray system discharges, etc.). Oil will be present only in case of an equipment discharge. It is general practice to provide containment systems that discharge the accumulated water into the drainage system of the substation or outside the station perimeter with a discharge control system.

These systems, described below, provide methods to release the accumulated water from the containment system while blocking the flow of discharged oil for later cleanup. Any collected water has to be released as soon as possible so that the entire capacity of the containment system is available for oil containment in the event of a spill. Where the ambient temperatures are high enough, evaporation may eliminate much of the accumulated water. However, the system still should be designed to handle the worst-case event.

8.3.2.1 Oil-Water Separator Systems (IEEE, 1994)

Oil-water separator systems rely on the difference in specific gravity between oil and water. Because of that difference, the oil will naturally float on top of the water, allowing the water to act as a barrier and block the discharge of the oil.

Oil-water separator systems require the presence of water to operate effectively, and will allow water to continue flowing even when oil is present. The presence of emulsified oil in the water may, under some turbulent conditions, allow small quantities of oil to pass through an oil-water separator system.

Figure 8.5 (IEEE, 1994) illustrates the detail of an oil-water gravity separator that is designed to allow water to discharge from a collecting or retention pit, while at the same time retaining the discharged oil.

Figure 8.6 (IEEE, 1994) illustrates another type of oil-water separator. This separator consists of a concrete enclosure, located inside a collecting or retention pit and connected to it through an opening located at the bottom of the pit. The enclosure is also connected to the drainage system of the substation. The elevation of the top of the concrete weir in the enclosure is selected to be slightly above the maximum elevation of discharged oil in the pit. In this way, the level of liquid in the pit will be under a layer of fire quenching stones where a stone-filled pit is used. During heavy accumulation of water, the liquid will flow over the top of the weir into the drainage system of the station. A valve is incorporated in the weir. This normally closed, manually operated valve allows for a controlled discharge of water from the pit when the level of liquid in the pit and enclosure is below the top of the weir.

Figure 8.7 (IEEE, 1994) provides typical detail of an oil trap type oil-water separator. In this system, the oil will remain on top of the water and not develop the head pressure necessary to reach the bottom of the inner vertical pipe. In order for this system to function properly, the water level in the manhole

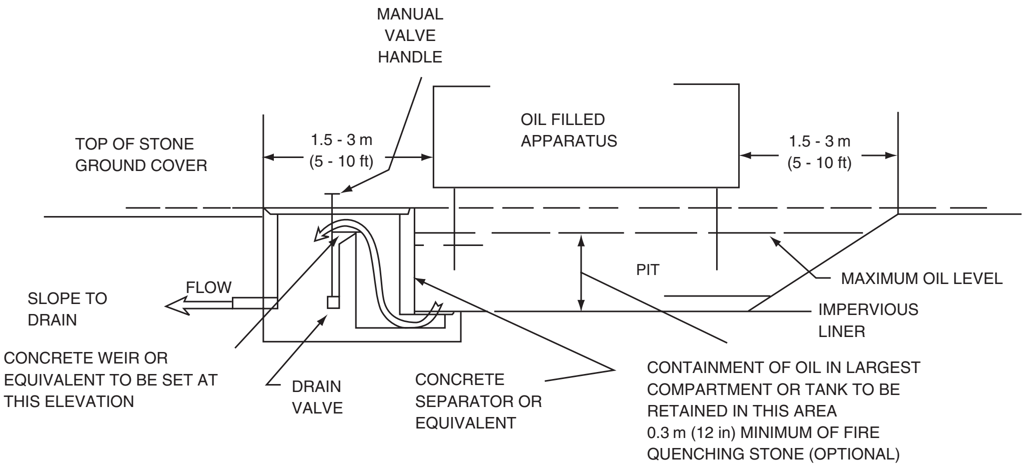

FIGURE 8.6 Equipment containment with oil-water separator.

portion of the oil trap must be maintained at an elevation no lower than 0.6 m (2 ft) below the inlet elevation. This will ensure that an adequate amount of water is available to develop the necessary hydraulic head within the inner (smaller) vertical pipe, thereby preventing any discharged oil from leaving the site. It is important to note that the inner vertical pipe should be extended downward past the calculated water-oil interface elevation sufficiently to ensure that oil cannot discharge upward through the inner pipe. Likewise, the inner pipe must extend higher than the calculated oil level elevation in the manhole to ensure that oil does not drain downward into the inner pipe through the vented plug. The reason for venting the top plug is to maintain atmospheric pressure within the vertical pipe, thereby preventing any possible siphon effect.

8.3.2.2 Flow Blocking Systems (IEEE, 1994)

Described below are two oil flow blocking systems that do not require the presence of water to operate effectively. These systems detect the presence of oil and block all flow (both water and oil) through the discharge system. The best of these systems have been shown to be the most sensitive in detecting and blocking the flow of oil. However, they are generally of a more complex design and may require greater maintenance to ensure continued effectiveness.

Figure 8.8 illustrates an oil stop valve installed inside a manhole. The valve has only one moving part: a ballasted float set at a specific gravity between that of oil and water. When oil reaches the manhole, the float in the valve loses buoyancy and sinks as the oil level increases until it sits on the discharge opening of the valve and blocks any further discharge. When the oil level in the manhole decreases, the float will rise automatically and allow discharge of water from the manhole. Some of the oil stop valves have a weep hole in the bottom of the valve that allows the ballasted float to be released after the oil is removed. This can cause oil to discharge if the level of the oil is above the invert of the discharge pipe.

Figure 8.9 illustrates a discharge control system consisting of an oil-detecting device and a pump installed in a sump connected to the collecting or retention pits of the oil-containment system. The oil-detecting device may use different methods of oil sensing (e.g., capacitance probes, turbidimeters, and fluorescence meters). The capacitance probe shown detects the presence of oil on the surface of the water, based on the significant capacitance difference of these two liquids and, in combination with a logic of liquid level switches, stops the sump pump when the water-oil separation layer reaches a preset height in the sump. Transformer low oil level or gas protection can be added into the control diagram of the pump in order to increase the reliability of the system during major spills.

Some containment systems consist of collecting pits connected to a retention pit or tank that have no link to the drainage system of the substation. Discharge of the liquid accumulated in these systems

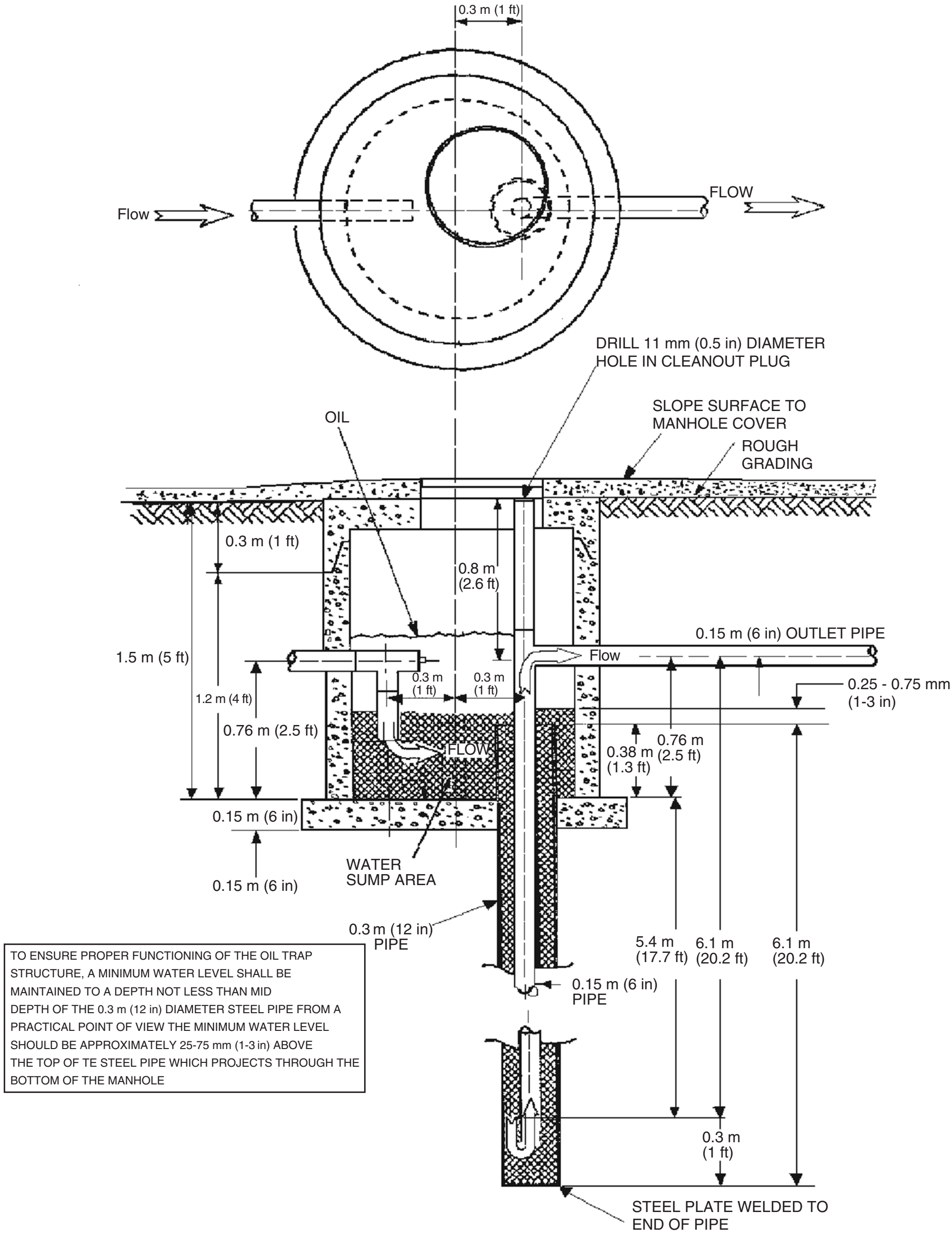

FIGURE 8.7 Oil trap type oil-water separator.

requires the use of permanently installed or portable pumps. However, should these probes become contaminated, they may cease to function properly. Operating personnel manually activate these pumps. This system requires periodic inspection to determine the level of water accumulation. Before pumping any accumulated liquid, an inspection is required to assess whether the liquid to be pumped out is contaminated.

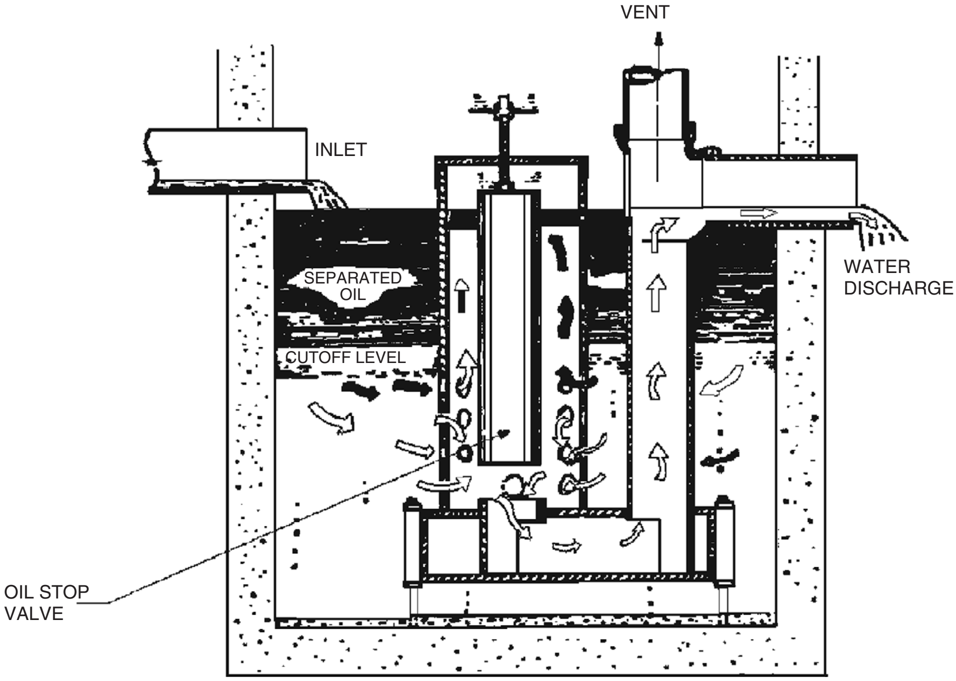

FIGURE 8.8 Oil stop valve installed in manhole.

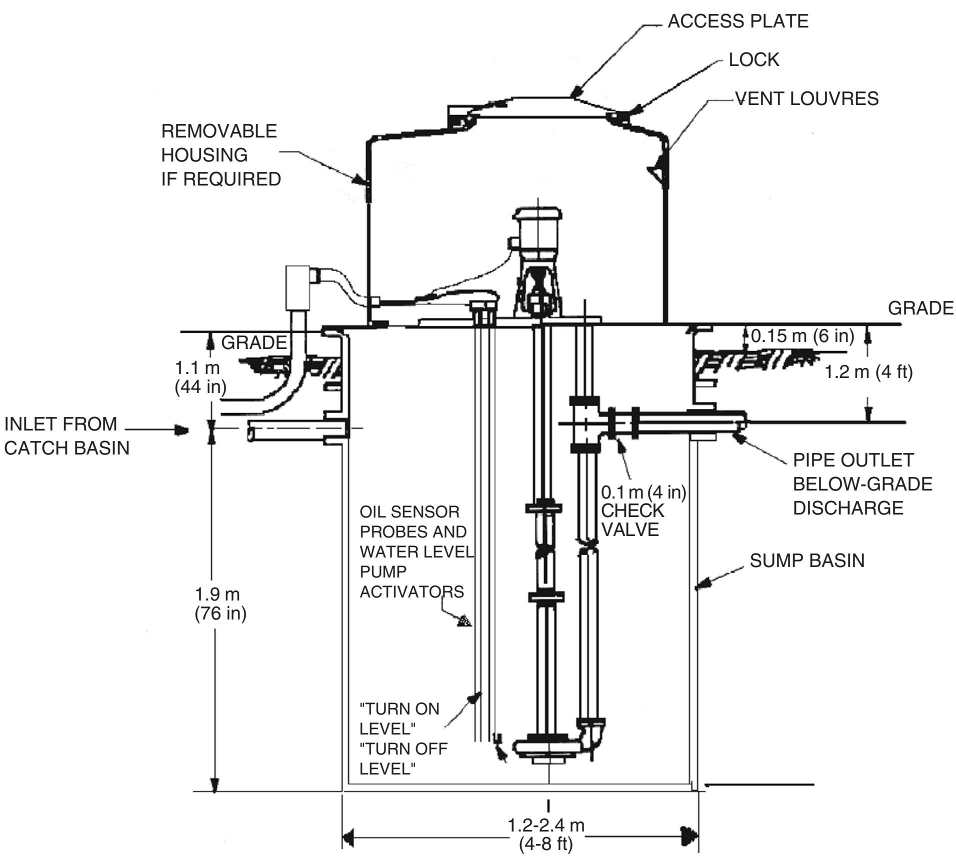

FIGURE 8.9 Sump pump water discharge (with oil sensing probe).

8.4 Warning Alarms and Monitoring (IEEE, 1994)

In the event of an oil spill, it is imperative that cleanup operations and procedures be initiated as soon as possible to prevent the discharge of any oil, or to reduce the amount of oil reaching navigable waters. Hence, it may be desirable to install an early detection system for alerting responsible personnel of an oil spill. Some governmental regulations may require that the point of discharge (for accumulated water) from a substation be monitored and/or licensed.

The most effective alarms are the ones activated by the presence of oil in the containment system. A low oil-level indicator within the oil-filled equipment can be used; however, it may not activate until 3–6% of the transformer oil has already discharged. In cases where time is critical, it may be worthwhile to also consider a faster operating alarm such as one linked to the transformer sudden gas pressure relay. Interlocks have to be considered as a backup to automatic pump or valve controls.

Alarms are transmitted via supervisory equipment or a remote alarm system to identify the specific problem. The appropriate personnel are then informed so that they can determine if a spill has occurred and implement the SPCC contingency plan.

References

1. *Design Guide for Oil Spill Prevention and Control at Substations*, U.S. Department of Agriculture, Rural Electrification Administration Bulletin 65-3, January, 1981.
2. *IEEE Guide for Containment and Control of Oil Spills in Substations*, IEEE Std. 980-1994 (R2001).

9

Community Considerations[1]

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9.1 Community Acceptance

Community acceptance generally encompasses the planning, design, and construction phases of a substation as well as the in-service operation of the substation. It takes into account those issues that could influence a community's willingness to accept building a substation at a specific site. New substations or expansions of existing facilities often require extensive review for community acceptance. Government bodies typically require a variety of permits before construction may begin.

For community acceptance, several considerations should be satisfactorily addressed, including the following:

- Noise
- Site preparations
- Aesthetics
- Fire protection
- Potable water and sewage
- Hazardous materials

[1]Chapters 4, 5, 6, 7, and 8 (excluding Sections 5.3.2.2, 5.3.5, 5.4.2.1, 5.4.2.2, 5.4.2.3, 5.4.3.1, 5.4.3.2, 5.4.3.3, 5.4.3.4, 5.4.3.5, 6.1, 6.2, 7.1.4, 7.4, 8.2.1., 8.2.2, Tables 8.1 and 8.2, and Figs. 8.1 and 8.2) reprinted from IEEE Std. 1127–1998, "IEEE Guide for the Design, Construction, and Operation of Electric Power Substations for Community Acceptance and Environmental Compatibility" Copyright© 1998, by the Institute of Electrical and Electronics Engineers, Inc. (IEEE). The IEEE disclaims any responsibility or liability resulting from the placement and use in the described manner. Information is reprinted with the permission of the IEEE.

- Electric and magnetic fields
- Safety and security

This chapter on Community Considerations is essentially a condensed version of IEEE Standard 1127–1998.

9.2 Planning Strategies and Design

Planning is essential for the successful design, construction, and operation of a substation. The substation's location and proximity to wetlands, other sensitive areas, and contaminated soils; its aesthetic impact; and the concerns of nearby residents over noise and electric and magnetic fields (EMF) can significantly impact the ability to achieve community acceptance. Public perceptions and attitudes toward both real and perceived issues can affect the ability to obtain all necessary approvals and permits.

These issues can be addressed through presentations to governmental officials and the public. Failure to obtain community acceptance can delay the schedule or, in the extreme, stop a project completely.

9.2.1 Site Location and Selection, and Preparation

The station location (especially for new substations) is the key factor in determining the success of any substation project. Although the site location is based on electric system load growth studies, the final site location may ultimately depend upon satisfying the public and resolving potential community acceptance concerns. If necessary, a proactive public involvement program should be developed and implemented. The best substation site selection is influenced by several factors including, but not limited to, the following:

1. Community attitudes and perceptions
2. Location of nearby wetlands, bodies of water, or environmentally sensitive areas
3. Site contamination (obvious or hidden)
4. Commercial, industrial, and residential neighbors, including airports
5. Permit requirements and ordinances
6. Substation layout (including future expansions) and placement of noise sources
7. Levels of electric and magnetic fields
8. Availability and site clearing requirements for construction staging
9. Access to water and sewer
10. Drainage patterns and storm water management
11. Potential interference with radio, television, and other communication installations
12. Disturbance of archaeological, historical, or culturally significant sites
13. Underground services and geology
14. Accessibility
15. Aesthetic and screening considerations

9.2.1.1 Wetlands

A site-development plan is necessary for a substation project that borders wetlands. Such a plan for the site and its immediate surroundings should include the following:

1. Land-use description
2. Grades and contours
3. Locations of any wetland boundaries and stream-channel encroachment lines
4. Indication of flood-prone areas and vertical distance or access to ground water
5. Indication of existing wildlife habitats and migratory patterns

The plan should describe how site preparation will modify or otherwise impact these areas and what permanent control measures will be employed, including ground water protection.

9.2.1.2 Site Contamination

Soil borings should be taken on any proposed substation site to determine the potential presence of soil contaminants.

There are many substances that, if found on or under a substation site, would make the site unusable or require excessive funds to remediate the site before it would be usable. Some of the substances are as follows:

1. Polychlorinated biphenyls (PCBs)
2. Asbestos
3. Lead and other heavy metals
4. Pesticides and herbicides
5. Radioactive materials
6. Petrochemicals
7. Dioxin
8. Oil

Governmental guidelines for the levels of these substances should be used to determine if the substance is present in large enough quantities to be of concern.

The cost of removal and disposal of any contaminants should be considered before acquiring or developing the site. If a cleanup is needed, the acquisition of another site should be considered as governmental regulations can hold the current owner or user of a site responsible for cleanup of any contamination present, even if substances were deposited prior to acquisition. If a cleanup is initiated, all applicable governmental guidelines and procedures should be followed.

9.2.1.3 Potable Water and Sewage

The substation site may need potable water and sewage disposal facilities. Water may be obtained from municipal or cooperative water utilities or from private wells. Sewage may be disposed of by municipal services or septic systems, or the site could be routinely serviced by portable toilet facilities, which are often used during construction. Where municipal services are used for either water or sewer service, the requirements of that municipality must be met. Septic systems, when used, should meet all applicable local, state, and federal regulations.

9.2.2 Aesthetics

Aesthetics play a major role where community acceptance of a substation is an issue. Sites should be selected that fit into the context of present and future community patterns.

Community acceptability of a site can be influenced by:

1. Concerns about compatibility with present and future land uses
2. Building styles in the surrounding environment
3. Landscape of the site terrain
4. Allowance for buffer zones for effective blending, landscaping, and safety
5. Site access that harmonizes with the community

In addition, the site may need to be large enough to accommodate mobile emergency units and future expansions without becoming congested.

9.2.2.1 Visual Simulation

Traditionally, a site rendering was an artist's sketch, drawing, painting, or photomontage with airbrush retouching, preferably in color, and as accurate and realistic as possible. In recent years, these traditional techniques, although still employed, have given way to two- and three-dimensional computer-generated images, photorealism, modeling, and animation to simulate and predict the impact of proposed developments.

This has led to increased accuracy and speed of image generation in the portrayal of new facilities for multiple-viewing (observer) positions, allowing changes to be made early in the decision-making process while avoiding costly alterations that sometimes occur later during construction.

A slide library of several hundred slides of aesthetic design choices is available from the IEEE. It is a compilation of landscaping, decorative walls and enclosures, plantings, and site location choices that have been used by various utilities worldwide to ensure community acceptance and environmental compatibility.

9.2.2.2 Landscaping and Topography

Landscaping: Where buffer space exists, landscaping can be a very effective aesthetic treatment. On a site with little natural screening, plantings can be used in concert with architectural features to complement and soften the visual effect.

All plantings should be locally available and compatible types, and should require minimum maintenance. Their location near walls and fences should not compromise either substation grounding or the security against trespass by people or animals.

Topography: Topography or land form, whether shaped by nature or by man, can be one of the most useful elements of the site to solve aesthetic and functional site development problems.

Use of topography as a visual screen is often overlooked. Functionally, earth forms can be permanent, visual screens constructed from normal on-site excavating operations. When combined with plantings of grass, bushes, or evergreens and a planned setback of the substation, berms can effectively shield the substation from nearby roads and residents.

Fences and walls: The National Electrical Safety Code® [(NESC®) (Accredited Standards Committee C2–2007)] requires that fences, screens, partitions, or walls be employed to keep unauthorized persons away from substation equipment.

Chain-link fences: This type of fence is the least vulnerable to graffiti and is generally the lowest-cost option. Chain-link fences can be galvanized or painted in dark colors to minimize their visibility, or they can be obtained with vinyl cladding. They can also be installed with wooden slats or colored plastic strips woven into the fence fabric. Grounding and maintenance considerations should be reviewed before selecting such options.

Wood fences: This type of fence should be constructed using naturally rot-resistant or pressure-treated wood, in natural color or stained for durability and appearance. A wood fence can be visually overpowering in some settings. Wood fences should be applied with caution because wood is more susceptible to deterioration than masonry or metal.

Walls: Although metal panel and concrete block masonry walls cost considerably more than chain-link and wood fences, they deserve consideration where natural or landscaped screening does not provide a sufficient aesthetic treatment. Brick and precast concrete can also be used in solid walls, but these materials are typically more costly. These materials should be considered where necessary for architectural compatibility with neighboring facilities. Walls can offer noise reduction (discussed later) but can be subject to graffiti. All issues should be considered before selecting a particular wall or fence type.

9.2.2.3 Color

When substations are not well screened from the community, color can have an impact on the visual effect.

Above the skyline, the function of color is usually confined to eliminating reflective glare from bright metal surfaces. Because the sun's direction and the brightness of the background sky vary, no one color can soften the appearance of substation structures in the course of changing daylight. Below the skyline, color can be used in three aesthetic capacities. Drab coloring, using earth tones and achromatic hues, is a technique that masks the metallic sheen of such objects as chain-link fences and steel structures, and reduces visual contrast with the surrounding landscape. Such coloring should have very limited variation in hues, but contrast by varying paint saturation is often more effective than a monotone coating. Colors and screening can often be used synergistically. A second technique is to use color to direct visual attention to more aesthetically pleasing items such as decorative walls and enclosures. In this use, some brightness is warranted, but highly saturated or contrasting hues should be avoided. A third technique is to brightly color equipment and structures for intense visual impact.

9.2.2.4 Lighting

When attractive landscaping, decorative fences, enclosures, and colors have been used to enhance the appearance of a highly visible substation, it may also be appropriate to use lighting to highlight some of these features at night. Although all-night lighting can enhance substation security and access at night, it should be applied with due concern for nearby residences.

9.2.2.5 Structures

The importance of aesthetic structure design increases when structures extend into the skyline. The skyline profile typically ranges from 6 m to 10 m (20 ft to 35 ft) above ground. Transmission line termination structures are usually the tallest and most obvious. Use of underground line exits will have the greatest impact on the substation's skyline profile. Where underground exits are not feasible, low-profile station designs should be considered. Often, low-profile structures will result in the substation being below the nearby tree line profile.

For additional cost, the most efficient structure design can be modified to improve its appearance. The following design ideas may be used to improve the appearance of structures:

1. Tubular construction
2. Climbing devices not visible in profile
3. No splices in the skyline zone
4. Limiting member aspect ratio for slimmer appearance
5. Use splices other than pipe-flange type
6. Use of gusset plates with right-angle corners not visible in profile
7. Tapering ends of cantilevers
8. Equal length of truss panel
9. Making truss diagonals with an approximate 60° angle to chords
10. Use of short knee braces or moment-resistant connections instead of full-height diagonal braces
11. Use of lap splice plates only on the insides of H-section flanges

9.2.2.6 Enclosures

Total enclosure of a substation within a building is an option in urban settings where underground cables are used as supply and feeder lines. Enclosure by high walls, however, may be preferred if enclosure concealment is necessary for community acceptance.

A less costly design alternative in nonurban locales that are served by overhead power lines is to take advantage of equipment enclosures to modify visual impact. Relay and control equipment, station batteries, and indoor power switchgear all require enclosures. These enclosures can be aesthetically designed and strategically located to supplement landscape concealment of other substation equipment. The exterior appearance of these enclosures can also be designed (size, color, materials, shape) to match neighboring homes or buildings.

Industrial-type, pre-engineered metal enclosures are a versatile and economic choice for substation equipment enclosures. Concrete block construction is also a common choice for which special shaped and colored blocks may be selected to achieve a desired architectural effect. Brick, architectural metal panels, and precast concrete can also be used.

Substation equipment enclosures usually are not exempt from local building codes. Community acceptance, therefore, requires enclosure design, approval, and inspection in accordance with local regulation.

9.2.2.7 Bus Design

Substations can be constructed partly or entirely within aboveground or belowground enclosures. However, cost is high and complexity is increased by fire-protection and heat-removal needs. The following discussion deals with exposed aboveground substations.

Air-insulated substations: The bus and associated substation equipment are exposed and directly visible. An outdoor bus may be multitiered or spread out at one level. Metal or wood structures and insulators support such bus and power line terminations. Space permitting, a low-profile bus layout is generally best for aesthetics and is the easiest to conceal with landscaping, walls, and enclosures. Overhead transmission line terminating structures are taller and more difficult to conceal in such a layout. In dry climates, a low-profile bus can be achieved by excavating the earth area, within which outdoor bus facilities are then located for an even lower profile.

Switchgear: Metal-enclosed or metal-clad switchgear designs that house the bus and associated equipment in a metal enclosure are an alternative design for distribution voltages. These designs provide a compact low-profile installation that may be aesthetically acceptable.

Gas-insulated substation (GIS): Bus and associated equipment can be housed within pipe-type enclosures using sulfur hexafluoride or another similar gas for insulation. Not only can this achieve considerable compactness and reduced site preparation for higher voltages, but it can also be installed lower to the ground. A GIS can be an economically attractive design where space is at a premium, especially if a building-type enclosure will be used to house substation equipment (see IEEE Std. C37.123-1996).

Cable bus: Short sections of overhead or underground cables can be used at substations, although this use is normally limited to distribution voltages (e.g., for feeder getaways or transformer-to-switchgear connections). At higher voltages, underground cable can be used for line-entries or to resolve a specific connection problem.

Noise: Audible noise, particularly continuously radiated discrete tones (e.g., from power transformers), is the type of noise that the community may find unacceptable. Community guidelines to ensure that acceptable noise levels are maintained can take the form of governmental regulations or individual/community reaction (permit denial, threat of complaint to utility regulators, etc.). Where noise is a potential concern, field measurements of the area background noise levels and computer simulations predicting the impact of the substation may be required. The cost of implementing noise reduction solutions (low-noise equipment, barriers or walls, noise cancellation techniques, etc.) may become a significant factor when a site is selected.

Noise can be transmitted as a pressure wave either through the air or through solids. The majority of cases involving the observation and measurement of noise have dealt with noise being propagated through the air. However, there are reported, rare cases of audible transformer noise appearing at distant observation points by propagating through the transformer foundation and underground solid rock formations. It is best to avoid the situation by isolating the foundation from bedrock where the conditions are thought to favor transmission of vibrations.

9.2.2.8 Noise Sources

Continuous audible sources: The most noticeable audible noise generated by normal substation operation consists of continuously radiated audible discrete tones. Noise of this type is primarily generated by power transformers. Regulating transformers, reactors, and emergency generators, however, could also be sources. This type of noise is most likely to be subject to government regulations. Another source of audible noise in substations, particularly in extra high voltage (EHV) substations, is corona from the bus and conductors.

Continuous radio frequency (RF) sources: Another type of continuously radiated noise that can be generated during normal operation is RF noise. These emissions can be broadband and can cause interference to radio and television signal reception on properties adjacent to the substation site. Objectionable RF noise is generally a product of unintended sparking, but can also be produced by corona.

Impulse sources: While continuously radiated noise is generally the most noticeable to substation neighbors, significant values of impulse noise can also accompany normal operation. Switching operations will cause both impulse audible and RF noise with the magnitude varying with voltage, load, and operation speed. Circuit-breaker operations will cause audible noise, particularly operation of air-blast breakers.

9.2.2.9 Typical Noise Levels

Equipment noise levels: Equipment noise levels may be obtained from manufacturers, equipment tendering documents, or test results. The noise level of a substation power transformer is a function of the MVA and BIL rating of the high voltage winding. These transformers typically generate a noise level ranging from 60 to 80 dBA.

Transformer noise will "transmit" and attenuate at different rates depending on the transformer size, voltage rating, and design. Few complaints from nearby residents are typically received concerning substations with transformers of less than 10 MVA capacity, except in urban areas with little or no buffers. Complaints are more common at substations with transformer sizes of 20–150 MVA, especially within the first 170–200 m (500–600 ft). However, in very quiet rural areas where the nighttime ambient can reach 20–25 dBA, the noise from the transformers of this size can be audible at distances of 305 m (1000 ft) or more. In urban areas, substations at 345 kV and above rarely have many complaints because of the large parcels of land on which they are usually constructed.

Attenuation of noise with distance: The rate of attenuation of noise varies with distance for different types of sound sources depending on their characteristics. Point sound sources that radiate equally in all directions will decrease at a rate of 6 dB for each doubling of distance. Cylindrical sources vibrating uniformly in a radial direction will act like long source lines and the sound pressure will drop 3 dB for each doubling of distance. Flat planar surfaces will produce a sound wave with all parts of the wave tracking in the same direction (zero divergence). Hence, there will be no decay of the pressure level due to distance only. The designer must first identify the characteristics of the source before proceeding with a design that will take into account the effect of distance.

A transformer will exhibit combinations of all of the above sound sources, depending on the distance and location of the observation point. Because of its height and width, which can be one or more wavelengths, and its nonuniform configuration, the sound pressure waves will have directional characteristics with very complex patterns. Close to the transformer (near field), these vibrations will result in lobes with variable pressure levels. Hence, the attenuation of the noise level will be very small. If the width (W) and height (H) of the transformer are known, then the near field is defined, from observation, as any distance less than $2\sqrt{WH}$ from the transformer.

Further from the transformer (far field), the noise will attenuate in a manner similar to the noise emitted from a point source. The attenuation is approximately equal to 6 dB for every doubling of the distance. In addition, if a second adjacent transformer produces an identical noise level to the existing transformer (e.g., 75 dBA), the total sound will be 78 dBA for a net increase of only 3 dB. This is due to the logarithmic effect associated with a combination of noise sources.

9.2.2.10 Governmental Regulations

Governmental regulations may impose absolute limits on emissions, usually varying the limits with the zoning of the adjacent properties. Such limits are often enacted by cities, villages, and other incorporated urban areas where limited buffer zones exist between property owners. Typical noise limits at the substation property line used within the industry are as follows:

- Industrial zone <75 dBA
- Commercial zone <65 dBA
- Residential zone <55 dBA

Additional governmental noise regulations address noise levels by limiting the increase above the existing ambient to less than 10 dB. Other regulations could limit prominent discrete tones, or set specific limits by octave bands.

9.2.2.11 Noise Abatement Methods

The likelihood of a noise complaint is dependent on several factors, mostly related to human perceptions. As a result, the preferred noise abatement method is time-dependent as well as site-specific.

Reduced transformer sound levels: Since power transformers, voltage regulators, and reactors are the primary sources of continuously radiated discrete tones in a substation, careful attention to equipment design can have a significant effect on controlling noise emissions at the substation property line. This equipment can be specified with noise emissions below manufacturer's standard levels, with values as much as 10 dB below those levels being typical.

In severely restrictive cases, transformers can be specified with noise emissions 20 dB less than the manufacturers' standard levels, but usually at a significant increase in cost. Also, inclusion of bid evaluation factor(s) for reduced losses in the specification can impact the noise level of the transformer. Low-loss transformers are generally quieter than standard designs.

Low-impulse noise equipment: Outdoor-type switching equipment is the cause of most impulse noise. Switchgear construction and the use of vacuum or puffer circuit breakers, where possible, are the most effective means of controlling impulse emissions. The use of circuit switchers or air-break switches with whips and/or vacuum bottles for transformer and line switching, may also provide impulse-emission reductions over standard air-break switches.

RF noise and corona-induced audible noise control: Continuously radiated RF noise and corona-induced audible noise can be controlled through the use of corona-free hardware and shielding for high-voltage conductors and equipment connections, and through attention to conductor shapes to avoid sharp corners. Angle and bar conductors have been used successfully up to 138 kV without objectionable corona if corners are rounded at the ends of the conductors and bolts are kept as short as possible.

Tubular shapes are typically required above this voltage. Pronounced edges, extended bolts, and abrupt ends on the conductors can cause significant RF noise to be radiated. The diameter of the conductor also has an effect on the generation of corona, particularly in wet weather. Increasing the size of single grading rings or conductor diameter may not necessarily solve the problem. In some cases it may be better to use multiple, smaller diameter grading rings.

Site location: For new substations to be placed in an area known to be sensitive to noise levels, proper choice of the site location can be effective as a noise abatement strategy. Also, locations in industrial parks or near airports, expressways, or commercial zones that can provide almost continuous background noise levels of 50 dB or higher will minimize the likelihood of a complaint.

Larger yard area: Noise intensity varies inversely with distance. An effective strategy for controlling noise of all types involves increasing the size of the parcel of real estate on which the substation is located.

Equipment placement: Within a given yard size, the effect of noise sources on the surroundings can be mitigated by careful siting of the noise sources within the confines of the substation property. In addition, making provisions for the installation of mobile transformers, emergency generators, etc. near the center of the property, rather than at the edges, will lessen the effect on the neighbors.

Barriers or walls: If adequate space is not available to dissipate the noise energy before it reaches the property line, structural elements might be required. These can consist of walls, sound-absorbing panels, or deflectors. In addition, earth berms or below-grade installation may be effective. It may be possible to deflect audible noises, especially the continuously radiated tones most noticeable to the public, to areas not expected to be troublesome. Foliage, despite the potential aesthetic benefit and psychological effect, is not particularly effective for noise reduction purposes.

Properly constructed sound barriers can provide several decibels of reduction in the noise level. An effective barrier involves a proper application of the basic physics of

1. Transmission loss through masses
2. Sound diffraction around obstacles
3. Standing waves behind reflectors
4. Absorption at surfaces

For a detailed analysis of wall sound barriers, refer to IEEE Std. 1127–1998.

Active noise cancellation techniques: Another solution to the problem of transformer noise involves use of active noise control technology to cancel unwanted noise at the source, and is based on advances in digital controller computer technology. Active noise cancellation systems can be tuned to specific problem frequencies or bands of frequencies achieving noise reduction of up to 20 dB.

9.2.3 Electric and Magnetic Fields

Electric substations produce electric and magnetic fields. In a substation, the strongest fields around the perimeter fence come from the transmission and distribution lines entering and leaving the substation. The strength of fields from equipment inside the fence decreases rapidly with distance, reaching very low levels at relatively short distances beyond substation fences.

In response to the public concerns with respect to EMF levels, whether perceived or real, and to governmental regulations, the substation designer may consider design measures to lower EMF levels or public exposure to fields while maintaining safe and reliable electric service.

9.2.3.1 Electric and Magnetic Field Sources in a Substation

Typical sources of electric and magnetic fields in substations include the following:

1. Transmission and distribution lines entering and exiting the substation
2. Buswork
3. Transformers
4. Air core reactors
5. Switchgear and cabling
6. Line traps
7. Circuit breakers
8. Ground grid
9. Capacitors
10. Battery chargers
11. Computers

9.2.3.2 Electric Fields

Electric fields are present whenever voltage exists on a conductor. Electric fields are not dependent on the current. The magnitude of the electric field is a function of the operating voltage and decreases with the square of the distance from the source. The strength of an electric field is measured in volts per meter. The most common unit for this application is kilovolts per meter. The electric field can be easily shielded (the strength can be reduced) by any conducting surface such as trees, fences, walls, buildings, and most structures. In substations, the electric field is extremely variable due to the screening effect provided by the presence of the grounded steel structures used for electric bus and equipment support.

Although the level of the electric fields could reach magnitudes of approximately 13 kV/m in the immediate vicinity of high-voltage apparatus, such as near 500-kV circuit beakers, the level of the electric field decreases significantly toward the fence line. At the fence line, which is at least 6.4 m (21 ft) from the nearest live 500-kV conductor (see the NESC), the level of the electric field approaches zero kV/m. If the incoming or outgoing lines are underground, the level of the electric field at the point of crossing the fence is negligible.

9.2.3.3 Magnetic Fields

Magnetic fields are present whenever current flows in a conductor, and are not voltage dependent. The level of these fields also decreases with distance from the source but these fields are not easily shielded. Unlike electric fields, conducting materials such as the earth, or most metals, have little shielding effect on magnetic fields.

Magnetic fields are measured in Webers per square meter (Tesla) or Maxwells per square centimeter (Gauss). One Gauss = 10^{-4} Tesla. The most common unit for this application is milliGauss (10^{-3} Gauss).

Various factors affect the levels of the fields, including the following:

1. Current magnitude
2. Phase spacing
3. Bus height
4. Phase configurations
5. Distance from the source
6. Phase unbalance (magnitude and angle)

Magnetic fields decrease with increasing distance (r) from the source. The rate is an inverse function and is dependent on the type of source. For point sources such as motors and reactors, the function is $1/r^2$; and for single-phase sources such as neutral or ground conductors the function is $1/r$. Besides distance, conductor spacing and phase balance have the largest effect on the magnetic field level because they control the rate at which the field changes.

Magnetic fields can sometimes be shielded by specially engineered enclosures. The application of these shielding techniques in a power system environment is minimal because of the substantial costs involved and the difficulty of obtaining practical designs.

9.2.4 Safety and Security

9.2.4.1 Fences and Walls

The primary means of ensuring public safety at substations is by the erection of a suitable barrier, such as a fence or a wall with warning signs. As a minimum, the barrier should meet the requirements of the NESC and other applicable electrical safety codes. Recommended clearances from substation live parts to the fence are specified in the NESC, and security methods are described in IEEE 1402–2000.

9.2.4.2 Lighting

Yard lighting may be used to enhance security and allow equipment status inspections. A yard-lighting system should provide adequate ground-level lighting intensity around equipment and the control-house area for security purposes without disruption to the surrounding community. High levels of nightly illumination will often result in complaints.

9.2.4.3 Grounding

Grounding should meet the requirement of IEEE Std. 80–2000 to ensure the design of a safe and adequate grounding system. All non-current-carrying metal objects in or exiting from substations should be grounded (generally to a buried metallic grid) to eliminate the possibility of unsafe touch or step potentials, which the general public might experience during fault conditions.

9.2.4.4 Fire Protection

The potential for fires exists throughout all stations. Although not a common occurrence, substation fires are an important concern because of potential for long-term outages, personnel injury or death, extensive property and environmental damage, and rapid uncontrolled spreading. Refer to IEEE Std. 979–1994 for detailed guidance and identification of accepted substation fire-protection design practices and applicable industry standards.

9.2.5 Permitting Process

A variety of permits may be required by the governing bodies before construction of a substation may begin. For the permitting process to be successful, the following factors may have to be considered:

1. Site location
2. Level of ground water
3. Location of wetlands
4. Possibility of existing hazardous materials
5. Need for potable water and sewage
6. Possible noise
7. Aesthetics
8. EMF

Timing for the permit application is a critical factor because the permit application may trigger opposition involvement. If it is determined that the situation requires public involvement, the preparation and implementation of a detailed plan using public participation can reduce the delays and costs associated with political controversy and litigation. In these situations, public involvement prior to permit application can help to build a positive relationship with those affected by the project, identify political and community concerns, obtain an informed consensus from project stakeholders, and provide a basis for the utility to increase its credibility and reputation as a good neighbor.

9.3 Construction

9.3.1 Site Preparation

9.3.1.1 Clearing, Grubbing, Excavation, and Grading

Concerns include the creation of dust, mud, water runoff, erosion, degraded water quality, and sedimentation. The stockpiling of excavated material and the disposal of excess soil, timber, brush, etc. are additional items that should be considered. Protective measures established during the design phase or committed to through the permitting process for ground water, wetlands, flood plains, streams, archeological sites, and endangered flora and fauna should be implemented during this period.

9.3.1.2 Site Access Roads

The preparation and usage of site access roads create concerns that include construction equipment traffic, dust, mud, water runoff, erosion, degraded water quality, and sedimentation. Access roads can also have an impact on agriculture, archaeological features, forest resources, wildlife, and vegetation.

9.3.1.3 Water Drainage

Runoff control is especially important during the construction process. Potential problems include flooding, erosion, sedimentation, and waste and trash carried off the site.

9.3.2 Noise

Noise control is important during construction in areas sensitive to this type of disturbance. An evaluation should be made prior to the start of construction to determine noise restrictions that may be imposed at the construction site.

9.3.3 Safety and Security

Safety and security procedures should be implemented at the outset of the construction process to protect the public and prevent unauthorized access to the site. These procedures should be developed in conformance with governmental agencies. See IEEE 1402–2000 for detailed descriptions of the security methods that can be employed. The safety and security program should be monitored continuously to ensure that it is functioning properly.

The following are suggestions for safety and security at the site:

1. Temporary or permanent fencing
2. Security guards
3. Security monitoring systems
4. Traffic control
5. Warning signs
6. Construction safety procedures
7. Temporary lighting

9.3.4 Site Housekeeping

During construction, debris and refuse should not be allowed to accumulate. Efforts should be made to properly store, remove, and prevent these materials from migrating beyond the construction site. Burning of refuse should be avoided. In many areas this activity is prohibited by law. Portable toilets that are routinely serviced should be provided.

9.3.5 Hazardous Material

The spillage of transformer and pipe cable insulating oils, paints, solvents, acids, fuels, and other similar materials can be detrimental to the environment as well as a disturbance to the neighborhood. Proper care should be taken in the storage and handling of such materials during construction.

9.4 Operations

9.4.1 Site Housekeeping

9.4.1.1 Water and Sediment Control

Routine inspection of control for water flows is important to maintain proper sediment control measures. Inspection should be made for basin failure and for gullies in all slopes. Inspection of all control measures is necessary to be sure that problems are corrected as they develop and should be made a part of regular substation inspection and maintenance.

9.4.1.2 Yard Surface Maintenance

Yard surfacing should be maintained as designed to prevent water runoffs and control dust. If unwanted vegetation is observed on the substation site, approved herbicides may be used with caution to prevent runoff from damaging surrounding vegetation. If runoffs occur, the affected area should be covered with stone to retard water runoff and to control dust.

9.4.1.3 Paint

When material surfaces are protected by paint, a regular inspection and repainting should be performed to maintain a neat appearance and to prevent corrosion damage.

9.4.1.4 Landscaping

Landscaping should be maintained to ensure perpetuation of design integrity and intent.

9.4.1.5 Storage

In some areas, zoning will not permit storage in substations. The local zoning must therefore be reviewed before storing equipment, supplies, etc. The appearance of the substation site should be considered so it will not become visually offensive to the surrounding community.

9.4.1.6 Noise

Inspection of all attributes of equipment designed to limit noise should be performed periodically.

9.4.1.7 Safety and Security

All substations should be inspected regularly, following established and written procedures to ensure the safety and security of the station. Safe and secure operation of the substation requires adequate knowledge and proper use of each company's accident prevention manual. See IEEE 1402–2000 for detailed descriptions of the security methods that can be employed.

Routine inspections of the substation should be performed and recorded, and may include the following:

1. Fences
2. Gates
3. Padlocks
4. Signs
5. Access detection systems
6. Alarm systems
7. Lighting systems
8. Grounding systems
9. Fire-protection equipment
10. All oil-filled equipment
11. Spill-containment systems

9.4.2 Fire Protection

Refer to IEEE Std. 979–1994 for detailed guidance and identification of accepted substation fire-protection practices and applicable industry standards. Any fire-protection prevention system installed in the substation should be properly maintained.

9.4.3 Hazardous Material

A spill-prevention control and counter-measures plan should be in place for the substation site and should meet governmental requirements. For general guidance, see IEEE Std. 980–1994.

9.5 Defining Terms (IEEE, 1998)

A-weighted sound level: The representation of the sound pressure level that has as much as 40 dB of the sound below 100 Hz and a similar amount above 10,000 Hz filtered out. This level best approximates the response of the average young ear when listening to most ordinary, everyday sounds. Generally designated as dBA.

Commercial zone: A zone that includes offices, shops, hotels, motels, service establishments, or other retail/commercial facilities as defined by local ordinances.

Hazardous material: Any material that has been so designated by governmental agencies or adversely impacts human health or the environment.

Industrial zone: A zone that includes manufacturing plants where fabrication or original manufacturing is done, as defined by local ordinances.

Noise: Undesirable sound emissions or undesirable electromagnetic signals/emissions.

Residential zone: A zone that includes single-family and multifamily residential units, as defined by local ordinances.

Wetlands: Any land that has been so designated by governmental agencies. Characteristically, such land contains vegetation associated with saturated types of soil.

For additional definitions, see IEEE Std. 100.

References

Guide for Electric Power Substation Physical and Electronic Security, IEEE 1402–2000.
IEEE Guide for the Design, Construction, and Operation of Electric Power Substations for Community Acceptance and Environmental Compatibility, IEEE Std. 1127-1998.
IEEE Guide for Safety in AC Substation Grounding, IEEE Std. 80–2000.
IEEE Guide to Specifications for Gas-Insulated, Electric Power Substation Equipment, IEEE Std C37.123–1996.
IEEE Guide for Substation Fire Protection, IEEE Std. 979-1994.
The IEEE Standard Dictionary of Electrical and Electronics Terms, IEEE Std. 100.
IEEE Standard Procedures for Measurement of Power Frequency Electric and Magnetic Fields from AC Power Lines, IEEE Std. 644-1994.
IEEE Guide for Containment and Control of Oil Spills in Substations, IEEE Std. 980–1994.
National Electrical Safety Code® (NESC®) (ANSI), Accredited Standards Committee C2-2007, Institute of Electrical Electronics Engineers, Piscataway, NJ, 2007.

10

Animal Deterrents/ Security

Mike Stine
Tyco Electronics

The vast majority of electrical utility substations desigfned to transform transmission voltages to distribution class voltages employ an open-air design. The configurations may vary, but usually consist of equipment that utilizes polymer or porcelain insulators or bushings to create electrically insulated creepage and dry arc distances between the potential voltage carried by the bus or conductor and the grounded portions of the equipment or structure. Although these insulators or bushings provide the proper insulation distance for normal operation voltages (AC, DC, and BIL), they do not provide sufficient distances to eliminate bridging of many animals from potential to ground. This animal bridging situation usually exists at the low side or distribution voltage portion of the substation (12 through 36 kV), but depending on the size and type of the animal, can also affect higher voltage equipment. Utilities have reported that animal-caused outages have become a major problem affecting the reliability and continuity of the electrical system and are actively taking steps to prevent it.

The effects of animal bridging ranges from nuisance trips of the electrical system which may be a momentary occurrence, to faults that may interrupt power for long periods of time. Aside from the inconvenience and reliability aspects of animal-induced outages, there can be damage to the substation equipment ranging from porcelain bushings and insulators that may cost as little as $20.00, to complete destruction of large transformers running into the millions of dollars. There can also be an environmental risk involved with catastrophic failure such as oil spillage from equipment that has ruptured due to electrical faults.

Damage from outages is not limited to the equipment owned by the electrical utility. Many heavy industrial plants such as pulp and paper, petrochemical, and car manufacturers employ processes that are sensitive to interruptions and may result in significant time and money to reestablish production. The proliferation of computers, programmable logic controllers (PLCs), and other electrically sensitive devices in the workplace is also a reliability concern.

In addition to the concern for protecting assets such as substation equipment, improving the reliability of the system, eliminating environmental risks, and ensuring customer satisfaction and loyalty, the conservation of endangered and protected animal species is an issue. It is important to be educated and informed about the species and types of animals that are protected in each individual area or location.

To evaluate the problem and its possible solutions, several aspects need to be investigated:

- Animal type, size, and tendencies
- Equipment voltage rating and clearance from electrical ground
- Natural surroundings
- Method animals enter substation
- Influences attracting the animals
- Barrier methods available to keep the animal out
- Deterrent methods to repel the animals
- Insulation options

10.1 Animal Types

10.1.1 Clearance Requirements

The following Table 10.1 has been developed to aid in establishing minimum phase-to-ground and phase-to-phase clearances for the associated animals. This table is for reference only.

10.1.2 Squirrels

In North America, a common culprit causing bridging is the squirrel. Although there are many varieties of squirrels, it can be assumed that the nominal length of a squirrel is 18″ (450 mm). Using this dimension, you can evaluate equipment and clearances to determine areas where bridging could occur between potential and ground or phase-to-phase. Clearances for modern substation equipment rated 35 kV and above will normally be sufficient to eliminate squirrel-caused problems; however, distances between phases and between phase and grounded structures should be examined.

There are several schools of thought regarding the reason squirrels often enter substations. One explanation offered is the proximity of trees and vegetation near the substation site that may attract squirrels. Some utilities report that removal of this vegetation had no effect on the squirrel-caused outages. Experts have theorized that the animals path is predetermined and the construction of a structure will not deter a squirrel from following his intended route. Others believe that the animals are attracted by heat or vibration emitted from the electrical equipment. Regardless of the reason, squirrels are compelled toward intrusion.

The entry into the substation does not always occur over, under, or through the outer fence of the site. Squirrels are very adept at traveling along overhead conductors and often enter the substation in this manner. Because of this fact, perimeter barriers are often ineffectual in preventing squirrel entry.

10.1.3 Birds

Birds create several problems when entering an electrical substation. The first and most obvious is the bridging between phase-to-ground or phase-to-phase caused by the wingspan when flying into or

TABLE 10.1 Typical Clearance Requirement by Animal

Animal Type	Phase-to-Phase	Phase-to-Ground
Squirrel	18″ (450 mm)	18″ (450 mm)
Opossum/Raccoon	30″ (750 mm)	30″ (750 mm)
Snake	36″ (900 mm)	36″ (900 mm)
Crow/Grackle	24″ (600 mm)	18″ (450 mm)
Migratory Large Bird	36″ (900 mm)	36″ (900 mm)
Frog	18″ (450 mm)	18″ (450 mm)
Cat	24″ (600 mm)	24″ (600 mm)

exiting the structure. Another problem is the bridging caused by debris used to build nests. Many times material such as strands of conductors or magnetic recording tape may be readily available from the surrounding area and be utilized by the birds. This conductive debris is often dragged across the conductor/busbar and results in flashovers, trips, or faults. The third problem is contamination of insulators caused by regurgitation or defecation of the birds. When this residue is allowed to remain, it can result in flashovers from potential to ground across the surface of the porcelain or polymer insulator by essentially decreasing the insulated creepage distance. The fourth possibility is commonly known as a "streamer outage." Streamers are formed when a bird defecates upon exiting a nest that has been built above an insulator. The streamers may create a path between the structure and conductor/bus, resulting in a flashover. Birds will tend to make nests in substations in an effort to eliminate possible predators from attacking the nest for food. The construction of nests in substations can, in turn, attract other animals such as snakes, cats, and raccoons into the area searching for food.

10.1.4 Snakes

Snakes are a major contributor to substation outages. In some areas, snakes are responsible for virtually all substation wildlife outages. Because of their size and climbing ability, snakes can reach most parts of a substation without difficulty. Snake-proofing substations can sometimes create problems rather than solving them. Snakes typically enter substations hunting birds and eggs. Eliminating these predators can lead to an increase in the bird population inside the substation boundaries. This bird infestation can then lead to bird-induced problems unless additional measures are taken.

10.1.5 Raccoons

Raccoons are excellent climbers and can easily gain access to substations. Unlike snakes, raccoons will occasionally enter substations for no particular reason except curiosity. Because of their large size, raccoons can easily bridge phase-to-phase and phase-to-ground distances on equipment with voltage ratings up to 25 kV.

10.2 Mitigation Methods

10.2.1 Barriers

Some of the barrier methods available include cyclone fences, small mesh wire fences, smooth climbing guards, electric fences, solid wall barriers, and fences with unconventional geometries. Barrier methods can be very effective against certain animals. Some utilities report that the use of small mesh fencing along the lower 3–4 feet (1–1.3 meters) of the perimeter has prevented intrusion of certain types of snakes. Several substation owners have incorporated the use of a bare wire attached to a PVC pipe energized with a low voltage transformer creating an electric fence that surrounds the structure inside of the normal property fence. This method has also been proven effective for snakes. Although these barrier designs prevent snakes from entering substations, they do little or nothing to eliminate legged animal intrusions. Smooth climbing guards are also used on structures to prevent some animals from scaling the vertical framework. While these guards work for some legged animals such as dogs and foxes, more agile animals such as squirrels, opossums, and cats can easily circumnavigate the devices.

10.2.2 Deterrents

There are a myriad of commercially available deterrent devices on the market. Many of the devices have actually come from applications in the household market to repel pests such as squirrels and pigeons from property. Although numerous, most devices have a limited effect on wildlife. Some of these include ultrasonic devices, devices producing loud noises at intermittent periods, chemical repellents, sticky gels, predator urine, plastic owls or snakes, poisons, and spined perching deterrents for birds. Ultrasonic devices tend to have an initial impact on animals, but have reportedly become ineffective after a relatively short period of time either due to the animal adapting to the sounds or the need to maintain the devices. Loud noise devices, like ultrasonics, soon lose the ability to repel the animals as they become familiar with the sound and lack of consequence. Chemical repellents, sticky gels, and predator urine have been shown effective against some animals when reapplied at frequent intervals. Poisons have been used to curb infestations of pests such as pigeons, but will sometimes result in collateral effects on pets and other animals if the pest is allowed to die outside of the substation boundaries. Spined perching deterrents have proven very successful in preventing smaller birds from building nests or congregating above electrically sensitive areas, but can sometimes serve as a functional anchor for greater sized birds to secure large nests.

10.2.3 Insulation

Insulating live conductors and hardware can be very effective in eliminating animal outages. Insulation systems are available in several forms:

- Spray on RTV coatings
- Insulating tapes
- Heat-shrinkable tubings, tapes, and sheet materials
- Pre-formed insulating covers

Insulation systems should be used at locations where animals can possibly make contact phase-to-ground or phase-to-phase. Typical applications include:

- Equipment bushing hardware (i.e., circuit breakers, reclosers, transformers, potential transformer, capacitors, regulators, etc.).
- Bus support insulator connections to structure or bus.
- Hook switch insulator connections to switch base or bus.
- Any area where clearance between bus and grounded equipment or structure is insufficient to eliminate bridging.
- Busbar and conductors where phase-to-phase spacing is inadequate.

Because these products are used as insulation on bus, conductor, or hardware, it is critical that they be of a material that is designed for the rigors of the high voltage environment. Unlike barriers and deterrents, the insulating materials are subjected to the electric field and are sometimes applied to the leakage path of other insulating materials such as porcelain. Care should be taken to select products that will withstand the outdoor environment as well as the electrical stress to which they may be subjected.

10.2.4 Isolation Devices

Isolation devices are rigid insulating discs that are installed in the leakage path of porcelain insulators. These devices force animals to climb onto them, isolating them from ground. These discs are used on both support insulators as well as switch insulators. As with insulating covers, the insulating material must be designed for the outdoor high voltage environment.

11

Substation Grounding

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11.1 Reasons for Substation Grounding System

The substation grounding system is an essential part of the overall electrical system. The proper grounding of a substation is important for the following two reasons:

1. It provides a means of dissipating electric current into the earth without exceeding the operating limits of the equipment.
2. It provides a safe environment to protect personnel in the vicinity of grounded facilities from the dangers of electric shock under fault conditions.

The grounding system includes all of the interconnected grounding facilities in the substation area, including the ground grid, overhead ground wires, neutral conductors, underground cables, foundations, deep well, etc. The ground grid consists of horizontal interconnected bare conductors (mat) and ground rods. The design of the ground grid to control voltage levels to safe values should consider the total grounding system to provide a safe system at an economical cost.

The following information is mainly concerned with personnel safety. The information regarding the grounding system resistance, grid current, and ground potential rise can also be used to determine if the operating limits of the equipment will be exceeded.

Safe grounding requires the interaction of two grounding systems:

1. Intentional ground, consisting of grounding systems buried at some depth below the earth's surface
2. Accidental ground, temporarily established by a person exposed to a potential gradient in the vicinity of a grounded facility

It is often assumed that any grounded object can be safely touched. A low substation ground resistance is not, in itself, a guarantee of safety. There is no simple relation between the resistance of the grounding system as a whole and the maximum shock current to which a person might be exposed. A substation with relatively low ground resistance might be dangerous, while another substation with very high ground resistance might be safe or could be made safe by careful design.

There are many parameters that have an effect on the voltages in and around the substation area. Since voltages are site-dependent, it is impossible to design one grounding system that is acceptable for all locations. The grid current, fault duration, soil resistivity, surface material, and the size and shape of the grid all have a substantial effect on the voltages in and around the substation area. If the geometry, location of ground electrodes, local soil characteristics, and other factors contribute to an excessive potential gradient at the earth surface, the grounding system may be inadequate from a safety aspect despite its capacity to carry the fault current in magnitudes and durations permitted by protective relays.

During typical ground fault conditions, unless proper precautions are taken in design, the maximum potential gradients along the earth surface may be of sufficient magnitude to endanger a person in the area. Moreover, hazardous voltages may develop between grounded structures or equipment frames and the nearby earth.

The circumstances that make human electric shock accidents possible are:

- Relatively high fault current to ground in relation to the area of the grounding system and its resistance to remote earth.
- Soil resistivity and distribution of ground currents such that high potential gradients may occur at points at the earth surface.
- Presence of a person at such a point, time, and position that the body is bridging two points of high potential difference.
- Absence of sufficient contact resistance or other series resistance to limit current through the body to a safe value under the above circumstances.
- Duration of the fault and body contact and, hence, of the flow of current through a human body for a sufficient time to cause harm at the given current intensity.

Relative infrequency of accidents is largely due to the low probability of coincidence of the above unfavorable conditions.

To provide a safe condition for personnel within and around the substation area, the grounding system design limits the potential difference a person can come in contact with to safe levels. IEEE Std. 80, IEEE Guide for Safety in AC Substation Grounding [1], provides general information about substation grounding and the specific design equations necessary to design a safe substation grounding system. The following discussion is a brief description of the information presented in IEEE Std. 80.

The guide's design is based on the permissible body current when a person becomes part of an accidental ground circuit. Permissible body current will not cause ventricular fibrillation, i.e., stoppage of the heart. The design methodology limits the voltages that produce the permissible body current to a safe level.

11.2 Accidental Ground Circuit

11.2.1 Conditions

There are two conditions that a person within or around the substation can experience that can cause them to become part of the ground circuit. One of these conditions, touch voltage, is illustrated in Figs. 11.1 and 11.2. The other condition, step voltage, is illustrated in Figs. 11.3 and 11.4. Figure 11.1 shows the fault current being discharged to the earth by the substation grounding system and a person touching a grounded metallic structure, H. Figure 11.2 shows the Thevenin equivalent for the person's feet in parallel, Z_{Th}, in series with the body resistance, R_B. V_{Th} is the voltage between terminal H and F when the person is not present. I_B is the body current. When Z_{Th} is equal to the resistance of two feet in parallel, the touch voltage is

$$E_{touch} = I_B(R_B + Z_{Th}) \quad (11.1)$$

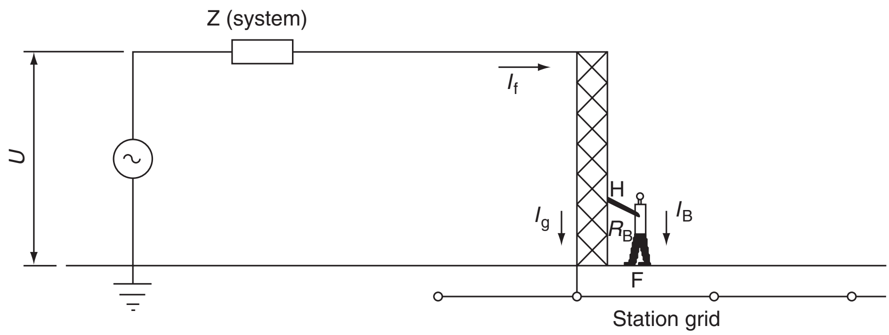

FIGURE 11.1 Exposure to touch voltage.

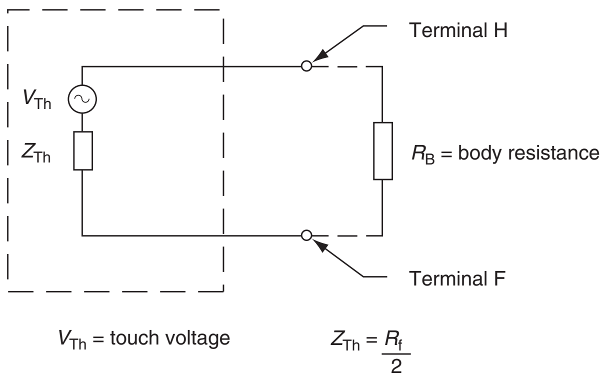

FIGURE 11.2 Touch-voltage circuit.

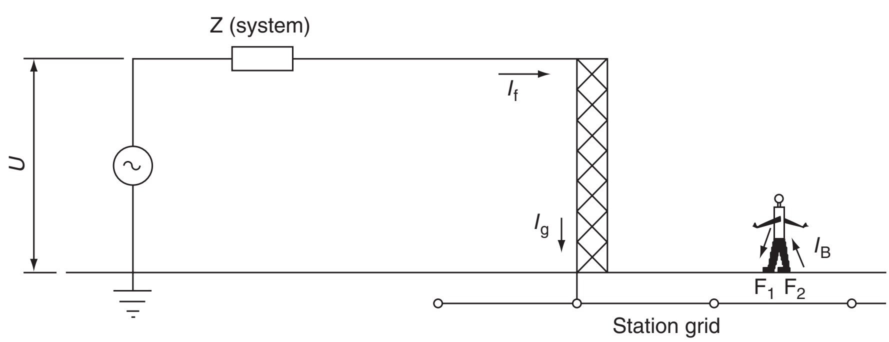

FIGURE 11.3 Exposure to step voltage.

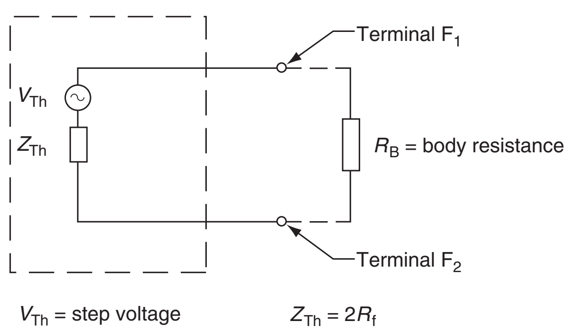

FIGURE 11.4 Step-voltage circuit.

Figures 11.3 and 11.4 show the conditions for step voltage. Z_{Th} is the Thevenin equivalent impedance for the person's feet in series and in series with the body. Based on the Thevenin equivalent impedance, the step voltage is

$$E_{\mathrm{step}} = I_{\mathrm{B}}(R_{\mathrm{B}} + Z_{\mathrm{Th}}) \tag{11.2}$$

The resistance of the foot in ohms is represented by a metal circular plate of radius b in meters on the surface of homogeneous earth of resistivity ρ (Ω-m) and is equal to

$$R_{\mathrm{f}} = \frac{\rho}{4b} \tag{11.3}$$

$$\text{Assuming } b = 0.08, \quad R_{\mathrm{f}} = 3\rho \tag{11.4}$$

The Thevenin equivalent impedance for two feet in parallel in the touch voltage, E_{touch}, equation is

$$Z_{\mathrm{Th}} = \frac{R_{\mathrm{f}}}{2} = 1.5\rho \tag{11.5}$$

The Thevenin equivalent impedance for two feet in series in the step voltage, E_{step}, equation is

$$Z_{\mathrm{Th}} = 2R_{\mathrm{f}} = 6\rho \tag{11.6}$$

The above equations assume uniform soil resistivity. In a substation, a thin layer of high-resistivity material is often spread over the earth surface to introduce a high-resistance contact between the soil and the feet, reducing the body current. The surface layer derating factor, C_{s}, increases the foot resistance and depends on the relative values of the resistivity of the soil, the surface material, and the thickness of the surface material.

The following equations give the ground resistance of the foot on the surface material:

$$R_{\mathrm{f}} = \left[\frac{\rho_{\mathrm{s}}}{4b}\right] C_{\mathrm{s}} \tag{11.7}$$

$$C_{\mathrm{s}} = 1 + \frac{16b}{\rho_{\mathrm{s}}} \sum_{n=1}^{\infty} K^n R_{\mathrm{m}(2nh_{\mathrm{s}})} \tag{11.8}$$

$$K = \frac{\rho - \rho_{\mathrm{s}}}{\rho + \rho_{\mathrm{s}}} \tag{11.9}$$

where

- C_{s} surface layer derating factor
- K reflection factor between different material resistivities
- ρ_{s} surface material resistivity in Ω-m
- ρ resistivity of the earth beneath the surface material in Ω-m
- h_{s} is the thickness of the surface material in m
- b is the radius of the circular metallic disc representing the foot in m
- $R_{\mathrm{m}(2nh_{\mathrm{s}})}$ is the mutual ground resistance between the two similar, parallel, coaxial plates, separated by a distance $(2nh_{\mathrm{s}})$, in an infinite medium of resistivity ρ_{s} in Ω-m.

A series of C_{s} curves has been developed based on Eq. (11.8) and $b = 0.08$ m, and is shown in Fig. 11.5.

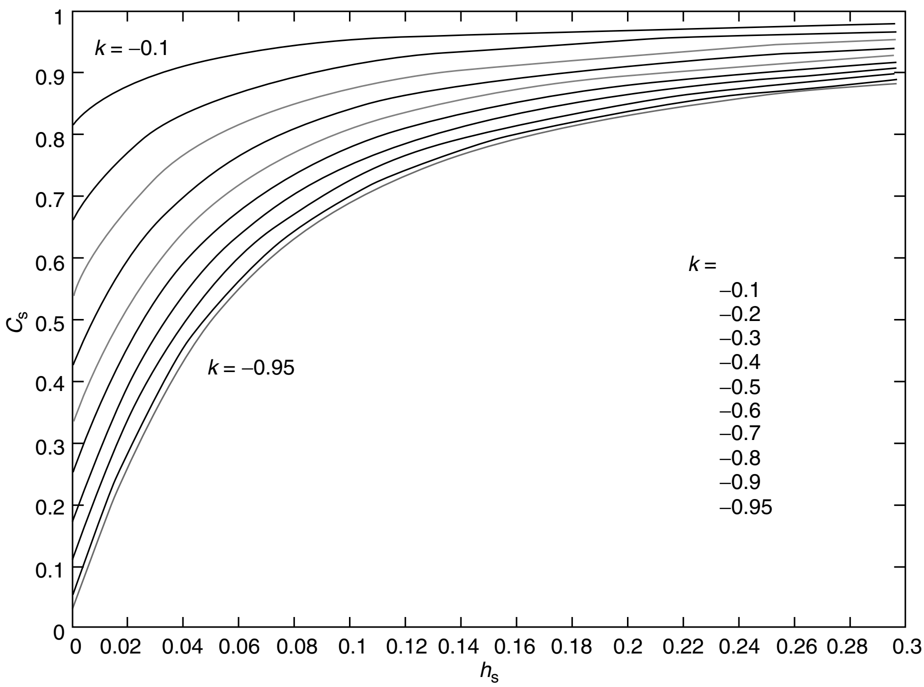

FIGURE 11.5 C_s vs. h_s.

The following empirical equation by Sverak [2], and later modified, gives the value of C_s. The values of C_s obtained using Eq. (11.10) are within 5% of the values obtained with the analytical method [3]:

$$C_s = 1 - \frac{0.09\left(1 - \frac{\rho}{\rho_s}\right)}{2h_s + 0.09} \tag{11.10}$$

11.2.2 Permissible Body Current Limits

The duration, magnitude, and frequency of the current affect the human body as the current passes through it. The most dangerous impact on the body is a heart condition known as ventricular fibrillation, a stoppage of the heart resulting in immediate loss of blood circulation. Humans are very susceptible to the effects of electric currents at 50 and 60 Hz. The most common physiological effects as the current increases are perception, muscular contraction, unconsciousness, fibrillation, respiratory nerve blockage, and burning [4]. The threshold of perception, the detection of a slight tingling sensation, is generally recognized as 1 mA. The let-go current, the ability to control the muscles and release the source of current, is recognized as between 1 and 6 mA. The loss of muscular control may be caused by 9–25 mA, making it impossible to release the source of current. At slightly higher currents, breathing may become very difficult, caused by the muscular contractions of the chest muscles. Although very painful, these levels of current do not cause permanent damage to the body. In a range of 60–100 mA, ventricular fibrillation occurs. Ventricular fibrillation can be a fatal electric shock. The only way to restore the normal heartbeat is through another controlled electric shock, called defibrillation. Larger currents will inflict nerve damage and burning, causing other life-threatening conditions.

The substation grounding system design should limit the electric current flow through the body to a value below the fibrillation current. Dalziel [5] published a paper introducing an equation relating the flow of current through the body for a specific time that statistically 99.5% of the population could survive before the onset of fibrillation. This equation determines the allowable body current:

$$I_B = \frac{k}{\sqrt{t_s}} \tag{11.11}$$

where

I_B rms magnitude of the current through the body, A

t_s duration of the current exposure, sec

k $\sqrt{S_B}$

S_B empirical constant related to the electric shock energy tolerated by a certain percent of a given population

Dalziel found the value of $k = 0.116$ for persons weighing approximately 50 kg (110 lb) or $k = 0.157$ for a body weight of 70 kg (154 lb) [6]. Based on a 50-kg weight, the tolerable body current is

$$I_B = \frac{0.116}{\sqrt{t_s}} \tag{11.12}$$

The equation is based on tests limited to values of time in the range of 0.03–3.0 sec. It is not valid for other values of time. Other researchers have suggested other limits [7]. Their results have been similar to Dalziel's for the range of 0.03–3.0 sec.

11.2.3 Importance of High-Speed Fault Clearing

Considering the significance of fault duration both in terms of Eq. (11.11) and implicitly as an accident-exposure factor, high-speed clearing of ground faults is advantageous for two reasons:

1. Probability of exposure to electric shock is greatly reduced by fast fault clearing time, in contrast to situations in which fault currents could persist for several minutes or possibly hours.
2. Both tests and experience show that the chance of severe injury or death is greatly reduced if the duration of a current flow through the body is very brief.

The allowed current value may therefore be based on the clearing time of primary protective devices, or that of the backup protection. A good case could be made for using the primary clearing time because of the low combined probability that relay malfunctions will coincide with all other adverse factors necessary for an accident. It is more conservative to choose the backup relay clearing times in Eq. (11.11), because it assures a greater safety margin.

An additional incentive to use switching times less than 0.5 sec results from the research done by Biegelmeier and Lee [7]. Their research provides evidence that a human heart becomes increasingly susceptible to ventricular fibrillation when the time of exposure to current is approaching the heartbeat period, but that the danger is much smaller if the time of exposure to current is in the region of 0.06–0.3 sec.

In reality, high ground gradients from faults are usually infrequent, and shocks from this cause are even more uncommon. Furthermore, both events are often of very short duration. Thus, it would not be practical to design against shocks that are merely painful and cause no serious injury, i.e., for currents below the fibrillation threshold.

11.2.4 Tolerable Voltages

Figures 11.6 and 11.7 show the five voltages a person can be exposed to in a substation. The following definitions describe the voltages:

Ground potential rise (GPR): The maximum electrical potential that a substation grounding grid may attain relative to a distant grounding point assumed to be at the potential of remote earth. GPR is

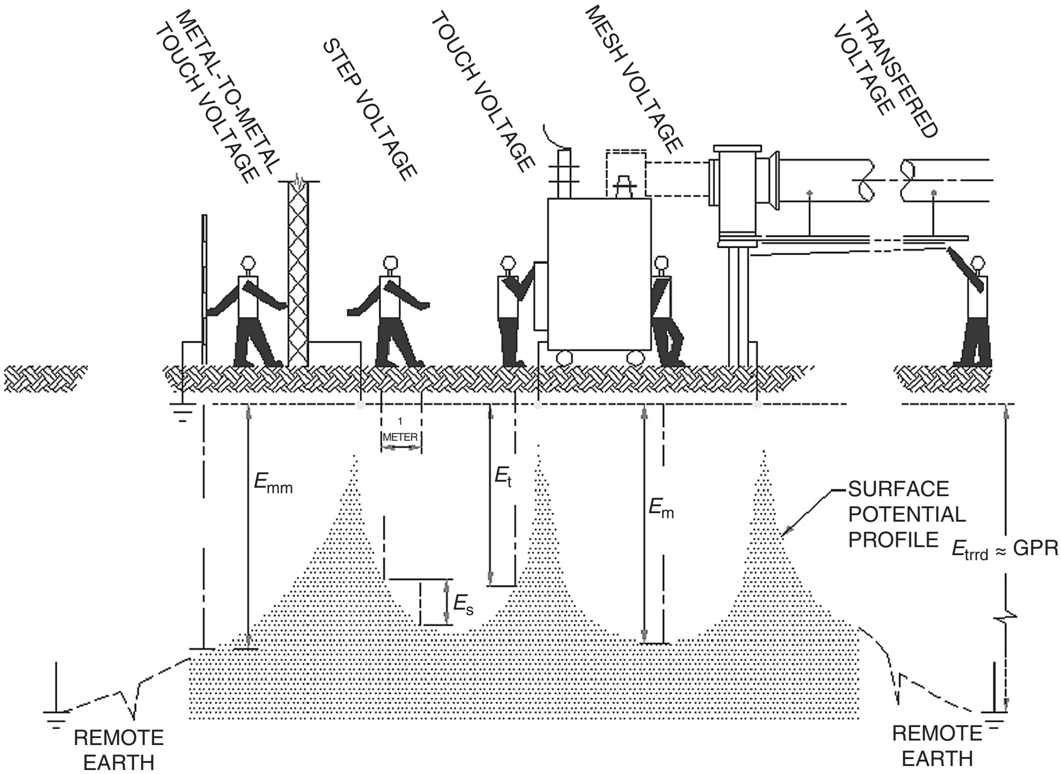

FIGURE 11.6 Basic shock situations.

the product of the magnitude of the grid current, the portion of the fault current conducted to earth by the grounding system, and the ground grid resistance.

Mesh voltage: The maximum touch voltage within a mesh of a ground grid.

Metal-to-metal touch voltage: The difference in potential between metallic objects or structures within the substation site that can be bridged by direct hand-to-hand or hand-to-feet contact.

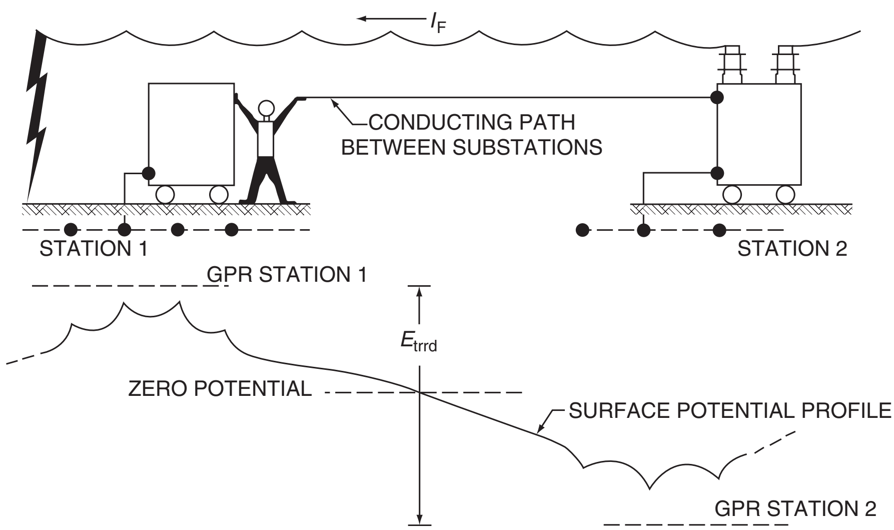

FIGURE 11.7 Typical situation of external transferred potential.

Note: The metal-to-metal touch voltage between metallic objects or structures bonded to the ground grid is assumed to be negligible in conventional substations. However, the metal-to-metal touch voltage between metallic objects or structures bonded to the ground grid and metallic objects inside the substation site but not bonded to the ground grid, such as an isolated fence, may be substantial. In the case of gas-insulated substations, the metal-to-metal touch voltage between metallic objects or structures bonded to the ground grid may be substantial because of internal faults or induced currents in the enclosures.

Step voltage: The difference in surface potential experienced by a person bridging a distance of 1 m with the feet without contacting any other grounded object.

Touch voltage: The potential difference between the GPR and the surface potential at the point where a person is standing while at the same time having a hand in contact with a grounded structure.

Transferred voltage: A special case of the touch voltage where a voltage is transferred into or out of the substation, from or to a remote point external to the substation site. The maximum voltage of any accidental circuit must not exceed the limit that would produce a current flow through the body that could cause fibrillation.

Assuming the more conservative body weight of 50 kg to determine the permissible body current and a body resistance of 1000 Ω, the tolerable touch voltage is

$$E_{\text{touch50}} = (1000 + 1.5C_s\rho_s)\frac{0.116}{\sqrt{t_s}} \tag{11.13}$$

and the tolerable step voltage is

$$E_{\text{step50}} = (1000 + 6C_s\rho_s)\frac{0.116}{\sqrt{t_s}} \tag{11.14}$$

where

- E_{step} step voltage, V
- E_{touch} touch voltage, V
- C_s determined from Fig. 11.5 or Eq. (11.10)
- ρ_s resistivity of the surface material, Ω-m
- t_s duration of shock current, sec

Since the only resistance for the metal-to-metal touch voltage is the body resistance, the voltage limit is

$$E_{\text{mm-touch50}} = \frac{116}{\sqrt{t_s}} \tag{11.15}$$

The shock duration is usually assumed to be equal to the fault duration. If re-closing of a circuit is planned, the fault duration time should be the sum of the individual faults and used as the shock duration time t_s.

11.3 Design Criteria

The design criteria for a substation grounding system are to limit the actual step and mesh voltages to levels below the tolerable touch and step voltages as determined by Eqs. (11.13) and (11.14). The worst-case touch voltage, as shown in Fig. 11.6, is the mesh voltage.

11.3.1 Actual Touch and Step Voltages

The following discusses the methodology to determine the actual touch and step voltages.

11.3.1.1 Mesh Voltage (E_m)

The actual mesh voltage, E_m (maximum touch voltage), is the product of the soil resistivity, ρ; the geometrical factor based on the configuration of the grid, K_m; a correction factor, K_i, which accounts for some of the errors introduced by the assumptions made in deriving K_m; and the average current per unit of effective buried length of the conductor that makes up the grounding system (I_G/L_M):

$$E_m = \frac{\rho K_m K_i I_G}{L_M} \tag{11.16}$$

The geometrical factor K_m [2] is as follows:

$$K_m = \frac{1}{2\pi}\left[\ln\left(\frac{D^2}{16hd} + \frac{(D+2h)^2}{8Dd} - \frac{h}{4d}\right) + \frac{K_{ii}}{K_h}\ln\left(\frac{8}{\pi(2n-1)}\right)\right] \tag{11.17}$$

For grids with ground rods along the perimeter, or for grids with ground rods in the grid corners, as well as both along the perimeter and throughout the grid area, $K_{ii} = 1$. For grids with no ground rods or grids with only a few ground rods, none located in the corners or on the perimeter,

$$K_{ii} = \frac{1}{(2n)^{\frac{2}{n}}} \tag{11.18}$$

$$K_h = \sqrt{1 + \frac{h}{h_0}} \quad h_0 = 1 \text{ m (grid reference depth)} \tag{11.19}$$

Using four grid-shaped components [8], the effective number of parallel conductors, n, in a given grid can be made applicable to both rectangular and irregularly shaped grids that represent the number of parallel conductors of an equivalent rectangular grid:

$$n = n_a n_b n_c n_d \tag{11.20}$$

where

$$n_a = \frac{2L_C}{L_p} \tag{11.21}$$

$n_b = 1$ for square grids
$n_c = 1$ for square and rectangular grids
$n_d = 1$ for square, rectangular, and L-shaped grids

Otherwise,

$$n_b = \sqrt{\frac{L_p}{4\sqrt{A}}} \tag{11.22}$$

$$n_c = \left[\frac{L_x L_y}{A}\right]^{\frac{0.7A}{L_x L_y}} \tag{11.23}$$

$$n_d = \frac{D_m}{\sqrt{L_x^2 + L_y^2}} \tag{11.24}$$

where

L_C total length of the conductor in the horizontal grid, m
L_p peripheral length of the grid, m
A area of the grid, m^2
L_x maximum length of the grid in the x direction, m
L_y maximum length of the grid in the y direction, m
D_m maximum distance between any two points on the grid, m
D spacing between parallel conductors, m
h depth of the ground grid conductors, m
d diameter of the grid conductor, m
I_G maximum grid current, A

The irregularity factor, K_i, used in conjunction with the above-defined n, is

$$K_i = 0.644 + 0.148n \tag{11.25}$$

For grids with no ground rods, or grids with only a few ground rods scattered throughout the grid, but none located in the corners or along the perimeter of the grid, the effective buried length, L_M, is

$$L_M = L_C + L_R \tag{11.26}$$

where

L_R = total length of all ground rods, m

For grids with ground rods in the corners, as well as along the perimeter and throughout the grid, the effective buried length, L_M, is

$$L_M = L_C + \left[1.55 + 1.22\left(\frac{L_r}{\sqrt{L_x^2 + L_y^2}}\right)\right] L_R \tag{11.27}$$

where

L_r = length of each ground rod, m

11.3.1.1.1 Geometrical Factor K_m

The equation for K_m has variables of D, the spacing between the conductors; n, the number of conductors; d, the diameter of the conductors; and h, the depth of the grid. Each variable has a different impact on K_m. Figure 11.8 shows how the distance between conductors affects K_m. For this example, changing the spacing from 10 to 40 m only changes K_m from 0.89 to 1.27. The greatest change takes place for relatively small spacings. The closer the spacing, the smaller K_m is. Figure 11.9 shows that as the number of conductors increases and the spacing and depth remain constant, K_m decreases rapidly. The diameter of the ground conductor as shown in Fig. 11.10 has very little effect on K_m. Doubling the diameter of the conductor from 0.1 m(2/0) to 0.2 m (500 kcmil) reduces K_m by approximately 12%. D and n are certainly dependent on each other for a specific area of grid. The more conductors are installed, the smaller the distance between the conductors. Physically, there is a limit on how close conductors can be installed and should be a design consideration. Changing the depth as shown in Fig. 11.11 also has very little influence on K_m for practical depths.

11.3.1.2 Step Voltage (E_s)

The maximum step voltage is assumed to occur over a distance of 1 m, beginning at and extending outside of the perimeter conductor at the angle bisecting the most extreme corner of the grid. The step-voltage

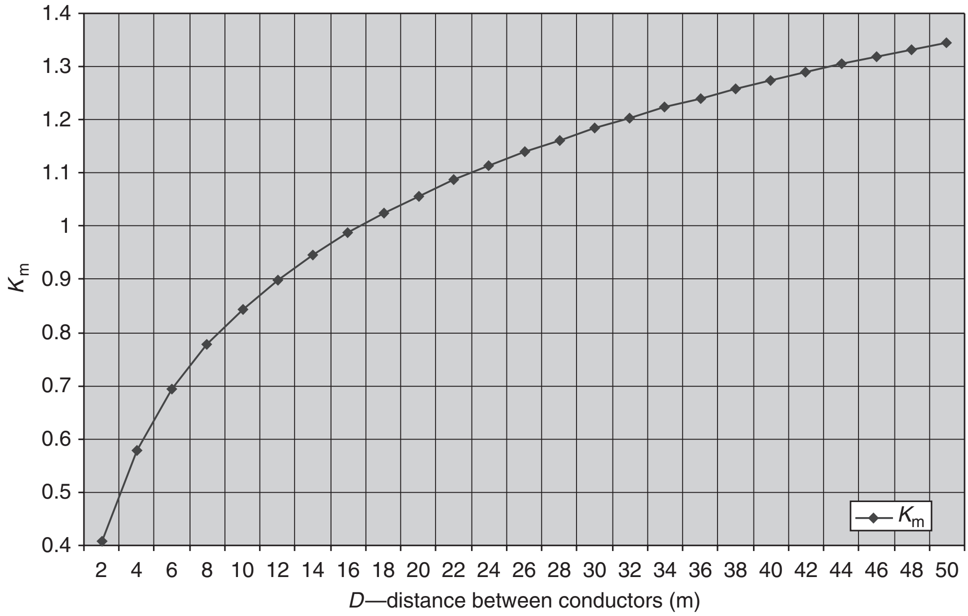

FIGURE 11.8 K_m vs. D.

values are obtained as a product of the soil resistivity ρ, the geometrical factor K_s, the corrective factor K_i, and the average current per unit of buried length of grounding system conductor (I_G/L_S):

$$E_s = \frac{\rho K_s K_i I_G}{L_S} \tag{11.28}$$

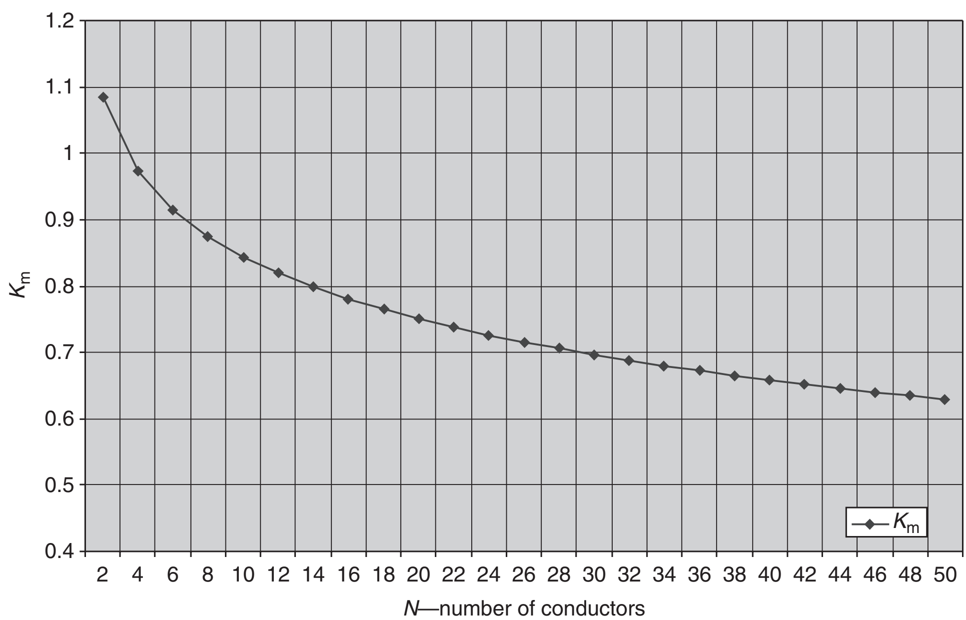

FIGURE 11.9 K_m vs. N.

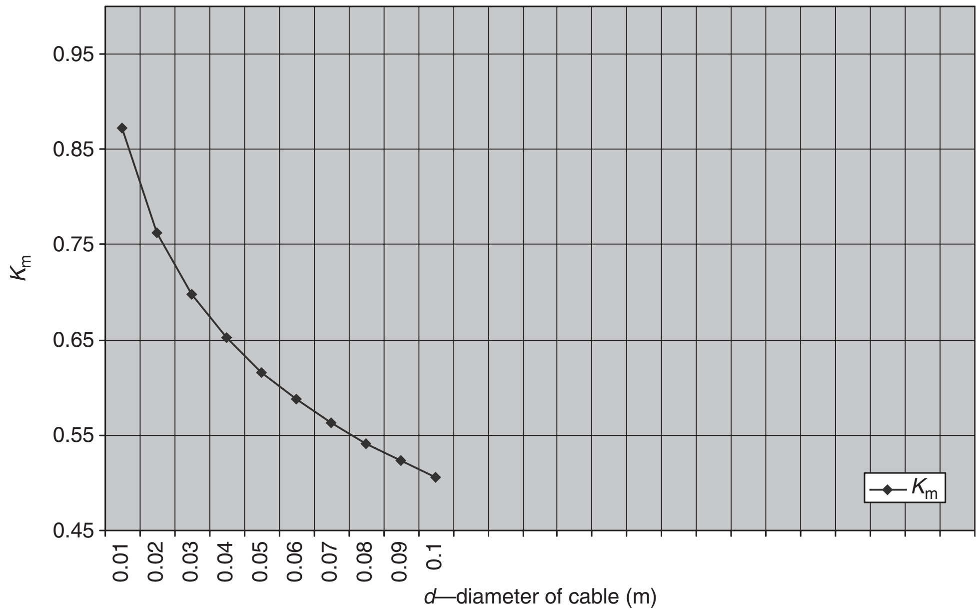

FIGURE 11.10 K_m vs. d.

For the usual burial depth of $0.25 < h < 2.5$ m [2], K_s is defined as

$$K_s = \frac{1}{\pi}\left[\frac{1}{2h} + \frac{1}{D+h} + \frac{1}{D}\left(1 - 0.5^{n-2}\right)\right] \tag{11.29}$$

and K_i as defined in Eq. (11.25).

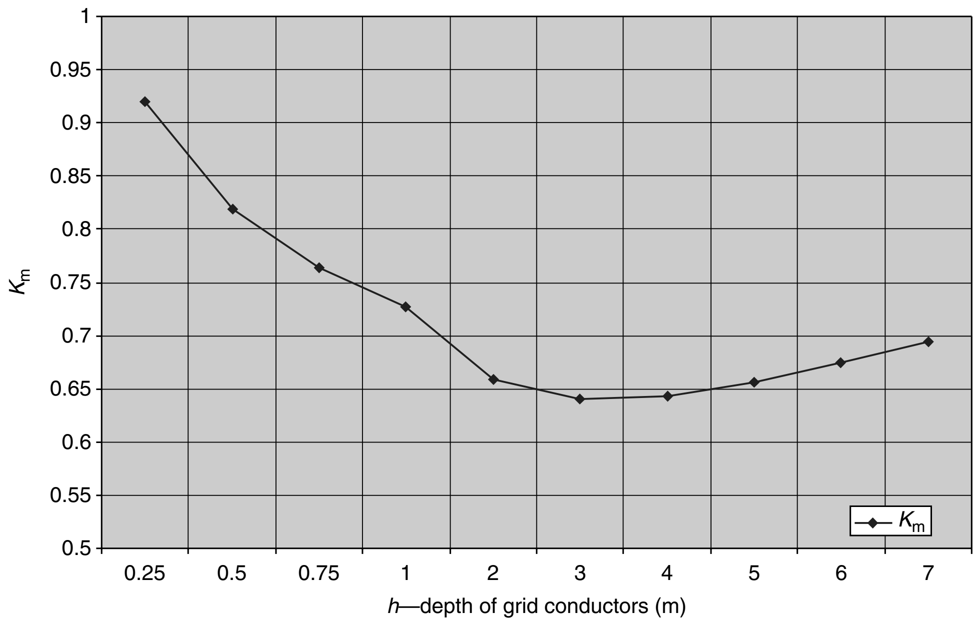

FIGURE 11.11 K_m vs. h.

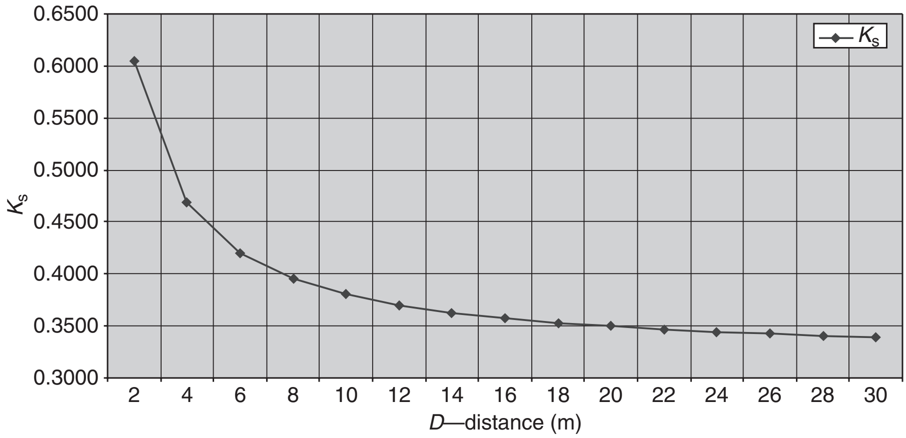

FIGURE 11.12 K_s vs. D.

For grids with or without ground rods, the effective buried conductor length, L_S, is defined as

$$L_S = 0.75L_C + 0.85L_R \tag{11.30}$$

11.3.1.2.1 Geometrical Factor K_s

The equation for K_s also has variables D, n, d, and h. K_s is not affected much by either the distance, D, between or the number, n, of conductors as can be seen in Figs. 11.12 and 11.13. This is reasonable since the step voltage lies outside the grid itself. The influence of each conductor as it moves from the edge is reduced. On the other hand, the depth of burial has a drastic affect on K_s. The deeper the conductor is buried, the lower the value of K_s as shown in Fig. 11.14. This is reasonable since there is a voltage drop as the current passes through the soil reducing the voltage at the surface.

11.3.1.3 Evaluation of the Actual Touch- and Step-Voltage Equations

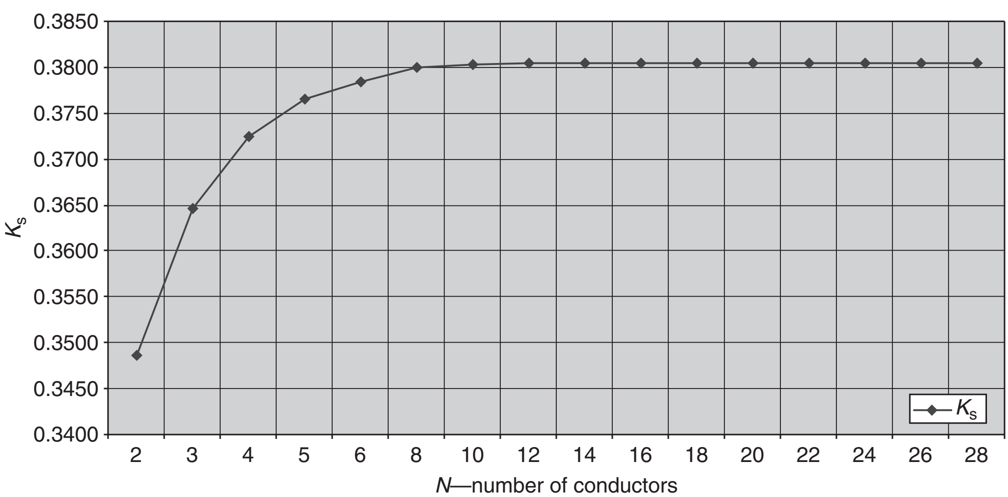

FIGURE 11.13 K_s vs. N.

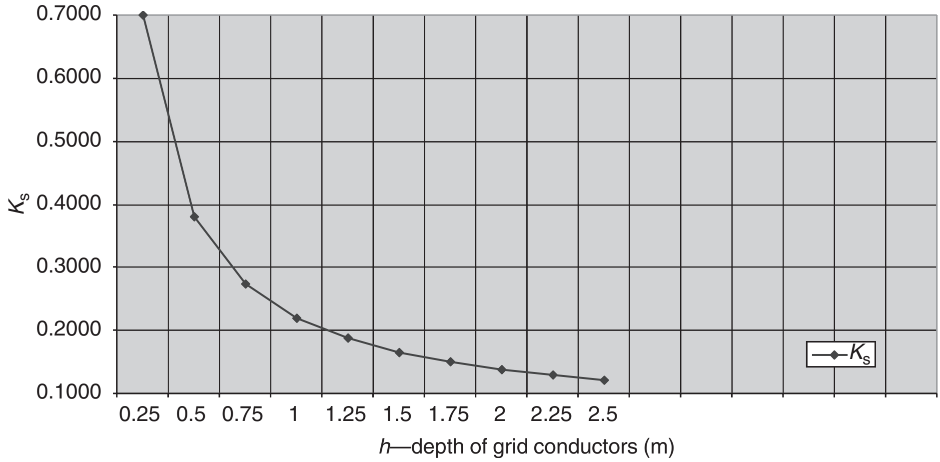

FIGURE 11.14 K_s vs. h.

It is essential to determine the soil resistivity and maximum grid currents to design a substation grounding system. The touch and step voltages are directly proportional to these values. Overly conservative values of soil resistivity and grid current will increase the cost dramatically. Underestimating them may cause the design to be unsafe.

11.3.2 Soil Resistivity

Soil resistivity investigations are necessary to determine the soil structure. There are a number of tables in the literature showing the ranges of resistivity based on soil types (clay, loam, sand, shale, etc.) [9–11]. These tables give only very rough estimates. The soil resistivity can change dramatically with changes in moisture, temperature, and chemical content. To determine the soil resistivity of a particular site, soil resistivity measurements need to be taken. Soil resistivity can vary both horizontally and vertically, making it necessary to take more than one set of measurements. A number of measuring techniques are described in detail in Ref. [12]. The most widely used test for determining soil resistivity data was developed by Wenner and is called either the Wenner or four-pin method. Using four pins or electrodes driven into the earth along a straight line at equal distances of a, to a depth of b, current is passed through the outer pins while a voltage reading is taken with the two inside pins. Based on the resistance, R, as determined by the voltage and current, the apparent resistivity can be calculated using the following equation, assuming b is small compared with a:

$$\rho_a = 2\pi a R \tag{11.31}$$

where it is assumed the apparent resistivity, ρ_a, at depth a is given by the equation.

Interpretation of the apparent soil resistivity based on field measurements is difficult. Uniform and two-layer soil models are the most commonly used soil resistivity models. The objective of the soil model is to provide a good approximation of the actual soil conditions. Interpretation can be done either manually or by the use of computer analysis. There are commercially available computer programs that take the soil data and mathematically calculate the soil resistivity and give a confidence level based on the test. Sunde [10] developed a graphical method to interpret the test results.

The equations in IEEE Std. 80 require a uniform soil resistivity. Engineering judgment is required to interpret the soil resistivity measurements to determine the value of the soil resistivity, ρ, to use in the equations. IEEE Std. 80 presents equations to calculate the apparent soil resistivity based on field measurements as well as examples of Sunde's graphical method. Although the graphical method and equations are estimates, they provide the engineer with guidelines of the uniform soil resistivity to use in the ground grid design.

11.3.3 Grid Resistance

The grid resistance, i.e., the resistance of the ground grid to remote earth without other metallic conductors connected, can be calculated based on the following Sverak [2] equation:

$$R_g = \rho \left[\frac{1}{L_T} + \frac{1}{\sqrt{20A}} \left(1 + \frac{1}{1 + h\sqrt{20/A}} \right) \right] \tag{11.32}$$

where
- R_g substation ground resistance, Ω
- ρ soil resistivity, Ω-m
- A area occupied by the ground grid, m^2
- h depth of the grid, m
- L_T total buried length of conductors, m

11.3.3.1 Resistance

The resistance of the grid is mainly determined by the resistivity and the area of the site. Adding more conductors or changing the depth of the grid does little to lower the resistance. The effect of ground rods depends on the location and depth of the ground rod with respect to the soil resistivity. The effects of ground rods on the resistance can be substantial, although it is sometimes difficult to determine the effects. In uniform soil, it is difficult to determine if the addition of more conductors or the addition of ground rods will affect the overall resistance the most. In most cases though, the addition of ground rods has a greater impact because the ground rods discharge current into the earth more efficiently than the grid conductors. Assuming a two-layer soil model with a lower resistivity soil in the lower layer, ground rods can have a substantial impact on the resistance of the grid. The more the ground rods penetrate into the lower resistivity soil, the more the rods will reduce the grid resistance [24–26]. These rods also add stability since the variations in soil resistivity due to moisture and temperature are minimized at lower depths. The effects of moisture and temperature on the soil resistivity can be quite dramatic. Ground rods placed on the outside of the grid have a greater impact than those placed in the interior of the grid because of current density.

The importance of the lower ground grid resistance is reflected in the GPR and actual touch and step voltages. Lowering the resistance of the grid normally reduces the GPR, although not necessarily proportionally. Lowering the resistance may somewhat increase the grid current because the change is the current split between all the ground current return paths. Another way to decrease the resistance is to install counterpoises. This, in effect, results in adding area to the grid. Although IEEE-80 equations cannot take into account these various methods to decrease the resistance, it is important for the engineer to understand there are methods that can be used to lower the resistance of a ground grid.

The following graphs show the effects of the area, number of conductors, and depth for a simple square grid with no ground rods. Figure 11.15 shows conclusively that the area has a great influence on the resistance. The length was not kept constant in the example since more conductor length is needed to cover the area. The number of conductors is related to the change in length and very little decrease in resistance takes place when the number of conductors is increased in a constant area. This can be seen by comparing the resistance of a constant area as the number of conductors increases. Since the amount of material is related to the number of conductors, adding more material does not influence the resistance very much.

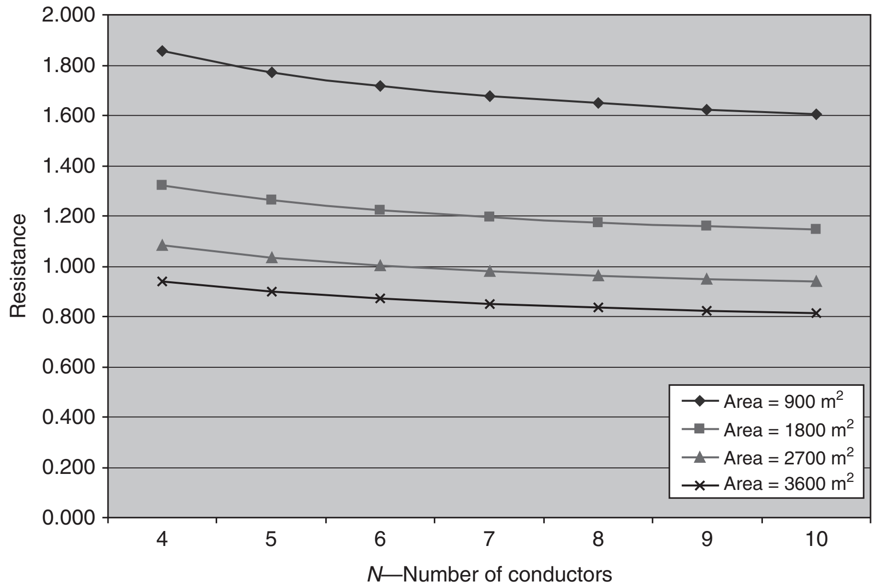

FIGURE 11.15 Resistance vs. *N*.

Figure 11.16 shows the effects of varying the depth of burial of the grid. The area for this example is 900 m^2. The depth is varied from 0.5 to 2.5 m and the number of conductors from 4 to 10. As can be seen from Fig. 11.16, there is very little change in the resistance even if the depth is increased by a factor of 5 and the number of conductors is changed from 4 to 10.

11.3.4 Grid Current

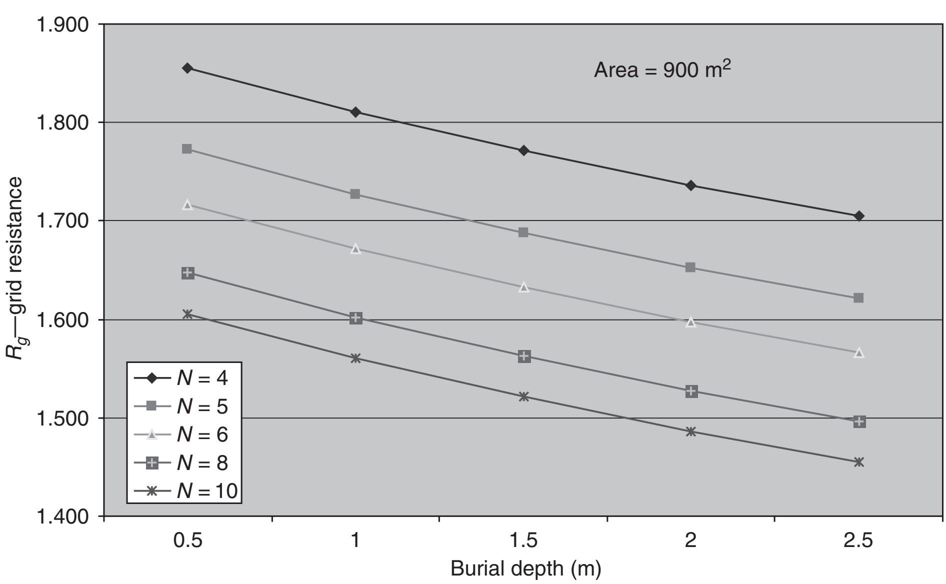

FIGURE 11.16 Resistance vs. depth.

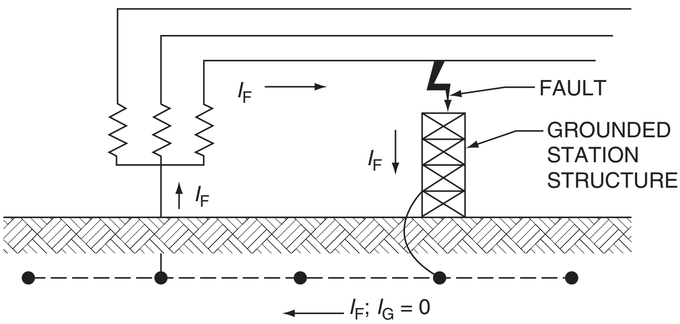

FIGURE 11.17 Fault within local substation, local neutral grounded.

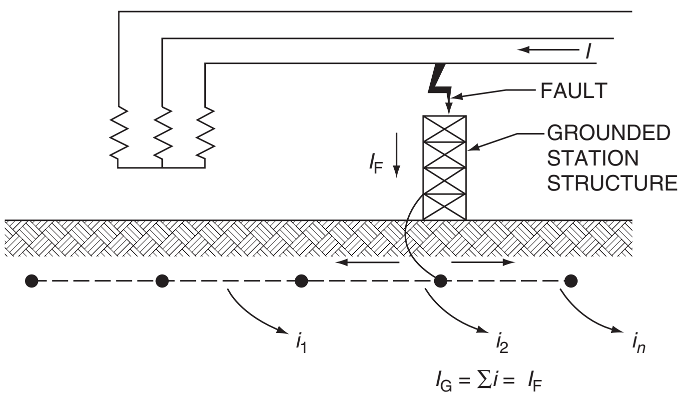

FIGURE 11.18 Fault within local substation, neutral grounded at remote location.

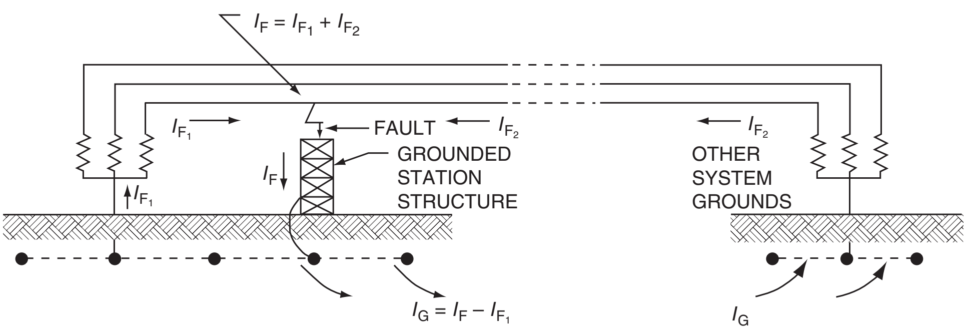

FIGURE 11.19 Fault in substation, system grounded at local station and also at other points.

The maximum grid current must be determined, since it is this current that will produce the greatest GPR and the largest local surface potential gradients in and around the substation area. It is the flow of the current from the ground grid system to remote earth that determines the GPR.

There are many types of faults that can occur on an electrical system. Therefore, it is difficult to determine what condition will produce the maximum fault current. In practice, single-line-to-ground and line-to-line-to-ground faults will produce the maximum grid current. Figures 11.17 through 11.19 show the maximum grid current, I_G, for various fault locations and system configurations.

Overhead ground wires, neutral conductors, and directly buried pipes and cables conduct a portion of the ground fault current away from the substation ground grid and need to be considered when

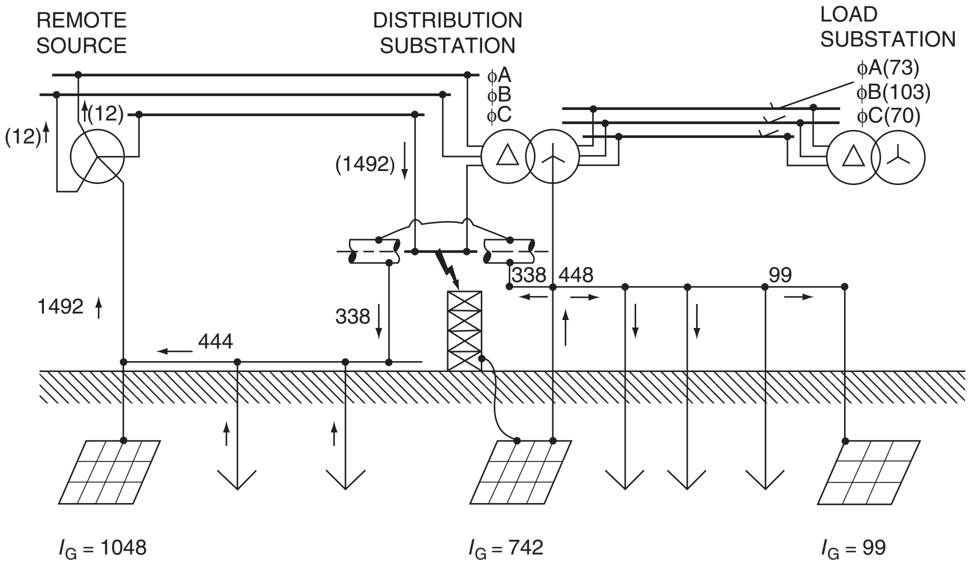

FIGURE 11.20 Typical current division for a fault on higher side of distribution substation.

determining the maximum grid current. The effect of these other current paths in parallel with the ground grid is difficult to determine because of the complexities and uncertainties in the current flow.

11.3.4.1 Current Division Consideration

There are many papers that discuss the effects of overhead static wires, neutrals, cables, and other ground paths. As shown in Fig. 11.20, the process of computing the current division consists of deriving an equivalent model of the current paths and solving the equivalent circuit to determine what part of the total current flows into the earth and through other ground paths. Endrenyi [13], Sebo [14], Verma and Mukhedkar [15], and Garrett [16] provide approaches to determine the current flows in different current paths for overhead circuits. Dawalibi [17] provides algorithms for deriving simple equations to solve for the currents in the grid and in each tower while Meliopoulos [18] introduces an equivalent conductor to represent the earth using Carson's equations. Sebo [19], Nahman [20], and Sobral [21] provide approaches to determine the current flow when substations are cable fed. Each method can provide insight into the effects of the other current paths on the grid current.

Computer programs are available to determine the split between the various current paths. There are many papers available to determine the effective impedance of a static wire as seen from the fault point. The fault current division factor, or split factor, represents the inverse of a ratio of the symmetrical fault current to that portion of the current that flows between the grounding grid and the surrounding earth.

$$S_f = \frac{I_g}{3I_0} \tag{11.33}$$

where

S_f fault current division factor
I_g rms symmetrical grid current, A
I_0 zero-sequence fault current, A

The process of computing the split factor, S_f, consists of deriving an equivalent representation of the overhead ground wires, neutrals, etc., connected to the grid and then solving the equivalent to determine what fraction of the total fault current flows between the grid and earth, and what fraction flows through the ground wires or neutrals. S_f is dependent on many parameters, some of which are:

1. Location of the fault
2. Magnitude of substation ground grid resistance
3. Buried pipes and cables in the vicinity of or directly connected to the substation ground system
4. Overhead ground wires, neutrals, or other ground return paths

Because of S_f, the symmetrical grid current I_g and maximum grid current I_G are closely related to the location of the fault. If the additional ground paths of items 3 and 4 above are neglected, the current division ratio (based on remote vs. local current contributions) can be computed using traditional symmetrical components. However, the current I_g computed using such a method may be overly pessimistic, even if the future system expansion is taken into consideration.

IEEE Std. 80 presents a series of curves based on computer simulations for various values of ground grid resistance and system conditions to determine the grid current. These split-current curves can be used to determine the maximum grid current. Using the maximum grid current instead of the maximum fault current will reduce the overall cost of the ground grid system.

11.3.5 Use of the Design Equations

The design equations above are limited to a uniform soil resistivity, equal grid spacing, specific buried depths, and relatively simple geometric layouts of the grid system. The basic requirements for a safe design have not changed through the various revisions of the guide from 1961 to the 2000 edition. The equations in IEEE-80 have changed over the years and will continue to change as better approximate techniques are developed.

It may be necessary to use more sophisticated computer techniques to design a substation ground grid system for nonuniform soils or complex geometric layouts. Commercially available computer programs can be used to optimize the layout and provide for unequal grid spacing and maximum grid current based on the actual system configuration, including overhead wires, neutral conductors, underground facilities, etc. Computer programs can also handle special problems associated with fences, interconnected substation grounding systems at power plants, customer substations, and other unique situations.

11.3.6 Selection of Conductors

11.3.6.1 Materials

Each element of the grounding system, including grid conductors, connections, connecting leads, and all primary electrodes, should be designed so that for the expected design life of the installation, the element will:

1. have sufficient conductivity, so that it will not contribute substantially to local voltage differences;
2. resist fusing and mechanical deterioration under the most adverse combination of a fault current magnitude and duration;
3. be mechanically reliable and rugged to a high degree; and
4. be able to maintain its function even when exposed to corrosion or physical abuse.

Copper is a common material used for grounding. Copper conductors, in addition to their high conductivity, have the advantage of being resistant to most underground corrosion because copper is cathodic with respect to most other metals that are likely to be buried in the vicinity. Copper-clad steel is usually used for ground rods and occasionally for grid conductors, especially where theft is a problem. Use of copper, or to a lesser degree copper-clad steel, therefore assures that the integrity of an underground network will be maintained for years, so long as the conductors are of an adequate size and not damaged and the soil conditions are not corrosive to the material used. Aluminum is used for ground grids less frequently. Though at first glance the use of aluminum would be a natural choice for GIS equipment with enclosures made of aluminum or aluminum alloys, there are several disadvantages to consider:

- Aluminum can corrode in certain soils. The layer of corroded aluminum material is nonconductive for all practical grounding purposes.
- Gradual corrosion caused by alternating currents can also be a problem under certain conditions.

Thus, aluminum should be used only after full investigation of all circumstances, despite the fact that, like steel, it would alleviate the problem of contributing to the corrosion of other buried objects. However, it is anodic to many other metals, including steel and, if interconnected to one of these metals in the presence of an electrolyte, the aluminum will sacrifice itself to protect the other metal. If aluminum is used, the high-purity electric-conductor grades are recommended as being more suitable than most alloys. Steel can be used for ground grid conductors and rods. Of course, such a design requires that attention be paid to the corrosion of the steel. Use of galvanized or corrosion-resistant steel, in combination with cathodic protection, is typical for steel grounding systems.

A grid of copper or copper-clad steel forms a galvanic cell with buried steel structures, pipes, and any of the lead-based alloys that might be present in cable sheaths. This galvanic cell can hasten corrosion of the latter. Tinning the copper has been tried by some utilities because tinning reduces the cell potential with respect to steel and zinc by about 50% and practically eliminates this potential with respect to lead (tin being slightly sacrificial to lead). The disadvantage of using tinned copper conductor is that it accelerates and concentrates the natural corrosion, caused by the chemicals in the soil, of copper in any small bare area. Other often-used methods are as follows:

- Insulation of the sacrificial metal surfaces with a coating such as plastic tape, asphalt compound, or both.
- Routing of buried metal elements so that any copper-based conductor will cross water pipelines or similar objects made of other uncoated metals as nearly as possible at right angles, and then applying an insulated coating to one metal or the other where they are in proximity. The insulated coating is usually applied to the pipe.
- Cathodic protection using sacrificial anodes or impressed current systems.
- Use of nonmetallic pipes and conduits.

11.3.6.2 Conductor Sizing Factors

Conductor sizing factors include the symmetrical currents, asymmetrical currents, limitation of temperatures to values that will not cause harm to other equipment, mechanical reliability, exposure to corrosive environments, and future growth causing higher grounding-system currents. The following provides information concerning symmetrical and asymmetrical currents.

11.3.6.3 Symmetrical Currents

The short-time temperature rise in a ground conductor, or the required conductor size as a function of conductor current, can be obtained from Eqs. (11.34) and (11.35), which are taken from the derivation by Sverak [22]. These equations evaluate the ampacity of any conductor for which the material constants are known. Equations (11.34) and (11.35) are derived for symmetrical currents (with no dc offset).

$$I = A_{\mathrm{mm}^2}\sqrt{\left(\frac{\mathrm{TCAP}\cdot 10^{-4}}{t_c\alpha_r\rho_r}\right)\ln\left(\frac{K_0+T_m}{K_0+T_a}\right)} \tag{11.34}$$

where

I rms current, kA
A_{mm^2} conductor cross section, mm^2
T_m maximum allowable temperature, °C
T_a ambient temperature, °C
T_r reference temperature for material constants, °C
α_0 thermal coefficient of resistivity at 0 ∞ C, 1/°C
α_r thermal coefficient of resistivity at reference temperature T_r, 1/°C
ρ_r resistivity of the ground conductor at reference temperature T_r, mΩ-cm
K_0 $1/\alpha_0$ or $(1/\alpha_r) - T_r$, °C
t_c duration of current, sec
TCAP thermal capacity per unit volume, J/(cm$^3 \cdot$ °C)

Note that α_r and ρ_r are both to be found at the same reference temperature of T_r °C . If the conductor size is given in kcmils (mm^2 $\times$ 1.974 = kcmils), Eq. (11.34) becomes

$$I = 5.07 \cdot 10^{-3}\ A_{kcmil}\sqrt{\left(\frac{\text{TCAP}}{t_c \alpha_r \rho_r}\right) \ln\left(\frac{K_0 + T_m}{K_0 + T_a}\right)} \tag{11.35}$$

11.3.6.4 Asymmetrical Currents: Decrement Factor

In cases where accounting for a possible dc offset component in the fault current is desired, an equivalent value of the symmetrical current, I_F, representing the rms value of an asymmetrical current integrated over the entire fault duration, t_c, can be determined as a function of X/R by using the decrement factor D_f, Eq. (11.37), prior to the application of Eqs. (11.34) and (11.35):

$$I_F = I_f \cdot D_f \tag{11.36}$$

$$D_f = \sqrt{1 + \frac{T_a}{t_f}\left(1 - e^{\frac{-2t_f}{T_a}}\right)} \tag{11.37}$$

where

t_f is the time duration of fault in sec
T_a is the dc offset time constant in sec [$T_a = X/(\omega R)$; for 60 Hz, $T_a = X/(120\pi R)$]

The resulting value of I_F is always larger than I_f because the decrement factor is based on a very conservative assumption that the ac component does not decay with time but remains constant at its initial subtransient value.

The decrement factor is dependent on both the system X/R ratio at the fault location for a given fault type and the duration of the fault. The decrement factor is larger for higher X/R ratios and shorter fault durations. The effects of the dc offset are negligible if the X/R ratio is less than five and the duration of the fault is greater than 1 sec.

11.3.7 Selection of Connections

All connections made in a grounding network above and below ground should be evaluated to meet the same general requirements of the conductor used, namely electrical conductivity, corrosion resistance, current-carrying capacity, and mechanical strength. These connections should be massive enough to maintain a temperature rise below that of the conductor and to withstand the effect of heating, be strong enough to withstand the mechanical forces caused by the electromagnetic forces of maximum expected fault currents, and be able to resist corrosion for the intended life of the installation.

IEEE Std. 837 (Qualifying Permanent Connections Used in Substation Grounding) [23] provides detailed information on the application and testing of permanent connections for use in substation grounding. Grounding connections that pass IEEE Std. 837 for a particular conductor size, range, and material should satisfy all the criteria outlined above for that same conductor size, range, and material.

11.3.8 Grounding of Substation Fence

Fence grounding is of major importance, since the fence is usually accessible to the general public, children, and adults. The substation grounding system design should be such that the touch potential on the fence is within the calculated tolerable limit of touch potential. Step potential is usually not a concern at the fence perimeter, but this should be checked to verify that a problem does not exist. There are various ways to ground the substation fence. The fence can be within and attached to the ground grid, outside and attached to the ground grid, outside and not attached to the ground grid, or separately grounded such as through the fence post. IEEE Std. 80 provides a very detailed analysis of the different grounding situations. There are many safety considerations associated with the different fence grounding options.

11.3.9 Other Design Considerations

There are other elements of substation grounding system design which have not been discussed here. These elements include the refinement of the design, effects of directly buried pipes and cables, special areas of concern including control and power cable grounding, surge arrester grounding, transferred potentials, and installation considerations.

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12

Direct Lightning Stroke Shielding of Substations[1]

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12.1 Lightning Stroke Protection

Substation design involves more than installing apparatus, protective devices, and equipment. The significant monetary investment and required reliable continuous operation of the facility requires detailed attention to preventing surges (transients) from entering the substation facility. These surges can be switching surges, lightning surges on connected transmission lines, or direct strokes to the substation facility. The origin and mechanics of these surges, including lightning, are discussed in detail in Chapter 10 of this handbook. This section focuses on the design process for providing *effective shielding* (that which permits lightning strokes no greater than those of critical amplitude [less design margin] to reach phase conductors [IEEE Std. 998–1996]) against direct lightning stroke in substations.

[1]A large portion of the text and all of the figures used in this chapter were prepared by the Direct Stroke Shielding of Substations Working Group of the Substations Commitee—IEEE Power Engineering Society, and published as IEEE Std. 998–1996, *IEEE Guide for Direct Lightning Stroke Shielding of Substrates*, Institute of Electrical and Electronics Engineers, Inc., 1996. The IEEE disclaims any responsbility of liability resulting from the placement or use in the described manner. Information is reprinted with the permission of the IEEE. The author has been a member of the working group since 1987.

12.1.1 The Design Problem

The engineer who seeks to design a direct stroke shielding system for a substation or facility must contend with several elusive factors inherent in lightning phenomena, namely:

- The unpredictable, probabilistic nature of lightning
- The lack of data due to the infrequency of lightning strokes in substations
- The complexity and economics involved in analyzing a system in detail

There is no known method of providing 100% shielding short of enclosing the equipment in a solid metallic enclosure. The uncertainty, complexity, and cost of performing a detailed analysis of a shielding system has historically resulted in simple rules of thumb being utilized in the design of lower voltage facilities. Extra high voltage (EHV) facilities, with their critical and more costly equipment components, usually justify a more sophisticated study to establish the risk vs. cost benefit.

Because of the above factors, it is suggested that a four-step approach be utilized in the design of a protection system:

1. Evaluate the importance and value of the facility being protected.
2. Investigate the severity and frequency of thunderstorms in the area of the substation facility and the exposure of the substation.
3. Select an appropriate design method consistent with the above evaluation and then lay out an appropriate system of protection.
4. Evaluate the effectiveness and cost of the resulting design.

The following paragraphs and references will assist the engineer in performing these steps.

12.2 Lightning Parameters

12.2.1 Strike Distance

Return stroke current magnitude and strike distance (length of the last stepped leader) are interrelated. A number of equations have been proposed for determining the striking distance. The principal ones are as follows:

$$S = 2I + 30(1 - e^{-1/6.8}) \quad \text{Darveniza et al. (1975)} \tag{12.1}$$

$$S = 10I^{0.65} \quad \text{Love (1987; 1993)} \tag{12.2}$$

$$S = 9.4I^{2/3} \quad \text{Whitehead (1974)} \tag{12.3}$$

$$S = 8I^{0.65} \quad \text{IEEE (1985)} \tag{12.4}$$

$$S = 3.3I^{0.78} \quad \text{Suzuki et al. (1981)} \tag{12.5}$$

where

S is the strike distance in meters

I is the return stroke current in kiloamperes

It may be disconcerting to note that the above equations vary by as much as a factor of 2:1. However, lightning investigators now tend to favor the shorter strike distances given by Eq. (12.4). Anderson, for example, who adopted Eq. (12.2) in the 1975 edition of the *Transmission Line Reference Book* (1987), now feels that Eq. (12.4) is more accurate. Mousa (1988) also supports this form of the equation. The equation may also be stated as follows:

$$I = 0.041\ S^{1.54} \qquad (12.6)$$

From this point on, the return stroke current will be referenced as the *stroke current*.

12.2.2 Stroke Current Magnitude

Since the stroke current and striking distance are related, it is of interest to know the distribution of stroke current magnitudes. The median value of strokes to OHGW, conductors, structures, and masts is usually taken to be 31 kA (Anderson, 1987). Anderson (1987) gave the probability that a certain peak current will be exceeded in any stroke as follows:

$$P(I) = 1/\left[1 + (I/31)^{2.6}\right] \qquad (12.7)$$

where

$P(I)$ is the probability that the peak current in any stroke will exceed I

I is the specified crest current of the stroke in kiloamperes

Mousa (1989) has shown that a median stroke current of 24 kA for strokes to flat ground produces the best correlation with available field observations to date. Using this median value of stroke current, the probability that a certain peak current will be exceeded in any stroke is given by the following equation:

$$P(I) = 1/\left[1 + (I/24)^{2.6}\right] \qquad (12.8)$$

where the symbols have the same meaning as above.

Figure 12.1 is a plot of Eq. (12.8), and Fig. 12.2 is a plot of the probability that a stroke will be within the ranges shown on the abscissa.

12.2.3 Keraunic Level

Keraunic level is defined as the average annual number of thunderstorm days or hours for a given locality. A daily keraunic level is called a thunderstorm-day and is the average number of days per year on which thunder will be heard during a 24-h period. By this definition, it makes no difference how

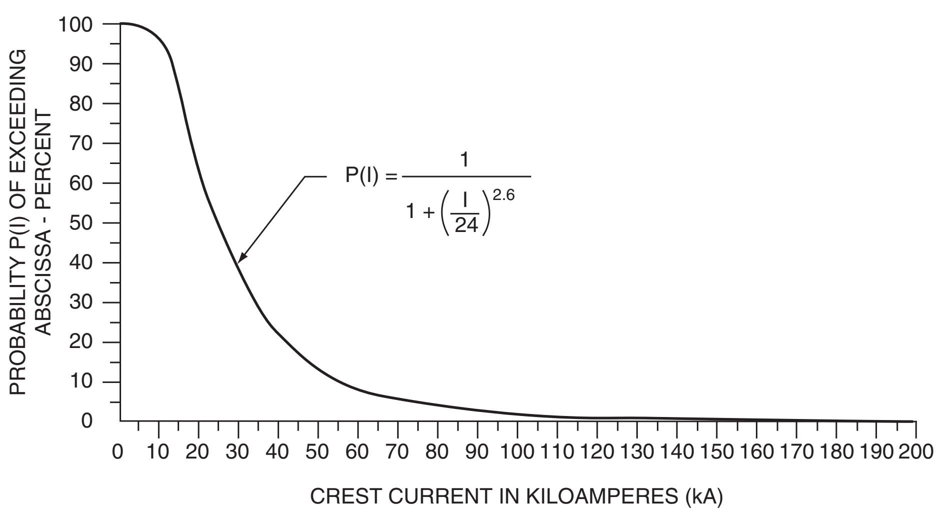

FIGURE 12.1 Probability of stroke current exceeding abscissa for strokes to flat ground. (IEEE Std. 998–1996. With permission.)

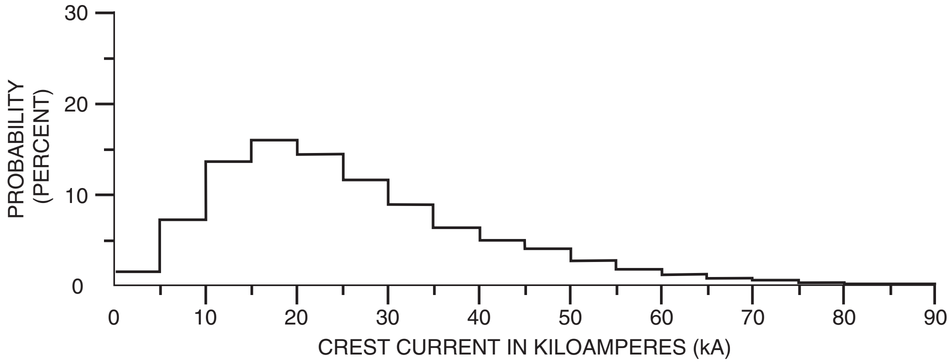

FIGURE 12.2 Stroke current range probability for strokes to flat ground. (IEEE Std. 998–1996. With permission.)

many times thunder is heard during a 24-h period. In other words, if thunder is heard on any one day more than one time, the day is still classified as one thunder-day (or thunderstorm day). The average annual keraunic level for locations in the U.S. can be determined by referring to isokeraunic maps on which lines of equal keraunic level are plotted on a map of the country. Figure 12.3 gives the mean annual thunderstorm days for the U.S.

12.2.4 Ground Flash Density

Ground flash density (GFD) is defined as the average number of strokes per unit area per unit time at a particular location. It is usually assumed that the GFD to earth, a substation, or a transmission or distribution line is roughly proportional to the keraunic level at the locality. If thunderstorm days are to be used as a basis, it is suggested that the following equation be used (Anderson, 1987):

$$N_k = 0.12T_d \tag{12.9}$$

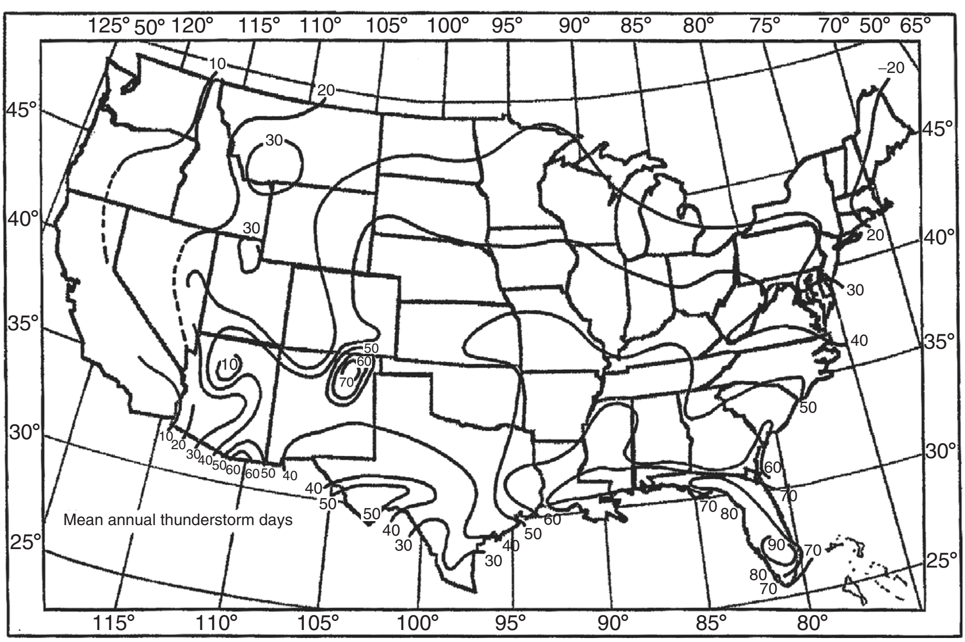

FIGURE 12.3 Mean annual thunderstorm days in the U.S. (IEEE Std. 998–1996. With permission.)

or

$$N_m = 0.31 T_d \tag{12.10}$$

where

N_k is the number of flashes to earth per square kilometer per year
N_m is the number of flashes to earth per square mile per year
T_d is the average annual keraunic level, thunderstorm days

12.2.5 Lightning Detection Networks

A new technology is now being deployed in Canada and the U.S. that promises to provide more accurate information about ground flash density and lightning stroke characteristics. Mapping of lightning flashes to the earth has been in progress for over a decade in Europe, Africa, Australia, and Asia. Now a network of direction finding receiving stations has been installed across Canada and the U.S. By means of triangulation among the stations, and with computer processing of signals, it is possible to pinpoint the location of each lightning discharge. Hundreds of millions of strokes have been detected and plotted to date.

Ground flash density maps have already been prepared from this data, but with the variability in frequency and paths taken by thunderstorms from year to year, it will take a number of years to develop data that is statistically significant. Some electric utilities are, however, taking advantage of this technology to detect the approach of thunderstorms and to plot the location of strikes on their system. This information is very useful for dispatching crews to trouble spots and can result in shorter outages that result from lightning strikes.

12.3 Empirical Design Methods

Two classical design methods have historically been employed to protect substations from direct lightning strokes:

1. Fixed angles
2. Empirical curves

The two methods have generally provided acceptable protection.

12.3.1 Fixed Angles

The fixed-angle design method uses vertical angles to determine the number, position, and height of shielding wires or masts. Figure 12.4 illustrates the method for shielding wires, and Fig. 12.5 illustrates the method for shielding masts. The angles used are determined by the degree of lightning exposure, the importance of the substation being protected, and the physical area occupied by the substation. The value of the angle alpha that is commonly used is 45°. Both 30° and 45° are widely used for angle beta. (Sample calculations for low voltage and high voltage substations using fixed angles are given in annex B of IEEE Std. 998–1996.)

12.3.2 Empirical Curves

From field studies of lightning and laboratory model tests, empirical curves have been developed to determine the number, position, and height of shielding wires and masts (Wagner et al., 1941; Wagner, 1942; Wagner et al., 1941). The curves were developed for shielding failure rates of 0.1, 1.0, 5.0, 10, and

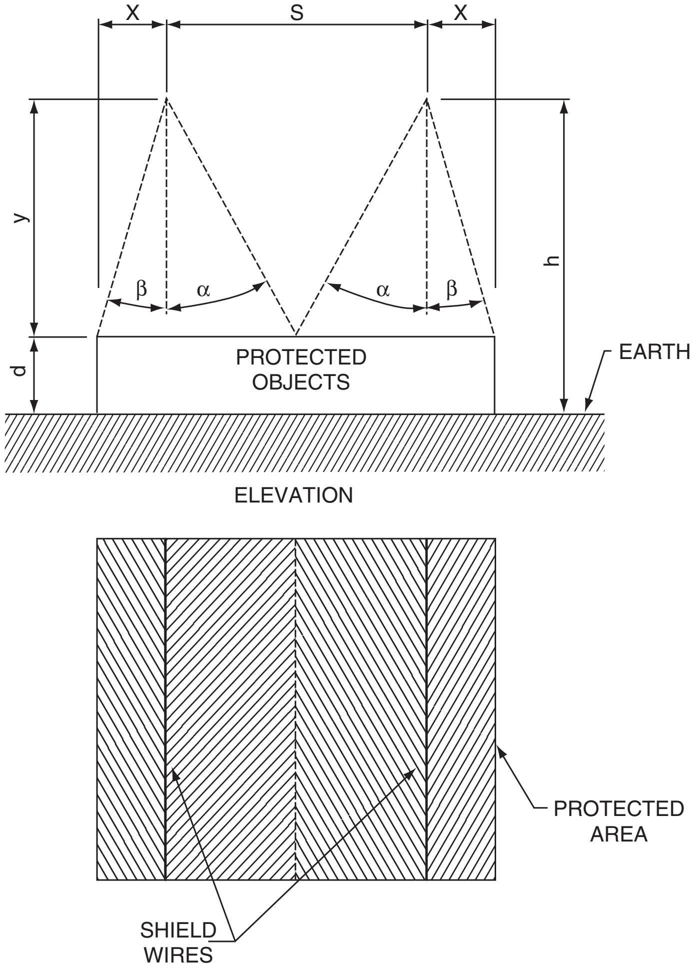

FIGURE 12.4 Fixed angles for shielding wires. (IEEE Std. 998–1996. With permission.)

15%. A failure rate of 0.1% is commonly used in design. Figures 12.6 and 12.7 have been developed for a variety of protected object heights, *d*. The empirical curve method has also been referred to as the Wagner method.

12.3.2.1 Areas Protected by Lightning Masts

Figures 12.8 and 12.9 illustrate the areas that can be protected by two or more shielding masts (Wagner et al., 1942). If two masts are used to protect an area, the data derived from the empirical curves give shielding information only for the point *B*, midway between the two masts, and for points on the semicircles drawn about the masts, with radius *x*, as shown in Fig. 12.8a. The locus shown in Fig. 12.8a, drawn by the semicircles around the masts, with radius *x*, and connecting the point *B*, represents an approximate limit for a selected exposure rate. Any single point falling within the cross-hatched area should have <0.1% exposure. Points outside the cross-hatched area will have >0.1% exposure. Figure 12.8b illustrates this phenomenon for four masts spaced at the distance s as in Fig. 12.8a.

The protected area can be improved by moving the masts closer together, as illustrated in Fig. 12.9. In Fig. 12.9a, the protected areas are, at least, as good as the combined areas obtained by superimposing those of Fig. 12.8a. In Fig. 12.9a, the distance s' is one-half the distance *s* in Fig. 12.8a. To estimate the

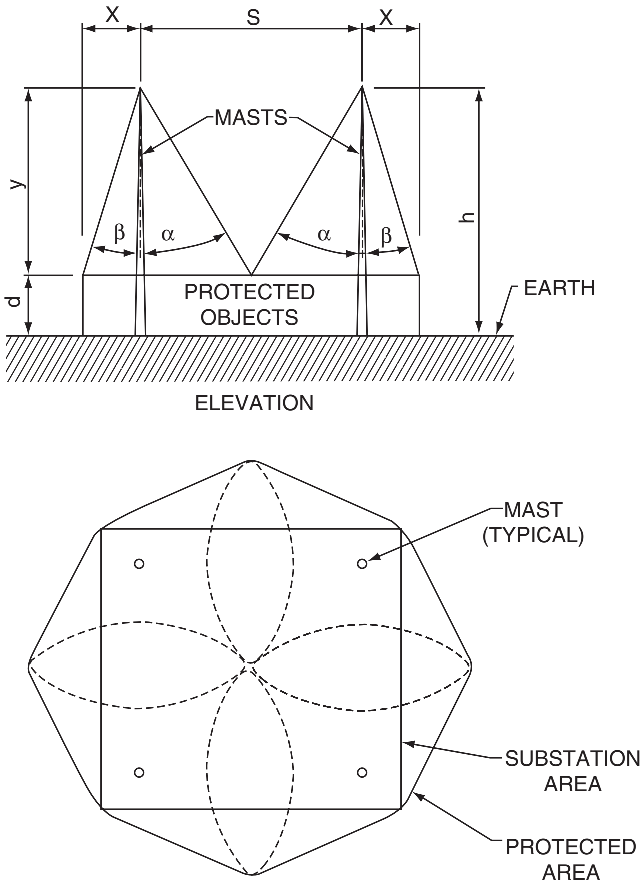

FIGURE 12.5 Fixed angles for masts. (IEEE Std. 998–1996. With permission.)

width of the overlap, x', first obtain a value of y corresponding to twice the distance, s' between the masts. Then use Fig. 12.6 to determine x' for this value of y. This value of x is used as an estimate of the width of overlap x' in Fig. 12.9. As illustrated in Fig. 12.9b, the size of the areas with an exposure greater than 0.1% has been significantly reduced. (Sample calculations for low voltage and high voltage substations using empirical curves are given in annex B of IEEE Std. 998–1996.)

12.4 The Electrogeometric Model (EGM)

Shielding systems developed using classical methods (fixed-angle and empirical curves) of determining the necessary shielding for direct stroke protection of substations have historically provided a fair degree of protection. However, as voltage levels (and therefore structure and conductor heights) have increased over the years, the classical methods of shielding design have proven less adequate. This led to the development of the electrogeometric model.

12.4.1 Whitehead's EGM

In 1960, Anderson developed a computer program for calculation of transmission line lightning performance that uses the *Monte Carlo Method* (1961). This method showed good correlation with

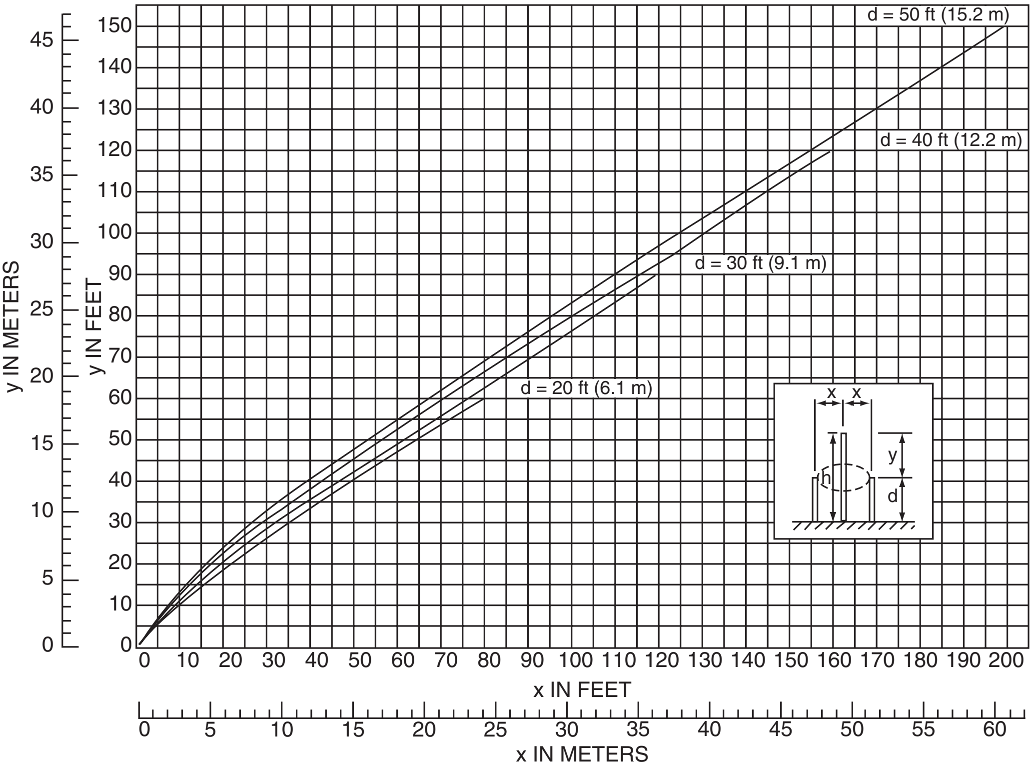

FIGURE 12.6 Single lightning mast protecting single ring of object—0.1% exposure. Height of mast above protected object, *y*, as a function of horizontal separation, *x*, and height of protected object, *d*. (IEEE Std. 998–1996. With permission.)

actual line performance. An early version of the EGM was developed in 1963 by Young et al., but continuing research soon led to new models. One extremely significant research project was performed by Whitehead (1971). Whitehead's work included a theoretical model of a transmission system subject to direct strokes, development of analytical expressions pertaining to performance of the line, and supporting field data that verified the theoretical model and analyses. The final version of this model was published by Gilman and Whitehead in 1973.

12.4.2 Recent Improvements in the EGM

Sargent made an important contribution with the *Monte Carlo Simulation* of lightning performance (1972) and his work on lightning strokes to tall structures (1972). Sargent showed that the frequency distribution of the amplitudes of strokes collected by a structure depends on the structure height as well as on its type (mast vs. wire). In 1976, Mousa extended the application of the EGM (which was developed for transmission lines) to substation facilities.

12.4.3 Criticism of the EGM

Work by Eriksson reported in 1978 and later work by Anderson and Eriksson reported in 1980 revealed apparent discrepancies in the EGM that tended to discredit it. Mousa (1988) has shown, however, that explanations do exist for the apparent discrepancies, and that many of them can be eliminated by adopting a revised electrogeometric model. Most investigators now accept the EGM as a valid approach for designing lightning shielding systems.

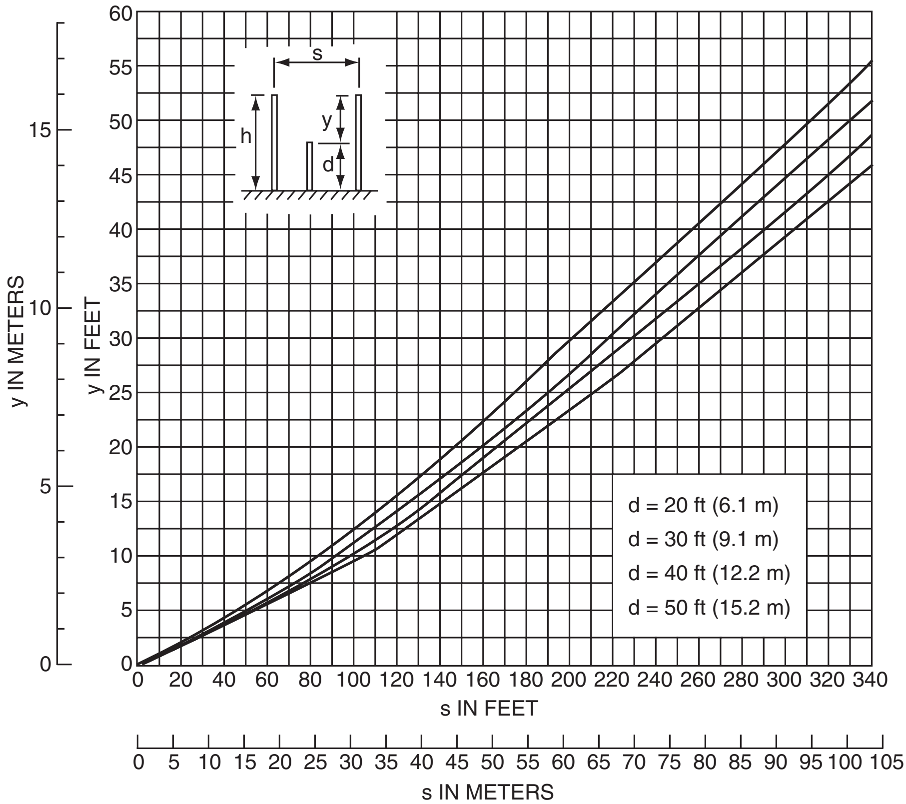

FIGURE 12.7 Two lightning masts protecting single object, no overlap—0.1% exposure. Height of mast above protected object, *y*, as a function of horizontal separation, *s*, and height of protected object, *d*. (IEEE Std. 998-1996. With permission.)

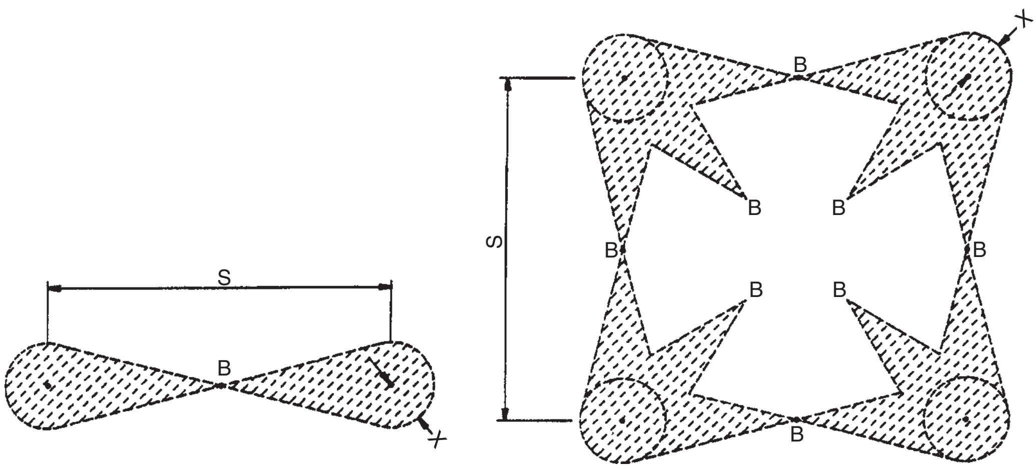

FIGURE 12.8 Areas protected by multiple masts for point exposures shown in Fig. 12.5. (a) With two lightning masts; 5.67 (b) with four lightning masts. (IEEE Std. 998–1996. With permission.)

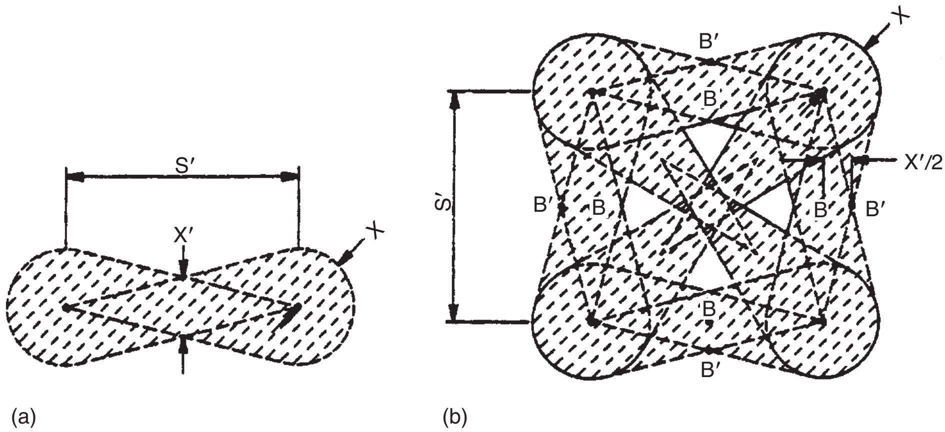

FIGURE 12.9 Areas protected by multiple masts for point exposures shown in Fig. 12.5. (a) With two lightning masts; (b) with four lightning masts. (IEEE Std. 998–1996. With permission.)

12.4.4 A Revised EGM

The revised EGM was developed by Mousa and Srivastava (1986; 1988). Two methods of applying the EGM are the modified version of the rolling sphere method (Lee, 1979; Lee, 1978; Orell, 1988), and the method given by Mousa and Srivastava (1988; 1991).

The revised EGM model differs from Whitehead's model in the following respects:

1. The stroke is assumed to arrive in a vertical direction. (It has been found that Whitehead's assumption of the stroke arriving at random angles is an unnecessary complication [Mousa and Srivastava, 1988].)
2. The differing striking distances to masts, wires, and the ground plane are taken into consideration.
3. A value of 24 kA is used as the median stroke current (Mousa and Srivastava, 1989). This selection is based on the frequency distribution of the first negative stroke to flat ground. This value best reconciles the EGM with field observations.
4. The model is not tied to a specific form of the striking distance equations (Eqs. 12.1 through 12.6). Continued research is likely to result in further modification of this equation as it has in the past. The best available estimate of this parameter may be used.

12.4.4.1 Description of the Revised EGM

Previously, the concept that the final striking distance is related to the magnitude of the stroke current was introduced and Eq. (12.4) was selected as the best approximation of this relationship. A coefficient k accounts for the different striking distances to a mast, a shield wire, and to the ground. Equation (12.4) is repeated here with this modification:

$$S_m = 8kI^{0.65} \tag{12.11}$$

or

$$S_f = 26.25kI^{0.65} \tag{12.12}$$

where

S_m is the strike distance in meters
S_f is the strike distance in feet
I is the return stroke current in kiloamperes
k is a coefficient to account for different striking distances to a mast, a shield wire, or the ground plane

Mousa (1988) gives a value of $k = 1$ for strokes to wires or the ground plane and a value of $k = 1.2$ for strokes to a lightning mast.

Lightning strokes have a wide distribution of current magnitudes, as shown in Fig. 12.1. The EGM theory shows that the protective area of a shield wire or mast depends on the amplitude of the stroke current. If a shield wire protects a conductor for a stroke current I_s, it may not shield the conductor for a stroke current less than I_s that has a shorter striking distance. Conversely, the same shielding arrangement will provide greater protection against stroke currents greater than I_s that have greater striking distances. Since strokes less than some critical value I_s can penetrate the shield system and terminate on the protected conductor, the insulation system must be able to withstand the resulting voltages without flashover. Stated another way, the shield system should intercept all strokes of magnitude I_s and greater so that flashover of the insulation will not occur.

12.4.4.2 Allowable Stroke Current

Some additional relationships need to be introduced before showing how the EGM is used to design a zone of protection for substation equipment. Bus insulators are usually selected to withstand a *basic lightning impulse level* (BIL). Insulators may also be chosen according to other electrical characteristics, including negative polarity *impulse critical flashover* (C.F.O.) voltage. Flashover occurs if the voltage produced by the lightning stroke current flowing through the surge impedance of the station bus exceeds the withstand value. This may be expressed by the Gilman & Whitehead equation (1973):

$$I_s = \text{BIL} \times 1.1/(Z_S/2) = 2.2(\text{BIL})/Z_s \qquad (12.13)$$

or

$$I_s = 0.94 \times \text{C.F.O.} \times 1.1/(Z_S/2) = 2.068(\text{C.F.O.})/Z_s \qquad (12.14)$$

where

- I_s is the allowable stroke current in kiloamperes
- BIL is the basic lightning impulse level in kilovolts
- C.F.O. is the negative polarity critical flashover voltage of the insulation being considered in kilovolts
- Z_s is the surge impedance of the conductor through which the surge is passing in ohms
- 1.1 is the factor to account for the reduction of stroke current terminating on a conductor as compared to zero impedance earth (Gilman and Whitehead, 1973)

In Eq. (12.14), the C.F.O. has been reduced by 6% to produce a withstand level roughly equivalent to the BIL rating for post insulators.

12.4.4.3 Withstand Voltage of Insulator Strings

BIL values of station post insulators can be found in vendor catalogs. A method is given below for calculating the withstand voltage of insulator strings. The withstand voltage in kV at 2 μs and 6 μs can be calculated as for

$$V_{I2} = 0.94 \times 820\, w \qquad (12.15)$$

$$V_{I6} = 0.94 \times 585\, w \qquad (12.16)$$

where

- w is the length of insulator string (or air gap) in meters
- 0.94 is the ratio of withstand voltage to C.F.O. voltage
- V_{I2} is the withstand voltage in kilovolts at 2 μs
- V_{I6} is the withstand voltage in kilovolts at 6 μs

Equation (12.16) is recommended for use with the EGM.

12.4.5 Application of the EGM by the Rolling Sphere Method

It was previously stated that it is only necessary to provide shielding for the equipment from all lightning strokes greater than I_s that would result in a flashover of the buswork. Strokes less than I_s are permitted to enter the protected zone since the equipment can withstand voltages below its BIL design level. This will be illustrated by considering three levels of stroke current: I_s, stroke currents greater than I_s, and stroke currents less than I_s. First, let us consider the stroke current I_s.

12.4.5.1 Protection Against Stroke Current I_s

I_s is calculated from Eq. (12.13) or Eq. (12.14) as the current producing a voltage the insulation will just withstand. Substituting this result in Eq. (12.11) or Eq. (12.12) gives the striking distance S for this stroke current. In 1977, Lee developed a simplified technique for applying the electromagnetic theory to the shielding of buildings and industrial plants (1982; 1979; 1978). Orrell extended the technique to specifically cover the protection of electric substations (1988). The technique developed by Lee has come to be known as the rolling sphere method. For the following illustration, the *rolling sphere* method will be used. This method employs the simplifying assumption that the striking distances to the ground, a mast, or a wire are the same. With this exception, the rolling sphere method has been updated in accordance with the revised EGM.

Use of the rolling sphere method involves rolling an imaginary sphere of radius S over the surface of a substation. The sphere rolls up and over (and is supported by) lightning masts, shield wires, substation fences, and other grounded metallic objects that can provide lightning shielding. A piece of equipment is said to be protected from a direct stroke if it remains below the curved surface of the sphere by virtue of the sphere being elevated by shield wires or other devices. Equipment that touches the sphere or penetrates its surface is not protected. The basic concept is illustrated in Fig. 12.10.

Continuing the discussion of protection against stroke current I_s, consider first a single mast. The geometrical model of a single substation shield mast, the ground plane, the striking distance, and the zone of protection are shown in Fig. 12.11. An arc of radius S that touches the shield mast and the ground plane is shown in Fig. 12.11. All points below this arc are protected against the stroke current I_s. This is the protected zone. The arc is constructed as follows (see Fig. 12.11). A dashed line is drawn parallel to the ground at a distance S (the striking distance as obtained from Eq. (12.11) or Eq. (12.12)) above the ground plane. An arc of radius S, with its center located on the dashed line, is drawn so the radius of the arc just touches the mast. Stepped leaders that result in stroke current I_s and that descend outside of the point where the arc is tangent to the ground will strike the ground. Stepped leaders that result in stroke current I_s and that descend inside the point where the arc is

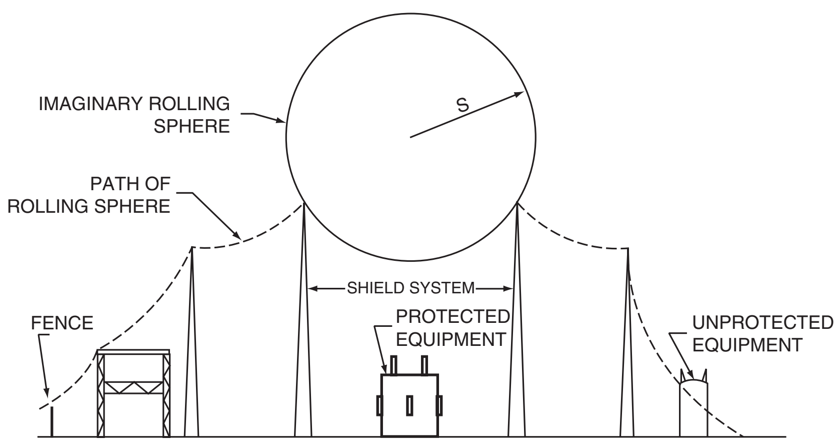

FIGURE 12.10 Principle of the rolling sphere. (IEEE Std. 998–1996. With permission.)

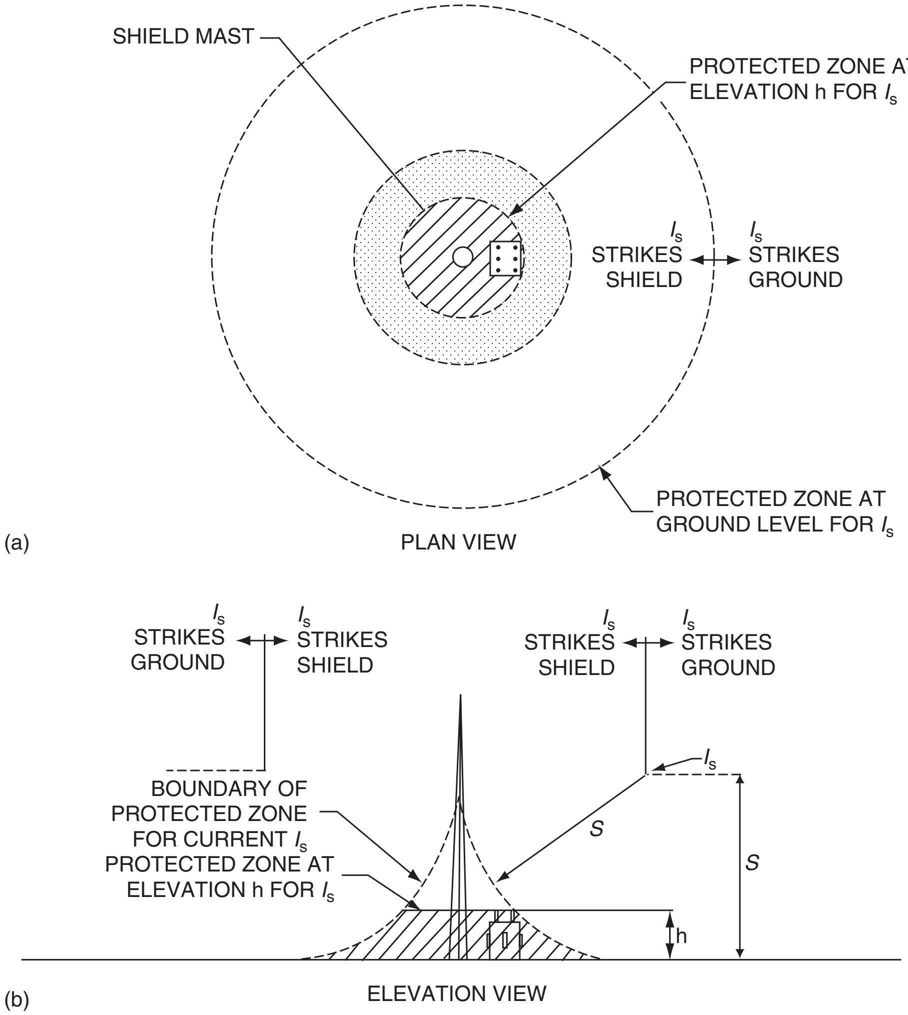

FIGURE 12.11 Shield mast protection for stroke current I_s. (IEEE Std. 998–1996. With permission.)

tangent to the ground will strike the shield mast, provided all other objects are within the protected zone. The height of the shield mast that will provide the maximum zone of protection for stroke currents equal to I_s is S. If the mast height is less than S, the zone of protection will be reduced. *Increasing the shield mast height greater than S will provide additional protection in the case of a single mast. This is not necessarily true in the case of multiple masts and shield wires.* The protection zone can be visualized as the surface of a sphere with radius S that is rolled toward the mast until touching the mast. As the sphere is rolled around the mast, a three-dimensional surface of protection is defined. It is this concept that has led to the name *rolling sphere* for simplified applications of the electrogeometric model.

12.4.5.2 Protection Against Stroke Currents Greater than I_S

A lightning stroke current has an infinite number of possible magnitudes, however, and the substation designer will want to know if the system provides protection at other levels of stroke current magnitude. Consider a stroke current I_{s1} with magnitude greater than I_s. Strike distance, determined from Eq. (12.11) or Eq. (12.12), is $S1$. The geometrical model for this condition is shown in Fig. 12.12. Arcs of

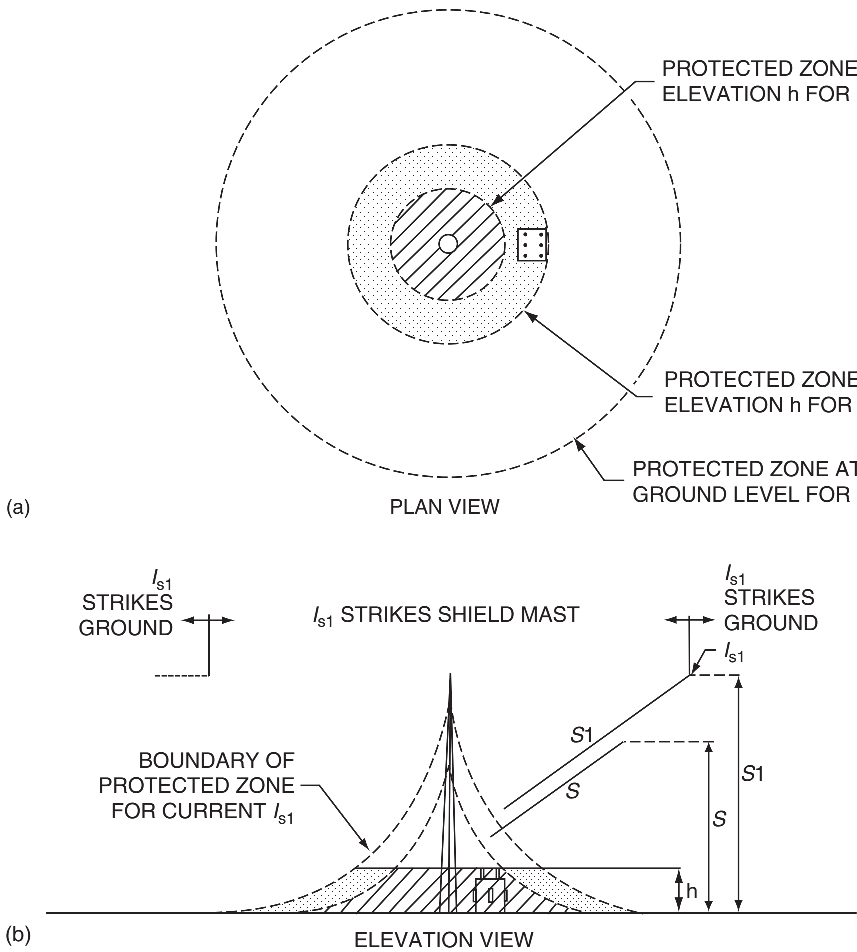

FIGURE 12.12 Shield mast protection for stroke current I_{s1}. (IEEE Std. 998–1996. With permission.)

protection for stroke current I_{s1} and for the previously discussed I_s are both shown. The figure shows that the zone of protection provided by the mast for stroke current I_{s1} is greater than the zone of protection provided by the mast for stroke current I_s. Stepped leaders that result in stroke current I_{s1} and that descend outside of the point where the arc is tangent to the ground will strike the ground. Stepped leaders that result in stroke current I_{s1} and that descend inside the point where the arc is tangent to the ground will strike the shield mast, provided all other objects are within the $S1$ protected zone. Again, the protective zone can be visualized as the surface of a sphere touching the mast. In this case, the sphere has a radius $S1$.

12.4.5.3 Protection Against Stroke Currents Less than I_s

It has been shown that a shielding system that provides protection at the stroke current level I_s provides even better protection for larger stroke currents. The remaining scenario to examine is the protection afforded when stroke currents are less than I_s. Consider a stroke current I_{s0} with magnitude less than I_s. The striking distance, determined from Eq. (12.11) or Eq. (12.12), is S_0. The geometrical model for this condition is shown in Fig. 12.13. Arcs of protection for stroke current I_{s0} and I_s are both shown. The figure shows that the zone of protection provided by the mast for stroke current I_{s0} is less than the zone of protection provided by the mast for stroke current I_s. It is noted that a portion of the equipment

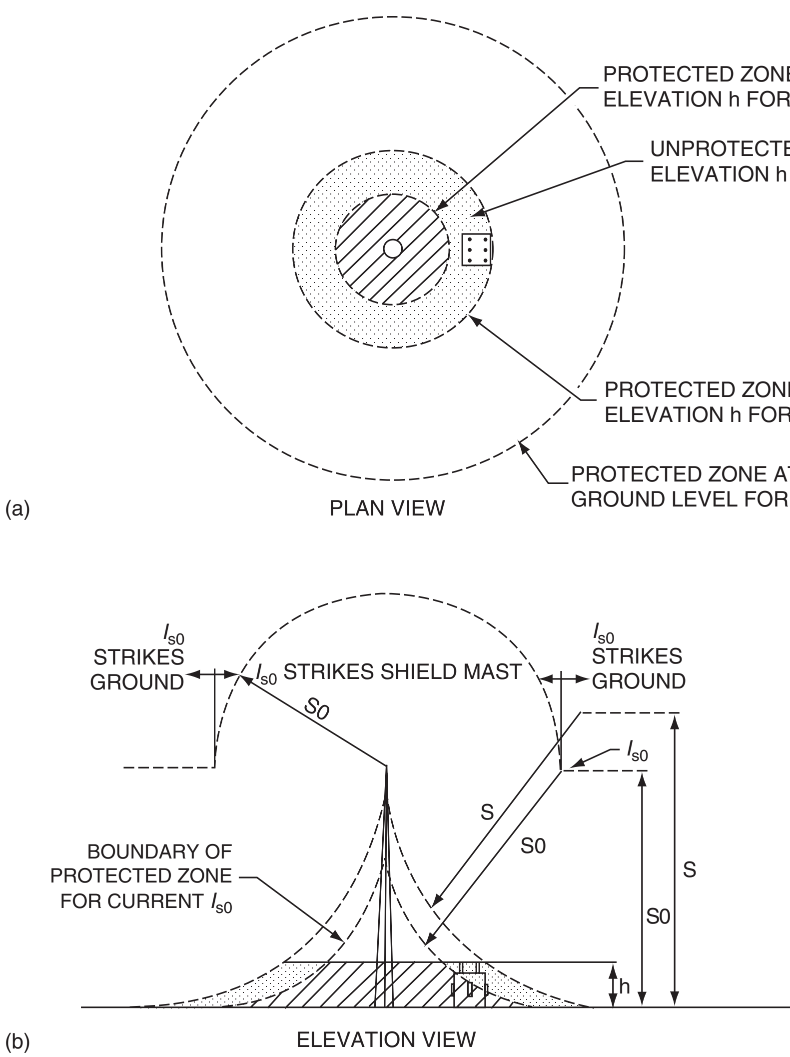

FIGURE 12.13 Shield mast protection for stroke current I_{s0}. (IEEE Std. 998–1996. With permission.)

protrudes above the dashed arc or zone of protection for stroke current I_{s0}. Stepped leaders that result in stroke current I_{s0} and that descend outside of the point where the arc is tangent to the ground will strike the ground. However, some stepped leaders that result in stroke current I_{s0} and that descend inside the point where the arc is tangent to the ground could strike the equipment. This is best shown by observing the plan view of protective zones shown in Fig. 12.13. Stepped leaders for stroke current I_{s0} that descend inside the inner protective zone will strike the mast and protect equipment that is h in height. Stepped leaders for stroke current I_{s0} that descend in the shaded unprotected zone will strike equipment of height h in the area. *If, however, the value of I_s was selected based on the withstand insulation level of equipment used in the substation, stroke current I_{s0} should cause no damage to equipment.*

12.4.6 Multiple Shielding Electrodes

The electrogeometric modeling concept of direct stroke protection has been demonstrated for a single shield mast. A typical substation, however, is much more complex. It may contain several voltage levels and may utilize a combination of shield wires and lightning masts in a three-dimensional arrangement.

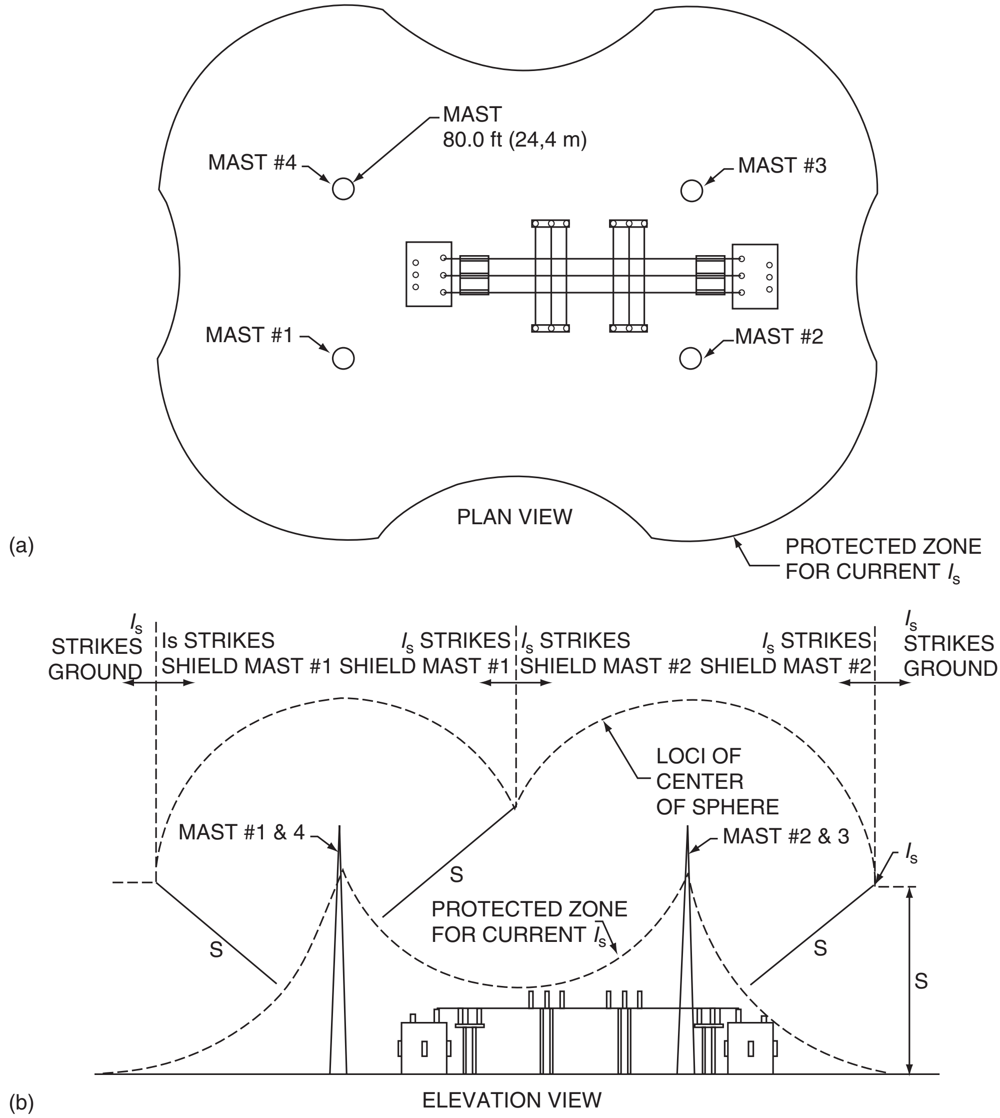

FIGURE 12.14 Multiple shield mast protection for stroke current I_s. (IEEE Std. 998–1996. With permission.)

The above concept can be applied to multiple shielding masts, horizontal shield wires, or a combination of the two. Figure 12.14 shows this application considering four shield masts in a multiple shield mast arrangement. The arc of protection for stroke current I_s is shown for each set of masts. The dashed arcs represent those points at which a descending stepped leader for stroke current I_s will be attracted to one of the four masts. The protected zone between the masts is defined by an arc of radius S with the center at the intersection of the two dashed arcs. The protective zone can again be visualized as the surface of a sphere with radius S, which is rolled toward a mast until touching the mast, then rolled up and over the mast such that it would be supported by the masts. The dashed lines would be the locus of the center of the sphere as it is rolled across the substation surface. Using the concept of rolling sphere of the proper radius, the protected area of an entire substation can be determined. This can be applied to any group of different height shield masts, shield wires, or a combination of the two. Figure 12.15 shows an application to a combination of masts and shield wires.

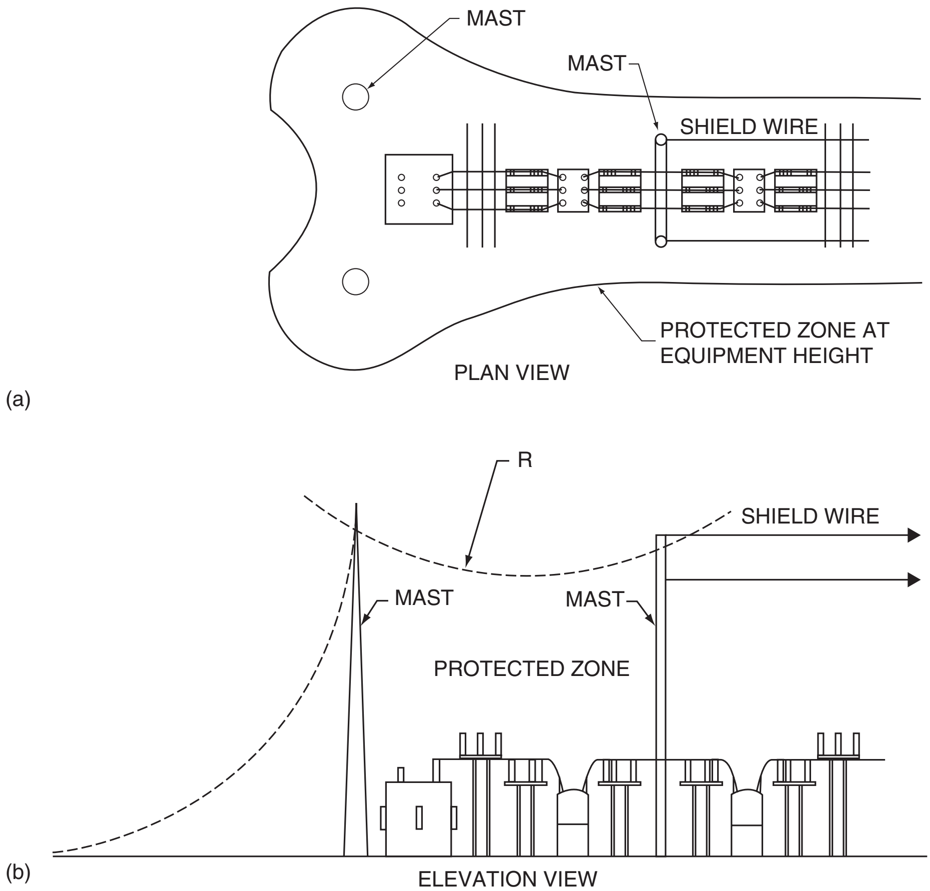

FIGURE 12.15 Protection by shield wires and masts. (IEEE Std. 998–1996. With permission.)

12.4.7 Changes in Voltage Level

Protection has been illustrated with the assumption of a single voltage level. Substations, however, have two or more voltage levels. The rolling sphere method is applied in the same manner in such cases, except that the sphere radius would increase or decrease appropriate to the change in voltage at a transformer. (Sample calculations for a substation with two voltage levels are given in annex B of IEEE Std. 998–1996.)

12.4.8 Minimum Stroke Current

The designer will find that shield spacing becomes quite close at voltages of 69 kV and below. It may be appropriate to select some minimum stroke current, perhaps 2 kA for shielding stations below 115 kV. Such an approach is justified by an examination of Figs. 12.1 and 12.2. It will be found that 99.8% of all strokes will exceed 2 kA. Therefore, this limit will result in very little exposure, but will make the shielding system more economical.

12.4.9 Application of Revised EGM by Mousa and Srivastava Method

The rolling sphere method has been used in the preceding paragraphs to illustrate application of the EGM. Mousa describes the application of the revised EGM (1976). Figure 12.16 depicts two shield wires, G1, and G2, providing shielding for three conductors, W1, W2, and W3. S_c is the critical striking distance as determined by Eq. (12.11), but reduced by 10% to allow for the statistical distribution of

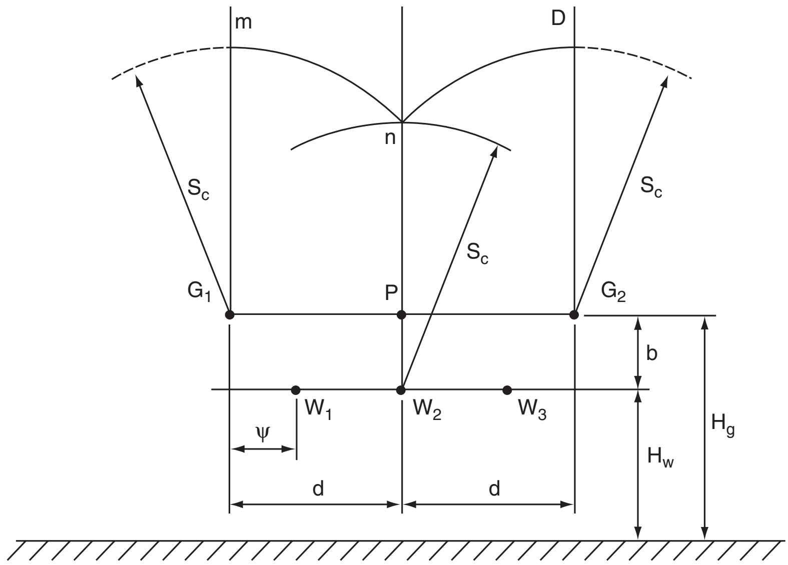

FIGURE 12.16 Shielding requirements regarding the strokes arriving between two shield wires. (IEEE Std. 998–1996. With permission.)

strokes so as to preclude any failures. Arcs of radius S_c are drawn with centers at G1, G2, and W2 to determine if the shield wires are positioned to properly shield the conductors. The factor ψ is the horizontal separation of the outer conductor and shield wire, and b is the distance of the shield wires above the conductors. Figure 12.17 illustrates the shielding provided by four masts. The height h_{mid} at the center of the area is the point of minimum shielding height for the arrangement. For further details in the application of the method, see Mousa (1976). At least two computer programs have been developed that assist in the design of a shielding system. One of these programs (Mousa, 1991) uses the revised EGM to compute the surge impedance, stroke current, and striking distance for a given arrangement of conductors and shield systems, then advises the user whether or not effective shielding is provided. (Sample calculations are provided in annex B of IEEE Std. 998–1996 to further illustrate the application.)

12.5 Calculation of Failure Probability

In the revised EGM just presented, striking distance is reduced by a factor of 10% so as to exclude all strokes from the protected area that could cause damage. In the empirical design approach, on the other hand, a small failure rate is permitted, typically 0.1%. Linck (1975) also developed a method to provide partial shielding using statistical methods. It should be pointed out that for the statistical approach to be valid, the size of the sample needs to be large. For power lines that extend over large distances, the total exposure area is large and the above criterion is met. It is questionable, therefore, whether the statistical approach is as meaningful for substations that have very small exposure areas by comparison. Engineers do, however, design substation shielding that permits a small statistical failure rate. Orrell (1988) has developed a method of calculating failure rates for the EGM rolling sphere method. (This method is described with example calculations in annex D of IEEE Std. 998–1996.)

12.6 Active Lightning Terminals

In the preceding methods, the lightning terminal is considered to be a *passive* element that intercepts the stroke merely by virtue of its position with respect to the live bus or equipment. Suggestions have been made that lightning protection can be improved by using what may be called *active* lightning terminals. Three types of such devices have been proposed over the years:

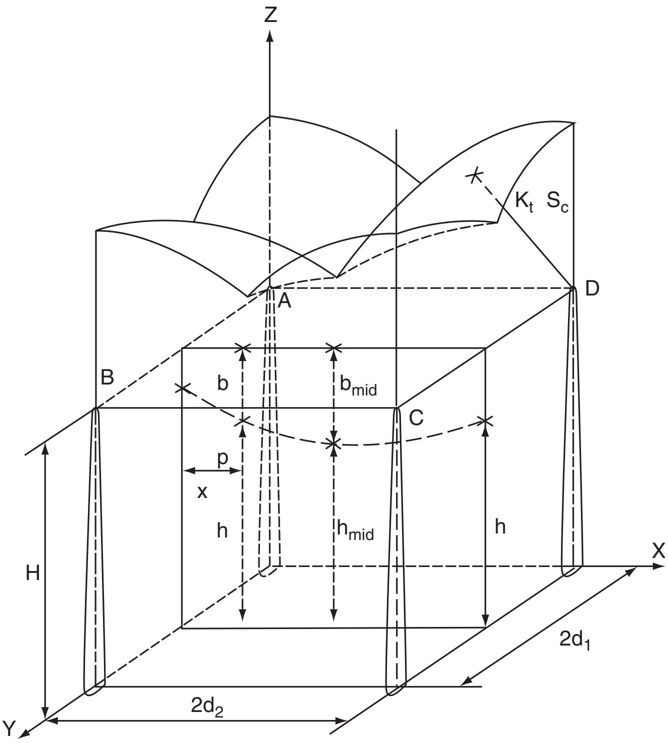

FIGURE 12.17 Shielding of an area bounded by four masts. (IEEE Std. 998–1996. With permission.)

- *Lightning rods with radioactive tips* (Golde, 1973). These devices are said to extend the attractive range of the tip through ionization of the air.
- *Early Streamer Emission (ESM) lightning rods* (Berger and Floret, 1991). These devices contain a triggering mechanism that sends high-voltage pulses to the tip of the rod whenever charged clouds appear over the site. This process is said to generate an upward streamer that extends the attractive range of the rod.
- *Lightning prevention devices.* These devices enhance the *point discharge* phenomenon by using an array of needles instead of the single tip of the standard lightning rod. It is said that the space charge generated by the many needles of the array neutralize part of the charge in an approaching cloud and prevent a return stroke to the device, effectively extending the protected area (Carpenter, 1976).

Some of the latter devices have been installed on facilities (usually communications towers) that have experienced severe lightning problems. The owners of these facilities have reported no further lightning problems in many cases.

There has not been sufficient scientific investigation to demonstrate that the above devices are effective; and since these systems are proprietary, detailed design information is not available. It is left to the design engineer to determine the validity of the claimed performance for such systems.

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13

Seismic Considerations[1]

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13.1 Historical Perspective

Prior to 1970, seismic requirements for the design of substation components were minimal. In the 1970s and 1980s, several large-magnitude earthquakes struck California, causing millions of dollars in damage to substation components, consequent losses of revenue, and disruption of service for a large number of customers. As a result of these losses and the increasing importance of reliable electric service, it became apparent to owners and operators of substation facilities in seismically active areas that the existing seismic requirements for substation components were inadequate. The 1997 version of the Institute of Electrical and Electronic Engineers (IEEE) Standard 693, Seismic Design for Substations [1] represented a major change in the requirements for the seismic design of substation equipment. The 2005 version of this document contains a number of important improvements based upon user experience, research advancements, and the continued contributions of utilities, manufacturers, consulting engineers, and the academic community. A companion document nearing completion by the American Society of Civil Engineers (ASCE), entitled Substation Structure Design Guide [2], focuses on the design of substation structures. Both of these documents have enhanced the current state of knowledge in this area. These documents also promote seismic standardization of substation power equipment in the electric power industry.

[1]Figures 13.2 and 13.3 are reprinted with permission from IEEE Std. 693-2005, Recommended Practice for Seismic Design of Substation by IEEE. The IEEE disclaims any responsibility or liability resulting from the placement and use in the described manner.

13.2 IEEE 693—A Solution

The process demonstrating that equipment and components will satisfy the seismic performance requirements specified by a user or purchaser is known as seismic qualification. Prior to the release of IEEE 693-1997, it was common for utilities and other users of electric substation equipment to each develop their own set of seismic qualification requirements. These user-specific seismic qualification requirements varied from one user to the next, depending on the user's experience, site-specific hazards, engineering practices, and other considerations. No standard existed that provided a single set of requirements for seismic qualification of power equipment. Available standards did not provide for the differences in types and classes of high-voltage substation equipment. This is the main goal of IEEE 693: to provide a single set of seismic qualification requirements for each typical type of equipment that can be easily specified by a user or purchaser of the equipment. Seismic qualification requirements that are common to multiple users enable a manufacturer to include seismic requirements in the initial development and design of the equipment and amortize the cost of the qualification over all of the expected buyers.

This chapter discusses the current version of IEEE 693-2005 [3], and highlights some of the important changes from the previous version published in 1997. While a number of important changes have been incorporated since the previous version, the overall philosophy of providing the user with an easy-to-specify method that refers to detailed requirements contained within the standard remains the same.

A user wishing to specify IEEE 693 can do so through the four steps outlined below:

1. Note the equipment type, such as surge arresters or circuit breakers
2. Select the qualification level—low, moderate, or high
3. Note the equipment *in situ* configuration, such as mounting information, etc.
4. Identify scheduling requirements

Annex U of IEEE 693 provides a template with suggested wording, and details of these steps.

This chapter is intended to guide substation designers who wish to use IEEE 693's single set concept for equipment qualification by illustrating the basic steps required for securing and protecting components within a given substation. It is only a guide and is not intended to be all-inclusive or to provide all the necessary details to undertake such work. For further details and information on this topic, the reader should review the documents listed at the end of this chapter.

13.3 Relationship between Earthquakes and Substations

To secure and protect substation equipment from damage due to a seismic event, the relationship between earthquakes and substation components must first be understood. Earthquakes occur when there is a sudden rupture along a preexisting geologic fault. Shock waves that radiate from the fracture zone amplify, and depending on the geology, these waves will arrive at the surface as a complex set of multifrequency vibratory ground motions with horizontal and vertical components.

The response of structures and buildings to this ground motion depends on their construction, ductility, dynamic properties, and design. Lightly damped structures that have one or more natural modes of vibration within the frequency band of the ground motion excitation can experience considerable movement, which can generate forces and deflections that the structures may not have been designed to accommodate.

Electrical substation equipments are complex machines whose primary functions require characteristics that are often at odds with those of a robust seismic design. This equipment commonly includes components of relatively low-strength, lightly damped, and brittle materials such as porcelain. In order for the equipment to be capable of performing its intended functions after the earthquake, the various structural load-carrying components must not be overstressed, and electrical functionality must be maintained.

A further complication occurs when two or more structures or pieces of equipment are mechanically linked by electrical conductors. In such a case, they will interact with one another, thus producing a modified response. If they are either not linked, or linked in such a way that the two pieces can move independently—an ideal situation—then no forces are transferred between the two components. However, recent research has shown that even a well-designed link may contribute to the response of the equipment or structure during a seismic event.

Unless instructed to do otherwise, construction personnel will usually install conductors with little or no slack, which gives the installation a neat and clean look. This practice does not allow for any freedom of movement between components. When the conductor is installed with little or no slack, even small differential motions of one piece of equipment can easily impact an adjacent piece of equipment. This is because each piece of interconnected equipment has its own frequency response to the earthquake. While the equipment at one end of a tight conductor line is vibrating at 1 Hz, for example, the other piece of equipment at the other end of the conductor is "trying" to vibrate at, say, 10 Hz. It is easy to see that when they displace toward each other, the line will go slack. When they displace away from each other, the line will suddenly become taut, which will impose additional forces on the equipment. This is a well-documented occurrence. In general, the more flexible equipment, which is often the larger and more massive, will pull on the stiffer equipment, which may be smaller and possibly weaker. Substation equipment with natural frequencies within the range of earthquake ground motions is especially vulnerable to this type of damage by seismic events. When specifying conductor slack, electrical clearance requirements must also be considered.

13.4 Applicable Documents

Once the relationship between substation components and earthquakes is understood, the substation designer should become familiar with the standards and references currently available (see reference list at the end of this chapter). It is important for the user to appreciate how the various documents interrelate. Although IEEE 693 is entitled "Recommended Practice for Seismic Design of Substations," it focuses on the seismic qualification and design of equipment, while other documents that were already available or under development would address other aspects of the seismic design of substations. Therefore, IEEE 693 simply refers users to the appropriate document if the information is not contained therein. It was also clear that a single set of seismic qualification requirements was needed; therefore, IEEE 693 emphasizes those aspects associated with the seismic qualification of power equipment.

While IEEE 693 focuses on equipment, the ASCE Substation Structure Design Guide provides information for structures within a substation, such as A-frames, bus supports, racks, and so on. Since IEEE 693 and the ASCE guide were under development during the same time period, the associated committees coordinated their efforts, such that the two documents would complement each other. Simply stated, IEEE 693 addresses the equipment and its "first" support structure (i.e., the primary above-ground support structure; the entire structure in the case of stand alone supports, or the portion supporting the equipment for structures carrying multiple pieces of equipment or conductor pull-off loads), while the ASCE guide addresses all other structures.

The seismic design of substation buildings is usually governed by one of several building codes, or a modified version of such a code that may have been adopted by the local jurisdiction.

13.5 Decision Process for Seismic Design Considerations

Once document familiarization is complete, the designer can follow the steps as outlined in Fig. 13.1, which was created with the assumption that each substation component will be reviewed independently.

As noted, IEEE 693 addresses the complete substation. It focuses upon equipment qualification and refers the user to appropriate documents for other aspects of the substation. However, it does address points unique to substations. The first step in the flowchart is to help the user identify the correct

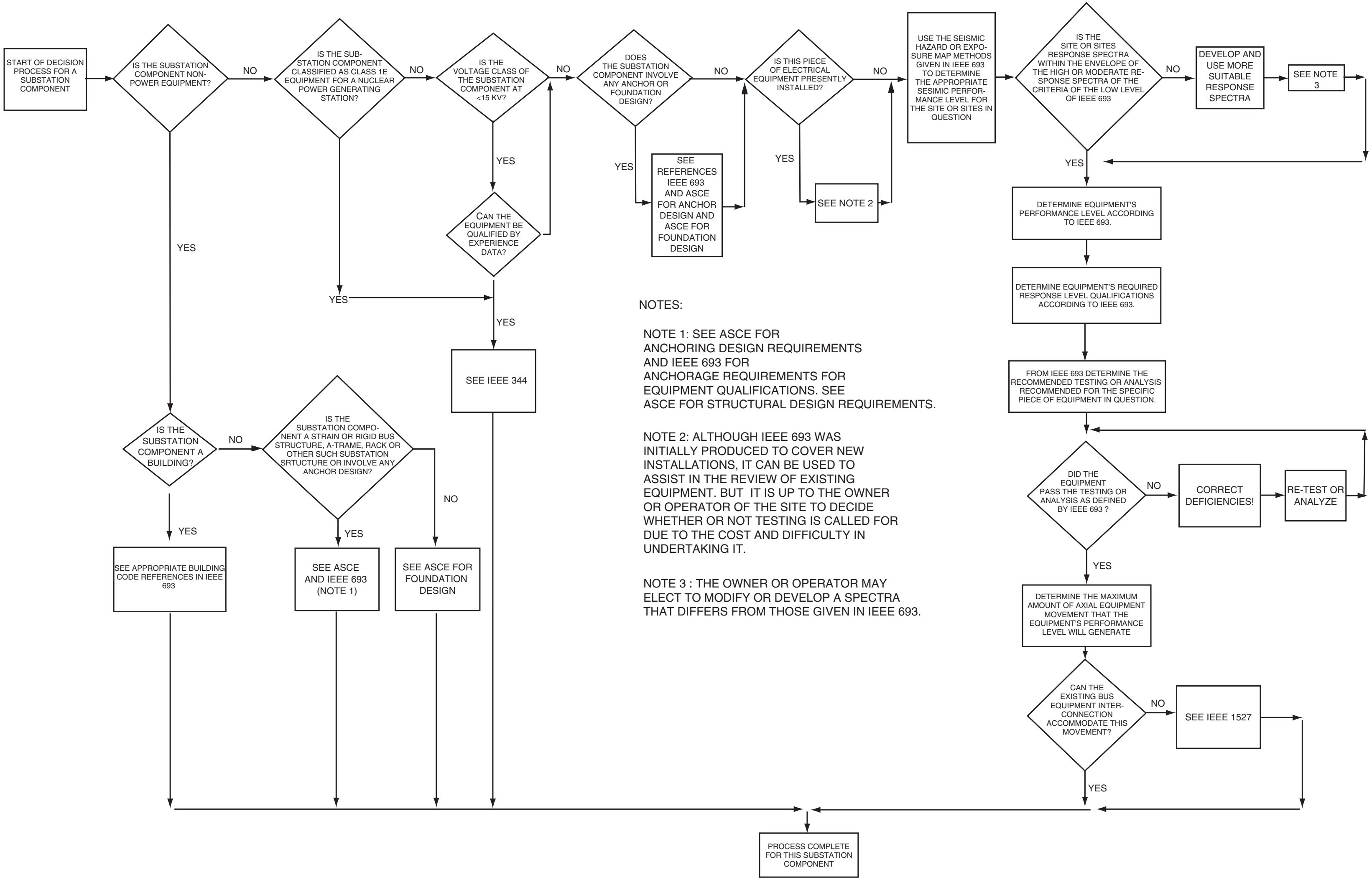


FIGURE 13.1 Decision process for seismic design considerations for substation components.

document for the component. This is simply done by using the decision of whether the component is equipment or some other component within the substation. For example, a component may be a bus support or a building.

If the substation component under consideration is a piece of power equipment, the next step in the power equipment decision process stream is to determine if this equipment is classified as Class 1E equipment for nuclear power generating stations. IEEE 693 does not apply to Class 1E equipment, but this information is available in IEEE 344 (2004) [4].

Most power equipment whose voltage class is less than 35,000 V is classified in IEEE 693 as "inherently acceptable," meaning that this equipment has performed well in earthquakes without additional requirements. Certain types of equipment can be qualified using the experience-based qualification method as per Annex Q of IEEE 693. If the equipment was qualified to a previous version of IEEE 693, the "grandfathering" provisions of the IEEE 693-2005 may apply. The grandfathering provisions require that the equipment manufacturers provide a justification reconciling the differences between the current version of the standard and the version to which the equipment was previously qualified. In certain instances, the grandfathering provisions do not apply. These instances are clearly indicated in the Annexes of the Standard, which discuss the detailed qualification requirements for the different types of equipment and components. In the 2005 version, only the shed seal test for composite polymer insulators is specifically excluded from the grandfathering clauses.

Power equipment that is not qualified through the inherently acceptable, experience-based, or grandfathering provisions of IEEE 693 must then be subjected to the detailed qualification requirements of the standard.

It should be noted that IEEE 693 was written primarily for new installations. It may be used to assist designers in the evaluation of the seismic acceptability for existing equipment. However, the user must understand that unless the existing equipment is fully qualified to all of the requirements of IEEE 693, the equipment cannot be identified as qualified to IEEE 693.

Anchor design issues should be addressed as per the ASCE document and IEEE 693, as indicated in IEEE 693.

Foundation design should be according to ASCE Substation Design Guide.

13.6 Seismic Qualification Levels and Performance Criteria

13.6.1 Qualification Levels

For power equipment, the appropriate level of seismic qualification must first be determined for the substation site at which the equipment will be installed. IEEE 693 provides three levels of qualification, termed high, moderate, and low, associated with different levels of ground shaking that are intended to satisfy the needs of most users. The primary reasons for establishing a small number of discrete qualification levels are simplification of the number of qualifications needed to be done by manufacturers and interchangeability of equipment. Regarding interchangeability of equipment, a utility may divide its service territory into large geographic areas based upon anticipated levels of shaking corresponding to the qualification levels of IEEE 693, and use a common seismic specification for all equipment to be installed in a given area. Such an approach benefits the utility by simplifying equipment procurement, and the stocking and deployment of spares. Equipment manufacturers also benefit, since fewer special configurations should be required to meet customers' needs.

Each of the three qualification levels is associated with a required response spectrum (RRS) or other description of ground shaking that defines the seismic loading environment. Equipment that meets the qualification requirements of a given level is expected to be undamaged and functional after being subjected to the shaking described by the corresponding RRS. Further, it is anticipated that the equipment will continue to function acceptably after ground shaking up to two times the RRS with little or no structural damage (see Section 13.6.3). This expectation is based upon the rather conservative acceptance criteria specified by the standard. These acceptance criteria follow allowable stress design

(ASD) or load resistance factor design (LRFD). In ASD, the internal stresses caused by the applied loads (in this case, earthquake forces) in the various structural load-carrying parts are measured or assessed, and compared with allowable stresses. Allowable stresses are usually defined as a percentage (typically 50–60%) of the yield strength, breaking strength, or load-carrying capacity of a material or element. Through this combination of conservative acceptance criteria and ground motion, IEEE 693 seeks to provide a degree of assurance that qualified equipment possesses a significant seismic safety margin beyond the loading levels of the required response spectra.

13.6.2 Selection of Qualification Level

The shape of the RRS is a broadband response spectrum that envelops the effects of earthquakes in different areas for site conditions ranging from soft soils to rock, as described in the Recommended Provisions for Seismic Regulations for New Buildings [5].

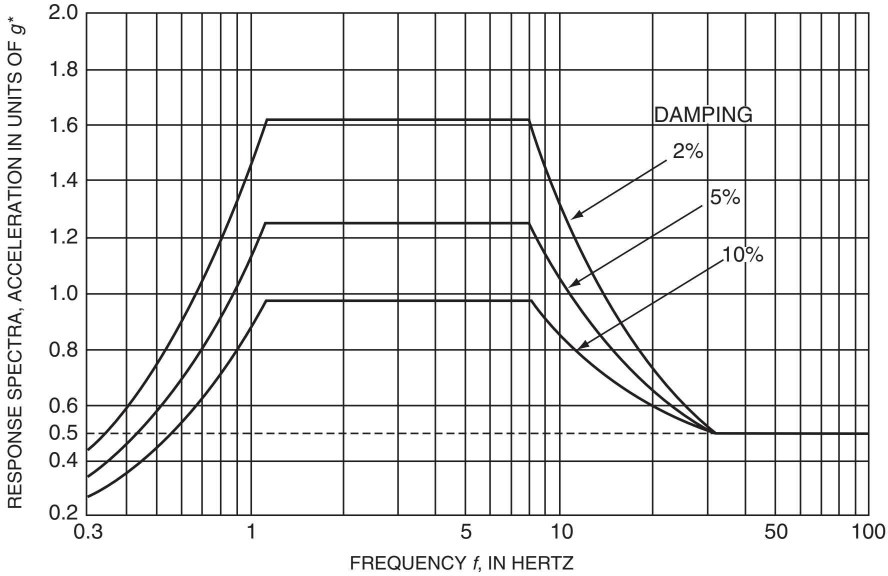
In particular, they provide longer period coverage for soft sites, but sites with very soft soils, sites located on moderate to steep slopes, or in the upper floors of buildings may not be adequately covered by these spectral shapes. In such cases, the user may develop a site-specific response spectrum for use in qualification activities. The site-specific spectra, however, must envelop the RRS given in IEEE 693 in order to conform to the Standard. Implementation of site-specific spectra may also require re-testing of previously qualified equipment, at additional costs. The high RRS is anchored to 0.5*g*, peak ground acceleration (pga), which is the acceleration at the high frequency end of the spectra. The moderate RRS has the same spectral shape, but is anchored to 0.25*g*, pga. Equipment that is qualified according to IEEE 693 using the high RRS is said to be seismically qualified to the high seismic level. Similarly, equipment that is qualified using the moderate RRS is said to be qualified to the moderate seismic level. The high required response spectra and moderate required response spectra are shown in Figs. 13.2 and 13.3, respectively, for different damping ratios.

Finally, equipment that has been qualified to the low level requirements of IEEE 693 is said to be qualified to the low seismic level. The low seismic qualification level is associated with a pga of 0.1*g* or less. Equipment that has no special seismic design features, but has been installed using good seismic installation and construction practices, automatically earns a qualification to the low seismic level. In general, it is expected that the majority of equipment will be qualified to the low seismic level.

The qualification level for a site may be determined by using either an earthquake hazard or seismic exposure map approach, as specified in IEEE 693. The earthquake hazard method consists of the following steps:

1. Establish the probabilistic earthquake hazard exposure of the site where the equipment will be placed. Use the site-specific pga and response spectra developed in a study of the site's seismic hazard, selected at a 2% probability of excedance in 50 years, modified for site soil conditions.
2. Compare the resulting site-specific pga value and response spectra with one of the three seismic levels—high, moderate, or low—that best accommodates the expected ground motions. If the pga is less than or equal to 0.1*g*, the site is classified as low. If the pga is greater than 0.1*g* but less than or equal to 0.5*g*, the site is classified as moderate. If the pga is greater than 0.5*g*, the site is classified as high. If the site-specific spectra exceed the RRS selected on the basis of pga, in the frequency range expected for the equipment, it may be necessary to select a higher level of qualification. This level then defines the seismic qualification level used for procurement.

The earthquake hazard method is the preferred approach and can be used at any site, but the seismic exposure map method may also be undertaken utilizing the International Building Code [6] ground motion maps in the U.S., the 1995 National Building Code of Canada (NBCC) maps for Canada, or the Manual de Disseno de Obras/de la Comision Federal de Electricidad (MDOC/CFE) maps for Mexico. Other countries should use equivalent country-specific maps.



THE ABOVE REQUIRED RESPONSE SPECTRA ARE DERIVED FROM THE FOLLOWING:

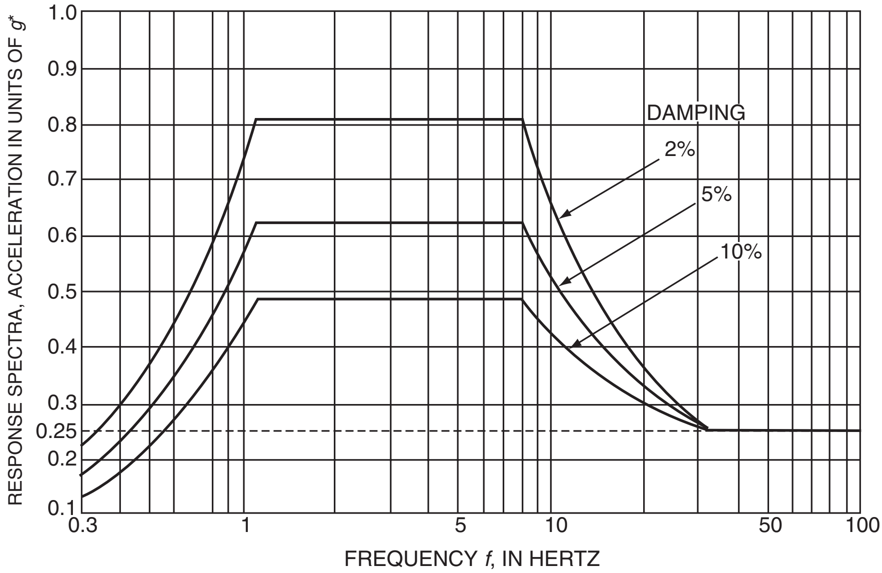
f is in Hertz
$\beta = [3.21 - 0.68 \ln(D)]/2.1156$
D = Percent of critical damping expressed as 1,2,5,10, etc.
0–1.1 Hz = $1.44\,\beta f$
1.1–8 Hz = $1.25\,\beta$
8–33 Hz = $(13.2\,\beta - 5.28)\,\frac{1}{f} - 0.4\,\beta + 0.66$
33 Hz and over = $0.5\,g$

FIGURE 13.2 High required response spectra (RRS). (From IEEE Std. 693–2005. Copyright 2005 IEEE. With permission.)

To select the appropriate seismic qualification level for a particular service area using the IBC ground motion maps, the steps outlined below should be followed:

1. Determine the soil classification of the site (A, B, C, D, E, or F) from Section 1615.1.1. Site class definitions.
2. Locate the site on the maps (Section 1615.1) for the Maximum Considered Earthquake Ground Motion 0.2-sec Spectral Response Acceleration (5% of critical damping).
3. Estimate the site 0.2-sec spectral acceleration, “Ss,” from this map.
4. Determine the value of the site “Fa” from Table 1615.1.2(1), as a function of site class and mapped spectral response acceleration at short periods (Ss).
5. Determine the pga, equal to (Fa Ss)/2.5.
6. Use the pga to select the seismic qualification level. If the pga is less than or equal to 0.1*g*, the low qualification level should be used. If the pga is greater than 0.1*g* but less than or equal to 0.5*g*, the moderate qualification level should be used. If the peak is greater than 0.5*g*, the high qualification level should be used.

Use of one of the three qualification levels given in IEEE 693 and the corresponding required response spectra is encouraged. Use of different utility-specific criteria will likely lead to higher cost and will not meet the intent of the standard with regard to uniformity.



THE ABOVE REQUIRED RESPONSE SPECTRA ARE DERIVED FROM THE FOLLOWING:

f is in Hertz

$\beta = [3.21 - 0.68 \ln(D)]/2.1156$

D = Percent of critical damping expressed as 1,2,5,10, etc.

0–1.1 Hz = $0.572\,\beta f$

1.1–8 Hz = $0.625\,\beta$

8–33 Hz = $(6.6\,\beta - 2.64)\frac{1}{f} - 0.2\,\beta + 0.33$

33 Hz and over = $0.25\,g$

FIGURE 13.3 Moderate required response spectra (RRS). (From IEEE Std. 693–2005. Copyright 2005 IEEE. With permission.)

Similar methods for establishing the seismic qualification levels from seismic zone maps used in Canada and Mexico are also given in IEEE 693, with appropriate country-specific references and maps as required. Other countries may use a method similar to those described in IEEE 693. Judgment and experience must be exercised when selecting the seismic level for qualification, as the site hazard may not fall directly on the high, moderate, or low seismic level. In this case, a strategy of accepting more or less risk will be required. It is recommended that large blocks of service areas be dedicated to a single qualification level to improve post event performance consistency, ease of interchangeability, and to help reduce costs through bulk purchases. For existing facilities requiring upgrade or repair design work, increased efficiencies may be realized. Additional operational requirements, substation network design, emergency response capabilities, equipment spares, and other factors deserve consideration when selecting equipment for an active inventory of an operating utility. The owner/operator may wish to evaluate all of the sites in the service territory and establish a master plan, designating the required (or desired, as the case may be) qualification level of each site and prioritizing those sites that need to be upgraded to meet current standards. Likewise, after a site for new electrical equipment has been identified, the owner or operator's agent should determine the appropriate seismic qualification level.

If the seismic response spectra for a specific site significantly exceed the response spectra depicted in Figs. 13.2 and 13.3, then a more appropriate response spectrum may be developed for use by the owner or operator at that specific site. Even in this case, the basic procedure laid out in the rest of the decision-making process of Fig. 1.1 of IEEE 693 can still be used. However, the high, moderate, and low levels specified in IEEE 693 should be used without deviation unless it is very clear that one of the qualification levels will not adequately represent the site or sites. Note that if the owner or operator elects to reduce, not meet, or remove any part of the IEEE 693 requirements, then the user cannot claim the equipment is in compliance with IEEE 693 and will lose the benefits of the standardization.

13.6.3 Performance Level and Projected Performance Level

The reader may have noted that during the selection process for the appropriate qualification level for an equipment at a particular location, sites having pga between 0.1*g* up to 0.5*g* required the use of the moderate level RRS (0.25*g* pga, see Fig. 13.3). In a similar manner, sites with a peak ground accelerations exceeding 0.5*g* required the use of the high level RRS (0.5*g* pga, see Fig. 13.2). This implies that equipment qualified to the high or moderate level RRS may be installed at sites subjected to, albeit infrequently, shaking levels higher than those used in its qualification. This is indeed the case, and the reasons for such an approach are discussed in this section.

As discussed earlier in this chapter, IEEE 693 specifies a conservative set of acceptance criteria coupled with the ground motion defined by the RRS to provide some assurance that a seismic safety margin beyond the qualification level is provided. IEEE 693 intends that equipment qualified to the requirements of the standard remains functional after an earthquake that imposes levels of shaking twice that actually tested. The level of shaking defined by twice the qualification level (RRS) is known as the performance level (PL). At the high seismic level, the RRS is anchored to a pga of 0.5*g*, and the high PL spectrum would be defined by the same spectral shape anchored to a pga equal to twice 0.5*g*, or 1*g*. That is, the entire 0.5*g* RRS is scaled by a factor of two to produce the PL spectrum. In a similar manner, the moderate PL spectrum is anchored to a pga of twice 0.25*g*, or 0.5*g*. The low seismic level is considered to be the same as the Low PL, and is set at 0.1*g* pga. Since substation site seismic hazards defining the high and moderate seismic levels are based upon earthquakes having a 2% probability of exceedance in 50 years or the maximum considered earthquake, it is clear that the earthquakes corresponding to the PL spectra are indeed very infrequent events. IEEE 693 permits seismic qualification to be demonstrated by testing to the PL, and due to the extreme nature of the load levels imposed on the equipment, the acceptance criteria for the PL are set at a level much closer to failure of the equipment. In the ideal case, it would be desirable to test every piece of equipment to the appropriate PL spectrum. It is, however, often neither practical nor cost effective to do so. Some of these considerations are as follows:

1. Test laboratory shake tables may not be able to attain the required acceleration levels, especially at low frequencies.
2. Testing at loading levels close to the theoretical fracture strength of brittle materials such as porcelain, may create safety hazards.
3. Permanent deformation of ductile elements in a test, which may be permissible under the PL acceptance criteria, would require a costly test article to be scrapped, resulting in a significant financial loss.

For these reasons, the primary means of qualification described in IEEE 693 are based upon testing or analysis using the qualification, or RRS levels rather than the PL. However, since testing to the appropriate PL is the most comprehensive and reliable means of demonstrating performance, IEEE 693 does not preclude nor discourage the testing of equipment to the PL.

When applying one of the qualification levels in IEEE 693, the equipment is tested or analyzed to a level of shaking that is only one-half of the PL. As discussed previously, such equipment is anticipated to perform acceptably at twice the qualification level due to the application of an ASD basis, or the LRFD method with appropriately factored loads as part of the qualification procedure. In the absence of tests performed at levels exceeding those at which the equipment was qualified, its performance at higher levels of shaking must be projected. If a reasonable understanding of the modes of failure of the equipment has been achieved, projecting the performance of the equipment beyond the qualification level may be justified.

It is cautioned that the validity of this approach is dependent upon identifying the most critically stressed locations within an individual piece of equipment, and then monitoring the stresses at these locations during testing or analysis. If the testing or analysis is not carried out in this manner, the critical locations within the equipment may fail prematurely—at levels below the performance level. In addition to these considerations, the response of the equipment to the dynamic load may change between the required response spectra level and the performance level. If such effects are not properly accounted for, premature failures may occur.

The discussion above pertains to the structural performance of the equipment. Qualification by analysis provides no assurance of electrical function. Shake-table testing provides assurance for only those electrical functions verified by electrical testing, and only to the levels applied in the test. Shake-table testing may be required for equipment that in previous years was qualified by dynamic analysis but performed poorly during past earthquakes. However, static or static-coefficient analysis may still be specified if past seismic performance of equipment qualified by such methods has consistently led to acceptable performance.

A rigorous seismic qualification, such as that required to meet the high and moderate performance levels, is not required for equipment qualified to the low performance level. That is, no RRS or seismic report is required. However, the following criteria should be met:

1. Anchorage for the low seismic performance level shall be capable of withstanding at least 0.2 times the equipment weight applied in one horizontal direction, combined with 0.16 times the weight applied in the vertical direction at the center of gravity of the equipment and support. The resultant load should be combined with the maximum normal operating load and dead load to develop the greatest stress on the anchorage. The anchorage should be designed using the requirements specified in IEEE 693 and the ASCE guide.
2. Equipment and its support structure should have a well-defined load path. The determination of the load path should be established so that it describes the transfer of loads generated by, or transmitted to, the equipment from the point of origin of the load to the anchorage of the supplied equipment. Among the forces that should be considered are seismic (simultaneous triaxial loading—two horizontal and one vertical), gravitational, and normal operating loads. The load path should not include the following:
   - Sacrificial collapse members
   - Materials or elements that will undergo non-elastic deformations, unrestrained translation, or rotational degrees of freedom
   - Solely friction-dependent restraint (control-energy-dissipating devices excepted)

13.7 Qualification Process

Once the qualification level has been established, the detailed qualification procedures required in the IEEE 693 document must be undertaken. Different methods of qualification are specified depending on the type of equipment being considered. Generally speaking, the most vulnerable equipment, which tend to be those in higher voltage classes (most massive, with the tallest insulators), are required to undergo the most stringent qualification procedures, often including shake-table testing. Other equipment or components may require analysis of different types (static, static coefficient, or dynamic), or perhaps, static pull-testing.

As an example, the steps needed to qualify a 138,000 Volts circuit breaker to meet the moderate seismic qualification level are outlined below. The following criteria, as specified in IEEE 693, must be successfully applied:

1. Seismic-withstand capability must be demonstrated by performing a dynamic analysis, and the analyzed equipment should include the control cabinet, stored energy sources, and the associated current transformer, assuming this equipment is on the same support structure.

2. Circuit breaker and the supporting structure must be designed so that there will be no damage during and following the seismic event.
3. Response spectrum shown in Fig. 13.3 should be used in the analysis.

The IEEE 693 document also provides guidance on the following for this piece of equipment:

a. General requirements for dynamic analysis
b. General and detailed qualification procedures required
c. Criteria for establishing when the qualification is considered acceptable
d. Equipment and support design
e. Report analysis checklist
f. Information on how to include base isolation and other damping systems in the analysis
g. Recommendations on seismic information that should be listed on the equipment identification plate

The IEEE 693 document also contains similar material for nearly all other substation components. Annex P, addressing Gas-Insulated Switchgear, has been added to the current version.

IEEE 693-2005 also incorporated a number of significant changes including the following:

- Revised input motion specifications for the development of time histories used for testing. Users wishing to develop their own input motions must comply with these new specifications. Also developed two sets (three components in each set) of pre-approved acceleration time histories that are available upon request to any user.
- Added provisions for applying load and resistance factor (strength) design approach in addition to ASD for steel elements.
- Added provisions for the use of static testing to supplement the qualification of parts and assemblies having complex geometries or other features not amenable to analysis or instrumentation (e.g., strain gauging) to establish their adequacy.
- Changed the manner in which the shed seal of composite polymer insulators is qualified. This change makes the shed seal test independent of a seismic shake table test, and provides better assurance of adequate performance under load.
- Revised general test requirements, and for various types of equipment. Required additional resonance search test and added discussion of various types of resonance search tests. Required addition of small lumped mass to partially account for effect of conductor during shake table tests. Added requirement for adjustment of clamping force to account for operating temperature, in center-clamped transformer bushings qualified by shake table test.

The list shown above is not all-inclusive. The reader should refer to the text of the standard for other revisions, and for additional discussion.

Because of the comprehensive set of requirements contained in IEEE 693, the information that users must provide in their tendering specifications is minimal. Therefore, it is strongly suggested that rather than copying information from the IEEE 693 document into the user's specifications, that the user refers to the document in its entirety by using the template in Annex U of the Standard. This eliminates the possibility of a misunderstanding between the owner and the manufacturer. If the document is not specified in its entirety, then the user and manufacturer should not claim that the equipment is in compliance with IEEE 693.

Based on the results of the testing and analysis undertaken in the qualification process, corrective measures, if necessary, should be carried out to bring the power equipment into compliance. The maximum displacement of the equipment, including terminal point displacements where conductors are attached, is also determined from these tests or from analysis. The final step of the decision process for the power equipment stream is to determine the flexible bus interconnection requirements for the piece of equipment. IEEE 693 provides guidance in determining the minimum length of flexible bus (i.e., displacement demand), while IEEE 1527 [7], will provide a more detailed design procedure.

The basic decision-making process for substation components that are classified as power equipment is now complete.

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14

Substation Fire Protection

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The risk of fire in substations has been historically low, but the possible impacts of a fire can be catastrophic. Fires in substations can severely impact the supply of power to customers, and the utility company's revenue and assets. These fires can also create fire hazards to utility personnel, emergency personnel, and the general public. The recognition of the fire hazards, the risks involved, and the appropriate fire protection mitigation measures are some of the key considerations for the design and operation of new or existing substations.

This chapter provides an overview to help substation designers to help to identify fire protection objectives, fire hazards within the substation, identify remedial measures, and to evaluate the value of incorporating these measures. It is only an overview and is not intended to be all-inclusive or to provide all the necessary details to carry out a project. For further details and information on this topic, it is recommended that the designer refers to IEEE 979 [1].

14.1 Fire Protection Objectives and Philosophies

Properly designed substation fire protection can mitigate the impacts of a fire on the station operational equipment and components that have failed during a fire and lessening the impact on the station's ability to supply the customer. Fire protection measures can also lessen the fire risks to operating personnel and emergency personnel during a fire at a substation facility.

14.1.1 Electrical Supply Reliability

Electrical supply customers are demanding higher levels of reliability for electrical services. This has caused some electrical power utilities to review their operational reliability. Also, a number of utilities had been required by their regulatory bodies to examine and justify their levels of operational reliability.

A number of utilities are setting goals of having operational reliability of 99.96% or greater. As a result of these high levels of operational reliability, the normal frequency of fires in breakers and transformers could have a significant impact on the utilities operational reliability. Secondarily, the provision of suitable fire protection could significantly lessen the station or equipment outage time, thereby helping the utility to meet its operational reliability objective.

From past experience, it has been difficult to quantify the impacts of fire related outages on the customers. Several research programs have quantified the societal impacts of substation outages. The societal impacts can be quantified in terms of the dollar value per megawatt lost for different mixes of customers (industrial, commercial, residential, and mixed). The societal impacts can range from $1 to $10 per kw/h depending on the customer mix and the outage duration. With the quantification of the societal loss, it becomes easier to estimate the benefits (shortened outage each time) from the provision of fire protection. For example, the fire protection will reduce the expected outage time from 24 h down to 2 h, and then a benefit is derived from the reduced societal impact.

14.1.2 Operational Safety

Fires in substations can indirectly and directly impact the public, emergency response services, and employees. The provision of fire protection and pre-fire planning can help to lessen the impacts of fires on these groups.

14.1.2.1 Public Impacts

There are a significant number of ways that substation fires can impact the public. The following is a list of some of the types of fire related mechanisms that can occur and can directly impact the public:

1. Shrapnel—bushing failures can result in shards or fragments of bushing ceramic being propelled for distances up to 250 ft or more. This shrapnel can be projected beyond the perimeter of the station and expose adjacent buildings and people.
2. Blast pressure—explosion in transformers can create blast pressures that could impact adjacent properties and structures.
3. Insulating oil pool fires as a result of the failure of oil-insulated equipment can cause thermal radiation impacts beyond the perimeter of the station and possibly ignited combustible vegetation and structures.
4. Oil pool fires can create very large fire plumes with flame heights over 33-m high. During periods of high winds, the fire flames and smoke plumes can be tilted significantly and expose adjacent buildings and structures. As a result, heat damage can occur to adjacent structures along with significant soot deposits in the down wind plumes area.
5. In substations without oil containment, burning oil spill fires had been known to spread beyond the station perimeter and impact adjacent buildings.

The above list is a small number of the possible impacts of the substation fire to adjacent public structures. Fire protection measures can be put in place to mitigate these impacts to the public.

A fire in a substation can also create significant indirect impacts on its customers. The following is a list of some of the indirect impacts of a fire in a substation:

- Loss of heating or cooling systems during inclement weather, which can cause significant health and safety concerns
- Loss of lighting and elevators in large high-rise buildings
- Loss of computer communication facilities in stores and businesses
- Loss of business revenue during outages
- Loss of wages during outage shutdown periods

14.1.2.2 Emergency Services

Fire department personnel responding to substation fires can be exposed to significant fire and electrical safety hazards that they may not be trained to deal with. The types of fire hazards found in indoor and outdoor substations are significantly different than the typical hazards to which public fire fighters are normally exposed. As such, they may be putting their own safety at risk.

The most significant hazards that fire department personnel are exposed to are the electrical safety hazards of the substation. Fire department personnel are trained to take an active role and aggressively suppress fires. In the case of a fire in an electrical substation, there may be long delays until utility operating people can arrive on-site and make the station electrically safe. In some cases, it may take up to an hour for electrical personnel to arrive on-site to make the station electrically safe. Therefore, the fire department personnel want to enter the facility and suppress the fire, before it is safe to do so. Also, delays of this type also create additional pressures on the responding fire departments, since they are concerned that while they are waiting to gain access to the substation, other alarms may be received, that they are not able to respond to. These tensions can create situations where responding personnel take serious risks of electrical contacts and exposures. Also, the type of equipment and facilities found in the substation is foreign to most of the buildings that the fire department operating personnel are exposed to. Therefore, it is very important to ensure that fire protection is installed in a substation to automatically control or suppress fires without the need for the fire department to obtain rapid access to the station.

14.1.2.3 Employees

Electrical-utility employees can be exposed to significant risks while trying to manually suppress fires in substation buildings and equipment. To ensure that the utility employees can safely fight major structural fires in the substation, they must

- receive ongoing thorough training;
- be supplied with adequate turnaround gear and self-contained breeding apparatus that must be inspected and tested on an ongoing basis;
- be tested and restricted to those with the proper fitness levels; and
- must be clean shaven at all times, otherwise, they cannot use self-contained breathing apparatus in smoke environments without the risk of being exposed to smoke.

The risks are significant when employees are used as fire fighters. Automatic fire protection measures should be considered, instead of the use of employees for manual fire fighting.

14.1.3 Revenue and Asset Preservation

One of the major objectives of all utilities is to generate revenue, or at least generate sufficient cash flow to cover their operating costs. Private sector utilities have strong objectives to generate profit. There are some substation fire related losses that can significantly affect the utilities ability to generate revenue and profit. A careful analysis of the substation equipment and operation can identify critical equipment that creates a significant fire hazard. Based on the possible revenue loss from a fire in a critical structure or piece of equipment, automatic fire protection systems may be justifiable.

Fires in electrical substations can have a very large impact on the station operating assets. A fire in a substation control building or control room can have a significant long-term impact on the ability of the station to operate. Therefore, assets such as substation control facilities are very critical and should be reviewed to determine the adequacy of the planned fire protection. Another example of significant substation assets is grouped transformers. There are very few fire protection related systems that can prevent a failure or fire in a transformer, but systems such as water spray deluge systems can suppress a fire in the transformer that has failed, and prevented from spreading to adjacent transformers.

All utilities operate in regulated political environments. A major substation fire and accompanying outage can create a number of political issues that can impact on the utilities revenue. The utility regulators can review the utilities operation and impose fines or directed actions to improve deficiencies. In government owned utilities, pressure can be imposed upon the operating personnel to change their practices and philosophies to address the risk of major outages. The utility shareholders can also apply pressure to the management of the utility to improve the outage reliability of the utility. Customers can cause changes to be made in the level of overall operational reliability through political, regulatory, or organizational channels. And, in special cases the customers can show their dissatisfaction with the utilities operational reliability by using another utility supplier.

14.1.4 Performance Objectives

In existing substations or planned substations, a number of fire protection objectives can be set out and incorporated in the station design in order to lessen or mitigate the impacts of a fire on the station operation, revenue, assets, and safety.

14.1.4.1 Specific Fire Protection Objectives

During the design stage of the station, the designer should determine the specific performance corporate objectives for the fire protection design of the station and the equipment. These performance objectives may range from compliance with regulatory requirements, to preserve assets and revenue, to lessen societal impacts and political concerns, to lessen the risk of a major fire, and to protect external public exposures.

14.1.4.1.1 Compliance

Some utilities operate in jurisdictions with mandated fire protection requirements for electrical substations. In these cases, the mandatory compliance with the appropriate codes and standards is a critical fire protection performance objective. The "Guide for Fire Protection in Substations JEAG 5002—2001" has been adopted in Japan, and is one such mandatory compliance code.

There are a number of other quasicompliance objectives that the utility may have to use for the design of a new substation or changes to an existing one. Specifically, recommended practices or guidelines in the industry set out "good engineering practice." Therefore, a utility can be exposed to some pressure to meet these practice standards or guidelines. If an incident occurred, and it was found that the utility did not comply with the general guidelines practices within the industry, there may be possible grounds for litigation. Also, the failure to be duly diligent may also create political or customer satisfaction related issues. IEEE 979, along with the NFPA and CIGRE substation fire protection documents, could form due diligence fire protection objectives.

14.1.4.1.2 Economic

It is a general objective of most utilities to preserve their assets and revenue. A utility can absorb fire related asset and revenue losses, mitigate these risks by installing fire protection, or transfer the risk by purchasing insurance. Depending on the frequency and consequences of electrical substation fires, the utility may not be able to accept the financial risk of the asset and revenue losses. The utility shareholders may also not be willing to accept the financial consequences of specific fire losses. The utility should then set criteria on the asset and revenue losses that they are willing to accept (i.e., $1,000,000 in asset losses per year and $5,000,000 in revenue losses). Each utility will have different tolerance levels for financial losses. The utility can also transfer part of the risk by purchasing insurance. In most cases, insurance companies will not accept all of the risk. Therefore, they set a deductible on all claims. The utility must be able to accept the deductible levels and the annual costs of the insurance coverage. The costs of insurance coverage can vary from year to year based on the conditions in the insurance market. The cost of business interruption insurance to protect against the loss of revenue is generally quite expensive. The other option that a utility has is to install fire protection to lessen the asset and revenue losses. As with all the other measures, there are capital costs and ongoing maintenance costs associated with fire protection measures. When the provision of fire protection measures is being considered, these measures can be evaluated to determine the level of financial benefit that may be achieved. These measures can be evaluated by an internal rate of return process, or a benefit cost ratio process. With both of these methods avoided lost costs of a fire are evaluated along with the cost of the proposed fire protection measure. These elements then form the basis for these calculations. As a financial objective, the utility could specify that the internal rate of return must be 15% or the benefit cost ratio must be 2 or greater. For the benefit cost ratio, this would mean that the benefit achieved by installing the fire protection must be twice the cost of installing and maintaining the fire protection. This type of calculation is shown in Section 14.3.5 and in chapter section titled "Economic Risk Analysis Example".

14.1.4.1.3 Risk

Utilities are starting to recognize that a risk strategy is important to maintaining their operations and controlling their asset losses. Risks are composed of two elements, the frequency or likelihood of the event and the consequences of the event. In the past, utilities have not directly set fire-risk objectives for their operations. There have been significant fire-risk strategies embedded in their insurance coverage and strategies. These have not been quantified directly into frequencies or consequences, normally. Risk practices are being adopted within the fire protection industry, based on the use of performance-based criteria from the petrochemical industry and nuclear industry. The new performance-based building codes are another area that is evolving in Europe and North America. These new codes and standards have embedded probabilistic criteria to evaluate acceptable levels for fire fatalities, or in the nuclear industry acceptable levels of reactor shutdown frequencies.

There are no commonly adopted criteria for acceptable fire risks within utility substations. There have been significant published data on the maximum tolerable risk criteria have been published in various countries could be easily adapted to form employee safety objectives. Specifically, the typical accepted ranges for individual maximum tolerable risk criteria range from 10^{-4} to 10^{-6} fatalities per year. The "Health and Safety Executive" in the United Kingdom has published individual risk criteria for workers and has recommended that the maximum tolerable risk per year for industry workers to be 10^{-3} fatalities/year.

Although the probabilistic methodology is one that could be adapted to substation design, more commonly the qualitative methodology is applied in a formal and informal process. The enclosed sample Risk Matrix (Fig. 14.3) is a typical qualitative analysis method where the consequences and the frequencies are selected for the specific work proposed. The intersection of the selection results in an overall risk ranking that aids in the prioritization of the proposed work.

14.1.4.1.4 Exposures

Exposures are risks that utilities should consider to protect substation operations or surrounding public or private buildings. Exposures are the facilities or structures that may be impacted by a fire situation in a substation. In some cases, exposures from outside the substation can have a severe impact on the operation of the substation. Wildland fires are an example of exposure fires that will impact or expose the substation to unacceptable consequences. As discussed in a previous section, substations can expose surrounding facilities by the following mechanisms:

a. Shrapnel—ceramic shrapnel from a transformer explosion may be propelled for distances up to 250 ft or more, and can result in injury or damage to surrounding facilities.
b. Blast pressure—the blast pressure from a transformer explosion can cause damage to the adjacent equipment or structures.
c. Oil spray—oil spray resulting from a transformer explosion can spray significant distances. If combustible structures are located within the substation or outside this station at short distances from the transformer, this oil spray could ignite those surfaces.
d. Transformer oil spill fires can spread within the substation or out of the station if suitable oil containment has not been installed. The resulting spill fire can impact other equipment or structures within the substation or structures outside of the station.

e. Transformer oil pool fires or spills can impact equipment within the station in the following scenarios:

   1. Radiation from a large pool of fire can ignite exposed combustible surfaces and can cause the failure of ceramic bushings on adjacent equipment.
   2. Large pool fire has a significant convective plume that can expose overhead bus structure to temperatures well above the yield temperatures for those steel structures, causing them to fail.
   3. When a large pool fire occurs within a substation, the fire can spread smoke over a significant area; and as the smoke rises and cools within the plume, soot can be deposited on adjacent buildings and structures. Also, the smoke from a substation fire can be introduced in two adjacent buildings through their fresh-air intakes that may require the evacuation of those buildings.

14.1.4.2 Specific Philosophies

14.1.4.2.1 Fire Prevention

Fire prevention is a philosophy of the selection of equipment materials and processes that will prevent or lower the risk of the fire. This philosophy is one that can have a high degree of effectiveness and reliability. The following are a number of typical fire prevention measures used in substations:

- Use SF_6 circuit breakers in place of oil-insulated breakers.
- Install lightning protection for the station.
- Use high flashpoint insulating oils for electrical equipment insulating in cooling fluids. Most fire prevention philosophies should be considered at the design stage for the substation or at the equipment selection stage.

14.1.4.2.2 Fire Protection

Fire protection philosophies are measures that are incorporated into the substation design to mitigate the hazards that are inherent in the substation design or equipment selection. The typical types of fire protection measures are discussed in greater detail in section 14.3. Fire protection systems are normally measures that can fail to perform as designed, and therefore, these failures must be taken into account.

14.1.4.2.3 Fire Suppression

If fire prevention and fire protection measures are not incorporated into the substation design or equipment selection, there is an expectation that the local fire department or fire brigade will have to suppress the fire manually. In remote stations, the utility may accept the risk of a total loss of the station due to the lack of a fire service response. Although the fire suppression philosophy may have a very low initial cost, it may result in significant losses of assets, revenue, and service to customers. The substation design should clearly document this type of philosophy because of the significant impacts that can be expected with a fire occurrence.

14.1.4.2.4 Fire Recovery

Another parallel philosophy to the fire suppression philosophy is to provide measures to recover the substation operation in the event of a catastrophic fire. Some examples are utilities that have temporary mobile substations and an inventory of breakers and transformers. There are components of a substation where a replacement or work-around philosophy will not work, such as large substation control buildings and control equipment. It can be applied to specific portions of the substation such as the provision of two transformers that are each capable of carrying the total of substation capacity. In the event of the loss of a single transformer, a substation is still operational. This philosophy can work for specific scenarios if a critical element analysis has been done and multiple critical elements are not a risk from a single event. Substation control building is a critical element where the fire recovery philosophy may not be practical.

FIGURE 14.1 Shows a transformer deluge system in operation during a fire.

Figure 14.1 shows the operation of a transformer deluge, protecting the transformer from an exposure fire. Figure 14.2 shows the aftermath of a transformer fire. The transformer was protected by a cycling water spray deluge system, a stone filled spill containment basin, and a masonry fire wall. A wood frame residential house is located in the background, approximately 10 m from the transformer. The fire protection was able to control and suppress the fire without the need for fire department's assistance.

The adjacent house was exposed to some burning oil spray from the tap changer failure. This minor fire was suppressed by the resident, using a garden hose.

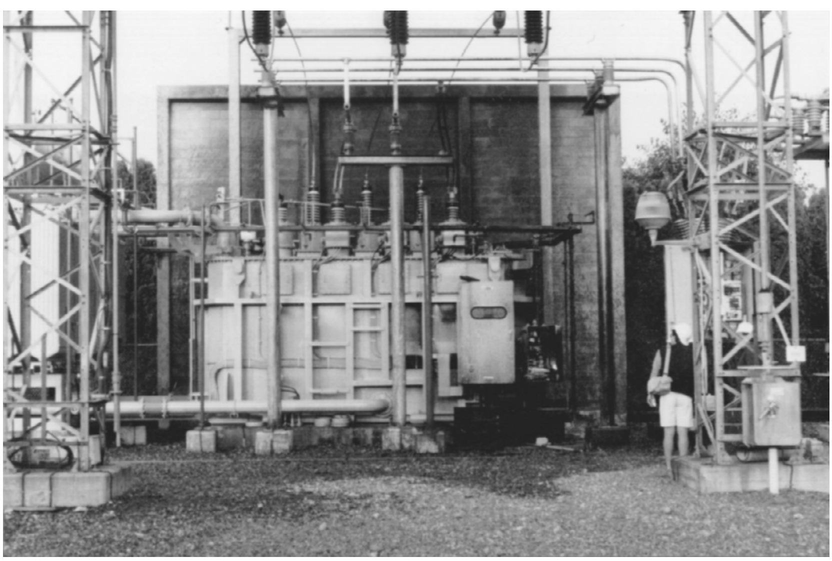

FIGURE 14.2 Shows the aftermath of a transformer fire where deluge water spray and a fire wall were in place.

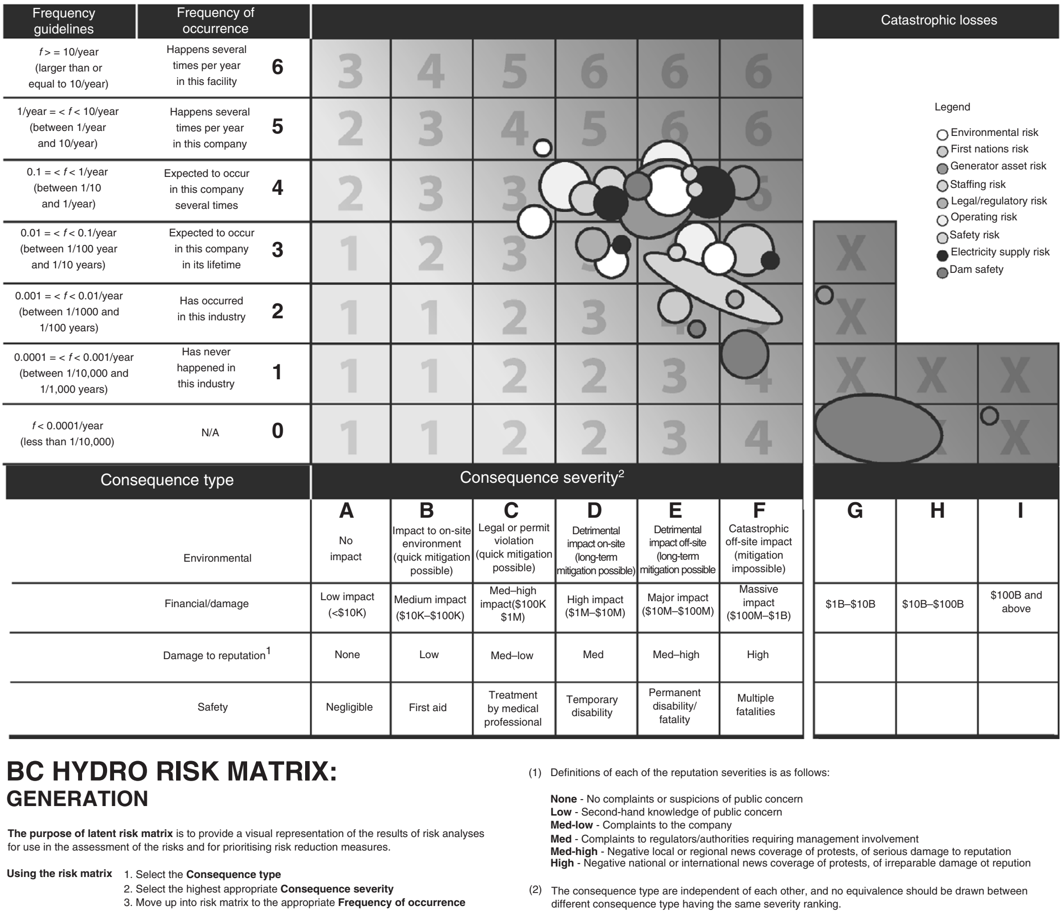

FIGURE 14.3 Typical risk matrix.

14.2 Fire Hazards

One of the key steps of the design of new substations and the assessment of existing substations is to identify conditions that are a fire hazard. When reviewing design concepts for a new substation or changes to an existing substation the ability to identify fire hazards allows design changes to eliminate, lessen, or mitigate the hazards. The assessment of existing substation operating conditions can allow fire hazards to be identified and eliminated, lessened, or mitigated.

There are a wide range of types and causes of fires experienced in substations. The types of fires are based on the equipment and systems used in the stations. Fires involving DC valves, outdoor or indoor oil-insulated equipment, oil-insulated cable, hydrogen-cooled synchronous condensers, or PCB-insulated equipment are usually well documented; therefore, these types of equipment are easily recognized as a fire hazard. There are a number of other substation specific types of fires that are not as well documented. IEEE 979, Factory Mutual Data Sheets, NFPA 851 Recommended Practice for Fire Protection for Current Converter Stations, and CIGRE TF 14.01.04 Report on Fire Aspects of HVDC Valves and Valve Halls give guidance on these types of fires. Also, the Edison Electric Institute's "Suggested Guidelines for Completing a Fire Hazards Analysis for Electric Utility Facilities (Existing or in Design) 1981" provides reference guidelines for the fire hazard analysis process.

Energized electrical cables with combustible insulation and jacketing can be a major hazard because they are a combination of fuel supply and ignition source. A cable failure can result in sufficient heat to

TABLE 14.1 Types and Origins of Fires Experienced by a Utility for the Period of 1971 to 1994

Types and Origins of Fires	Percentages (%)
Oil-insulated circuit breakers	14
Current transformers	14
Power transformers	9.3
Hot work procedures (welding, cutting, and grinding)	9.3
Potential transformers	7.8
Engine driven generators	7.0
Arson	6.3
Smoking	6.0
Lightning	4.7
Flammable liquid storage or handling	3.1
Terrorism	1.6
Miscellaneous fires	15.8

ignite the cable insulation that could continue to burn and produce high heat and large quantities of toxic smoke. Oil-insulated cables are an even greater hazard since the oil increases the fuel load and spill potential.

The hazard created by mineral oil-insulated equipment such as transformers, reactors, and circuit breakers is that the oil is a significant fuel supply that can be ignited by an electrical failure within the equipment. Infiltration of water, failure of core insulation, exterior fault currents, and tap changer failures are some of the causes of internal arcing within the mineral insulating oil that can result in fire. This arcing can produce breakdown gases such as acetylene and hydrogen. Depending on the type of failure and its severity, the gases can build up sufficient pressure to cause the external shell of the transformer tank or ceramic bushings to fail or rupture. Once the tank or bushing fails, there is a strong likelihood that a fire or explosion will occur. The possible explosion could create blast damage. The resulting oil spill fire could spread to form a large pool fire depending on the volume of oil, spill containment, slope of the surrounding area, and the type of the surrounding ground cover (i.e., gravel or soil). The oil spill fire can also create damage due to the thermal radiation to surrounding structures and convective heating to structures above the fire area.

Substations are exposed to the common industrial hazards such as flammable compressed gases use and storage, hot work, flammable liquid storage and handling, refuse storage, heating equipment, and dangerous goods storage. The local fire codes or NFPA codes can provide assistance in the recognition of common fire hazards.

A study was carried on the reported substation fires by a major utility for the period from 1971 to 1994. Data in Table 14.1 give an indication of the types of fires and the hazards experienced.

The miscellaneous fires category covers a wide range of fires from grass fires to a plastic wall clock failing and catching fire. It is impossible to predict all of the different types of fires that can occur.

14.2.1 Switchyard Hazards

Some of the specific components encountered in substation switchyards that are a fire hazard are

- oil-insulated transformers and breakers;
- oil-insulated potheads;
- hydrogen-cooled synchronous condensers;
- gasoline storage or dispensing facilities;
- vegetation;
- combustible service building;
- pesticide or dangerous goods storage;
- storage warehouses;
- stand-by diesel generator buildings.

The failure of some of the critical components such as transformers and breakers directly results in losses of revenue or assets. Other switchyard components could create a fire exposure hazard to critical operational components (i.e., combustible service buildings located close to bus support structures or transmission lines). Also, see the Switchyard Fire Protection Assessment Process checklist.

14.2.2 Control and Relay Building Hazards

Some of the specific components in a control or relay building:

- Use of exposed combustible construction
- Use of combustible finishes
- Presence of emergency generators, shops, office, and other noncritical facilities in the control buildings
- Batteries and charger systems
- Switchyard cable openings that have not been firestopped
- Adjacent oil-insulated transformers and breakers
- High-voltage equipment
- Dry transformers

Fires in any of the above components could result in damage or the destruction of critical operation control or protection equipment. Damages could result in a long duration outage to customers as well as significant revenue losses.

14.2.3 Indoor Station Hazards

Fires in indoor stations are caused by some of the same substation related hazards as switchyards and control rooms. The impacts of any fires involving oil-insulated equipment, oil-insulated cable, and HVDC valves in an indoor station can result in major fires with the accompanying large asset losses and service disruptions. The basic problem with major fires in indoor stations is that the building contains blast pressure, heat, and smoke, which result in the following damage:

- Oil-insulated equipment explosions could cause blast damage to the building structure (structural failure)
- Thermal damage to the building structure (structural failure)
- Smoke damage to other equipment (corrosion damage)

14.3 Typical Fire Protection Measures

The measures to mitigate or lessen fire hazards are normally called fire protection measures. The National Fire Protection Association standards and local building codes set the standards for application and design of fire protection. The type of measures can be broken down as follows:

a. Life safety
b. Passive fire protection
c. Active fire protection
d. Manual fire protection

The following is a brief description of the above measures.

14.3.1 Life Safety

Life safety measures generally include the fire protection measures required under the building, fire, or life safety codes. The main objective of these codes is to ensure that

- the occupants are able to leave the station without being subject to hazardous or untenable conditions (thermal exposure, carbon monoxide, carbon dioxide, soot, and other gases);
- fire fighters are safely able to effect a rescue and prevent the spread of fire; and
- building collapse does not endanger people (including firefighters) who are likely to be in or near the building.

To meet these objectives, fire safety systems provide the following performance elements:

- Detect a fire at its earliest stage.
- Signal the building occupants and the fire department of a fire.
- Provide adequate illumination to an exit.
- Provide illuminated exit signs.
- Provide fire-separated exits within reasonable travel distances from all areas of a building. These exits shall terminate at the exterior of the building.
- Provide fire separations between building floors and high hazard rooms to prevent the spread of fire.
- Provide passive protection to structural components to prevent their failure due to fire exposure.

14.3.2 Passive Measures

Passive measures are static measures that are designed to control the spread of fire and withstand the affects of fire. These measures are the most frequently used methods of protecting life and property in buildings from a fire. This protection confines a fire to a limited area or ensures that the structure remains sound for a designate period of fire exposure. Its popularity is based on the reliability of this type of protection, since it does not require human intervention or equipment operation. Common types of passive protection include fire stopping, fire separations, equipment spacing, use of noncombustible construction materials, use of low flame spread or smoke developed rated materials, substation grading, provision of crushed rock around oil filled equipment, etc.

The degree of passive protection for building structure would be based on the occupancy of the area and the required structural integrity. The structural integrity of a building is critical in order to preserve life and property. The premature structural failure of a building before the occupants can evacuate or the fire department can suppress the fire is a major concern. IEEE 979 includes recommendations on these measures relative to substation design.

14.3.3 Active Measures

Active fire protection measures are automatic fire protection measures that warn occupants of the existence of fire, and extinguish or control the fire. These measures are designed to automatically extinguish or control a fire at its earliest stage, without risking life or sacrificing property. The benefits of these systems have been universally identified and accepted by building and insurance authorities. Insurance companies have found significant reduction in losses when automatic suppression systems have been installed.

An automatic suppression system consists of an extinguishing agent supply, control valves, a delivery system, and fire detection and control equipment. The agent supply may be virtually unlimited (such as with a city water supply for a sprinkler system) or of limited quantity (such as with water tank supply for a sprinkler system). Typical examples of agent control valves are deluge valves, sprinkler valves, and Halon control valves. The agent delivery systems are a configuration of piping, nozzles, or generators that apply the agent in a suitable form and quantity to the hazard area (e.g., sprinkler piping and heads). Fire detection and control equipment may be either mechanical or electrical in operation. These systems may incorporate a fire detection means such as sprinkler heads or they use a separate fire and detection system as part of their operation. These detection systems detect a fire condition, signal its occurrence, and activate the system.

Active systems include wet, dry and pre-action sprinklers, deluge systems, foam systems, and gaseous systems. Detailed descriptions of each of these systems, code references and recommendations on application are covered in IEEE 979.

14.3.4 Manual Measures

Manual measures included items such as the various types of fire extinguishers, fire hydrants, hose stations, etc. requiring active participation by staff or the fire department to detect, control, and extinguish a fire.

Typical readily accessible portable fire equipment is provided for the extinguishment of incipient stage fires by building occupants. Since the majority of fires start small, it is an advantage to extinguish them during their incipient stage to ensure that potential losses are minimized. Detailed descriptions of each of these systems, code references and recommendations on application are covered in IEEE 979.

14.3.5 Fire Protection Selection Criteria

Fire protection measures can be subdivided into life safety and investment categories.

Life safety measures are considered to be mandatory by fire codes, building codes, or safety codes. As such the code mandates specific types of fire protection with very little flexibility in their selection. Investment related fire protection is provided to protect assets, conserve revenue, and help to maintain service to customers. This type of fire protection is not commonly mandated by legislation but is driven by economic reasons such as asset losses, revenue losses, and the possible loss of customers. Therefore, there is considerable flexibility in when the fire risks are mitigated, the fire protection measures used, whether the risk is offset by purchasing insurance, or whether the risk accepted as a cost of doing business (go on risk).

The selection of investment related fire protection can be done based on company policies and standards, insurance engineering recommendations, industry practices, specific codes and standards (IEEE 977 and NFPA 850), or by an economic risk analysis.

The economic risk analysis is the evaluation of the investment measures in relation to the probability of fire, the potential losses due to fire, and the cost of the fire protection measures. This analysis requires a reasonable database of the probability of fires for the different hazard areas or types, an assessment of the effectiveness of the proposed fire protection measures, an estimate of the fire loss costs, and a fair degree of engineering judgment. The potential losses usually include the equipment loss as well as an assessment of the lost revenue due to the outage resulting from the loss of equipment.

One of the most common economic risk analysis measures is a benefit/cost analysis. This analysis is calculated from the following equation:

$$\text{Benefit/cost ratio} = \frac{(\text{Annual frequency of fire} \times \text{fire loss costs (assets and revenue)})}{(\text{Cost of the fire protection} \times (1/\text{effectiveness of the fire protection measure})}$$

Normally, this ratio should be greater than 1 and preferably greater than 2. A benefit/cost ratio of 2 means that the avoided fire loss cost or benefit is twice the cost of the fire protection. Therefore, it is a good investment.

One of the greatest difficulties is to estimate the frequency of fire for the specific hazards. Some companies have extensive fire loss histories and loss databases. These databases can be used to estimate specific fire frequencies, but the results may be poor due to the small statistical sample size based on the companies' records. There are a number of other databases and reports that are in the public domain that provide useful data (i.e., NFPA data shop, EPRI Fire Induced Vulnerability Evaluation Methodology, and IEEE 979 Transformer Fire Survey). The IEEE 979 Transformer Fire Survey estimated probability of fire is given in Table 14.2.

TABLE 14.2 IEEE 979 Transformer Survey

Transformer Voltage (kV)	Annual Fire Frequency/Year
69	0.00034
115–180	0.00025
230–350	0.0006
500	0.0009

Once the potential financial loss due to a fire has been calculated, the designer should input costs and effectiveness of any proposed fire protection measure into the benefit/cost equation and determine the B/C ratio. If the B/C ratio is less than 1, the provision of the fire protection measure is not an acceptable investment.

14.4 Economic Risk Analysis Example

The following is a simplified example of an economic risk analysis:

- Substation has four 138 kV single-phase oil-insulated transformers. One of these transformers is a spare and is located remote from the others. The load supplied by these transformers is 25 MW. A water spray deluge system is being considered to suppress or control a fire in the transformers. The deluge system is expected to protect the adjacent transformers. The estimated cost of a deluge system for all three transformers is $60,000. The individual transformers have a replacement value of $300,000.
- Utility's Chief Financial Officer questions whether this is a good investment.
- Company uses a discount rate of 10% and requires that all investments have a benefit/cost ratio of greater than 2. The assigned value of energy is $25/MW. The standard amortization period is 25 years.
- Annual frequency of fire for a single 138 kV transformer is estimated as 0.00025/year. Therefore, the combined frequency for the three transformers is 0.00075 fires/year.
- Estimated effectiveness of the deluge system protecting the adjacent transformers is 0.9. The deluge system will not save the transformer in which the fire originates, it is assumed to be a total loss.
- Fire is assumed to originate in the center transformer in the bank of three single-phase transformers. It is assumed that in the absence of the suppression, the fire will spread to destroy the two adjacent transformers. The spare transformer is not affected because it is remote from the other transformers.
- Estimated station outage period for this scenario is the difference between the outage time to replace all three transformers (a fire in the center transformer could destroy all three transformers) and the outage time to replace the center transformer (assuming the deluge system will protect the adjacent transformers). The outage time to replace a single unit is 5 days and to replace three units is 40 days. Therefore, the expected outage loss period is 35 days.
- Expected lost revenue is 35 days $\times$ 24 h/day $\times$ 25 MW/h $\times$ \$25/MW = \$525,000.
- Estimated annual revenue and equipment loss costs = (composite annual fire frequency) $\times$ (revenue loss for the station outage period + replacement value of the adjacent transformers) = (0.00075 fires/year) $\times$ [\$525,000 + (2 $\times$ \$300,000)] = \$843.75/year.
- Net present value of the annual revenue and equipment losses for the 25-year amortization period at a discount rate of 10% = \$7659.
- Benefit/cost ratio = \$7659/(\$60,000 $\times$ (1.0/0.9)) = 0.115.
- Example conclusion.

The calculated Benefit/Cost ratio of 0.115 is considerably less than the minimum required ratio of 2. The proposal to install deluge protection should be rejected, since it is not economical. Other fire protection measures could be considered or the risk could be transferred by purchasing insurance to cover the possible loss of the assets (transformers) and the revenue. These other measures can also be analyzed using this economic risk analysis methodology.

It should be noted that the above example does not include societal costs, loss of reputation, and possible litigation.

14.5 Conclusion

The assessment of the hazards involved with an existing or planned substation and the selection of the most appropriate fire protection are the best ways to ensure that the power supply to customers, company revenue, and assets are protected from fire. Substation, switchyard and control building fire protection review checklists are enclosed in the appendix to aid in the assessment process. The IEEE "Guide for Substation Fire Protection #979" provides an excellent guide to the assessment process.

Appendix A Control Building Fire Protection Assessment Checklist

Risk Assessment

- Review the criticality of the control room and building fire loss to the substation operation and asset base.
- Review the historical frequency of fire in control buildings.

Life Safety Assessment

- Review the control room layout to ensure that the room has a minimum of two outward swinging exit doors.
- Ensure that the travel distance from any area within the control building to an exit does not exceed 100 ft.
- Ensure that exit signs are installed at each exit door.
- Review that emergency lighting is provided that will provide a minimum lighting level of 10 lux at the floor, along the exit paths.
- Review the size and number of stories of the building to ensure proper exits are provided to ensure that maximum travel distances to the exits do not exceed 100 ft.
- Determine if there are any building or fire code requirements for the installation of a fire detection system.

Fire Protection Assessment

- Review the availability of a fire department response to the site.
- Review the availability of fire fighting water supply at or adjacent to the site.
- Review the adequacy of any existing control building fire protection.
- Review criticality of control building equipment, hazards involved, and response time of station personnel and the fire department.
- Determine the type of detection that will provide an acceptable very early detection (air sampling detection) to detect a fire at a very early stage (small electronic component failure—arcing) or at an early stage with smoke detection (photoelectric detection) to detect a fire at a smoldering or small flame stage.
- Determine the type of fire-suppression system that will provide an acceptable equipment losses and outages (i.e., gaseous suppression systems to suppress a fire at an early stage [component loss], or sprinkler protection to suppress a fire at the stage where the loss would be restricted to a single control cabinet).

- Review the occupied hours of the building and ability of site personnel to safely extinguish a fire with portable fire equipment. Determine the levels of portable fire equipment required by the local fire code and that is suitable for safe staff operation.

Hazard Assessment

- Review the other uses (shops, offices, storage, etc.) within the control building and their exposure to the critical substation equipment.
- Review the use of combustible construction in the control building (i.e., exterior surfaces and roofs).
- Review the use of combustible interior surface finishes in the control room and ensure that the surface finishes have a flame spread rating of less than 25.
- Review the combustibility of any exposed cable used in the building to ensure that it meets the requirements of IEEE 383.
- Review the control room separation walls to other occupancies to ensure that the walls have a fire resistance rating of a minimum of 1 h.

Appendix B Switchyard Fire Protection Assessment Checklist

- Determine the initial electric equipment layout and equipment types

Risk Assessment

- Review the criticality of the various pieces of equipment
- Review types of insulating fluid used and their flammability
- Review the historical frequency of fire for the various types of equipment
- Review the availability of a fire department response to the site
- Review the availability of a fire fighting water supply at or adjacent to the site
- Review the adequacy of any existing substation fire protection

Radiant Exposure Assessment

- Review the spacing between individual single-phase transformers and breakers with IEEE 979 Table 1.
- Review the spacing between large three phase transformers, banks of single-phase transformers, or groups of breakers with IEEE 979 Table 1.
- Review the spacing of oil-filled equipment with respect to substation buildings with IEEE 979 Table 2. Note: the presence of combustible surfaces and unprotected windows on exposed surfaces of the buildings may require detailed thermal radiation calculations or the application of safety factors to the table distances. The Society of Fire Protection Engineers "Engineering Guide for Assessing Flame Radiation to External Targets from Pool Fires" can be used as a reference for detailed thermal radiation calculations.
- Review the distances between oil-filled equipment and the property line. Note: combustible vegetation and building structures beyond the property line of the substation may be exposed to high enough heat fluxes to ignite combustible surfaces. Detailed thermal radiation calculations should be considered.
- Review the use of the various methods of fire protection discussed in IEEE 979 that will address the hazard determined in the radiant exposure assessment such as changing the type of equipment and insulating fluid used, increased spacing, provision of gravel ground cover, oil containment, fire barriers, and automatic water deluge fire protection.

Fire Spread Assessment

- Is the surface around oil-filled equipment pervious (gravel) or impervious? Use of 12-in. thick gravel ground covers will suppress the flames from a burning oil spill fire. Impervious surfaces can allow the burning oil to form a large pool fire, which will increase the heat flux to adjacent equipment and structures.

- Is there any oil containment in place around the oil-filled equipment? Oil containment can contain pool fires and prevent their spread.
- Does the grade surrounding the oil-filled equipment slope toward the equipment or away from the oil-filled equipment toward adjacent oil-filled equipment, cable trenches, drainage facilities or buildings? The burning oil released from ruptured oil-filled equipment can spread for significant distances if the ground surrounding the equipment has a slope greater than 1%.
- Review the use of the various methods of fire protection discussed in IEEE 979 that will address the hazard determined in the fire spread assessment. These methods include the following:

— Changing the type of equipment and insulating fluid used
— Increasing the spacing, use of gravel ground cover
— Provision of oil containment
— Changing the grade surrounding the equipment
— Use of liquid tight noncombustible cable trench cover adjacent to oil-filled equipment
— Fire stopping of cable trenches entries into Control buildings
— Use of automatic water deluge fire protection

16

Physical Security of Substations

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16.1 Introduction

Electric substations exist in almost every neighborhood and in every city. They are adjacent to or within the town proper of every small town. They exist in isolated, remote, and rural areas. More often than not, they exist next to every major commercial or industrial facility in the country. They range in size from fused cutouts that separate a couple of feeders to huge substations covering tens of acres. They exist at voltages up to 765 kV AC and +/−500 kV DC.

They are also essential to our everyday life. As the nerve centers of our electricity supply system, substations are essential components of its reliable operation—hence the need to protect them from all types of threats; internal and external, cyber and physical.

But how do you protect the thousands of substations spread out around the country? Who is a threat? What needs to be protected? How do you protect it? How much does it cost? Who is responsible?

A threat can be either man made or natural. Events such as September 11, 2001, the Northeast Blackout of 2003, and hurricane Katrina have raised the bar for security and reliability. In addition, now that terrorism is a part of the energy lexicon, the federal government has established organizations to audit the electric power industry. Not only are they collecting information about the loss of power, but they have also mandated the reporting of these events in real-time to allow the detection of a coordinated attack on the system.

As a result, the protection of the electric system now requires that an owner/operator use a systematic, comprehensive approach to the development and design of a physical substation security system.

The intent of this chapter is to help shed light on this complicated topic and to answer the most pressing questions with regard to the physical security of substations. Its intent is not to answer all questions and provide definitive answers, but to be a primer for the development and implementation of a physical security program.

A security program can be designed and implemented using a systematic approach. This chapter discusses the basic elements of such an approach which will determine the type of physical security most appropriate for a particular electric system. This includes the following critical steps:

1. Threat assessment
2. System analysis (which includes):
   a. Criticality assessment
   b. Vulnerability assessment
   c. Risk assessment
3. Risk management
4. Implementation

It is important to note that this chapter only discusses physical substation security, specifically security measures to prevent human intrusion. The chapter does not discuss security programs and methods for power plants or the physical security methods for substations attached to nuclear power plants since the substation security methods for these stations are generally included in the plant's security program. Cyber network security, the prevention of intrusion into a substation using electronic methods (hacking), will only be discussed in so far as it relates to assuring electronic equipment in a substation is secure from intrusion once other physical security systems have been breached.

16.1.1 Definitions

This chapter uses several key terms with specific definitions. The table below outlines these key definitions:

Term	Definition
Asset	Any substation or substation component
Critical asset	Substation or substation components, which, if damaged, destroyed, or rendered unavailable would affect the performance of business, the reliability or the operability of the electric supply system
ESISAC	Electric Sector Information Sharing and Analysis Center, the organization responsible for communicating with other security organizations and the government about threat indications, vulnerabilities, and protective strategies
Intruder	Any individual or organization performing unauthorized activity within a substation
Intrusion	Unauthorized entry into a substation. Intrusion can be a person or organization, a vehicle, a projectile, or it can be electronic (hacking)
NERC	North American Electric Reliability Council, the organization whose principal mission is to set standards for the reliable operation and planning of the bulk electric system
Owner/operator	Anyone, or entity, that has the responsibility for the security and safety of an electric supply substation
Risk	The probability that a particular threat will exploit a particular vulnerability of a substation
Risk management	Decisions to accept exposure or to reduce vulnerabilities by either mitigating the risks or applying cost-effective controls
Substation	Meant to be all inclusive for this chapter. The term substation includes all stations classified as switching, collector bus, transmission, and distribution substations
Terrorist attack	A specific type of threat that involves the use of violence and force, if necessary, to deliberately cause the destruction or functional loss of a substation
Threat	Any event or circumstance with the potential to damage or destroy a substation or a component of a substation
Vulnerability	The degree to which a component of a substation is open to a threat

16.2 Electric System Today

In order to put the need for physical security into its proper context, we must understand the size and importance of the electric system to our current way of life.

16.2.1 Size

In 2002, the electric system represented 5% of the gross domestic product.[1] The total installed capacity at that time was 813 GW with 10,400 generating substations, approximately 300,000 transmission level substations and 3,836 billion kilowatts of connected load.[2] According to U.S. Energy Information Administration (EIA) the electric system today is growing at a very rapid rate. The EIA is predicting the demand on the electric system will grow another 30% in the next 10 years.[2] Preliminary estimates indicate that utilities have increased, or are intending to increase, their investment in the system by U.S. $28 billion, or 60% over the amount invested in the last five years.[3]

16.2.2 As an Essential Service

The system size and growth rate are directly tied to its need within our society. Every facet of our life and our economy is dependent on the presence of electricity. It is the key essential service. See Figure 16.1. According to Paul Gilbert, the Director Emeritus of Parson's Brinckerhoff, Inc. in testimony before Congress for a hearing on the "Implications of Power Blackouts on America's Cyber Networks and Critical Infrastructure," outlined the importance of this system: "Our way of life is dependant on a highly utilized set of infrastructure components that provide our communities and way of life with vitally needed services and support. Only the electric supply system has the unique ability to seriously impact, or cause the complete loss of all of the others."[4]

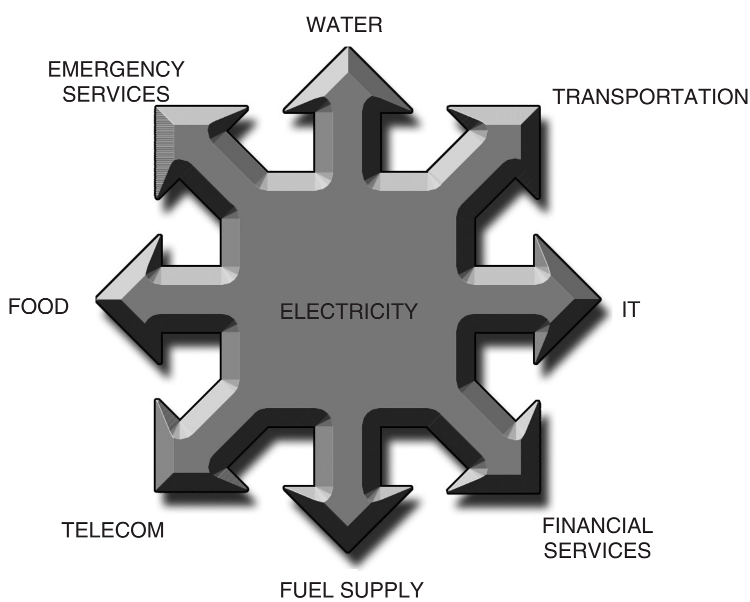

FIGURE 16.1 Electricity is the key essential service within our society. (From Gent, M., 2003, Reflections on Security, *IEEE Power and Energy.*)

[1]IEEE-USA, Position Paper on Electric Power Reliability Organization. November 13, 2002; www.ieee.usa.org

[2]National Research Council. 2002. *Making the Nation Safer: The Role of Science and Technology in Countering Terrorism*, Washington, DC: National Academies Press, p. 180.

[3]*IEEE Power and Energy, IEEE Power & Energy*, Vl 3, No 5.

[4]Congress, National Academies of Engineering. 2003. 108th Cong., 2nd sess. Gilbert, P., Testimony at Joint Hearing on Implications of Power Blackouts on America's Cyber Networks and Critical Infrastructure; www.nae.edu

System Type	Unavailability Minutes/Year	Availability (%)	Availability Class
Unmanaged	50,000	90	1
Managed	5,000	99	2
Well managed	500	99.9	3
Fault tolerant	50	99.99	4
Highly available	0	99.999	5
Very highly available	0.5	99.9999	6
Ultra highly available	0.05	99.99999	7

FIGURE 16.2 Availability standards require a high degree of availability. Even managed systems need to be operating 99 percent of the time. (From Gellings, Clark; Samotyj Marek; Howe, Bill. "The Future's Smart Delivery System." *IEEE Power and Energy Magazine.* p. 41.)

As the *key* essential service, our electric system comes with a daunting requirement: it must never fail. One measure of the increased need for system reliability is availability. Over the past decade, the total time the system is allowed to be unavailable per year has dropped from hours to fractions of a minute. *IEEE Power and Energy* published availability standards in its September 2005 issue (see Fig. 16.2), which demonstrate the high degree of availability required, even for "managed" system types (99% available).

16.2.3 Structure

The overall structure of the electric utility system has changed dramatically in the past 50 years. The electric system today has evolved away from the post–World War II, vertically organized system of public and privately owned utilities. At that time, these companies owned their own generation, transmission, and distribution systems. Today, the general trend is for the electric system to be horizontally organized into separate generation, transmission, and distribution companies. It is comprised of owner/operators that consist of public and private entities, independent power producers, and industrial companies. To allow equal access to the electric system for all, independent system operators (ISO) have been formed to schedule and manage power flows across the system.

With the Energy Policy Act of 2005, Congress has now mandated "the development of a new mandatory system of reliability standards and compliance that would be backstopped in the United States by the Federal Energy Regulatory Commission (FERC). On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005, which authorizes the creation of an electric reliability organization (ERO) with the statutory authority to enforce compliance with reliability standards among all market participants."[5]

16.2.4 Need for Security

Many believe that the size of the system, the rate of growth, the lack of investment in recent years, the demand on reliability, and the changes in business structure make the system more vulnerable to failure than in the past. These vulnerabilities coupled with the electric system's role as the key essential service mean our way of life cannot tolerate the loss of the system due to natural disasters, human-made disasters, or terrorist attacks. Hence, the need for protection of these facilities is more important now than ever.

16.2.4.1 IEEE Standard 1402–2000, IEEE Guide for Electric Power Substation Physical and Electronic Security

In the mid-1990s, a group of utility engineers and private consultants worked together to develop a physical security standard for electric supply substations. The result was IEEE Standard 1402–2000,

[5]NERC Web site, introductory comments about NERC.

IEEE Guide for Electric Power Substation Physical and Electronic Security. This standard was completed prior to the events of September 11, 2001. The term "intrusion" was coined at that time to define any unauthorized entry into a substation whether it was by a person, a vehicle, a projectile or electronic means (hacking). The focus was on the most prevalent problems all owner/operators were facing at the time. The guide looked at ways intrusion could occur, the stages of property ownership and use, and geographical, economic, social, and industrial conditions that could influence when an intrusion would occur.

The group conducted a nationwide survey to collect data on the effectiveness of the most common security systems in use at the time. The balance of the guide discussed the various security methods available, and weighed their associated advantages and disadvantages. A final section was added that outlined the structure of a security program.

Since IEEE Standard 1402 was last published, national events have brought security and reliability to the forefront. The protection of the electric system now requires that the owner/operator use a systematic, comprehensive approach to the development and design of their physical substation security system. These changes will likely result in significant revisions to IEEE Standard 1402 in coming years.

16.3 Threat Assessment

The first step in a comprehensive security plan is the threat assessment. The threat assessment identifies the outside elements that can cause harm to a substation or its component equipment. A threat is any event, circumstance, or sequence of steps that leads to substation property being stolen, damaged, or destroyed. A threat can be a single act such as a gunshot at the equipment located in a substation or it can be a series of acts such as an intruder cutting or climbing a fence to enter a substation, crossing the yard, breaking into the control building and then operating circuit breakers. In both cases listed above, the motives of the person or group that creates a threat to the system may be different. A gunshot can be an act of frustration during hunting season or it can be a deliberate attempt to damage or destroy the substation or its equipment.

Regardless of intent, an owner/operator must choose the appropriate physical security methods to protect the substation from as many threats as possible. For the purposes of the threat assessment, the owner/operator must be able to identify potential threats and potential vulnerabilities.

Intruders create potential threats. Intrusion is the unauthorized entry onto the substation property or into the fenced area of the substation. An intruder then can be a person or a group, or it can be an object such as a bullet or a rock. If a person or object is not authorized to be there, then he, she, or it is defined as an intruder. The owner/operator must be able to identify the persons or groups that pose the threat and the circumstances or conditions that may allow them to gain unauthorized access. But the selection of individuals or groups with the potential to cause harm is not a random process based on speculation. It must be a methodical investigation of the potential intruders active in the area and the type of activities they are likely to perform.

16.3.1 Presence, Capability, and Intent

Any individual or group to be watched should meet each of these three criteria.

They should have:

- Presence—Although nationally or internationally active, has the group or individual exhibited local activity?
- Capability—Does the group or individual have the ability to attack the substation?
- Intent—Does the group or individual have the interest, desire, i.e., the intent to attack or harm the substation in any way?

Be aware of the activities of those groups specifically identified to be operating in your area. Look for and be vigilant for signs of activity and take extra precautions, if warranted. This can include general threats to the electric industry, its customers, or special interest groups, which have been threatened. Look for warning signs that activity might be imminent. This can include people seen at sites with no apparent reason for being there, missing documents or credentials, etc., which would be necessary to gain knowledge or access to critical sites and components. In 2003, Department of Homeland Security and the Federal Bureau of Investigation issued a memorandum on suspicious activity.

It is important to make the distinction between perceived and actual threats to your system. For example, the International Council on Large Electric Systems (CIGRE) conducted a survey in 2004 that assessed the perceived threats to electric power substations. Thirty-five percent of the respondents believed terrorism was the largest threat, followed by theft and vandalism (both around 20%). However, actual historical information reported by the survey respondents in the same report was in sharp contrast to these perceived threats. This information showed the highest percentage of intruder events involved theft (32%). Terrorism was not on the list.

A comprehensive threat assessment must include a review of historical data, i.e., the threats faced as well as the potential threats. The physical methods to be used must take both into consideration. But, when looking at the potential threats, it is vitally important to apply the test of presence, capability, and intent in order to assure that the physical security methods chosen are focused on the probability of a threat to your substations rather than speculative possibilities based on national/international events. For instance, the focus today is on international terrorist groups. But national terrorist organizations such as the Environmental Liberation Front (ELF) may pose a more immediate and larger threat. In another instance, if a terrorist organization is active and making threats against the federal government, what is the probability that this organization will become a threat in a particular area to an owner/operator of an electric supply system?

16.3.2 Intruders

For the purpose of this chapter, all potential threats to a substation involve intrusion. They are initiated by outside sources or influences. To reiterate, intrusion is defined as the unauthorized access to a substation property. The gunshot in the example above is an intrusion even though no one entered the yard. The second example is more easily understood as an intrusion because it involves the act of someone entering the substation. However, in both cases the acts are equal under the definition of intrusion. Intrusion can be accidental, deliberate but nonspecific (vandalism), or deliberate with a premeditated purpose (malicious destruction or a terrorist act). Intruders can be classified as follows:

- General public
- Thieves
- Vandals
- Disgruntled employees
- Terrorists

16.3.2.1 General Public

The general public is the group that most frequently comes into contact with these facilities. On a daily basis we drive by and/or work next to some portion of the transmission system. In the event that we come into contact with substations, it is generally by accident. Unplanned, "accidental" intrusion is the category of least concern. The threat to the system is minimal. The risk to the intruder is the largest concern.

16.3.2.2 Thieves

Theft is driven by economic conditions. Theft will rise and fall with the cost of copper, aluminum, and other common metals. In one incident, a utility used concertina (razor) wire on the substation fence to prevent intrusion only to have a thief steal the wire instead. Thieves will enter a site for its copper ground wire, copper control and power cable, or any aluminum material stored on site. Thieves will break into a control building in hopes of finding tools, components, or hardware that may be of value. Attempts to track down thieves and recover stolen material have had mixed results. In most cases the materials can be found but it is very difficult to prove who the original owner is. Without proof of ownership you cannot prove it was stolen.

Preventing theft is the most common reason for many of the physical security methods discussed later in this chapter and the most difficult to prevent. Thieves can be of any age and of any economic background. Although their purpose is premeditated, their choice of targets is random and unpredictable. Any substation which is deemed to have the requisite metals or materials will be of interest to the thief.

16.3.2.3 Vandals

Individuals, couples, groups of teenagers, vagrants, drug dealers, and urban gangs all have been known to use a substation property as a gathering place to have parties, to reside, or to conduct unlawful activities. The damage these groups do to a substation may or may not be deliberate and malicious, but these actions generally are considered random. They have not targeted the system or the substation for a political or social purpose and, therefore, their actions can be classified as acts of vandalism. Some actions practiced by these groups that can lead to a forced outage of the equipment include the discharging of firearms which could in turn damage circuit breaker and transformer bushings, the throwing of chains over an energized bus, and the damaging of control panels in control buildings.

Communities want substations to be invisible. Today's communities view substations as detractors to the value of their property. The owner/operator will try to make them more acceptable by planting trees and shrubbery around them to give them an esthetic, environmentally pleasing appearance. But hiding the substation can increase the probability of vandalism by making the grounds more attractive as a meeting place where their actions can be hidden from the public eye.

In many cases, especially in urban locations, the property can be part of a gang's territory. To indicate this they will mark their territory with the type of graffiti called "tagging." By tagging the property, they have warned rival gangs of their claim to the property, which can lead to "turf wars" between these gangs on the property which, again, increases the threat of destruction to the property.

16.3.2.4 Disgruntled Employees

There are numerous instances on record of disgruntled employees causing damage within a substation as the result of a grievance with the owner/operator. They pose a higher threat than the previous three because they represent an internal threat to the system. Their acts are not only deliberate; they possess specialized knowledge that can be used to increase the impact to the owner/operator and to the community.

There are many cases of disgruntled employees opening the oil valves on transformers. There is a case on record of a disgruntled employee attaching an improvised explosive device (IED) to a piece of electrical equipment. One disgruntled employee during the 2002 Winter Olympics went into the substation control building and opened several specific breakers, which caused an area power outage of one hour affecting 33,000 residential customers.[6]

Disgruntled employees usually work alone. They prefer to remain anonymous. Their anger is focused solely at their employer. Their acts are not intended to cause regional or national outages.

16.3.2.5 Terrorists

Terrorism is defined in the U.S. by the Code of Federal Regulations as: "...the unlawful use of force and violence against persons or property to intimidate or coerce a government, the civilian population, or any segment thereof, in furtherance of political or social objectives." (28 C.F.R. Section 0.85).

There is no generally accepted definition or classification in use today for terrorist groups. They can be classified as either domestic or internationally based. They can be grouped into such general categories

[6]The Salt Lake Tribune, Friday, September 20, 2002.

as social or political groups, environmental and religious extremists, rogue states or state-sponsored groups, and nationalist groups. They can act for social, ideological, religious, or apocalyptic reasons. In today's world, rather than being structured groups like those of the 1960s and 1970s, they now can be *ad hoc* groups that coalesce, come together for an attack, and then disband and disperse. In today's world they practice a form of leaderless resistance. That is, the specific tactics are left up to the individuals so that compromise of a part does not compromise the whole.[7]

Regardless of the method used to classify them, terrorists differ from all of the other groups discussed in several ways. They are determined. Their intent is to interfere with some process or the completion of some project. Their actions are planned and carefully organized; their intent is to bring public attention to their cause. They wish to create chaos, panic, and terror within the community or to create a diversion as a cover for some other primary but unrelated target. They can be well funded; they can have access to weapons and intelligence.

16.3.2.6 Resources

Aside from an owner/operator's own historical database of incidents, there are numerous other resources available to assist with gathering information about potential intruders that may be active in a particular area. The most critical step is for an owner/operator to establish a relationship with local and state police agencies to get a sense of the threat conditions in their area. In addition to these, other essential sources include the FBI's InfraGard program, the U.S. Bureau of Alcohol, Tobacco, and Firearms (ATF), U.S. Marshals, and state and local law enforcement organizations.

Online Internet sources include the National Memorial Institute for the Prevention of Terrorism (www.mipt.org), the Antidefamation League (www.adl.org), and LexisNexis (www.lexisnexis.com). In addition, there are numerous private security consulting companies that can be retained to assist.

16.4 System Analysis

The second step in a comprehensive security program is to determine in what way the system may be affected by the threats identified above. System research includes determining the criticality of the assets an owner/operator owns (stations and components) and the vulnerabilities they possess. Once these two are known, then the risk to loss of these assets can be quantified.

A comprehensive system analysis must take into account two important ideas: a substation's "criticality" and a substation's "vulnerability." There is a distinct difference between the criticality of a substation or its components and the vulnerability of the same substation or its components. Criticality is a measure of the importance of the substation or equipment to the performance of the system. A substation or substation's components are critical if their loss affects system reliability, system operations, or represent an unacceptable loss to the owner/operator. The more unacceptable a loss is and the more impact it has on the electric system, the more critical the asset becomes.

Vulnerability, on the other hand, identifies individual weaknesses or ways in which the substation or its components can be compromised. All substations have some form of vulnerability. These two terms are explored further below.

16.4.1 Criticality Assessment

All substations require some level of physical security but not all substations are critical or have critical assets. Factors that would raise or lower the criticality of a substation would include its importance to generation, switching or load, its voltage levels, the type of bus arrangement, overall age, whether it is enclosed in a building or outdoors, above or below ground, or the effect the loss of the station would

[7]NA, Field Manual Section 1: Principles Justifying the Arming and Organizing of a Militia, 1994, Wisconsin, The Free Militia, p. 78 IA/NE Conference 10/04/05 David Cid.

have on public image. Criticality would be assigned an increasing value as the effect of its loss moves from local, to regional, to the overall system. Its value would also be increased in relation to the cost of replacement power while the station is out of service or the clean up costs if a spill occurs and the impact to public perception. The criticality of individual components would be raised or lowered based on replacement costs, delivery time, location of manufacturing (domestic or foreign), type of communications and EMS equipment it uses, or if it has highly specialized technology, such as a high voltage, solid state, electronically controlled device, e.g., a static VAR compensator (SVC) or DC/AC inverter.

For the owner/operator, a critical asset can be a substation with only local importance. However, at the federal level, ESISAC would classify a critical asset as only those assets that would affect the reliability or operability of the bulk electric system. Each owner/operator must decide what constitutes a critical asset for themselves. But, in general, the criticality of a substation or its components can be determined by the following conditions:

- *Unable to provide service to customers.* Does the substation serve critical or sensitive loads such as emergency or other essential services, military installations or major industries that have been the target of threats themselves? Does critical load served by this substation have alternate sources of power available during emergencies? What is the maximum length of time required to restore or replace damaged critical equipment in this substation? Is this length of time acceptable? Can the system or its critical and sensitive loads tolerate loss of power for this length of time?
- *Unable to maintain system integrity.* Is the substation designed to provide at least double contingency protection for all critical loads and lines?
- *Unable to maintain system reliability.* Will loss of this equipment cause area wide voltage fluctuation, frequency, stability, or reliability problems?

16.4.2 Vulnerability Assessment

As stated above, vulnerability is the individual weaknesses or ways in which a substation or its components can be compromised. All station equipment is vulnerable to damage or destruction from an external threat, such as a gunshot. But there are other vulnerabilities as well: the operation of breakers and control equipment by someone in the control building; damage or destruction of equipment operator mechanisms; the loss of control and protection schemes by cutting control wiring in the yard, in marshalling cabinets or in the back of relay panels in the control building; the loss of primary protection communication channels by switching them off; bus faults caused by throwing chains over air-insulated buses; structure failure caused by the removal of structural bolts or destruction of insulator supports; or the loss of system control by switching equipment from remote to local control using the manual switches in the control building. These vulnerabilities are exacerbated by other environmental factors (which are vulnerabilities in and of themselves). These include the location of a substation (urban, suburban, rural, or industrial), access to a substation by the public, whether it is manned or unmanned. The stages of development of a substation (preconstruction, storage, construction, operation, and when decommissioned) are also vulnerabilities that affect the risk of a threat.

16.4.3 Risk Assessment

The third component of the system analysis is the risk assessment. To manage risk, it must first be measured. Once measured, the risk to substations and components can be prioritized. To perform a risk assessment, the owner/operator must first have a completed threat, vulnerability, and criticality assessment.

To measure risk is to quantify the probability that a threat to a specific vulnerability will occur, resulting in loss of a critical component or substation. Typical scenarios would include:

- What is the risk of a gunshot penetrating the wall of a critical transformer, causing failure of the transformer?
- What is the risk that the loss of the above transformer will cause a severe capacity overload of the electric system resulting in a system cascade?

- What is the risk that an intruder breaking into a control building will destroy or disable the protection schemes for several critical transmission lines? What is the risk this will occur without detection by the owner/operator?
- What is the risk that failure to one of these lines will lead to major damage of the line before repair or replacement of the damaged protection equipment?
- What is the risk that an intruder will break into the control building of a substation and gain control of the substation via the local control switches?
- What is the risk that an intruder will break into the control building of a substation and gain control of the substation using a laptop to access the SCADA RTU or protective relays? What is the risk that the intruder will use this access to gain access to ERP databases or gain control of equipment located in the operations center or other substations?
- What is the risk that theft of a portion of the substation ground grid will cause a severe disturbance to the system?
- What is the risk that someone will be injured or killed during the attempt to steal portions of the ground grid?

A substation or a substation's components must be susceptible to the identified threat for there to be a risk of failure. In addition, the risk must be ranked in importance to the owner/operator and to the system as a whole. For instance, in the case of the transformer described above, its importance to the system may be critical and risk of intrusion to the substation quite high. But, if the only identified threat to the substation is entry to steal the ground grid, then the overall risk associated with the transformer, the critical component within the substation, and the operability of the substation itself, may be very low. Hence extra effort to protect the transformer from damage or destruction from this type of threat may not be warranted. Only the owner/operator of the electric system can make these decisions.

A number of risk assessment guides along with sample work sheets have been created to assist with the above process. Three in particular are located on ESISAC's Web site, http://www.esisac.com/library-assessments.htm. They are:

- Risk-Assessment Methodologies for Use in the Electric Sector, September 2005
- Energy Infrastructure Risk Management Checklists for Small and Medium Sized Energy Facilities, August 19, 2002
- Assessment Methodology Worksheet and Worksheet Instructions (located in the Library of CIP Documents), September 2003

16.5 Risk Management

Now, in order to take appropriate action for the risks that have been identified, an owner/operator must review the data collected during the system analysis (discussed above in Section 16.4) and determine the best physical security methods. Together, the analysis and decision process is called "risk management."

The dictionary definition of risk management is "a decision to accept exposure or to reduce vulnerabilities by either mitigating the risks or applying cost effective controls."[8] In the case of physical security of the electric system, ESISAC suggests four methods to manage the risk associated with a threat. The owner/operator can:

- Accept the risk by acknowledging that all risk cannot be eliminated.
- Avoid the risk by preventing the incident from happening.
- Mitigate the risk by reducing the consequences.
- Transfer the risk by moving it to another party such as insurance or contract.[9]

[8] www.utmb.edu/is/security/glossary.htm
[9] 71 ESISAC Risk-Assessment Methodologies for Use in the Electric Utility Industry.

Risk management is practiced all the time in the design of a station, its layout, and protection for system-type failures. Consider a power transformer. Manufacturing defects, age, and operating conditions create vulnerabilities that can individually—or in concert—cause a transformer to fail under through-fault conditions. Since it is recognized that these types of failures can happen, owner/operators employ various bus arrangements, parallel transformers, switching schemes, and protection schemes to protect the transformer and the supply of electricity to customers from the consequences of this type of vulnerability.

In this example, the fault is the threat, the age and operating condition of the transformer is the vulnerability. Risk management is exercised in several ways when dealing with the consequences of this type of failure. The risk can be eliminated by replacing the transformer before age and operating conditions make the risk of loss too high. The risk can be mitigated by implementing protection schemes designed to clear the fault before it can damage the transformer. The risk can be transferred by employing bus arrangements and switching operations to route the power to other equipment if the fault persists and the transformer bus must be cleared. Finally, insurance may be purchased to reduce the cost of replacement of the transformer if it is damaged or destroyed.

16.6 Responsibility for Security

Security concerns for the electric system are no longer the responsibility of the owner/operator alone. Recent legislative changes and federal agency rule implementations have shifted some of the substation owner/operator's responsibilities to a shared responsibility between the owner/operator and the federal government.

16.6.1 Owner/Operator

For an effective physical substation security program, it is important that an owner/operator identify the person (or persons) or department who will have responsibility for security implementation and administration. To be successful, a security plan should include a policy, procedures, and guidelines in order to be effective across the organization. To establish a successful security plan, the policy must be created and mandated at the corporate level, then monitored at all levels to assure its implementation. Defined levels of responsibility, along with procedures and guidelines that define specific tasks, are required throughout the organization.

Each company should have someone specifically in charge of substation security. This individual should be responsible for assuring that a security plan is developed, implemented, regularly reviewed, and updated. The regular inspection of each substation to assure that security measures are in effect should be part of the security plan. In addition, employee training and the development of methods that enable employees to report irregularities or breaches of security are also necessary. Management must accept a high level of responsibility to make sure that those security systems installed are maintained at all times.

16.6.2 Federal Government

The federal government has taken a number of actions in recent years to both legislate and mandate the auditing of the level of preparedness for incidents, monitoring the operation of the system, and reporting in real-time the occurrence of outages. The most significant recent acts include:

- The federal government has established security agencies specifically required to monitor, to collect data and perform analyses on the probability of, and probable location, of a terrorist strike on the electric supply system.
- The federal government has initiated security audits of major utilities.
- The Energy Policy Act of 2005, which establishes the creation of an ERO, has been enacted. The ERO will have the ability to levy fines for outages that affect the stability and reliability of the electric system.

- The federal government has set up guidelines defining a significant power outage and is now requiring the mandatory, real-time reporting of these occurrences to the Office of Emergency Management (OEM).

16.6.2.1 Reportable Incidents

The Department of Energy has prepared a guideline that defines a reportable incident. Reportable incidents include every kind of outage that can occur in a system except those that can be caused by vandalism. They include:

- Loss of firm power
- Minimum 3% voltage reductions
- Voluntary load reductions if needed to maintain power
- Vulnerability action which includes any incident that degrades reliability
- Fuel supply emergencies
- Other events which result in continuous three hour or longer interruption

16.6.2.2 Reporting Procedures

In the event of an outage, a full technical report may be required by DOE from the utility including restoration procedures utilized. The report is required on a timely basis. During the event, the DOE encourages interim notification via email on a "heads up" basis to be followed by a full report later.

Government form, EIA-4178R, covers the reporting requirements and the format for the report. Find the form in the OEM website, or can be acquired by calling the OEM at 202-586-8100.

16.6.3 NERC Security Guidelines[10]

To assist the owner/operator with the development of security management departments, security reporting and methods, NERC has developed a comprehensive set of guidelines. These guidelines are being developed in cooperation with the industry and cover in more detail the topics we have covered in this primer. The guidelines can be obtained by contacting NERC directly. They cover the following areas:

- Vulnerability and risk assessment
- Threat response capability
- Emergency management
- Continuity of business processes
- Communications
- Physical security
- Information technology/cyber security
- Employment screening
- Protecting potentially sensitive information

16.7 Implementation (Methods)

Upon completion of a vulnerability analysis and risk assessment, a program needs to be implemented that addresses the findings of those studies. This section will provide many methods that can be used in such a program. These methods have been used to prevent or deter access to a substation–or failing that, provide notification that access has occurred. Each of these methods has a cost/benefit question that varies by application and should be reviewed by the user prior to application. All of the methods are listed for their security value only.

[10]Security Guidelines for the Electricity Sector DOC43.

While a number of methods listed are in common use today, many others are still in the developmental stage. Some of these methods are meant to be suggestive, imaginative, or thought-provoking in an attempt to encourage new methods to be developed by the reader.

Security requirements should be identified in the early design stages of a substation project. Generally, it is more economical to anticipate and incorporate security measures into the initial design rather than retrofit substations at a later date. The type of security used should take into account the type of intrusion it will likely see over the course of its life.

The types of methods listed here have been divided into four categories: physical, system, contractual, and organizational/management. Each of these categories represents a different approach. While they may be used alone, it is highly recommended that security systems be layered by using a combination of methods.

In utilizing these methods, the user must take into consideration whether the intended measures are counterproductive. For example, do the measures actually aid the intruder? Do they interfere with visual patrols putting maintenance personnel at risk? Do they interfere with the operation and maintenance of the substation? For example, solid walls are ideal for preventing equipment damage due to projectiles, but they also prevent drive-by inspection of the interior by patrols from the outside. Once inside, an intruder can, if detection equipment is not present, roam the substation property without detection. There are reported incidents of maintenance crews being attacked during daylight hours by individuals that have entered a substation with solid walls. Locking gates while a crew is inside is one solution, but some owner/operators have instituted rules that prohibit locking gates so the crews inside have an exit route during emergencies.

16.7.1 Physical Methods

16.7.1.1 Fences and Walls

As a minimum, every substation should have a perimeter fence around that portion of the property used for energized equipment. It is the first line of defense against intrusion. Internal fences provide an additional safety barrier for trained personnel working within the yard. Fences may also be used to prevent vehicular intrusion into the substation. Two or more layers of fencing might also be employed for additional protection.

The National Electric Safety Code (NESC), ANSI Standard C2, latest edition, can provide basic fence requirements. The NESC sets minimum requirements for height and material. It also specifies a minimum distance from internal energized equipment to the fence. In addition there are numerous IEEE standards and guides detailing the fencing requirements for various applications such as shunt and series capacitor banks, and shunt reactors.

Fences can be constructed of various materials. A fabric fence will stop the casual intruder from entering the substation yard. They usually consist of a chain link fabric attached to metal posts with three strands of barbed wire at the top to discourage an intruder from climbing the fence to gain entry. This barbed wire may be angled to the inside or the outside of the substation, subject to local ordinances.

Most applications use a commercial grade, galvanized fabric, consisting of either 3.0 mm (11 gage) or 3.8 mm (9 gage) wire. The mesh opening size should preferably be 50 mm (2 in.), but not larger than 60 mm (2.4 in.) to resist climbing. The addition of fiberglass or wooden slats to the fence fabric can also provide visual screening.

The height of the fence should be a minimum of 2.1 m (7 ft) above ground line. In areas of the country that experiences snowfall, it is desirable for the fence to be of sufficient height such that 2.1 m (7 ft) of the fence projects above the maximum snow accumulation. In higher risk areas consider using razor wire, coiled in a cylinder along the fence or angled toward the outside away from the facility. Areas vulnerable to vehicle penetration may require 19 mm or larger aircraft cable mounted to the fence supports, inside the mesh fabric, at a height of approximately 0.76 m (30 in.) above ground level to reinforce the fence. The U.S. Department of State provides various crash rated designs, which can be accessed for further information. Please refer to “Specification for Vehicle Crash Test of Perimeter Barriers and Gates, SD-STD-02.01, Revision A,” dated March 2003. This specification provides for various “K” ratings, which are based on vehicle weight and speed.

Metal fabric fences should be grounded for safety. Further information is available in Chapter 11. Solid walls, which can be of either masonry or metal construction, are an alternative to fencing. Solid walls have the advantage of providing screening of the substation and its equipment. In addition, solid walls may prevent external vandalism such as gunshot damage. The walls should be constructed to provide a barrier similar in height to the fencing discussed above and in a manner that does not provide hand or footholds.

16.7.1.2 Gates and Locks

Access to a substation is generally through a swinging gate of various materials. The gate should provide at least the same level of protection as the substation fence or wall. Crash-proof gates of an acceptable rating might be considered. (See U.S. Department of State specification above.) No openings that would allow a small child to enter the substation should be allowed.

All entrances to a substation should be locked. Control building doors should have locked metal doors. All outdoor electrical equipment should have a provision for locking cabinets and operating handles. Padlocks should utilize nonreproducible keys.

It is strongly recommended that a key control program be implemented to control the distribution and return of all keys. This will insure that each person in possession of a key is accountable for the location and control of the key.

16.7.1.3 Landscaping

While landscaping can be utilized to screen the substation and its electrical equipment from view and may be required to obtain public acceptance or approval, this section may be best described more as what *not* to do. Any landscaping treatment around substations should be carefully designed so as not to create hidden areas that are attractive to people and groups as a meeting place. Landscaping must be regularly maintained. Trees and shrubbery must be pruned to avoid concealing intrusion and illegal activity. A “pride in ownership” appearance, along with regular personnel visits, will keep many would be intruders away from the facility. No tree should be planted in a location that will allow the tree to be used as an access or climbing aid into the substation. The final growth dimensions of the tree should be considered in determining this location.

Landscaping, in the form of berms, can be used to prevent direct line-of-site with equipment similar to solid walls or fences with fabric. Although they require additional land, berms may be less expensive to construct than walls or fences with fabric screens. The additional land can provide a clear buffer zone around the substation. Berms may also be a deterrent to vehicular intrusion into a substation. A series of small nonlandscaping-type berms can be installed around a substation outside the fence so that a vehicle attempting to penetrate the substation property will become high centered. Keep in mind that these berms need to be placed so that a vehicle would not be able to navigate between them.

16.7.1.4 Barriers

Access to energized equipment and bus work may be of concern if the perimeter security measures are breached. Polycarbonate or other barriers on ladders and structure legs can be used to provide additional barriers. Refer to the NESC and Occupational Safety and Health Administration (OSHA) requirements. These barriers may also function as animal deterrents.

All sewer and storm drains that are located inside the substation perimeter, with access from the outside, should be fitted with a vertical grillwork or similar barrier to prevent entry. Manhole covers or openings should be located on the inside of the substation perimeter fence and locked down.

Driveway barriers (gates, guardrails, ditches, etc.) at the property line for long driveways can help limit vehicular access to the substation property. Additionally, use boulders, jersey barriers, or impassable ditches in locations where vehicle or off-road vehicles can gain access to the perimeter fence.

16.7.1.5 Grounding and Ground Mats

Theft of metals, particularly copper, is one reason for intruders to enter a substation. To reduce the availability of copper, the use of a copper-clad steel conductor for substation ground grid system construction is recommended. Additional considerations should include:

- Making connections from the grounding grid to the fence fabric and fence posts below grade
- Covering exposed grounding connections with conduit or other material to hide from view
- Adding a hardening, ground enhancing material to the soil used to backfill the grounding grid trench. This material will increase the diameter of the ground grid conductor making it more difficult to pull from the ground
- Placing a notification sign on the fence stating the use of copper clad steel conductors
- Forming a partnership program with local police officials and scrap yards to identify and recover stolen materials

16.7.1.6 Lighting

The exterior and interior of the substation may be designed with dusk-to-dawn lighting. A typical minimum lighting level of approximately 20 Lux (two footcandles) is suggested. However, it is recommended that the use of sodium vapor lighting be avoided if the lighting is intended to assist with the identification of intruders or if lighting is intended to be used in conjunction with video surveillance equipment. This type of lighting produces a yellow or orange cast, which will interfere with attempts to identify the person, his clothing, and the description of the person's vehicle.

Wiring to the lighting posts should be in conduit or concealed to minimize tampering by an intruder. Areas outside the fence, but within the facility property, should also be considered for lighting to deter loitering near the substation. Community acceptance of this level of lighting may prohibit its use. Light fixture covers and lenses should be damage resistant.

16.7.1.7 Control Building Design

In general, most building materials provide adequate security protection. However, the type of building construction should be suitable for the level of security risk. This construction could include hardened walls, armor plating of outside building walls, and impenetrable ceilings. An active system, which fills the room with eye and skin irritant gas (tear gas or some other vapor) to expel intruders from the building if intrusion is detected, might be considered. Additional features that should be included are steel doors with tamper-proof hinges and roof-mounted heating/air conditioning units. Any wall openings (i.e., wall air conditioners) should have security bars over and around the unit. A building that is part of the perimeter fence line should be at least as secure as the fence.

16.7.1.8 Security Patrols

At critical substations or in areas where vandalism has been a chronic problem, the judicious use of a security patrol service should be considered. A partnership can be established with local law-enforcement agencies to facilitate these patrols. Specific security procedures should be established that identify who handles security alarms and what the response notification procedures should be within the company and with local law enforcement agencies. These procedures may be augmented to include rapid response by local authorities to substation sites when alerted by the owner/operator, posted security guards and required identity checks during unusual occasions—labor disputes, major events, or visiting dignitaries.

16.7.1.9 Signs

Signs should be installed on the perimeter fence to warn the public that:

- There is a danger of electrical shock inside.
- Entry is not permitted.
- Alarm systems are providing security for the substation.

Please refer to the NESC, as there are additional requirements.

16.7.1.10 Clear Areas and Safety Zones

In addition, structures and poles should be kept a sufficient distance from the fence perimeter to minimize the use of structures as a climbing aid.

Where practical, a 6 m (20 ft) to 9 m (30 ft) clear zone around the exterior of the perimeter fence should be considered. This zone will provide a clear field of view which will make it easier to detect someone from illegal entry.

16.7.1.11 Site Maintenance

Frequent and routine inspection of the site should be provided to insure a minimum level of care. Maintaining the substation in a clean and orderly fashion can help discourage various groups from using the property as a meeting place. Any deficiencies should be rapidly reported.

16.7.1.12 Intrusion Detection Systems

Numerous systems are now on the market to detect unlawful entry to a substation. These include video, motion, sound, and seismic detection systems that can distinguish, among other things, two-legged versus four-legged intruders along with their speed of movement, sound, and vibration. Before employing any of these systems, the owner/operator must determine the objectives for their use. For instance, if the purpose is to stop an intrusion in progress, the anticipated response to a detected intrusion by local authorities must be determined. If no response or a delayed response is all that is possible, then the use of these systems will still act as deterrent but may not provide their original intention.

Sophisticated motion detection systems, video camera surveillance equipment, and building security systems are becoming more common. The software associated with these systems can be customized to filter out some nuisance detections. The systems use local processors for detection and only send data to the operations center when a change is detected. All of these systems are designed to provide early detection of an intruder.

Perimeter systems using photoelectric, laser-sensing, fiber optics, or microwave may be utilized to provide perimeter security. Generally these sensors are mounted on a fence and alarm upon detection of either movement of the fence or the characteristic sound that a fence will make when it is moved. These can be effective to detect intruders that either climb the fence or pry the fence up at the bottom. Other technologies use a fiber optic cable embedded in the fence fabric that look at the speckle pattern and received level of light, then alarm at a predefined threshold. In both cases the systems are able to locate the source of the alarm. Other perimeter systems use microwave technology to set a volume (three-dimensional space) of detection either around the exterior of the station, immediately inside the station, or around critical equipment. Defeating this type of detection system is much more difficult than the fence mounted systems because of the size of the three-dimensional space within the detection zone.

Video systems can be deployed to monitor the perimeter of the substation, the entire substation area, or building interiors. They can have zoom lens added to them that allow reading gauges located in the yard. They can be programmed to move to a specific combination of angle and zoom to provide a clear reading of a level or temperature gauge. They can also be moved to view any specific area of the substation yard where illegal entry is suspected. Video systems are available that use microwave and infrared to activate a slow-scan video camera, which can be alarmed and monitored remotely and automatically videotaped.

Control building door alarm systems are quite common. These systems include, at a minimum, magnetic contacts on all the doors and have provisions to communicate to the operations center through the existing telephone network or SCADA system. They can also include a local siren or strobe light located on the outside of the building that is activated under an alarm condition. The systems should be capable of being activated or deactivated using an alphanumeric keypad, keyed switch, or card reader system located inside the building. All siren boxes and telephone connections should have contacts to initiate an alarm if they are tampered with.

16.7.1.13 Video Motion Detection Systems

A completely new family of technologies is becoming commercially available that utilizes a CCTV coupled with motion sensing equipment for intrusion detection. The concept of video motion detection is not new. When it was first introduced two decades ago, an alarm was generated when one or more pixels in a video scene changed. While this provided a very sensitive way to detect motion, it turned out to be very difficult to implement in an exterior situation because of the many ways an exterior scene changes that does not necessarily represent a potential intrusion. For example, the passage of a cloud over the sun would darken all or a portion of the field of view, generating an alarm.

With the advent of digital cameras and the increase in available on board computing power, a number of products are now on the market that hold promise for cost-effective video-based motion detection in the exterior environment. These particular products offer a number of attractive features that allow the end user to tailor the performance of the system to their specific site and security needs. These features include the ability to define multiple detection areas in a camera's field of view. The software also uses various decision algorithms to distinguish between normal and threatening activity. These algorithms can include shape filters to identify the source of the motion. Other filters include direction of motion, speed of motion, and consistency of internal motion of the object. They can also provide the ability to perform various camera control functions upon detection of motion. This would include zooming in on the source of the motion upon detection, and in some cases, track the moving object subsequent to detection.

16.7.1.14 Substation Service

Two or more substation, station service power sources are recommended. A third source based on generation from a local fuel supply may be warranted.

16.7.1.15 Personnel Access

As described in Section 16.7.1.1 "Fences and Walls," substation access keys should only be provided to personnel on an "as-needed" basis. For critical substations this group may be limited even further. Electronic access systems using electronic identification cards and touch pad password readers should be considered. The identification cards should be used only for substation access and the passwords changed periodically. A higher level of security can be provided by biometric devices, if required, such as finger print and retinal pattern readers. Smart badges (utilizing RFI devices), which can follow the location of personnel within the substation, are also available.

16.7.1.16 Drawings and Information Books

The storage of information at a substation facility, which could allow a knowledgeable intruder to cause damage or increase the damage that is done, should be avoided. Serious consideration should be given before making the following information available on site:

- Station construction drawings
- One-line and three-line drawings
- Relay functional drawings
- Relay and SCADA manuals
- Electrical equipment manuals
- Anything containing password information
- Easy access to this information from an onsite Internet device

16.7.1.17 SCADA/Communications Equipment

Special attention should be paid to SCADA and communication systems. These systems should be provided with at least two independent power sources. Installing these systems in a separate, hardened location—accessed with a separate entry control—is also recommended. This location might be shielded to restrict electronic intrusion.

16.7.1.18 Relay and Control Equipment

The proper operation of relaying and control equipment systems is critical. Unauthorized personnel must be restricted from access and easy operation of these systems. The following is a list of possible methods to prevent unauthorized access to relay and control equipment:

- Primary and backup relaying for each line is not the same or on adjacent panels.
- No panel, protective equipment, or switch legends. All equipment is unidentified on the panels.
- No visible control switches or the switches are remote mounted in a hardened cabinet (patrolman carries switch handles with them).
  - Dual switch handles one on the panel and one master switch remotely located so it takes two people to operate a switched device such as a breaker.
  - Specially keyed shafts similar to antitheft lugs used on car tire lugs. Unique shafts would prevent use of common switch handles taken from other substations or ordered from a manufacturer being used in a critical substation.
  - Control switches with a socket instead of shaft protruding from the panel to prevent turning the switch with pliers. The shaft is part of the switch handle instead of part of the switch.
- Each panel covered with tamper-proof doors front and back with bullet-resistant glass on the front doors, the breaking of which should set off alarms.
- Each relay requires a password to access its display panel and activate function keys. Two passwords are required; one created by a random number generator and issued by the system operator within an hour of the request to access the relay, the other is linked to the Personnel ID system.
- Relay communication ports use intrusion detection cables.
- Encryption software on each intelligent electric device within the substation should be activated.
- Remote access to the intelligent electric device through the use of a dial up phone line can only be accomplished by closing a SCADA operated contact from the operations center. This access can be automatically limited to a specific time interval.

16.7.2 System Methods

Some security measures are much more effective than others. None are 100% effective, either singly or working in combination. With this in mind, the security of a substation must be viewed in the larger context of the security of the overall electric system. To provide this greater security, the following should be considered:

- Perform load flow, stability, and reliability studies that measure how the system will react if key equipment or substations are destroyed or put offline. Focus the upgrade and design of new substations with built-in contingency capacity and equipment that mitigates the effect of the loss of key substations and equipment.
- Build a redundant network. The transmission system should remain stable during the outage of any two lines or substations anywhere in the system. This is a double contingency (N-2) planning criteria.
- Maintain spares, for critical hard-to-replace pieces of equipment. This can include transformers, breakers, and even substation structures.
- Partial assembly and storage of all the equipment necessary to build an entire substation. Partial assembly would allow a more rapid response during an emergency.
- Earmark spare equipment that is critical to the region and enter into agreements with the utilities in the region for the storage, availability, and use of the equipment.
- Design substation yards to include wide internal roadways that provide easy access for mobile transformer equipment. Provide attachment points for mobile transformer equipment to minimize the time required to restore partial power to critical loads.
- Use underground feeders for critical loads.

- Consider distributed generation resources near critical loads or near critical substations that do not meet the N-2 double contingency criteria.
- Consider placing new substations indoors using gas-insulated equipment and use underground feeders.
- Use single-phase units for very large power transformers. Single phase units are easier to move in emergency situations than three-phase units. Also, they can be shared more easily with other utilities in the immediate area.
- Consider alternate bus designs that provide higher levels of line protection and source-load redundancy. Space equipment farther apart, if possible, to prevent collateral damage.

16.7.3 Contractual Methods

If the detection and deterrent methods described above are unsuccessful, the replacement or restoration of damaged equipment may be required. The cost of these actions can, of course, be covered by an insurance contract, but, to expedite this work, the following contractual arrangements or plans should be considered:

- Establish agreements with adjacent utilities in regard to common design standards, which will facilitate the use of spare equipment for emergencies.
- Establish construction contracts with specific contractors for the emergency repair and replacement of failed equipment.
- Negotiate agreements with major equipment manufacturers for the emergency production and delivery of major, long lead, or special design components that cannot be or are not readily available from storage. Such equipment should include:
  - Large power transformers
  - Solid-state switching equipment associated with SVC and AC/DC inverters
  - Specialized cooling systems for critical components
  - Circuit breakers if their voltage class or fault duty present long lead time delivery
  - Switches when manufacturing lead times exceed acceptable limits
  - Steel structures when manufacturing lead times exceed acceptable limits
  - Electrical bus, insulators, and connectors
  - Control cable
- Establish agreements with local law enforcement agencies, pubic or private, to provide rapid response during emergencies or when called to a substation site by the operations center. Provide their personnel with substation safety training to assure their conduct and safety within an energized substation.

16.7.4 Management/Organizational Methods

The methods used for substation security should be modified as needed to address current and changing needs. The following are suggested to determine those needs:

- Continually review past events and determine how to upgrade or configure the system to prevent deliberate and similar events.
- Establish alliances with other utilities to develop and share information about the history of intrusion and the results of security analysis.
- Engage the services of a security consultant to help develop profiles and perform risk assessments.

The following additional organization and procedural methods that will limit access to sensitive information are also provided:

- Do not publish design guides and design standards that provide installation and operation details about security devices to be adopted for substations.
- Develop security design details on separate drawings and place these drawings in separate secure file directories.

17

Cyber Security of Substation Control and Diagnostic Systems

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17.1 Introduction

There have been more than 80 unpublished cases where control and diagnostic systems have been impacted by cyber incidents in electric power (including transmission and distribution substations), water, oil/gas, chemicals, and manufacturing. These cases have occurred in North America, South America, Europe, and Asia. Impacts have ranged from trivial to significant equipment and environmental damage to deaths [1]. The majority of the control system cyber cases to date have been either unintentional or viruses and worms. In most cases, appropriate control system security policies and procedures could have either prevented the event or minimized the impacts. As substations become more interconnected and automated, potential cyber vulnerabilities grow. Consequently, there is a need to protect these critical assets.

The traditional concerns of electric utilities about the security of their substation assets have centered on protecting the substation from physical threats, both natural and human threats. With the significant

TABLE 17.1 Differences between the Traditional Threats to Utility Substation Assets and Contemporary Threats

Traditional Threats	Contemporary Threats
The threat is direct damage to the physical assets of the utility.	The threat is damage to utility computer systems, which may lead to damage to the physical assets.
The threat is local.	The threat originates from local or distant sources.
The threat is from an individual.	The threat may come from individuals, competitors, or well-funded and highly motivated organizations.
An attack occurs at a single site.	An attack may be unleashed simultaneously at many sites within many utilities, and may be coordinated with cyber or physical attacks on other elements of key infrastructure.
A successful attack causes immediate and obvious damage.	A successful attack may be undetected. It may result in changes to utility software that lie dormant, and are triggered to operate at some future time.
A successful attack causes obvious damage.	A utility may not know the nature of the damage to software caused by a successful attack.
An attack is a single episode.	As a result of an attack, software may be modified to cause continued damage.
Restoration can take place safely after the attack.	Since the attacker may still have access to the systems, restoration plans can be impacted.

exception of countries with civil strife, the main human threats were believed to be from a disgruntled employee, angry customer, or politically motivated vandal. In the case of all of these threats, the malfeasant had to be within, or physically close, to the substation to cause damage. Traditionally, providing physical security meant having fences, locked gates, security cameras, SCADA-monitored intrusion alarms, and occasional visits by utility staff.

In contemporary times, the nature and the magnitude of the threat to substation assets have changed. The nature of the threat has changed because the equipment to monitor and control substation devices is now frequently connected by communication lines to wide area networks potentially accessible by the general public. (See, for example, the discussions in Chapter 7). As a consequence, an individual seeking to damage utility assets can do so from places hundreds or thousands of miles distant as well as potentially impact multiple substations simultaneously.

The magnitude of the threat has changed because organized and well-funded groups have publicly stated the goal of damaging elements of our critical infrastructure. Newspaper articles and industry notices show that some organizations have been gathering information about public utilities in general, and specifically about SCADA technology. Every day provides evidence of continuing probes of the electronic defenses of corporate computing networks [2]. Additionally, there have been several notices from the Electric Sector Information Sharing and Analysis Center (ISAC) about SCADA cyber security events. There are numerous industry and government documents that have been issued on cyber security of SCADA systems and substation communications. An Internet search on “SCADA Security” will provide numerous references.

Table 17.1 summarizes the differences between the traditional threats to utility substation assets and contemporary threats. (The traditional threats have by no means evaporated; the new threats have to be seen as an addition to, and not as a replacement of, the traditional threats.)

Chapter 16 discussed protecting the physical security of the substation. This chapter addresses the nature of cyber threats, their potential to damage utility assets and means to protect against them, detect them when they do occur, and recover from them.

17.2 Definitions and Terminology

CIGRE — CIGRE is the International Conference on Large High Voltage Electric Systems. CIGRE is recognized as a permanent non-governmental and non-profit-making international association based in France. It focuses on issues related to the planning and operation of power systems, as well as the design, construction, maintenance, and disposal of high voltage equipment and plants.

Cyber Security — Security (q.v.) from threats conveyed by computer or computer terminals; also, the protection of other physical assets from modification or damage from accidental or malicious misuse of computer-based control facilities.

Default Password — A "password" is a sequence of characters that one must input to gain access to a file, application, or computer system. A "default password" is the password that was implemented by the supplier of the application or system.

DNP3 — Distributed network protocol: A non-proprietary communications protocol (q.v.) designed to optimize the transmission of data acquisition information and control commands from one computer to another.

Firewall — A device that implements security policies to keep a network safe from unwanted data traffic. It may operate by simply filtering out unauthorized data packets based on their addresses, or it may involve more complex inspection of the sequence of messages to determine whether the communications are legitimate. A firewall may also be used as a relay between two networks, breaking the direct connection to outside parties.

IDS — Intrusion detection system: A device that monitors the traffic on a communications line with the aim of detecting and reporting unauthorized users of the facilities. IDSs are programmed to identify and track specific patterns of activity.

IEC — International Electrotechnical Commission: An international organization whose mission it is to prepare and publish standards for all electrical, electronic, and related technologies.

IED — Intelligent electronic device: Any device incorporating one or more processors with the capability to receive or send data and control from or to an external source (e.g., electronic multifunction meters, digital relays, and controllers) [3].

NIST — National Institute of Standards and Technology.

Port — A communications pathway into or out of a computer or networked device such as a server. Ports are often numbered and associated with specific application programs. Well-known applications have standard port numbers; for example, port 80 is used for HTTP traffic (Web traffic).

Protocol — A formal set of conventions governing the format and relative timing of message exchange between two communications terminals; a strict procedure required to initiate and maintain communication [4].

Remote Access — Access to a control system or IED by a user whose operations terminal is not directly connected to the control systems or IED. Applications using remote access include Telnet, SSH, and remote desktop software such as pc. Anywhere, Exceed, DameWare, and VNC. Transport mechanisms typical of remote access include dial-up modem, frame relay, ISDN, Internet, and wireless technologies.

RTU — Remote Terminal Unit: The entire complement of devices, functional modules, and assemblies that are electrically interconnected to effect the remote station supervisory functions. The equipment includes the interface with the communication channel but does not include the interconnecting channel [5].

Security — The protection of computer hardware and software from accidental or malicious access, use, modification, destruction, or disclosure [6].

17.3 Threats to the Security of Substation Systems

Substation control systems and IEDs are different than traditional IT business systems. These differences have led to several myths about control system cyber security [1].

- Firewalls make you secure—Firewalls have been described as nothing but "speed bumps" for a knowledgeable attacker.
- Virtual private networks—VPNs (and encryption) make you secure—VPNs are a "secure tunnel." Any distrusted or compromised packets entering the VPN will be encrypted with no warning that the packets could be distrusted.
- Intrusion detection systems (IDSs) can identify possible control system attacks—IDSs use pattern recognition to identify potential attacks. As of now, there are no known patterns for SA cyber attacks.
- Messaging can be one-way—All IP messaging requires a dual "handshake." Consequently, messaging cannot be one-way.
- Field devices can't be hacked—Field devices (e.g., Programmable logic controllers, RTUs, IEDs, diagnostic systems) have been successfully compromised.
- More and better widgets can solve security problems—Without appropriate control system policies and procedures, all security technology can be defeated.

Even though the general public may not be aware of these systems, the hardware, software, architecture, and communication protocols for substations are well known to the utilities, equipment suppliers, contractors, and consultants throughout the industry. Often, the suppliers of hardware, software, and services to the utility industry share the same level of trust and access as the utility individuals themselves. Consequently, the concept of an insider is more encompassing. A utility employee knows how to access the utility's computer systems to gather information or cause damage, and also has the necessary access rights (keys and passwords). The utility has to protect itself against disgruntled employees who seek to cause damage as well as against employees who are motivated by the prospect of financial gain. Computer-based systems at substations have data of value to a utility's competitors as well as data of value to the competitors of utility customers (e.g., the electric load of an industrial plant). Corporate employees have been bribed in the past to provide interested parties with valuable information; we have to expect that this situation will also apply to utility employees with access to substation systems. Furthermore, we cannot rule out the possibility of an employee being bribed or blackmailed to cause physical damage, or to disclose secrets that will allow other parties to cause damage.

A second potential threat comes from employees of suppliers of substation equipment. These employees also have the knowledge that enables them to access or damage substation assets; and often they have access as well. One access path is from the diagnostic port of substation monitoring and control equipment (see Chapter 7). The C1 Working Group of the IEEE Power Systems Relay Committee (PSRC) is developing a technical paper addressing the cyber security issues for protective relays [7]. It is often the case that the manufacturer of a substation device has the ability to establish a link with the device for the purposes of performing diagnostics via telephone and modem (either via the Internet or by calling the device using the public switched telephone network). An unscrupulous employee of the manufacturer may use this link to cause damage or gather confidential information. Additionally, an open link can be accessed by an unscrupulous hacker to obtain unauthorized access to a system. This has occurred frequently in other industries.

Another pathway for employees of the utility or of equipment suppliers to illicitly access computer-based substation equipment is via the communications paths into the substation. Ensuring the security of these communications paths is the subject of Section 15.8 and Section 15.9.

A third threat is from the general public. The potential intruder may be a hacker who is simply browsing and probing for weak links or who possibly wants to demonstrate their prowess at penetrating corporate defenses. Or the threat may originate from an individual who has some grievance against the utility or against society in general and is motivated to cause some damage. The utility should not underestimate the motivation of an individual outsider or amount of time that they can dedicate to investigating vulnerabilities in the utility's defenses.

A fourth threat may be posed by criminals who attempt to extort money (by threatening to do damage), or to gain access to confidential corporate records, such as those maintained in the customer database, for sale or use.

The fifth, and arguably the most serious threat, is from terrorists or hostile foreign powers. These antagonists have the resources to mount a serious attack. Moreover, they can be quite knowledgeable, since the computer-based systems that outfit a substation are sold worldwide with minimal export restrictions, and documentation and operational training is provided to the purchaser. The danger from an organized hostile power is multiplied by the likelihood that an attack, if mounted, would occur in many places simultaneously, and would presumably be coupled with other cyber, physical, or biological attacks aimed at crippling the response capabilities.

However, the most likely “cyber threat” will be the unintentional threat. This is where substation control or diagnostic systems are impacted because of inappropriate testing or procedures. Even if laptop computers, TCP/IP communications, or both are used in substation environments, it does not mean that traditional IT testing such as scanning of networks should be performed without due care and caution.

17.4 Substation Automation (SA) System Vulnerabilities

Traditional IT business systems have been the object of a wide variety of cyber attacks as documented by CERT/CC, Computer Security Institute, and other computer security tracking organizations [2,8]. These attacks include an exploitation of programming errors in operating systems and application software, guessing or cracking user passwords, taking advantage of system installations that leave extraneous services and open ports open to attack, and improperly configured firewalls that do not exclude unauthorized communications. In addition to manifesting these common vulnerabilities, the control and diagnostic systems in substations have a number of special cyber vulnerabilities.

This section will not attempt to discuss the manifold vulnerabilities of conventional computer systems, which are well documented in other sources. Instead, this section describes some of the characteristics of substation control and diagnostic systems that give rise to special vulnerabilities. Section 17.5 will then cover how the user can reduce the threats to cyber security, and some of the characteristics of substation systems that make it difficult to apply conventional protective measures.

17.4.1 Slow Processors with Stringent Real-Time Constraints

One way to strengthen the privacy and authenticity of messages transmitted across insecure channels is to authenticate and encrypt the communications. The two primary types of encryption are block encryption, where encryption is completed after a block has been filled, and streaming encryption, which is performed as the data is transmitted. Block encryption generally is too resource-intensive for most current IEDs and many existing SA systems. Many substation communications channels do not have sufficient bandwidth for the transmission of longer block-encrypted messages. Furthermore, vendor testing has demonstrated that utilizing existing encryption technology will significantly slow down processing and inhibit timing functions. The remote terminal units (RTUs) and IEDs in substations in some cases use early microprocessor technology. They have limited memory and often have to meet stringent time constraints on their communications. It is often not feasible to require that these RTUs or IEDs enhance communications security by encrypting the data messages, because their microprocessors do not have the processing capability to support the additional computational burden. IEEE C4 (IEEE-1689—Trial Use Standard for Retrofit Cyber Security of Serial SCADA Links and IED Remote Access) has been formed to address the cyber security of IED remote access.*

*The language in the PAR makes it clear that this standard is for retrofit applications. At the time of balloting, the WG will submit a PAR revision to add the word “Retrofit” to the document’s title.

17.4.2 Real-Time Operating Systems that Preclude Security

Another security risk is posed by the design of the real-time operating systems that are embedded within many IEDs. At the present time, the suppliers of these embedded operating systems have not been faced with the need to meet the requirements for secure communications. Their software systems have been designed to operate in an environment poor in computing resources but where there is a need for deterministic response to events. Such systems are configured to prioritize the execution of tasks and communications, but not to implement information security policies. The embedded operating systems cannot make the requisite calls to authenticate the other party, encrypt data before sending it, and decrypt it upon reception.

17.4.3 Insecure Communications Media

The data messages that substation IEDs exchange with the outside world are often transmitted over media that are potentially open to eavesdropping or active intrusion. Dial-in lines are common; IEDs will accept phone calls from anyone who knows or discovers their phone number. Many IEDs are IP-enabled; that is, they can be addressed by computers connected to the Internet.

In addition, much of the data traffic to and from a substation goes over wireless networks (see Chapter 15). Intruders with the proper equipment can record and interpret data exchanges and can insert their own messages to control power system devices. Other data traffic goes over leased lines, passing through telephone company switching centers where they are subject to monitoring or interference. In this latter case, the security of substation operations can be no better than the security of the switching center of the telephone company.

Furthermore, the electronic equipment at substations frequently employs remote desktop applications (such as X-Terminal, pcAnywhere, and Exceed) that are specifically designed to allow users at remote locations to interact with the equipment as if they were present in the substation and directly at the local keyboard. There are numerous vulnerabilities associated with versions of these remote access programs.

Substations are seldom configured with firewalls to help safeguard the systems from intrusion, and IDSs are not yet available for substation environments to alert the system operator when cyber intrusions of SA equipment occur (see Section 17.5.2).

17.4.4 Open Protocols

The communications protocols most frequently used in substations are well known. For communications among IEDs, Modbus, Modbus-Plus, and DNP3 are the most frequently used protocols. These protocols are well documented and used worldwide. Many protocols have been used for communications between the substation and the utility's control center. In the past, protocols were often vendor-specific and proprietary, but in recent years the majority of implementations have been with IEC 60870-5 (in Europe) and DNP3 (in North America), and, to a much more limited extent, IEC 60870-6 TASE.2 (also called "ICCP"). These protocols are all non-proprietary, well documented, and available to the general public. Security was not a factor when these protocols were designed, and they contain no features to ensure the privacy or authenticity of the data transmitted. However, IEC TC57 Working Group 15 and the DNP Users Group [9] are beginning to address the security concerns of ICCP and DNP3, respectively. It should be noted that the new substation integration protocol, IEC-61850, will also need to be extended to address security.

Moreover, devices called "RTU test sets" are commercially available. An RTU test set is typically a portable device with a communications port that interfaces with an RTU or IED. The test set has a user interface that interprets the messages sent to and from an RTU or an IED and that allows the user to define and issue commands to the substation device. Tabletop demonstrations have shown that an

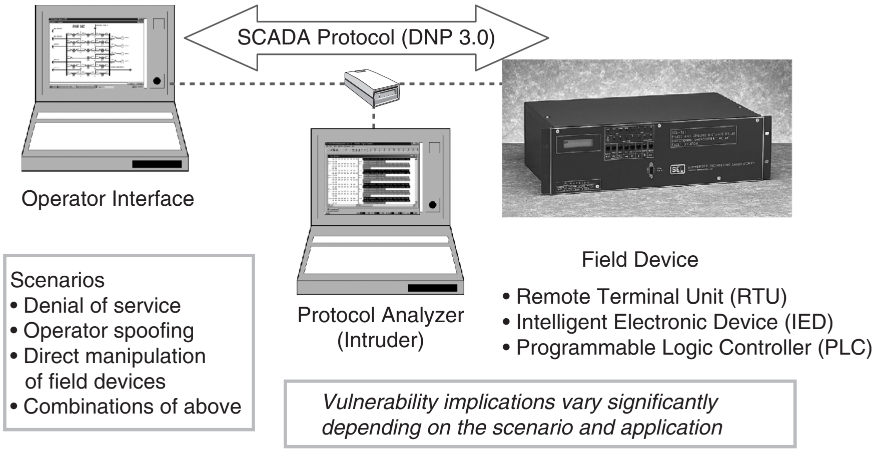

FIGURE 17.1 Bench scale vulnerability demonstrations. (From Dagle, J., Pacific Northwest National Laboratory, Demonstration at KEMA 2nd Conference: Current Status and National Test Bed Planning Workshop, April 7–9, 2003, Denver, CO (unpublished).)

intruder can patch into the communications channel to a substation and use a test set to operate devices at the substation (Fig. 17.1). Depending on how the protocol has been implemented in the SCADA system, it is possible for an intruder to operate a device using a test set without the SCADA system recognizing the intrusion.

17.4.5 Lack of Authentication

Communication protocols in current use do not provide a secure means for systems that exchange data to authenticate each other's identity. If an intruder gains access to a communications line to a controllable device, they can execute a control as if they were an authorized user. An intruder could also mimic a data source and substitute invalid data. In most cases, the program receiving the data performs very little effective data-validity checking to detect this kind of interference.

17.4.6 Low Priority for Cyber Security

Another characteristic of SA systems that adds to their vulnerability to cyber intrusion is managerial rather than technical. Owners of the systems often do not assign a high priority to cyber security.

Utilities have often zealously guarded their operational systems from perceived interference from corporate information technology staff. Yet it is the corporate IT staff that often is most aware of the cyber threats to computer systems and most knowledgeable about the ways to protect these systems. Such knowledge is less frequently present among the staff responsible for SA systems.

Often, the maintenance of substation equipment is divided among different staff: for example, relay technicians for relay IEDs, substation technicians for transformer-monitoring IEDs, and communications technicians for RTUs. There is often no single individual with authority for ensuring the cyber security of these various systems. As a corollary, there seldom are resources dedicated to providing security.

Finally, because the subject of cyber security has, until recently, not received much attention, cyber-security-related policies and procedures specific to SA equipment need to be developed, approved, and put into practice.

17.4.7 Lack of Centralized System Administration

Unlike the IT domain, where there is a central system administrator to designate and track authorized users, SA system users are often their own system administrators, and as such have the authority to perform all security functions. This often results in allowing personnel who have no reason for access to SA systems to have such access. Additionally, the system administration function allows what is known as "root access." A user with root access has access to all critical functions including assigning passwords, assigning log-in IDs, configuring the system, and adding or deleting software. This can lead to significant cyber vulnerabilities.

17.4.8 Large Numbers of Remote Devices

A typical utility has from several dozen to several hundred substations at geographically dispersed locations, and each automated substation typically has many IEDs. Therefore, there is a high cost to implementing any solution that requires upgrading, reprogramming, or replacing the IEDs.

17.4.9 Substation Diagnostic Systems

RTU and IED suppliers are beginning to address cyber security deficiencies. Substation diagnostic systems such as transformer monitoring and capacitor bank monitoring also utilize remote access and are often integrated into the SA data network. However, many substation diagnostic system suppliers have not begun to address cyber security deficiencies and can be a "backdoor" into the SCADA network.

17.5 Measures to Enhance Cyber Security

The principles for enhancing the cyber security of control and diagnostic systems at substations are the same as those for other corporate computer systems: (1) prevent cyber intrusion where you can; (2) detect intrusion where it could not be prevented; (3) recover from an intrusion after it was detected; and (4) improve the preventive measures on the basis of experience.

17.5.1 Protecting Substation Systems against Cyber Intrusion

There are two avenues of potential cyber intrusion to the computer-based equipment in a substation: those originating from the users on the corporate network, and those originating outside. These are treated in separate sections below.

17.5.1.1 Cyber Intrusion from Inside the Corporate Network

To the extent that substation control and monitoring systems are connected to a utility's corporate wide-area network, a large potential threat to these systems is derived from unauthorized users on the corporate network. Consequently, the first step in securing substation assets should be to ensure that the corporate network is made as secure as possible. The important measures are well known. They include the following:

- Removing all default user IDs and default passwords on installed systems
- Ensuring that all accounts have strong passwords
- Closing unneeded ports and disabling unneeded services
- Installing security patches from software suppliers in a timely manner
- Removing all sample scripts in browsers
- Implementing firewalls with appropriate rules to exclude all unneeded and/or unauthorized traffic
- Implementing IDSs, and logging and investigating all suspicious activity

The details of these measures, and further measures to protect the corporate network, are the subject of much active discussion elsewhere, and will not be covered in this volume.

Even though measures have been taken to enhance the cyber security of the corporate network, cyber intrusions may still occur. Therefore, additional measures should be taken to further protect substation systems from successful penetrations onto the corporate network. These measures will also help protect the substation stations from malevolent activity from employees who have access to the corporate network:

- Most important measure is one of the simplest. That is, to ensure that all default passwords have been removed from all substation systems and that there are no accounts without any password. (This may not be possible however if the equipment supplier has "burned-in" the default password into the system firmware or if the system will not accept passwords.)
- Password policy should be implemented to ensure that users' passwords are not easily guessable. However, as is well known, passwords that are difficult to guess are also difficult to remember. It defeats the entire sense of having passwords if the users post their passwords on the terminal of the system being protected. Users should be given instruction in ways to generate "difficult" passwords that they can remember without difficulty.
- Procedure should be in place to immediately terminate a password as soon as its owner leaves employment or changes their job assignment.
- Different sets of privileges should be established for different classes of users. For example, some users should be allowed only to view historical substation data. Other users may be permitted to view real-time data. Operators will be given control privileges, and relay engineers will be given the authority to change relay settings.
- Utility might consider requiring a stricter measure of authentication of the user before permitting access to a substation system. For example, the utility may consider requiring that a user desiring access to a system present a smart card for authentication, or instituting some form of biometric identification of the user (such as a personal fingerprint reader). The cost of purchasing the hardware to implement these protective measures is not high, but the administrative costs may make such measures impractical. As is often the case with issues of security, the utility must weigh the costs of the measure against the value of the asset being protected and the perceived risk of damage.

17.5.1.2 Cyber Intrusion from Outside the Corporate Network

The possibility of intrusions into the substation by outsiders gaining direct access to substation devices through unprotected communications channels raises new challenges to the cyber security of substation systems. There are two main communication paths into the substation that are the potential target for eavesdropping or intrusion: the SCADA communication lines and dial-up lines to IEDs.

17.5.1.2.1 SCADA Communication Lines

The SCADA communication line is the communications link between the utility's control center and the RTU at the substation. This line carries real-time data from substation devices to the utility dispatchers at the control center and control messages from the dispatchers back to the substation. (For substations equipped for SA, a data concentrator or a SA host processor will play the role of the RTU in sending substation data to the control center and in responding to the dispatcher's control commands.)

A variety of media are used to connect the substation RTU with the control center: power line, leased lines, microwave, multiple address radio, satellite-based communications, fiber optic cable, etc. The topic is discussed in detail in Chapter 15. It is quite common for communications from the control center to substation to use different media along different segments of the path.

Per the C1 Working Group paper [7], there are a large variety of communications routes for access of devices in substations. The physical media can be point-to-point (telephone lines), microwave, and higher bandwidth transport (T1, SONET, or Ethernet).

- POTS (plain old telephone service) dial-up via phone line is the most common medium used to access relays remotely. Modems are required to interface the phone line with the IEDs.

Line switchers typically allow one phone line to be switched and used for relay access, meter access, phone conversations, etc.

- Leased lines are typically used for SCADA connection. They are dedicated lines that are connected 24 hours a day, 7 days a week. They allow constant data acquisition and control capability of substation equipment.
- Wireless communication (cellular phones) is a technology that is useful in the substation environment. Additional wireless communication using IEEE-802 or equivalent networks are increasingly being used to expand the control connectivity boundaries in the substation environment. These networks typically are connected to one of the other communication media described above expanding the communication depth and breadth.
- 900 MHz radio is another medium used by utilities. These radios can either be licensed or unlicensed depending on the frequency selected. The unlicensed installations have a lower installed cost, but there is no protection from interference by other users.
- Microwave is a high frequency radio signal that is transmitted through the atmosphere. Transmitted signals require a direct line of site path, and accurate antenna alignment. The Federal Communications Commission (FCC Parts 21, and 94) controls operation and frequency allocations.
- In digital microwave systems, the data modems required in an analog system are replaced by digital channel banks. These channel banks can be combined to form a multiplexed system. The channel banks convert analog voice and data inputs into a digital format using pulse code modulation (PCM). The digital channel bank combines 24 voice channels into a standard 1.544 Mbps DS-1 signal. The DS-1 level is further multiplexed into DS-3 before being transmitted over the radio link.
- Many substations are served by T1, SONET, or Ethernet access equipment to provide a communications path to the substation device. T1 is a term for a digital carrier facility used to transmit a DS-1 formatted digital signal at 1.544 Mbps. T1 was developed by AT&T in 1957 and implemented in the early 1960s to support long-haul PCM voice transmission. The primary innovation of T1 was to introduce "digitized" voice and to create a network fully capable of digitally representing what was, up until then, a fully analog telephone system. T1 is used for a wide variety of voice and data applications. They are embedded in the network distribution architecture as a convenient means of reducing cable pair counts by carrying 24 voice channels in one four-wire circuit. T1 multiplexers are used to provide DS0 (64 kbps) access to higher order transport multiplexers such as SONET. SONET (Synchronous Optical NETwork) is the American National Standards Institute (ANSI) standard for synchronous data transmission on optical media. Some of the most common SONET applications include transport for all voice services, Internet access, frame relay access, ATM transport, cellular/PCS cell site transport, inter-office trunking, private backbone networks, metropolitan area networks, and more. SONET operates today as the backbone for most, if not all, interoffice trunking as well as trans-national and trans-continental communications.
- IP communications (Ethernet) are growing as a substation access technology. The transport is often over a SONET layer, but Ethernet LANs are also used. The communications network can be privately owned by the utility, or leased from a carrier. A local area network (LAN) can have its own dedicated communications links or exist as a virtual local area network (VLAN) where the transport layer is shared with other, unrelated traffic. The LAN or VLAN may interconnect with a wide area network (WAN) that carries corporate traffic or is a public transportation network. A demonstration was performed by the Idaho National Laboratory to demonstrate the vulnerability of SCADA networks utilizing IP communications [11]. The demonstration illustrated that breakers could be remotely manipulated and operator displays changed by inserting appropriate scripts in buffer overflow compromises without being detected or blocked by IT security technologies including multiple firewalls.

These media are vulnerable to eavesdropping or active intrusion. At least one case has been reported in which an intruder used radio technology to commandeer SCADA communications and sabotage the system (in this case, a waste water treatment facility) [12]. Recently, the cyber vulnerability of 900 MH spread spectrum radio communications utilized in substation communications was demonstrated by Pacific Northwest National Laboratory [13]. Refer to Section 15.8 and Section 15.9 for a discussion of measures to protect SCADA communications.

17.5.1.2.2 Dial-Up Lines to IEDs

The other path to substation control and monitoring devices is via dial-up lines directly to IEDs. As discussed in Chapter 7, IEDs are devices that intrinsically support two-way communications. IEDs are frequently configured so a user can dial up the IED. Once the user has logged on to the IED, he may use the connection to do the following:

- Acquire data that the IED has stored
- Change the parameters of the IED (e.g., the settings of a protective relay)
- Perform diagnostics on the IED
- Control the power system device connected to the IED (e.g., operate a circuit breaker)

These dial-up lines can offer a simple path for a knowledgeable intruder into the substation. There are three lines of defense that a utility can take: (a) strengthen the authentication of the user; (b) encrypt communications with the IED; or (c) eliminate the dial-up lines.

17.5.1.2.2.1 Strengthening the Authentication of the User Authentication refers to the process of ensuring that the prospective user of the IED is the person they claim to be.

As the very first step, the utility should ensure that the default passwords originally supplied with the IEDs are changed and that a set of strong passwords are implemented, if possible.

A simple second step would be to confirm that the telephone call comes from a recognized source. For this purpose, it is not sufficient to get the user ID of the caller and confirm that it is on a pre-approved list. Hackers are often familiar with telephone technology, and the caller ID can be changed or disguised. A more secure approach would be for all dial-in calls to be received by a dial-back device at the substation (also known as a call-back device). The device receives the incoming call, requires that the caller enter a user ID and password, searches an internal list for the telephone number that the call should be made from, terminates the incoming call, and dials back the caller at the phone number found in the list. In essence, the incoming call is replaced by an outgoing call.

It should be noted that the use of dial-back is not foolproof however. According to one source [14],

> *There are several ways an intruder can defeat the protection offered by a dial-back modem. For example, if the same modem and line are used for returning the call to the user, the intruder may be able to maintain control of the line while fooling the modem into acting as thought the user had hung up after the original call. The modem would then place the return call, but the intruder's equipment would be mimicking the operation of the telephone system and the return call would be connected to the intruder's modem. Alternatively, the intruder could modify the telephone switch setup to direct the return call to the intruder's telephone number regardless of the pre-arranged number stored in the modem.*

The report recommends that the utility consider the use of a separate line for the call-back, to defend against this threat. The telephone switch must also be carefully protected, since the security of the substation depends on the integrity of the telephone switch.

17.5.1.2.2.2 Encrypting Communications A second approach to enhancing the security of communications to IEDs would be to encrypt the messages between the user and the IED. Encryption could help ensure that only users in possession of the secret key would be able to interpret data from the IED and change IED parameters.

For this discussion, alongside encryption, the alternative should be mentioned of embedding a "secure hash" in messages. This technique entails computing a special code that is added to the message.

The code is a function of the contents of the message and of a secret key that should be known only to the user and the IED. Computing a secure hash is much less computationally intensive than encrypting the whole message.

In IED design, the two paramount factors are performance and cost. The high computational requirements of processors to implement some encryption schemes make encryption impractical for the low-performance microprocessors currently used in many IEDs. And the suppliers of IEDs do not wish to add functions that will raise the cost. In addition, the standards community has not yet agreed upon a unified approach to encryption. Consequently, it would take a special effort on the part of a utility to encrypt messages to and from IEDs.

Nevertheless, there are active developments along several fronts that may cause this situation to change. Higher performance microprocessors are being manufactured at ever-lower cost, reducing the cost and performance penalties of encryption. In addition, several groups are making progress in defining encryption standards for the communication protocols used in substations, including IEC Technical Committee 57, Working Groups 7 and 15, and the DNP Users Group. The IEC 61850 protocol is based on international standard communication profiles.

17.5.1.2.2.3 Eliminating the Dial-Up Lines Where possible, another approach to securing the communications to IEDs would be to eliminate dial-up lines into the substation entirely. This is dependent on the manufacturers not embedding wired or wireless modems into the IEDs. This approach is being followed by several utilities that place a high value on cyber security.

Under this approach, all communications to the IEDs originate from within the secure network, and are transmitted through and mediated by the data concentrator or substation host processor at the substation. The data concentrator or substation processor forwards the message to the appropriate IED, and routes the response back to the original caller. (In the terminology of Chapter 7, these messages use "pass through" communications.) No communications to the substation are permitted that originate outside the secure utility network. Communications to the substation IEDs would be even more secure if, as suggested earlier, fiber optic lines were used for substation communications.

The security of this approach is dependent, of course, on the success of the utility in preserving the security of its internal network. That issue is beyond the scope of this chapter.

17.5.2 Detecting Cyber Intrusion

One of the axioms of cyber security is that although it is extremely important to try to prevent intrusions into one's systems and databases, it is essential that intrusions be detected if they do occur. An intruder who gains control of a substation computer can modify the computer code or insert a new program. The new software can be programmed to quietly gather data (possibly including the log-on passwords of legitimate users) and send the data to the intruder at a later time. It can be programmed to operate power system devices at some future time or upon the recognition of a future event. It can set up a mechanism (sometimes called a "backdoor") that will allow the intruder to easily gain access at a future time.

If no obvious damage was done at the time of the intrusion, it can be very difficult to detect that the software has been modified. For example, if the goal of the intrusion was to gain unauthorized access to utility data, the fact that another party is reading confidential data may never be noticed. Even when the intrusion does result in damage (e.g., intentionally opening a circuit breaker on a critical circuit), it may not be at all obvious that the false operation was due to a security breach rather than some other failure (e.g., a voltage transient, a relay failure, or a software bug).

For these reasons, it is important to strive to detect intrusions when they occur. To this end, a number of IT security system manufacturers have developed intrusion selection systems (IDS). These systems are designed to recognize intrusions based on a variety of factors, including primarily (a) communications attempted from unauthorized or unusual addresses and (b) an unusual pattern of activity. They generate logs of suspicious events. The owners of the systems then have to inspect the logs manually and determine which represent true intrusions and which are false alarms.

Unfortunately, there is no easy definition of what kinds of activity should be classified as unusual and investigated further. To make the situation more difficult, hackers have learned to disguise their network probes so they do not arouse suspicion. In addition, it should be recognized that there is as much a danger of having too many events flagged as suspicious as having too few. Users will soon learn to ignore the output of an IDS that announces too many spurious events. (There are outside organizations however that offer the service of studying the output of IDSs and reporting the results to the owner. They will also help the system owner to tune the parameters of the IDS and to incorporate stronger protective features in the network to be safeguarded.)

Making matters more difficult, most IDSs have been developed for corporate networks with publicly accessible Internet services. More research is necessary to investigate what would constitute unusual activity in a SCADA/SA environment. In general, SA and other control systems do not have logging functions to identify who is attempting to obtain access to these systems. Efforts are underway in the commercial arena and with the National Laboratories to develop intrusion detection capabilities for control systems.

In summary, the art of detecting intrusions into substation control and diagnostic systems is still in its infancy. Until dependable automatic tools are developed, system owners will have to place their major efforts in two areas: (a) preventing intrusions from occurring, and (b) recovering from them when they occur.

17.5.3 Responding to Cyber Intrusion

The "three R's" of the response to cyber intrusion are recording, reporting, and restoring.

Theoretically, it would be desirable to record all data communications into and out of all substation devices. In that manner, if an intruder successfully attacks the system, the recordings could be used to determine what technique the intruder used, in order to modify the system and close that particular vulnerability. Secondly, the recording would be invaluable in trying to identify the intruder. In addition, if the recording is made in a way that is demonstrably inalterable, then it may be admissible as evidence in court if the intruder is apprehended.

However, due to the high frequency of SCADA communications, the low cost of substation communications equipment, and the fact that the substations are distant from corporate security staff, it may be impractical to record all communications.

In practice, although theoretically desirable, system owners will probably defer any attempts to record substation data communications until (a) storage media are developed that are fast, voluminous, and inexpensive or (b) SCADA-oriented IDSs are developed, which can filter out the non-suspicious usual traffic and record only the deviant patterns.

But even if the communications sequence responsible for an intrusion is neither detected nor recorded when it occurs, nevertheless it is essential that procedures be developed for the restoration of service after a cyber attack.

It is extremely important that the utility maintain backups of the software of all programmable substation units and documentation regarding the standard parameters and settings of all IEDs. These backups and documentation should be maintained in a secure storage, not normally accessible to the staffs who work at the substation. It would appear advisable that these backups be kept in a location other than the substation itself to lower the amount of damage that could be done by a malicious insider.

After the utility concludes that a particular programmable device has been compromised (indeed, if it just suspects a successful intrusion), the software should be reloaded from the secure backup. If the settings on an IED had been illicitly changed, the original settings must be restored. Unless the nature of the breach of security is known and can be repaired, the utility should seriously consider taking the device off-line or otherwise making it inaccessible to prevent a future exploitation of the same vulnerability.

17.6 Devising a Security Program

In order to put the recommendations of this chapter into practice, a utility should establish and implement an auditable security program developed specifically for SCADA and SA applications. Per final approval from FERC, there are regulatory mandates, NERC CIP 002-009 [15], as well as business reasons for establishing a control system security program. For federal entities such as TVA, BPA, WAPA, and the Bureau of Reclamation SCADA and SA facilities, federal law requires compliance to NIST Special Publication (SP) 800-53, *Recommended Security Controls for Federal Information Systems* [16]. The security program should consist of policies, procedures, testing, and compliance with a senior manager having responsibility and accountability for implementing and maintaining the security program. The security program must be developed specifically to control systems as traditional IT security policies, procedures, and testing have led to impacts on control systems. Additionally, SCADA systems have failed IT security compliance audits as control systems have different operational requirements. IEEE, ISA, CIGRE, and AGA have initiated efforts to address control system security policies that could apply to SCADA and SA systems.

The program for securing the utility's computer systems should also be correlated with a program for ensuring the physical security of the utility's assets. (Some of the components of a plan for cyber security will be very similar to the analogous plan for physical security.) (See Chapter 15.) The utility should consider the following issues when devising the cyber security program.

Assets

- What are the assets of the substation that the policy seeks to protect from critical infrastructure and business perspectives? (As a corollary, what assets are not protected by the policy?)
- What level of protection should be given to each asset (device, control system, communications system, and database)?
- What must a user do or have to gain access to each asset?

Threats

- What are the threats to the security of the substation that the policy seeks to address? (Also, what threats are not addressed?)
- What is the damage that can result from each of the threats?
- What measures should be taken to protect against each threat? (Several alternatives may be considered.)
- What should be done to test the protective measures that have been taken? (Should an outside organization be employed to probe for weaknesses?)
- Who will monitor the changing nature of cyber threats and update the security policy accordingly?

Threat Detection

- What measures will be taken to detect intrusion? (Should an outside party be employed to analyze intrusion records?)
- What should be done if an intrusion is suspected?
- Whom should an intrusion be reported to?
- What records should be kept and for how long?

Incident Response

- What immediate steps should be taken in response to each type of incident?
- What role will law enforcement play?
- How will the incident be reported to regulatory agencies, reliability councils, or cyber-incident recording centers?
- What improvements must be made (to policy, to documentation, to training, etc.) as a result of lessons learned?

Training and Documentation

- What are the training programs for security? (General and control system–specific security awareness; access procedures; restoration procedures)
- What are the plans for practicing restoration, and how often will they be applied?
- What are the plans for supporting manual operation if control systems suffer long-term damage?
- Who will issue the documentation for the restoration procedures, and where will the documents be kept?

Administration

- Who has the ultimate responsibility for cyber security at the utility?
- What are the responsibilities of each relevant job category?
- What are the potential consequences for staff of a violation of policy?
- How will compliance with the policy be monitored? (Should an outside organization be used?)
- How will the security policy be revised?

Software Management

- Controlling and installing software updates
- Installing security patches
- Maintaining backups
- Password policy and password maintenance

17.7 Future Measures

It should be clear from previous discussions that, at the time of publishing, technologies are not mature for ensuring the cyber security for substation control and diagnostic systems. To a certain extent, a utility will be forced to make do with partial measures. It is not practical to eliminate all security risks or to close all security vulnerabilities. The utility must evaluate what assets have the highest value and deserve the greatest effort at protecting.

Strenuous efforts are being taken in several areas however to improve the defenses against cyber threats. It will be worthwhile for the utility to monitor these developments and update their security policies to take advantage of technological advances. (As was the case with the arms race, it however must be anticipated that adversaries will develop new attack strategies as current vulnerabilities are closed; it is important that the utility monitor and respond to the changing nature of the threat as well.)

This chapter describes some current developments that will make it easier to provide for the cyber security of substation systems, and indicates where further work is needed.

17.7.1 Authentication and Encryption

The various standards groups who are responsible for defining the protocols used in substation communications are actively working on defining the standards for authentication and encryption. Concurrently, IEDs are being manufactured with faster microprocessors and more memory, making it feasible to implement encryption in embedded processors. Furthermore, the channel capacity of communications lines to substations is growing, making the performance penalty for encryption less significant. As a result of these trends, it will soon be feasible to encrypt communications between control centers and substations. In addition, if there is demand for the function from the user community, it may be possible to implement encryption of communications among IEDs within a substation at acceptable cost.

17.7.2 Secure Real-Time Operating Systems

An ancillary, but important function is to develop real-time operating systems with security policies. This will enable calls to be made to authorize, authenticate the other party, and encrypt and decrypt data.

17.7.3 Test Beds

It is difficult for a utility, unaided, to discover all the security vulnerabilities in the various systems installed at a substation. In recognition of the need for a more concerted effort, the U.S. government is dedicating resources to investigate the security vulnerabilities of elements of the critical infrastructure. Several national laboratories have taken on the task of establishing the National SCADA Test Bed where the SCADA systems in common use can be studied, their vulnerabilities discovered, and remedies implemented. It is expected that the role of the test beds will be expanded to include control and diagnostic systems in common use in substations.

17.7.4 Incident Reporting Sites

For several years, the CERT Coordination Center (CERT/CC), operated by Carnegie Mellon University [8], has served as a storehouse for reports of security incidents. CERT declares, "Our work involves handling computer security incidents and vulnerabilities, publishing security alerts, researching long-term changes in networked systems, and developing information and training to help you improve security at your site."

The CERT Web site (http://www.cert.org/) has a form that allows the manager of a computer system or network to report a security incident. CERT also publishes an advisory of cyber security problems, which is emailed to a very large number of destinations. At the current time, the incidents maintained on the CERT database are almost entirely traditional computer problems; problems with SCADA and SA systems have not been identified in their advisories. However, there have been many cases of intentional and unintentional cyber impacts on control systems in various industries including electric power. Very few cases have been formally documented. Consequently, US CERT has been expanded to include control system issues. Utilities are encouraged to make use of the US CERT incident reporting service to report security incidents, and thereby inform others of common vulnerabilities.

17.7.5 Intrusion Detection and Firewalls

It is important to be able to reliably recognize an intrusion into substation computer systems and networks.

Currently, almost all IDSs currently focus on traditional computer networks, and have not been adapted for the special circumstances characterizing the systems found at substations. Work is currently in progress to use neural networks to define a "usual" state of activity and to recognize an intrusion by the change in the patterns. Currently, these efforts have not yet been proven to be effective. It is hoped that these developments will prove successful, and IDSs appropriate for utility application will be available.

Firewalls can protect the network by limiting information from accepted addresses only. However, firewall technology is currently not capable of inspecting data packets and making go/no go decisions on passing data to the control system. Consequently, all data that appear to be from an accepted address is passed. As previously mentioned, recent demonstrations have shown that malformed control system packets can bypass firewalls and impact control systems [13]. There is on-going work and a NISCC Best Practice on firewalls for control systems [17].

17.7.6 Secure Recovery

If a computer-based system has been compromised, the process of restoring the system to its pristine state is lengthy, labor-intensive, and error-prone. It is especially difficult when the software has been modified since it was first installed. The utility must answer the difficult question about when the system was compromised, and whether the software that is being restored perhaps contains the infected code.

Developments that would allow a quick and reliable restoration of uninfected system software would be of great value to the operators of substation control and diagnostic systems.

17.7.7 Developing and Emerging Standards

1. The North American Electric Reliability Council (NERC) that has recently become the ERO has issued the Critical Infrastructure Protection (CIP) cyber security standards (CIP002-009) [15]. FERC is currently reviewing the NERC standards.
2. The IEEE Power Engineering Society (PES) is developing several standards that will affect substation cyber security including IEEE-1689—Trial Use Standard for Retrofit Cyber Security of Serial SCADA Links and IED Remote Access.*
3. IEC Technical Committee 57 Working Groups 7 and 15 are addressing IEC 60870-6 TASE.2 ("ICCP").
4. ISA has established a standards committee for process controls cyber security—ISA SP99. These standards will be applicable to substation applications. ISA has issued two standards [18,19] and is working on several others.
5. The DNP committee is addressing security of DNP3.
6. Cigré JWG D2/B3/C2-01 has issued CIGRE Technical Brochure, *Security for information systems and intranets in electric power systems.*
7. CIGRE has formed a new working group on security, D2.22, Treatment of Information Security for Electric Power Utilities (EPUs).

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*The language in the PAR makes it clear that this standard is for retrofit applications. At the time of balloting, the WG will submit a PAR revision to add the word "Retrofit" to the document's title.

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18

Gas-Insulated Transmission Line

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18.1 Introduction

The gas-insulated transmission line (GIL) is a system for the transmission of electricity at high power ratings over long distances. In cases where overhead lines are not possible, the GIL is a viable technical solution to bring the power transmitted by an overhead line underground without a reduction of power transmission capacity.

As a gas-insulated system, the GIL has the advantage of electrical behavior similar to that of an overhead line, which is important to the operation of the complete network. Because of the large cross section of the conductor, the GIL has low electrical losses compared with other transmission systems (overhead lines and cables). This reduces the operating and transmission costs, and it contributes to reduction of global warming because less power needs to be generated.

Safety of personnel in the vicinity of a GIL is very high because the solid metallic enclosure provides reliable protection. Even in the rare case of an internal failure, the metallic enclosure is strong enough to withstand damage. This allows the use of GILs in street and railway tunnels and under bridges with public traffic. No flammable materials are used to build a GIL. The use of GILs in traffic tunnels makes the tunnels more economical and can solve some environmental problems. If GIL is added to a traffic tunnel, the cost can be shared between the electric power supply company and the owner of the traffic part (train, vehicles). The environmental advantage is that no additional overhead line needs to be built parallel to the tunnel. Because of the low capacitive load of the GIL, long lengths of 100 km and more can be built.

Where overhead lines are not suitable due to environmental factors or where they would spoil a particular landscape, the GIL is a viable alternative because it is invisible and does not disturb the landscape. The GIL consists of three single-phase encapsulated aluminum tubes that can be directly buried in the ground or laid in a tunnel. The outer aluminum enclosure is at ground potential. The interior, the annular space between the conductor pipe and the enclosure, is filled with a mixture of gas, mainly N_2 (80%) with some SF_6 (20%) to provide electrical insulation. A reverse current, more than 99% of the conductor current value, is induced in the enclosure. Because of this reverse current, the outer magnetic field is very low.

GIL combines reliability with high transmission capacity, low losses, and low emission of magnetic fields. Because it is laid in the ground, GIL also satisfies the requirements for power transmission lines without any visual impact on the environment or the landscape. Of course, the system can also be used to supply power to meet the high energy-demands of conurbations and their surroundings. The directly buried GIL combines the advantage of underground laying with a transmission capacity equivalent to that of an overhead power line [1–3].

The changes in the electric power industry coming from deregulation and the separation of power generation, transmission, distribution, and powertrade have a very strong influence to the load flow in the electric power net. With new generation units, e.g., gas fired turbines or dispersed generation such as wind power generation and photovoltaic, the existing electrical net is used differently to the days when it was planned and installed in the first place. In consequence, this load flow changes are leading to congestions in the electric net and to so-called bottlenecks.

New high-power transmission lines are needed in the future, and the GIL plays an important role when overhead line solutions are not possible. When underground solutions are required because of public interest to not have aboveground installations, then the GIL can solve the transmission problem for high power ratings (2000 MVA and more) and long distances (30 km and more) [4,5].

18.2 History

The GIL was invented in 1974 to connect the electrical generator of a hydro pump storage plant in Schluchsee, Germany. Figure 18.1 shows the tunnel in the mountain with the 400-kV overhead line. The GIL went into service in 1975 and has remained in service without interruption since then, delivering peak energy into the southwestern 420-kV network in Germany. With 700 m of system length running through a tunnel in the mountain, this GIL is still the longest application at this voltage level in the world. Today, at high-voltage levels ranging from 135 to 550 kV, a total of more than 100 km of GILs have been installed worldwide in a variety of applications, e.g., inside high-voltage substations or power plants or in areas with severe environmental conditions.

Typical applications of GIL today include links within power plants to connect high-voltage transformers with high-voltage switchgear, links within cavern power plants to connect high-voltage transformers in the cavern with overhead lines on the outside, links to connect gas-insulated switchgear (GIS) with verhead lines, and service as a bus duct within GIS. The applications are carried out under a wide range of climate conditions, from low-temperature applications in Canada, to the high ambient

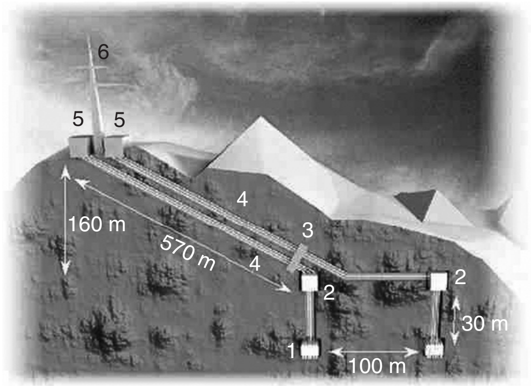

FIGURE 18.1 GIL (420 kV, 2500 A) in Schluchsee, Germany. (Courtesy of Siemens.)

temperatures of Saudi Arabia or Singapore, to the severe conditions in Europe or in South Africa. The GIL transmission system is independent of environmental conditions because the high-voltage system is completely sealed inside a metallic enclosure.

The GIL technology has proved its technical reliability in more than 2500 km/y of operation without a major failure. This high system reliability is due to the simplicity of the transmission system, where only aluminum pipes for conductor and enclosure are used, and the insulating medium is a gas that resists aging.

In the early days, the high cost of GIL restricted its use to special applications. However, with the second-generation GIL, a total cost reduction of 50% has made the GIL economical enough for application over long distances. The breakthrough in cost reduction is achieved by using highly standardized GIL units combined with the efficiencies of automated orbital-welding machines and modern pipeline laying methods. This considerably reduces the time required to lay the GIL, and angle units can be avoided by using the elastic bending of the aluminum pipes to follow the contours of the landscape or the tunnel. This breakthrough in cost and the use of N_2–SF_6 gas mixtures have made possible what is now called second-generation GIL, and it is a very interesting transmission system for high-power transmission over long distances, especially if high power ratings are needed.

The second-generation GIL was first built for eos (energie ouest suisse) at the PALEXPO exhibition area, close to the Geneva Airport in Switzerland. Since January 2001, this GIL has been in operation as part of the overhead line connecting France with Switzerland. The success of this project has demonstrated that the new laying techniques are suitable for building very long GIL transmission links of 100 km or more within an acceptable time schedule.

18.3 System Design

18.3.1 Technical Data

The main technical data of the GIL for 420- and 550-kV transmission networks are shown in Table 18.1. For 550-kV applications, the SF_6 content or the diameter of the enclosure pipe might be increased.

The rated values shown in Table 18.1 are chosen to match the requirements of the high-voltage transmission grid of overhead lines. The power transmission capacity of the GIL is 2000 MVA whether

TABLE 18.1 Technical Data for 420- and 550-kV GIL Transmission Networks

Type	Value
Nominal voltage (kV)	420/550
Nominal current (A)	3150/4000
Lightning impulse voltage (kV)	1425/1600
Switching impulse voltage (kV)	1050/1200
Power frequency voltage (kV)	630/750
Rated short-time current (kA/3 s)	63
Rated gas pressure (bar)	7
Insulating gas mixture	80% N_2, 20% SF_6

Source: Courtesy of Siemens.

tunnel laid or directly buried. This allows the GIL to continue with the maximum power of 2000 MVA of an overhead line and bring it underground without any reduction in power transmission [6,7]. The values are in accordance with the relevant IEC standard for GILs, IEC 61640 [8].

18.3.2 Standard Units

Figure 18.2 shows a straight unit combined with an angle unit. The straight unit consists of a single-phase enclosure made of aluminum alloy. In the enclosure (1), the inner conductor (2) is fixed by a conical insulator (4) and lies on support insulators (5). The thermal expansion of the conductor toward the enclosure is adjusted by the sliding contact system (3a, 3b). One straight unit has a length up to 120 m made by single pipe sections welded together by orbital-welding machines. If a directional change exceeds what the elastic bending allows, then an angle element (shown in Fig. 18.2) is added by orbital welding with the straight unit. The angle element covers angles from 4 to 90°. Under normal conditions of the landscape, no angle units are needed because the elastic bending, with a bending radius of 400 m, is sufficient to follow the contour.

At distances of 1200–1500 m, disconnecting units are placed in underground shafts. Disconnecting units are used to separate gas compartments and to connect high-voltage testing equipment for the commissioning of the GIL. The compensator unit is used to accommodate the thermal expansion of the enclosure in sections that are not buried in the earth. A compensator is a type of metallic enclosure, a mechanical soft section, which allows movement related to the thermal expansion of the enclosure. It compensates the length of thermal expansion of the enclosure section. Thus compensators are used in tunnel-laid GILs as well as in the shafts of directly buried GILs.

The enclosure of the directly buried GIL is coated in the factory with a multilayer polymer sheath as a passive protection against corrosion. After completion of the orbital weld, a final covering for corrosion protection is applied on site to the joint area.

Because the GIL is an electrically closed system, no lightning impulse voltage can strike the GIL directly. Therefore, it is possible to reduce the lightning impulse voltage level by using surge arresters at the end of the GIL. The integrated surge-arrester concept allows reduction of high-frequency overvoltages by connecting the surge arresters to the GIL in the gas compartment [9].

For monitoring and control of the GIL, secondary equipment is installed to measure gas pressure and temperature. These are the same elements that are used in gas-insulated switchgear (GIS). For commissioning, partial-discharge measurements are obtained using the sensitive very high frequency (VHF) measuring method.

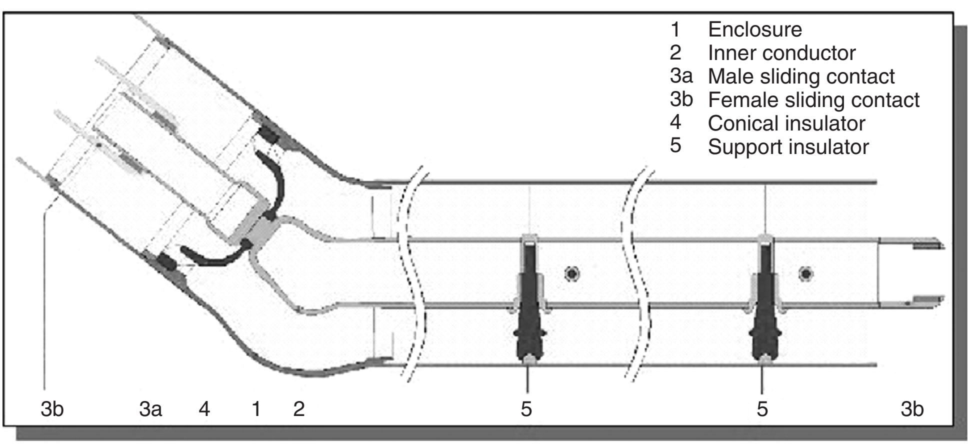

FIGURE 18.2 Straight construction unit with an angle element. (Courtesy of Siemens.)

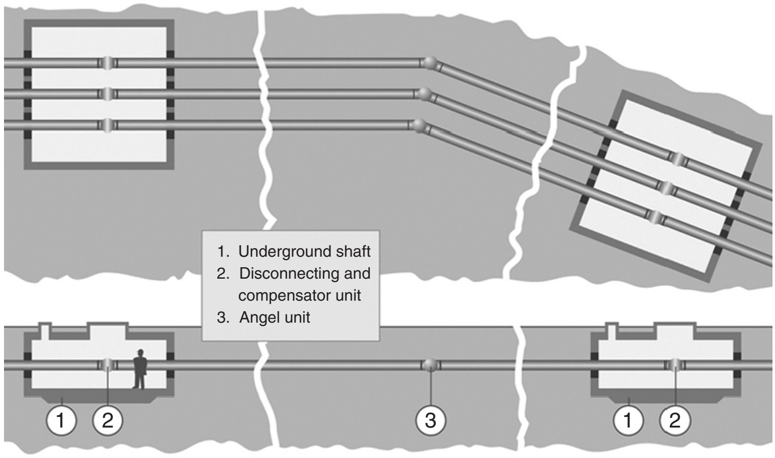

FIGURE 18.3 Directly buried GIL system components. (Courtesy of Siemens.)

An electrical measurement system to detect arc location is implemented at the ends of the GIL. Electrical signals are measured and, in the very unlikely case of an internal fault, the position can be calculated by the arc location system (ALS) with an accuracy of 25 m.

The third component is the compensator, installed at the enclosure. In the tunnel-laid version or in an underground shaft, the enclosure of the GIL is not fixed, so it will expand in response to thermal heat-up during operation. The thermal expansion of the enclosure is compensated by the compensation unit. If the GIL is directly buried in the soil, the compensation unit is not needed because of the weight of the soil and the friction of the surface of the GIL enclosure.

The fourth and last basic module used is the disconnecting unit, which is used every 1.2–1.5 km to separate the GIL in gas compartments. The disconnecting unit is also used to carry out sectional high-voltage commissioning testing.

An assembly of all these elements as a typical setup is shown in Fig. 18.3, which illustrates a section of a GIL between two shafts (1). The underground shafts house the disconnecting and compensator units (2). The distance between the shafts is between 1200 and 1500 m and represents one single gas compartment. A directly buried angle unit (3) is shown as an example in the middle of the figure. Each angle unit also has a fix point, where the conductor is fixed toward the enclosure.

18.3.3 Laying Methods

The GIL can be laid aboveground on structures, in a tunnel, or directly buried into the soil like an oil or gas pipeline. The overall cost for the directly buried version of the GIL is, in most cases, the least expensive version of GIL laying. For this laying method, sufficient space is required to provide accessibility for working on site. Consequently, directly buried laying will generally be used in open landscape crossing the countryside, similar to overhead lines, but invisible.

18.3.3.1 Directly Buried

The most economical and fastest method of laying cross country is the directly buried GIL. Similar to pipeline laying, the GIL is continuously laid within an open trench. A nearby preassembly site reduces the cost of transporting GIL units to the site. With the elastic bending of the metallic enclosure, the GIL can flexibly adapt to the contours of the landscape. In the soil, the GIL is continuously anchored, so that no additional compensation elements are needed [10,11].

The laying procedure for a directly buried GIL is shown in Fig. 18.4. The left side of the figure shows a digging machine opening the trench, which will have a depth of about 1.2–2 m. The building shown close to the trench is the prefabrication area, where GIL units of up to 120 m in length are preassembled

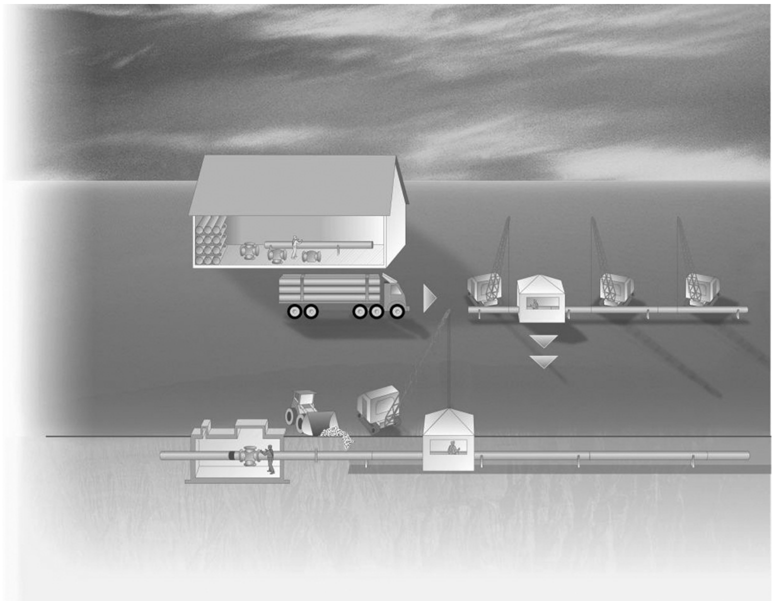

FIGURE 18.4 Laying procedure for a directly buried GIL. (Courtesy of Siemens.)

FIGURE 18.5 Laying the GIL into the soil. (Courtesy of Siemens.)

FIGURE 18.6 Bended tube and backfilling. (Courtesy of Siemens.)

and prepared for laying. The GIL units are transported by cranes close to the trench and then laid into the trench. The connection to the already laid section is done within a clean housing tent in the trench. The clean housing tent is then moved to the next joint and the trench is backfilled. Figure 18.5 shows the moment of laying the GIL into the trench. Figure 18.6 shows the bended tube and backfilling of the trench.

18.3.3.2 Aboveground Installation

Aboveground GIL installations are usually installed on steel structures at heights of 1–5 m aboveground. The enclosures are supported in distances of 20–40 m. This is because of the rigid metal enclosure. Because of the mechanical layout of the GIL, it is also suitable to use existing bridges to cross, e.g., a river.

The aboveground installations are typical for installations within substations to connect, e.g., the bay of a GIS with an overhead line, where larger distances between the phases of the three-phase system are used, or to connect the GIS directly with the step-down transformer. The GIL is often chosen if very high reliability is needed, e.g., in nuclear power stations.

Another reason for GIL applications in substation power is that the aboveground installations are used for the transmission of very high electrical power ratings. The strongest GIL has been installed in Canada at the Kensington Nuclear Power Station in a substation with GIS where single sections of the GIL bus bar system can carry currents of 8000 A and can withstand short circuit currents of 100,000 A.

Aboveground GIL installations inside substations are widely used in conjunction with GIS. Usually, the substations are fenced and, therefore, not accessible to the public. If this is not the case, laid tunnel or directly buried GIL will be chosen for safety reasons. Accessibility of GIL to the public is generally avoided so as not to allow manipulations on the GIL (e.g., drilling a hole into the enclosure), which can be dangerous because of the high-voltage potential inside.

18.3.3.3 Tunnel-Laid

If there is not enough space available to bury a GIL, laying the GIL into a tunnel will be the most appropriate method. This tunnel-laying method is used in cities or metropolitan areas as well as when crossing a river or interconnecting islands. Because of the high degree of safety that GIL offers, it is possible to run a GIL through existing or newly built street or railway tunnels, e.g., in the mountains.

Modern tunneling techniques have been developed during the past few years with improvements in drilling speed and accuracy. So-called microtunnels, with a diameter of about 3 m, are economical solutions in cases when directly buried GIL is not possible, e.g., in urban areas, in mountain crossings, or in connecting islands under the sea. Such microtunnels are usually the shortest connection between two points and, therefore, reduce the cost of transmission systems. After commissioning, the system is easily accessible. Figure 18.7 shows a view into a GIL tunnel at the IPH test field in Berlin. This tunnel of 3 m in diameter can accommodate two systems of GIL for rated voltages of up to 420/550 kV and with rated currents of 3150 A. This translates to a power transmission capacity of 2250 MVA for each system.

Figure 18.8 shows a view into the tunnel at PALEXPO at Geneva Airport in Switzerland with two GIL systems. The tunnel dimensions in this case are 2.4 m wide and 2.6 m high. The transmission capacity of this GIL is also 2250 MVA at 420/550-kV rated voltage with rated currents up to 3150 A.

In both laying methods—directly buried and tunnel laid—the elastic bending of the GIL can be seen in Figs. 18.6 and 18.8, respectively. The minimum acceptable bending radius is 400 m.

Figure 18.9 shows the principle for the laying procedure in a tunnel. GIL units of 11–14 m in length are brought into a tunnel by access shafts and then connected to the GIL transmission line in the tunnel. In cases with horizontal accessibility—such as in a traffic tunnel for trains or vehicles—the GIL units can be much longer, 20–30 m by train transportation. This increase in length reduces the assembly work and time and allows major cost reductions. A special working place for mounting and welding is installed at the assembly site [12]. As seen in Fig. 18.9, the delivery and supply of prefabricated elements (1) is brought to the shaft or

FIGURE 18.7 View into the tunnel. (Courtesy of Siemens.)

FIGURE 18.8 Tunnel-laid GIL for voltages up to 550 kV. (Courtesy of Siemens.)

tunnel entrance. After the GIL elements are brought into the shaft to the mounting and welding area (2), the elements are joined by an orbital-welding machine. The GIL section is then brought into the tunnel (3). When a section is ready, a high-voltage test is carried out (4) to validate each section.

18.3.3.4 Covered Trench

To lay the GIL in a covered trench is another low-cost solution. The trench is usually a U-shape concrete structure laid underground. The U-shape concrete structure is usually prefabricated and transported on site for laying in the open trench and connecting section by section.

Once the U-shape concrete structure is laid, the GIL can be inserted and fixed to the bottom or to the sidewalls by steel structures. The steel structures can be fixed by bolts to the concrete U-shape structure and will carry the GIL pipes on rolls or slide pads if flexibility is needed for thermal expansion. Or the GIL pipes can be fixed to the steel structure by a steel band, to realize a fix point where no thermal expansion is allowed. The GIL pipes are usually laid with expansion joints allowing flexibility to the pipes concerning the thermal expansion and the bending radius.

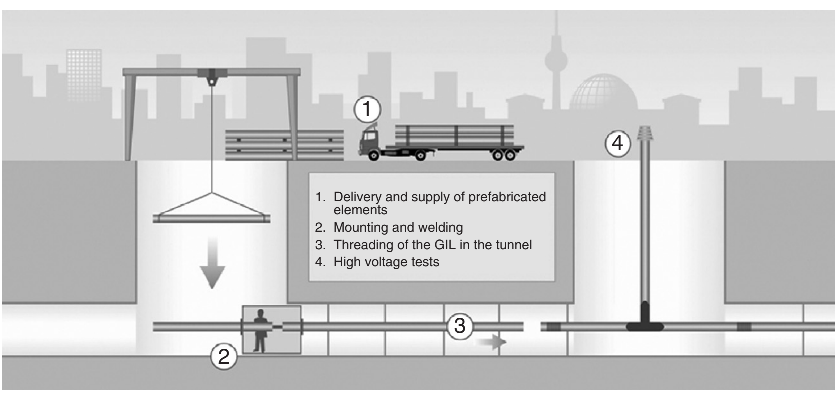

FIGURE 18.9 Laying and testing in a tunnel. (Courtesy of Siemens.)

To close the U-shape concrete, different covers are possible depending on the surrounding and protection. A totally closed cover made of concrete, steel, or aluminum can be chosen to avoid any direct contact to the GIL outer pipe. This is usually the case in areas where public access is given. In other cases it can be possible to use cattle grid or other open covers. This may be the case if the area is fenced, e.g., within a substation or power plant.

18.4 Development and Prototypes

Development of the second-generation GIL was based on the knowledge of gas-insulated technologies and was carried out in type tests and long-duration tests. The type tests proved the design in accordance with IEC 60694, IEC 60517, IEC 61640, and related standards [13,14]. An expected lifetime of 50 years has been simulated in long-term duration tests involving combined stresses of current and high-voltage cycles that were higher than the nominal ratings. At the IPH test laboratory in Berlin, Germany, tests have been carried out on tunnel-laid and directly buried GIL in cooperation with the leading German utilities.

A prototype tunnel-laid GIL of approximately 70-m length has been installed in a concrete tunnel. The jointing technique of a computer-controlled orbital-welding machine was applied under realistic on-site conditions. The prototype assembly procedure has also been successfully proved under realistic on-site conditions.

The directly buried GIL is a further variant of GIL. After successful type tests, the properties of a 100-m-long directly buried GIL were examined in a long-duration test with typical accelerated load cycles. The results verified a service life of 50 years. Installation, construction, laying, and commissioning were all carried out under real on-site conditions. The test program represents the first successfully completed long-duration test for GIL using the insulating N_2–SF_6 gas mixture. The technical data for the directly buried and tunnel-laid GIL are summarized in Table 18.2.

The values shown in Table 18.2 are chosen for the application of GIL in a transmission grid with overhead lines and cables. Because the GIL is an electrically closed system, meaning the outer enclosure is completely metallic and grounded, no lightning impulse voltage can directly strike the GIL. Therefore, it is possible to reduce the lightning impulse voltage level by using surge arresters at the ends of the GIL. The integrated surge-arrester concept allows the reduction of high-frequency overvoltages by connecting the surge arresters to the GIL in the gas compartment [9,33–35].

18.4.1 Gas Mixture

Like natural air, the gas mixture consists mainly of nitrogen (N_2), which is chemically even more inert than SF_6. It is therefore an ideal and inexpensive admixture gas that calls for almost no additional handling work on the gas system [15]. The low percentage (20%) of SF_6 in the N_2–SF_6 gas mixture acquires high dielectric strength due to the physical properties of these two components. Figure 18.10

TABLE 18.2 Technical Data for Tunnel-Laid and Directly Buried GIL Transmission Networks

	Tunnel-Laid GIL	Directly Buried GIL
Nominal voltage (kV)	420/550	420/550
Nominal current (A)	3150	3150
Lightning impulse voltage (kV)	1425	1425
Switching impulse voltage (kV)	1050	1050
Rated short-time current (kA/3 s)	63	63
Rated transmission capacity (MVA)	2250	2250
Insulating gas mixture	80% N_2	80% N_2
	20% SF_6	20% SF_6
Pipe outside dimension (mm)	520	600

Source: Courtesy of Siemens.

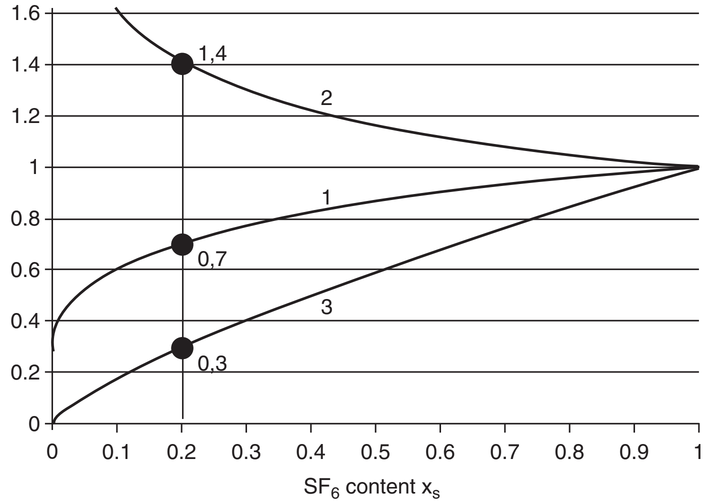

FIGURE 18.10 Normalized ideal intrinsic properties of N_2–SF_6 mixtures. 1. Pressure-reduced critical field; 2. necessary pressure for mixtures of equal critical field strength; 3. necessary amount of SF_6 for mixtures of equal critical field strength. (Courtesy of Siemens.)

shows that a gas mixture with an SF_6 content of only 20% has 70% of the pressure-reduced critical field strength of pure SF_6. The curves are defined in Fig. 18.10. A moderate pressure increase of 40% is necessary to achieve the same critical field strength of pure SF_6.

N_2–SF_6 gas mixtures are an alternative to pure SF_6 if only dielectric insulation is needed and there is no need for arc-quenching capability, as in circuit breakers or disconnectors. Much published research work has been performed and properties ascertained in small test setups under ideal conditions [16]. The arc-quenching capability of N_2–SF_6 mixtures is inferior to pure SF_6 in approximate proportion to its SF_6 content [17]. N_2–SF_6 mixtures with a higher SF_6 concentration are successfully applied in outdoor SF_6 circuit breakers in arctic regions in order to avoid SF_6 liquefaction, but a reduced breaking capability has to be accepted.

In the event of an internal arc, the N_2–SF_6 gas mixture with a high percentage of N_2 (80%) behaves similar to air. The arc burns with a large footpoint area. Footpoint area is the area covered by the footpoint of an internal arc during the arc burning time of typically 500 ms. Consequently, the thermal-power-flow density into the enclosure at the arc footpoint is much less, which causes minimal material erosion of the enclosure. The result is that the arc will not burn through, and there is no external impact to the surroundings or the environment.

18.4.2 Type Tests

The type tests were based on the new IEC 61640 standard [8]. The test parameters for additional tests to assess GIL lifetime performance were defined with reference to the CIGRE recommendation for prequalification tests (WG 21–03, September 1992) and IEC 61640. For the type tests, full-scale test setups were installed, containing all essential design components.

18.4.2.1 Short-Circuit Withstand Tests

The short-circuit withstand tests were carried out on the test setup shown in Fig. 18.11. The GIS test setup was assembled using the different GIS units: straight unit, angle unit, compensator unit, and disconnector unit. From left to right in Fig. 18.11 there is: the straight unit; next a 90° angle unit; and at the far right a disconnection unit. Table 18.3 lists the parameters for the short-circuit withstand test. The different values for the duration of short-circuit currents are not related to design criteria but, rather, reflect regional market requirements.

FIGURE 18.11 High-current and internal-arc test setup. (Courtesy of Siemens.)

After these tests, no visible damage was seen, and the functionality of the GIL prototype was not impaired. The contact resistivity was measured after the test and was well within the range of what was allowed by the IEC 61640 standard. Actually, the contact resistivity of the GIL sliding contact after the test was even a little lower than before, indicating the system's very good current-carrying capability.

18.4.2.2 Internal-Arc Test

To check whether arcing due to internal faults causes burn-through of the enclosure, an internal-arcing test was performed on the GIL prototype. Tests were carried out with arc currents of 50 and 63 kA and arc duration times of 0.33 and 0.5 s. The results of the internal-arcing tests showed only little damage, with the wall thickness of the enclosure eroding by only a few micrometers. The pressure rise was very low because of the size of the compartment of about 20 m in length. Figure 18.12, a view into the GIL after the arc fault test, shows very few distortions. The resistance to arcing damage means that the GIL can use the autoreclosure function, the same as with overhead lines.

Results of the internal-arc tests can be summarized as follows:

- No external influence during and after the internal-arc test was noticed.
- No burn-through of the enclosure occurred. Very low material erosion was observed on the enclosure and conductor.
- The pressure rise within the enclosures during arcing was so low that even the rupture discs did not open.
- The arc characteristic is much smoother compared with the characteristics in pure SF_6 (e.g., large arc diameter and lower arc traveling speed).
- Cast-resin insulators were not seriously affected.

All of these results speak in favor of the safe operation of the GIL. Eveno in the very unlikely event of an internal arc, the external environment is not affected. The results of the arc fault test also showed that in the case of a tunnel-laid GIL, there is no danger to the people traveling through the tunnel. This makes the

TABLE 18.3 Parameters for Short-Circuit Withstand Test

GIL Test Parameter	Tunnel-Laid GIL	Directly Buried GIL
Short-circuit peak current (kA)	185	165
Short-time current (kA)	75	63
Duration of short-circuit current (s)	0.5	3

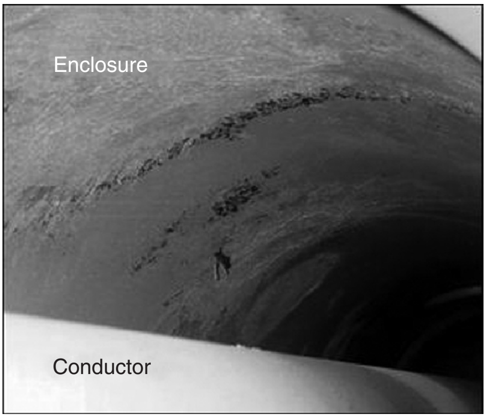

FIGURE 18.12 View into the GIL after an arc fault of 63 kA and 0.5 s. (Courtesy of Siemens.)

GIL the only high-power transmission system that can be used in public traffic tunnels together with trains and street traffic.

18.4.2.3 Dielectric Tests

Dielectric type tests were carried out on the full-scale test setup in the high-voltage laboratory of Siemens in Berlin (Fig. 18.13) and in the IPH test laboratory, also in Berlin. The tunnel-laid and directly buried GIL systems were tested according to the rated voltages and test voltages given in IEC standard 61640. The gas pressure was set to 7 bar abs. Test parameters are presented in Table 18.4. The tests were applied with 15 positive and 15 negative impulses, and the power-frequency withstand-test voltage was applied for 1 min. All tests were passed.

18.4.3 Long-Duration Tests

To check the GIL system's suitability for practical use, every effort was made to implement a test setup that came close to real conditions. Therefore, the tunnel-laid GIL was assembled on site and installed in a tunnel made of concrete tubes (total length: 70 m). The directly buried GIL was laid in soil (total length: 100 m). The test parameters are given in Table 18.5.

The test values are derived from typical applications for directly buried and tunnel-laid GIL. The lower test voltages for the tunnel-laid GIL reflect the fact that such systems are typically used in metropolitan areas, where they are usually connected to cable systems and therefore have lower overvoltages from the net. The higher voltages for the directly buried GIL represent the typical application as part of the overhead line net, with higher overvoltages due to lightning. In any case, both applications of test voltages can be used for directly buried and tunnel-laid GIL.

FIGURE 18.13 Test setup for high-voltage tests. (Courtesy of Siemens.)

TABLE 18.4 Parameters for Dielectric Type Tests at 7-bar Gas Pressure

	Test Parameters GIL	
	Directly Buried and Tunnel-Laid	Directly Buried
Maximum voltage of equipment Um	420 kV	550 kV
AC withstand test, 1 min	630 kV	750 kV
Lightning impulse test	1425 kV	1600 kV
Switching impulse test	1050 kV	1200 kV

Source: Courtesy of Siemens.

The duration and cycle times of the current and high-voltage sequences were chosen to apply maximum stress to heat up and cool down the GIL system. After a heat cycle of 12 or 24 h, the current was switched off, and the high voltage was applied to the GIL at the moment when the strongest mechanical forces were coming with the cool-down phase of the GIL. The sequences are listed in Table 18.6.

The total time of the long-duration test was 2500 h, which represents a lifetime of 50 years due to the overvoltage (double value) and the mechanical stress. The complete long-duration test is shown in Fig. 18.14.

GIL conductor and enclosure temperature, as well as GIL movement due to thermal expansion/contraction, were monitored during load cycles. All tests were performed successfully.

18.4.3.1 Long-Duration Test on a Tunnel-Laid GIL

A 70-m-long prototype was assembled and laid in a concrete tunnel of 3-m diameter (Fig. 18.15). The arrangement contained all major components of a typical GIL, including supports for the tunnel installation. The tunnel segments are original concrete units that are laid 20–40 m under the street level. The technology of drilling such tunnels has improved during the past few years, and a large reduction in costs can be obtained through today's improved measuring and control techniques.

Figure 18.16 shows a top view of the long-duration test setup, which consists of a 50-m straight-construction unit, an angle unit, and another 20-m section after the directional change. The axial compensator took care of the thermal expansion of the enclosure during the load cycles. The disconnecting unit separates the GIL toward the high-voltage connection and the connection to the high-current source. Sliding contacts inside the GIL compensate for the thermal expansion of the conductor, which slides on support insulators.

TABLE 18.5 Parameters of the Commissioning Test and the Recommissioning Test after Demonstration of a Repair Process

	Test Parameters GIL, Directly Buried		Test Parameters GIL, Tunnel-Laid	
Commissioning	AC withstand test, 1 min with PD monitoring	630 kV	AC withstand test, 10 s	550 kV
	lightning impulse test	1300 kV	AC withstand test, 1 min with PD monitoring	504 kV
	switching impulse test	1050 kV	Lightning impulse test	1140 kV
Re-commissioning, after demonstration of repair process	AC withstand test, 1 min with PD monitoring	630 kV	AC withstand test, 10 s	550 kV
	lightning impulse test	1300 kV	AC withstand test, 1 min with PD monitoring	504 kV
	switching impulse test	1050 kV	lightning impulse test	1140 kV
	AC, 48 h with PD monitoring	480 kV		
Final test (tunnel-laid, after 2500 h) (directly buried, after 2880 h)	AC withstand test, 1 min with PD monitoring	630 kV	AC withstand test, 10 s	550 kV
	lightning impulse test	1300 kV	AC withstand test, 1 min with PD monitoring	504 kV
	switching impulse test	1050 kV	lightning impulse test	1140 kV
	AC, 48 h with PD monitoring	480 kV		

Source: Courtesy of Siemens.

TABLE 18.6 Load Cycles and Intermediate Tests of the Long-Duration Test

Test Parameters GIL, Tunnel-Laid			Test Parameters GIL, Direct Buried		
Load cycles	Total duration	2500 h	Load cycles, time parameters change every 480 h	Total duration	2880 h
	Duration of one cycle	12 h		Duration of one cycle	12/24 h
	Number of cycles	210		Number of cycles	120/50
	Heating current, 7 h	3200 A		Heating current, 8 h	4000 A
	High voltage, 5 h	480 kV		High voltage, 4/16 h	480 kV
Intermediate tests, every 480 h	Switching impulse test	1050 kV	Intermediate tests, every 480 h	Lightning impulse test	1140 kV

Source: Courtesy of Siemens.

The segments of the GIL are welded with an orbital-welding machine, as seen in Fig. 18.17. The orbital-welding machine is highly automated and gives a high-quality, reproducible weld. Together with the orbital welding, an automated, ultrasonic measuring system provides 100% quality control of the weld, which guarantees a gas-tight enclosure with a gas leakage rate of almost zero.

In addition to the above-mentioned long-duration test with extremely high mechanical and electrical stresses, the sequence was interrupted after 960 h and a planned repair process—including the substitution of a tube length—was carried out (Fig. 18.18). The total process of exchanging a segment of the GIL, including the recommissioning high-voltage testing, was finished in less than 1 week. The results demonstrate that the GIL can be repaired on site and then returned to service without any problems. The repair process requires only simple tools and is easily carried out in a short time.

Mixing of the gas was performed on site using a newly developed computer-controlled gas mixing device. The mixing process is continuous and arrives at a very high accuracy of the chosen gas mixture in the GIL. The gas mixture can be stored in standard high-pressure gas compartments (up to 200 bar) and can be reused after recommissioning.

18.4.3.2 Long-Duration Test on a Directly Buried GIL

The long-duration test for the buried GIL was carried out on a 100-m-long test setup. Figure 18.19 shows the site arrangements. The laying procedure was carried out under realistic on-site conditions. Installation of the GIL under these conditions has proved the suitability of this laying procedure. The economy of the tools and procedures developed for this solution has been successfully demonstrated.

The tunnel-laid GIL described here is the first one with a N_2–SF_6 gas mixture to be tested and qualified in a long-duration test. The long-duration test—which involves extremely high stresses over a

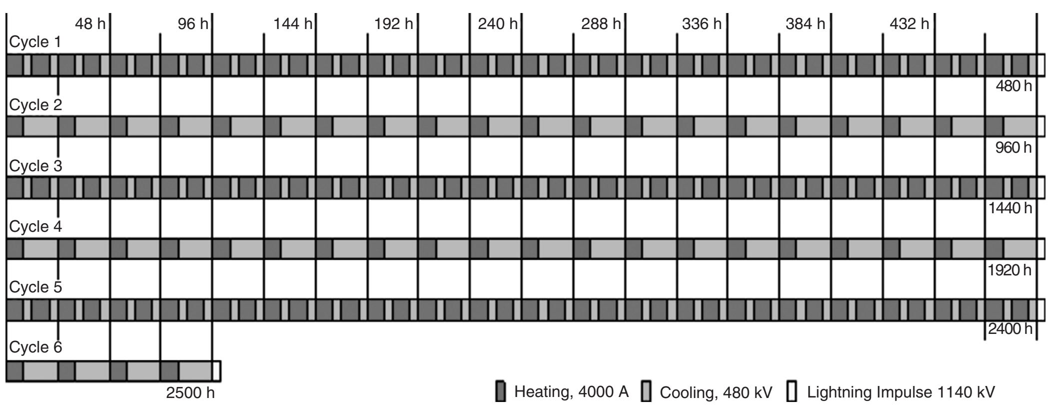

FIGURE 18.14 Long-duration test cycle of the directly buried GIL. For the tunnel-laid GIL, the test sequences of cycle type 1 had been applied for the total duration. (Courtesy of Siemens.)

FIGURE 18.15 Tunnel arrangement of two systems GIL for the long-term test. (Courtesy of Siemens.)

period of 2500 h (simulating a lifetime of more than 50 years) and a planned interruption to simulate a repair process—was concluded successfully. The results demonstrate once again the excellent performance and high reliability of the GIL [18,19].

Figure 18.19 shows the IPH high-voltage test laboratory in Berlin with the high-voltage connection to shaft 1. From shaft 1, the trench with the directly buried GIL of 100-m length, including elastic bending and a directly buried angle module, proceeds to shaft 2 at the end. In shaft 2, a ground switch closes the current loop. The current-injection devices are in shaft 1. The shaft structures at the ends of the tunnel-laid GIL accommodate the separating modules and expansion fittings. The secondary equipment with the telecommunications system is also located there.

A crane transports the assembled GIL unit from the nearby assembly building to the welding container situated beside the trench, where the straight GIL segments are joined using an orbital-welding machine.

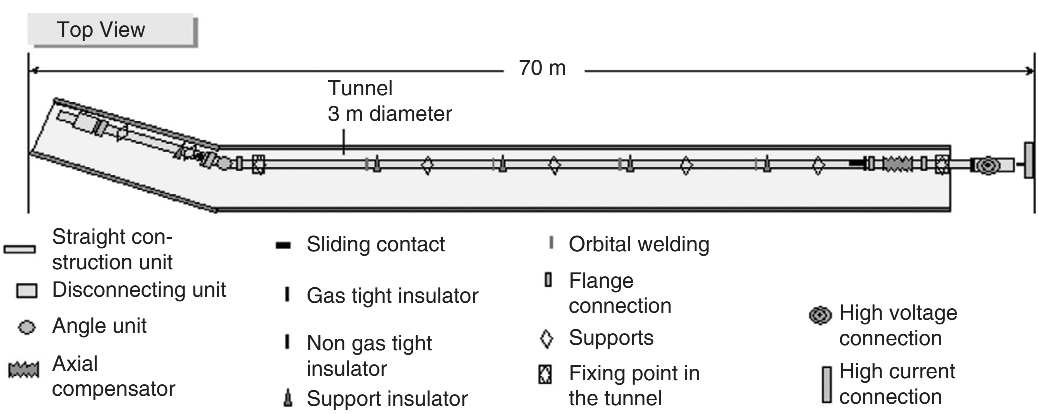

FIGURE 18.16 Arrangement of long-duration test setup. (Courtesy of Siemens.)

FIGURE 18.17 Computer-controlled orbital welding on site. (Courtesy of Siemens.)

The final on-site assembly takes place either beside the trench or in the shaft structures. The place of assembly depends on the civil engineering design dictated by local conditions. The installation finishes with the laying of the GIL in its final position. Figure 18.20 shows the trench-laying of the

FIGURE 18.18 Cutting the enclosure pipe with a saw. (Courtesy of Siemens.)

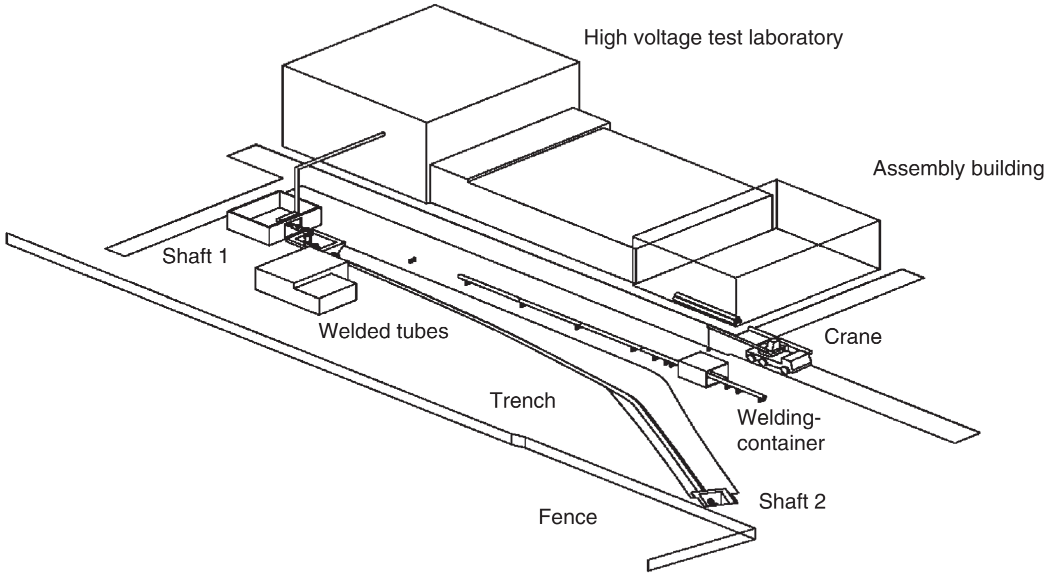

FIGURE 18.19 Site arrangements of the directly buried long-duration test. (Courtesy of Siemens.)

FIGURE 18.20 Trench of 55-m-long section during laying and view into the trench. (Courtesy of Siemens.)

TABLE 18.7 Tests on Commissioning and Recommissioning

Pressure test	Verification per Pressure Vessel Regulation
Gas-tightness test	Checking of flange joints
State of gas mixture	Mixture ratio Filling pressure Dew point
Corrosion protection coating voltage test	10 kV/1 min.
Resistance test	Main circuit

Source: Courtesy of Siemens.

GIL with cranes. The trench follows a spherical curve with a bending radius of 400 m, which can be seen in Fig. 18.20.

The process of constructing the trench and laying the GIL is quick and cost effective. The thermal expansion of the enclosure is absorbed by the surrounding bedding of coarse material by means of frictional forces. The bedding must also have sufficient thermal conductivity to dissipate the heat losses from the GIL. The temperature at the transition from the enclosure to the ground does not exceed 50°C when 2250 MVA are transmitted continuously by the GIL.

For the purpose of commissioning, comprehensive electrical and mechanical tests are necessary to verify the properties of the directly buried GIL. In addition to verifying the dielectric properties and checking the secondary equipment, the tests listed in Table 18.7 must be performed.

In addition, the typical elements of the secondary equipment of the GIL were employed: thus, partial discharge (PD) measurement was carried out during commissioning and online during the test. The gas properties, such as temperature and pressure, were monitored on a continuous basis. Arc-location sensors were implemented. Radio sensors measured conductor temperature, gas density at the conductor, and the enclosure temperature in the ground at several points. The mechanical behavior of the GIL was studied by monitoring data from displacement sensors in the shaft structures and along the route. These sensors record the movement of the GIL relative to the ground or to the building.

During the course of the long-term test, the essential physical variables that describe the GIL—and that are used to prove the parameters of the calculations—are recorded. In addition to the electrical stress imposed on the system by voltage and current, the above-mentioned temperatures and movement were recorded.

18.4.3.3 Results of the Long-Duration Testing

Thermal Aspects

The GIL and its surrounding soil is a system of thermally coupled bodies, with inner heat produced by circulation of electrical current in both the conductor and the enclosure. Convection and radiation remove the heat losses from the conductor to the enclosure, whereas heat transfer in the annulus by conduction is negligible. This heat, adding to the losses by Joule effect from the enclosure, dissipates in the soil mainly in the radial direction to the surface of the soil and then flows into the ambient air by convection. The soil parameters were obtained from various literature sources documenting the soil properties in Berlin.

Before performing the unsteady-state study of the thermal behavior of the GIL, a steady-state model was developed taking into account the mechanisms of conduction in a solid body, natural convection in a cylindrical cavity, and radiation and convection in the interface between the soil surface and the air. The thermal system was divided into two parts—the GIL and the surrounding soil—and the physical phenomena occurring in each part was modeled. The FEM method (ANSYS program) was used first to check the accuracy of the developed analytical model and then to carry out the unsteady-state analyses of the thermal behavior of the buried GIL.

Calculation Model

Calculations were carried out using the finite element method. Heat loss, heat-transfer coefficient, and thermal resistance in the annular gap between the conductor and enclosing tube were calculated using a steady-state method according to the IEC 60287 standard [18,20]. These results were then used as constants in the transient calculation.

Calculations for the GIL cross section at the first location were carried out with the following parameters:

Cover $h = 0.7$ m ($h = 2.6$ m for the second location)
Thermal conductivity, $l = 1.6$ W/mK
Soil temperature, $T_s = 15$°C
Initial values for soil temperature, $T_i = 20$°C

The thermal resistance of the soil was measured at the start of the test at three different places (at the ends of the line and in the center). At each of these points, measurements were taken at two depths between 0.9 and 2.3 m. The average thermal resistance measured varied from 0.46 to 0.80 mK/W, a 70% difference between the extreme measured values. The measurements show a wide scatter from the mean value. The thermal resistance that was used in the calculations was taken as the mean values of the measurements.

The boundary conditions used in the calculations were as follows:

- Interface between soil and air: heat-transfer coefficient 20 W/m^2 K
- Air temperature is taken as an approximation of the measured air temperature by a sine function
- Temperature of soil: 15°C (20 m away from the GIL)
- Initial temperature of soil: 20°C
- Bisecting line: heat loss 0 W/m^2 (symmetry conditions)

Calculations were carried out for the following cycles load:

- Short cycle
- 8 h, $I = 4000$ A, loss = 145 W/m
- 4 h, $I = 0$ A, loss = 0 W/m
- Long cycle
- 8 h, $I = 4000$ A, loss = 145 W/m
- 16 h, $I = 0$ A, loss = 0 W/m

Comparison of Calculations and the Test Results

In order to compare the measured temperatures with the calculated temperatures, heating of the GIL during the whole test time was simulated. Comparisons of the measured and the calculated temperatures for a 1-m depth and 16 days (01.09.99 to 16.09.99), with two cycles occurring above, below, and to the side of the enclosing tube. The calculations agree well with the measured values. The maximum temperatures rose slowly during the short cycles and reached 35°C after 8 days. During the second period, the cooling phase was extended from 4 to 16 h, which was why the temperatures in the GIL system fell (Fig. 18.21). In this case, the maximum enclosing-tube temperatures were less than 33°C.

The calculations, unlike the measurements, show that the maximum temperature is to be found around the circumference of the underside of the enclosing tube, since the effect of heat transfer by natural convection from the inner conductor to the enclosing tube is not taken into account in the calculations. In the upper and lower parts of the enclosing tube, the different temperatures can be explained by variations in the resistance of the soil.

The diagram in Fig. 18.22 shows the temperature distribution of the calculations in the soil at time 188 h (7.8 days) during the heating phase. The temperature measured during the test is assumed as a marginal condition for the air temperature. Temperature distributions during the day and the night show a difference only in the higher layer of soil immediately below the ground surface. This can be explained

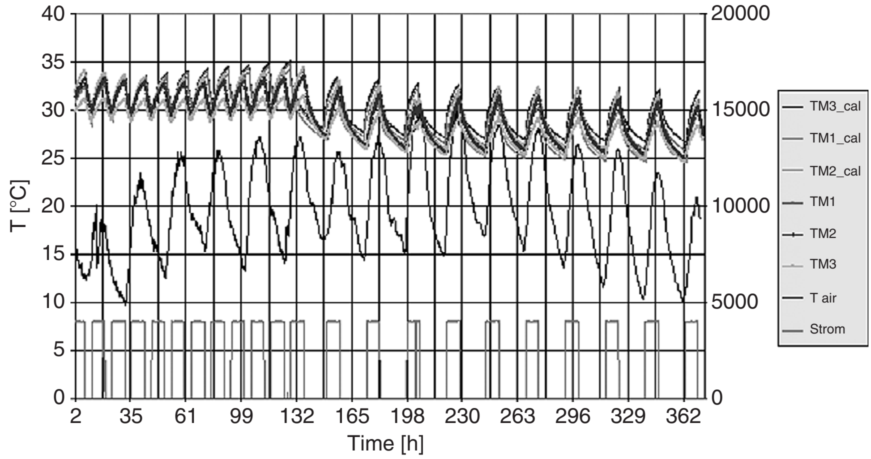

FIGURE 18.21 Comparison of numerical and experimental results of overload current rating of a directly buried GIL long-duration test, short and long cycle. (Courtesy of Siemens.)

by the heat transmission between air and the surface of the ground due to the lower air temperature during the night. Heat transmission from the GIL is better at night, since the temperatures in the soil are slightly lower. The fluctuation in air temperature between night and day did not have as great an influence on the temperature distribution in the GIL and the soil as those that caused the load variation.

Further simulations of the test were carried out for a depth of 2.9 m during the same period as above (01.09.99 to 16.09.99). A comparison of calculations and measurements showed good agreement between the calculations and the measurements.

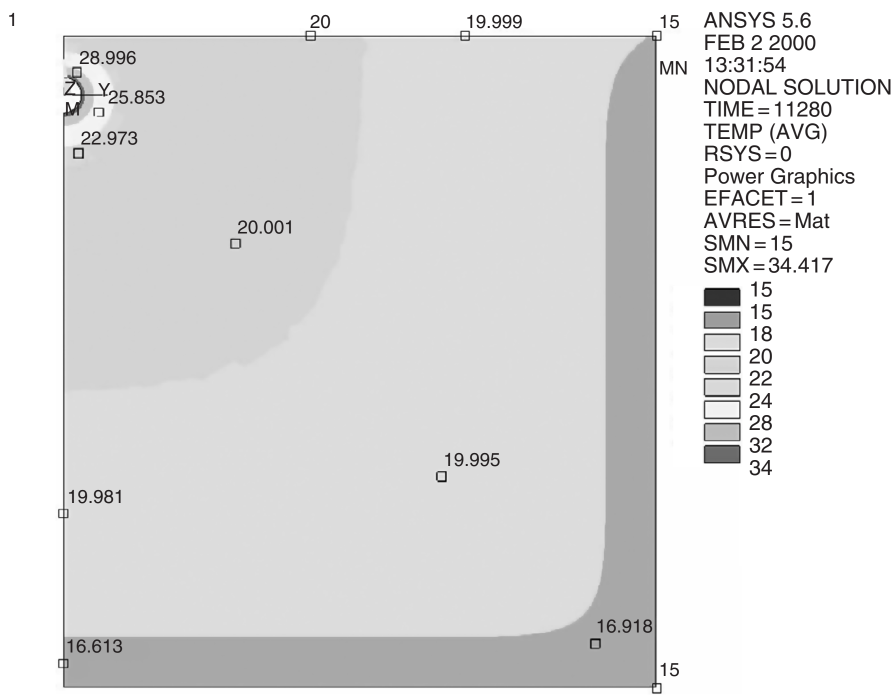

FIGURE 18.22 Temperature distribution at time $t = 188$ h and at depth 1.2 m, heating phase. (Courtesy of Siemens.)

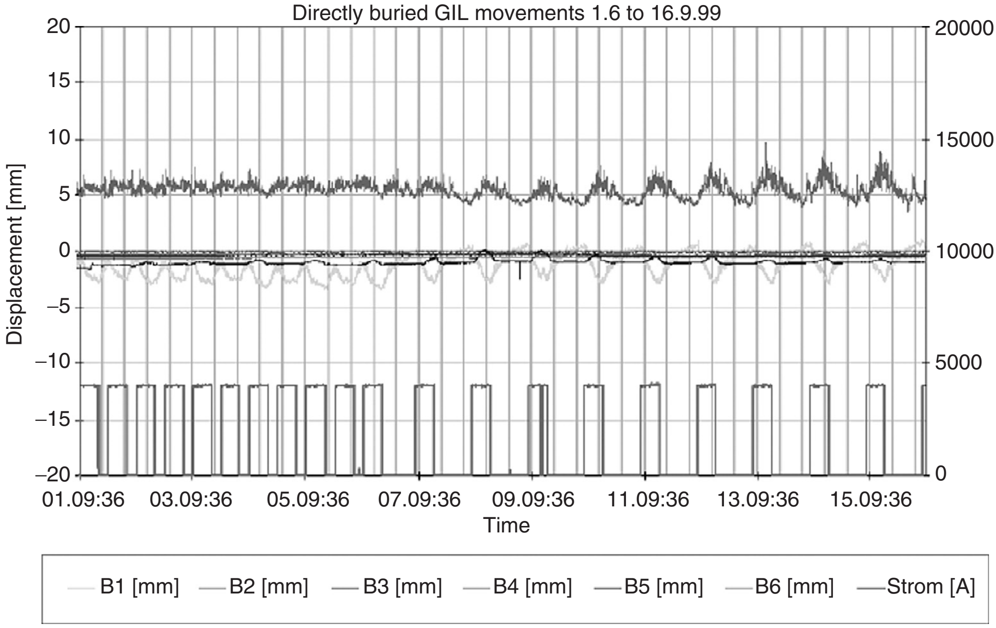

FIGURE 18.23 Mechanical aspects, movements of the enclosing tube during long-term testing of the directly buried GIL. (Courtesy of Siemens.)

The calculations show that the temperatures at the bottom and the top are higher than the temperature at the sides, and the temperature difference is less than 2°C. The temperature at the bottom is slightly higher than the temperature at the top (DT = 0.5°C). In contrast to this, the test showed a considerable temperature difference between the bottom, the top, and the sides, with a high value at the top and a low value at the bottom. In this example, the temperature at the circumference of the pipe is not constant because the not-unsteady effect of the natural convection between the inner conductor and the enclosing tube was included in the calculation.

Mechanical Aspects

At measurement points in the middle of the right section on the buried GIL, only very minor movements were recorded. The measured values vary between −1.1 and 0 mm. This corresponds to the maximum absolute movement of the long section of pipe near the bend enclosure in the direction of shaft 1, which connected to the longest section (Fig. 18.19). The two sections of pipe can be regarded as an adhesion zone.

A measurement point in the shaft at the end of the test section measures the movement of the expansion joint and at the same time corresponds to the change in the pipe. Measurements of the pipe movements are shown in Fig. 18.23. The enclosing-tube temperatures at the first cross section at a

TABLE 18.8 GIL Movement in Long-Duration Tests

	Movement (mm)	Absolute Distance (mm)
Pt 2	−0.6/−0.4	0.2
Pt 3	−0.5/−0.3	0.2
Pt 4	−0.1/0	0.1
Pt 5	−1.1/−0.6	0.5

Source: Courtesy of Siemens.

distance of about 9 m from the shaft vary on average between 28 and 34°C in the case of the short cycles (DT = 6°C) and between 25 and 33°C in the case of the long cycles (DT = 8°C). During this period, the enclosing tube in the shaft moved from −3.4 to +0.8 mm, which corresponds to an absolute distance of Dl = 4.2 mm. See Table 18.8.

18.5 Advantages of GIL

The GIL is a system for the transmission of electricity at high power ratings over long distances. Current ratings of up to 4000 A per system and distances of several kilometers are possible in tunnel-laid or directly buried GILs. As a gas-insulated system, the GIL has the advantage of electrical behavior similar to that of an overhead line, which is important to the operation. Furthermore, the gases do not age, so there is almost no limitation in lifetime, which is a huge cost advantage given the high investment costs of underground power transmission systems.

Because of the large cross section of the conductor, the GIL has the lowest electrical losses of all available transmission systems, including overhead lines and cables. This reduces operating costs while reducing the utility's contribution to global warming, since less power needs to be generated.

Personnel safety in the presence of a GIL is very high because the metallic enclosure provides reliable protection. Even in the rare case of an internal failure, the metallic enclosure is strong enough to withstand the stress of failure. The inherent safety of the GIL system, which contains no flammable materials, makes it suitable for use in street or railway tunnels and on bridges. The use of existing tunnels has obvious economic advantages by sharing the costs and can solve some environmental problems because no additional overhead line is needed. Because of the low capacitive load of the GIL, long lengths of 100 km and more can be built.

The GIL is a viable and available technical solution to bring the power transmitted by overhead lines underground, without reducing power transmission capacity, in cases where overhead lines are not possible.

18.5.1 Safety and Gas Handling

The GIL is a gas-filled, high-voltage system. The gases used, SF_6 and N_2, are inert and nontoxic. The 7-bar filling pressure of the GIL is relatively low. The metallic enclosure is solidly grounded and, because of the wall thickness of the outer enclosure, offers a high level of personal safety. The mechanized orbital-welding process ensures that the connections of the GIL segments are gastight for the system's lifetime.

Even in case of an internal failure, which is very unlikely, the metallic encapsulation withstands the internal arc so that no damage is inflicted on the surroundings. In arc fault tests in a laboratory, it was proven that no burn-through occurs with fault currents up to 63 kA, and the increase of internal pressure during an arc fault is very low. Even under an arc fault condition, no insulating gas is released into the atmosphere.

For the gas handling of the N_2–SF_6 gas mixture, devices are available for emptying, separating, storing, and filling the N_2–SF_6 gas mixtures. Figure 18.24 shows the closed circuit of the insulation gas with all devices used for gas handling. The initial filling is done by mixing SF_6 and N_2 in the gas mixing device (5) in the required gas mixture ratio. The initial filling is normally sufficient for the whole lifetime of the GIL because of the system's high gastightness. For emptying the GIL system, the gas is pumped out with a vacuum pump (1), filtered, and then separated (2) into pure SF_6 and a remaining gas mixture of N_2–SF_6. This N_2–SF_6 gas mixture has an SF_6 content of only a few percent (1–5%), so it can be stored under high pressure up to 200 bar in standard steel bottles (3). Three sets of steel bottles can hold the gas content of a 1-km section for storage. The pure SF_6 is stored (4) in liquid state. To fill or refill the GIL system, a gas mixing device (5) is used, including a continuous gas monitoring system for temperature, humidity, SF_6 percentage, and gas flow. The gas mixing device has input connections for pure N_2 (6),

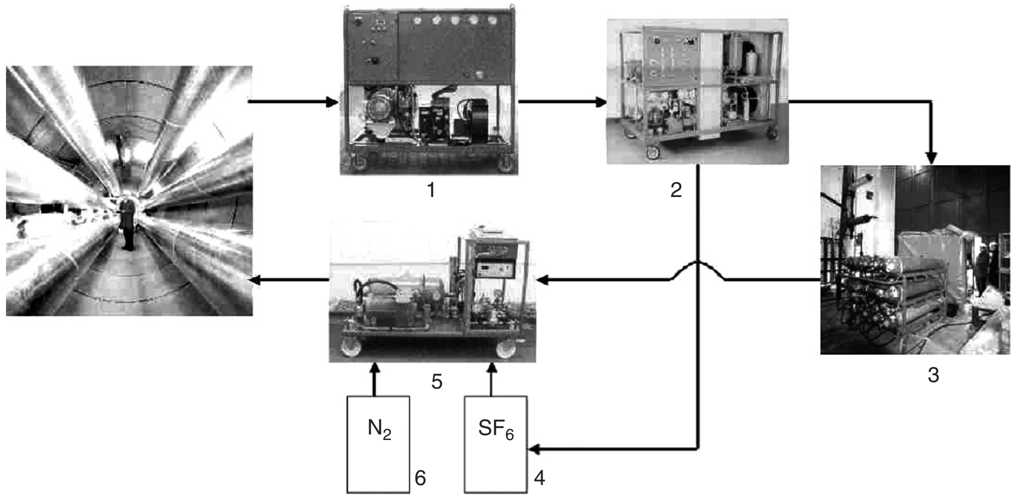

FIGURE 18.24 Gas-handling devices. (Courtesy of Siemens.)

pure SF_6 (4), and gas mixtures containing a low percentage of SF_6. The mixing device adjusts the required N_2–SF_6 gas percentage used in the GIL, e.g., 80% N_2.

With these gas-handling devices, a complete cycle of use and reuse of the gas mixture is available. In normal use, the SF_6 and N_2 will not be separated completely because the gas mixture will be reused again. A complete separation into pure SF_6, as used, e.g., in GIS, can be done by the SF_6 manufacturers. Thus the requirements of IEC 60480 [13] and IEC 61634 [3] are fulfilled.

18.5.2 Magnetic Fields

18.5.2.1 General Remarks

Magnetic fields can disturb electronic equipment. Devices such as computer monitors can be influenced by magnetic-field inductions of ≥ 2 μT. Furthermore, magnetic fields may also harm biological systems, including human beings, a subject of public discussion. A recommendation of the International Radiation Protection Association (IRPA) states a maximum exposure figure of 100 μT for human beings. In Germany, this value has been a legal requirement since 1997 [21].

Several countries have recently reduced this limit for power-frequency magnetic fields. In Europe, Switzerland and Italy were the first to establish much lower values. In Switzerland, the maximum magnetic induction for the erection of new systems must be below 1 μT in buildings, according to NISV [22]. Today some exceptions may be accepted. In Italy, 0.5 μT has been proposed for residential areas in some regions, with the goal of allowing a maximum of 0.2 μT for the erection of new systems. This trend suggests that, in the future, electrical power transmission systems with low magnetic fields will become increasingly important.

The GIL uses a solid grounded earthing system, so the return current over the enclosure is almost as high as the current of the conductor. Therefore, the resulting magnetic field outside the GIL is very low. The installation at PALEXPO in Geneva demonstrates that GILs can fulfill the high future requirements that must be expected in European legislation.

18.5.2.2 Measurements of the Magnetic Field at PALEXPO, Geneva

The measurements at PALEXPO in Geneva were carried out with both GIL systems under operation with a current of 2 ¥ 190 A. Based on the measured values, the magnetic induction was calculated for the load of 2 ¥ 1000 A. Inside the tunnel between the two GIL systems, the maximum magnetic induction amounts to 50 μT.

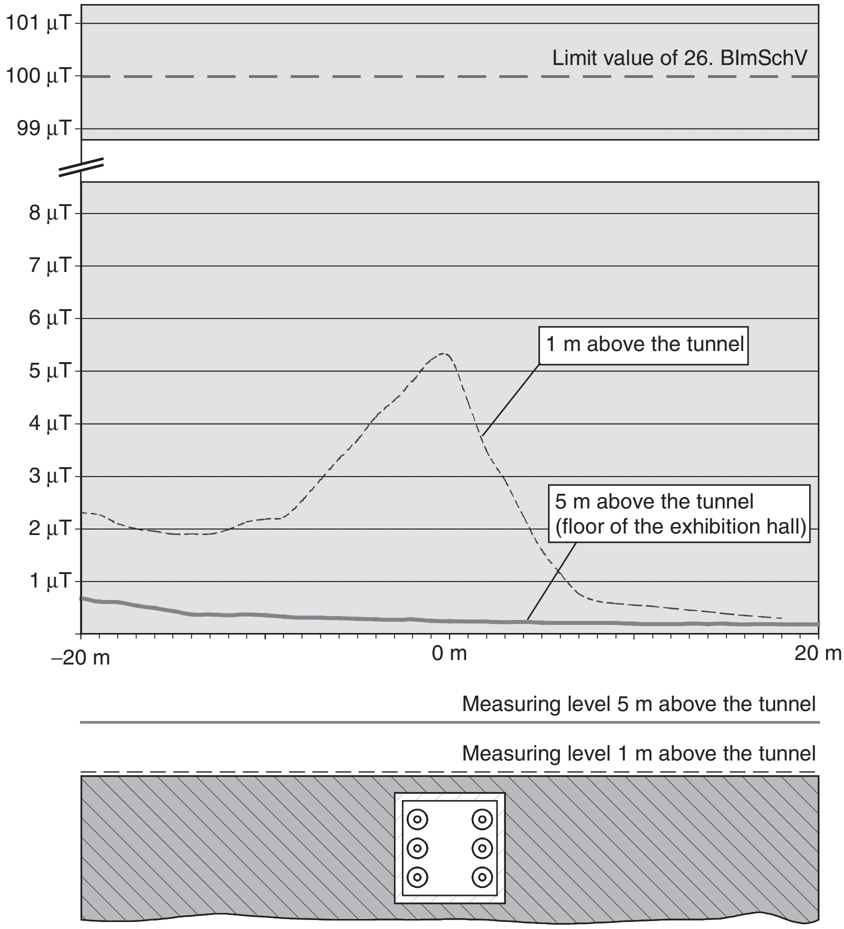

FIGURE 18.25 Measured values of the magnetic induction above the GIL tunnel at PALEXPO, Geneva, at a rated current of 2 ¥ 1000 A. (Courtesy of Siemens.)

The magnetic field at right angles to the GIL tunnel is presented in Fig. 18.25. The measurements were taken at 1 and 5 m above the tunnel, which is equivalent to the street level and to the floor of the PALEXPO exhibition hall. The magnetic induction on the floor of the fair building is relevant for fulfilling the Swiss regulations for continuous exposure to magnetic fields. The 1-m maximum value amounts to 5.2 μT above the center of the tunnel. The maximum induction at 5 m above the tunnel is 0.25 μT. This result is only 0.25% of the permissible German limit [14] and 25% of the new Swiss limit [22].

It is worth mentioning that cross-bonded high-voltage cable systems need to be laid at a depth of 30 m or more to achieve comparable induction values. There is a range of possibilities for reducing the magnetic field in cable systems, such as ferromagnetic shielding, compensation wires, or laying in steel tubes. All these measures, however, increase the losses markedly. Table 18.9 provides a comparison of different 400-kV transmission systems.

A comparison of calculations and measurements made at PALEXPO shows that it is not sufficient to focus on the GIL only. The current distribution through the grounding systems around the GIL also has a significant influence. Along the overhead line, a current is induced into the ground wire and then conducted through the enclosure of the GIL. The increase in the magnetic field at a distance of 20 m from the GIL (Fig. 18.25) is related to induced currents in the ground grid.

TABLE 18.9 Comparison of Different 400-kv Transmission Systems

	VPE-Cable 2XS(FL)2Y[a] 1 × 2500, Cross Bonding	Overhead Line 4 × 240/40 Al/St	GIL[a] 520/180
Rated voltage (kV)	400	400	400
Thermal limit load (MVA)	1080	1790	1790
Overload (60 min)	1.2 times	1.2 times	1.5 times
Reactive power compensation	Needed	Not needed	Not needed
Max. induction in (μT) at 2 × 1000 MVA at ground level	29	23.5	1.4
Thermal system losses[b] at 1000 MVA (W/m)	71	194	43
External influences (environment, animals)	No	Yes	No
Behaviour in case of fire	Fire load with plastic	No additional fire load	No additional fire load
Damage to neighbouring phases in event of failure	Possible	Possible	Not possible
Maintenance	Maintenance free[c]	Needed	Maintenance free[c]

[a]Tunnel laying, natural cooling, level above ground 2 m.
[b]Conductor temperature 20°C.
[c]Corrosion protection test is required only for direct burial.
Source: Courtesy of Siemens.

The magnetic inductions above the GIL trench are negligible and meet the Swiss requirements under full-load conditions. However, the results show that the magnetic fields induced by the grounding system also need to be considered in the system design. All measured and calculated values of the induction from the GIL are far smaller than those for comparable overhead lines and conventional cable systems.

18.6 Application of Second-Generation GIL

The first application of the second-generation of GIL was implemented between September and December 2000. After only 3 months erection time, the overhead line was brought underground into a tunnel. Graphical explanation is given in Fig. 18.27. In January 2001 the line was energized again.

Figure 18.26 shows the delivery of GIL transport units to the preassembly area. The preassembly tent was placed directly under the overhead line and above the shaft connected to the tunnel right under the street. The space was limited because of an airport access road on one side and the highway to France on the other side. Nevertheless, the laying proceeded smoothly. The positive experience from this project shows that even GIL links for long distances can be installed within a reasonable time. The highly automated laying process has proved to guarantee a consistent quality on a very high level over the complete laying process, and the commissioning of the system was carried out without any failures.

During erection of the GIL, a preassembly tent was placed directly above the access shaft connected to the tunnel near Pylon 175 (Fig. 18.27). The narrow space between an airport access road on one side and the highway A1 to France on the other side necessitated the use of the space directly under the existing overhead line for the site work. A total of 162 pieces of straight GIL units, each 14-m long, were preassembled, brought into the tunnel, welded together, and continuously pulled toward the end of the tunnel at Pylon 176. Thanks to advanced site experience, it was possible to double productivity for assembly of the GIL sections from two connections per shift per day to four.

Erection of the PALEXPO GIL started in September 2000 and was completed within 3 months. The double-circuit overhead line was brought underground into a square tunnel (Fig. 18.8). The elastic bending of the GIL aluminum alloy tubes (minimum bending radius of 400 m) was sufficient to follow the layout of the tunnel route.

FIGURE 18.26 Delivery of transport unit to the preassembly area. (Courtesy of Siemens.)

The technical data for the PALEXPO GIL are shown in Table 18.10. The power transmission capacity of the tunnel-laid GIL allows the maximum power of an overhead line to continue underground without any power transmission reduction. Surge arresters are used at the GIL terminations.

For monitoring and control of the GIL, secondary equipment is installed to measure the gas density. An electrical measurement system is used to detect arc location. Very fast transient electrical signals are

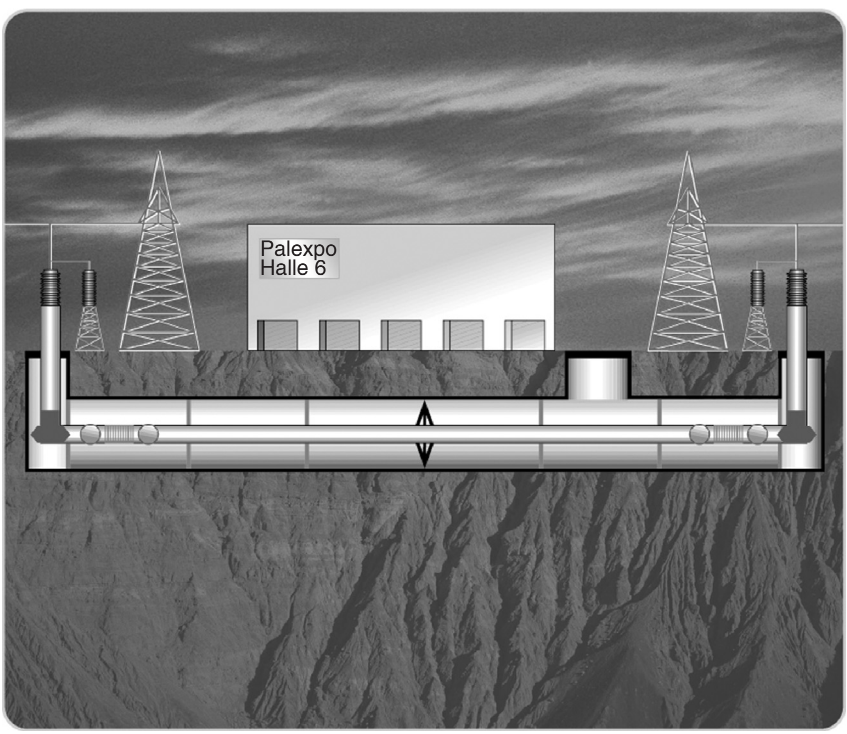

FIGURE 18.27 Principle of the PALEXPO project. (Courtesy of Siemens.)

TABLE 18.10 Technical Data for the PALEXPO GIL

Type	Design	Project
Nominal voltage	420 kV	300 kV
Nominal current	3150 A/4000 A	2000 A
Lightning impulse voltage	1425 kV	1050 kV
Switching impulse voltage	1050 kV	850 kV
Power frequency voltage	650 kV	460 kV
Rated short time current	63 kA/3 s	50 kA/3 s
Rated gas pressure	7 bar	7 bar
Insulating gas mixture	80% N_2, 20% SF_6	80% N_2, 20% SF_6

Source: Courtesy of Siemens.

measured at the ends of the GIL, and the position of a very unlikely internal fault can be calculated with an accuracy of ± 25 m.

Given the importance of this high-voltage line for the power system—and despite the security constraints for the construction site—the operator endeavored to keep the line in service during the whole construction period. Operation of the link was suspended only for a span of three weeks during the GIL commissioning tests and connection.

18.7 Quality Control and Diagnostic Tools

In the complex insulation system of a real GIL, the intrinsic dielectric strength of N_2–SF_6 mixtures—presented in Section 18.4.1 by the pressure-reduced critical field—is affected by many factors. The usual surface roughness of metal surfaces is well understood in gas-insulated systems [23]. Metal protrusions or mobile particles are also studied in many cases, and their influence is also well understood [24].

The statistical distribution of breakdown voltage in gas mixtures was found to be similar to that of pure SF_6 of equal dielectric strength [25]. Therefore, the approved conventional test procedures for GIS can be applied to confirm the required withstand levels [23]. For insulation coordination (to make the correct choice of high voltage and best voltages for type testing) of extended transmission lines, the Weibull distribution has to be applied because of the statistical distribution of the flashover voltage levels [26]. Thus the knowledge and experience of more than 25 years of GIS installations and operation can be fully applied to GIL installations because GIS and GIL show the same statistical behavior for high-voltage flashovers.

With careful assembly and efficient quality control, defects are practically ruled out. Mobile particles are the most common defect, and these are usually eliminated by conditioning procedures during power-frequency high-voltage testing [10]. In a conventional GIS with a complex insulation system, particles are moved by a stepwise increased ac field stress into low-field regions that act as natural particle traps. However, there are no such natural particle traps in the plain insulation system of a GIL. Therefore it has been equipped with artificial particle traps all along the GIL extension, and these traps have proved to be very efficient.

Modern diagnostics are applied for the detection, localization, and identification of defects. The VHF method proved to be most efficient [10]. Its application is restricted by signal attenuation and the correspondingly limited measuring range of installed sensors. In a GIS, this attenuation is mainly caused by the conical spacers that are usually installed. The maximum distance between sensors should therefore normally not exceed 20 m. In a GIL, an efficient VHF PD measurement can be carried out even with distances between sensors of several hundred meters. This enables use of the UHF method in a GIL, as successfully performed for the first time on site in Geneva [11].

Moisture penetration by diffusion through the enclosure and from the bulk of the insulators into the gas occurs much less frequently in a GIL than in a conventional GIS because of the excellent gastightness and the low amount of solid insulating material. The insulation quality of the insulator surfaces can therefore reliably be preserved by conventional measures to avoid dewy surfaces of reduced dielectric strength.

Altogether, it can be expected that the GIL will give the same or even better long-term performance than a GIS, which demonstrates a long service lifetime with no critical aging even after 30 years of operation [27]. The GIL uses almost the same materials, while the amount of solid insulating material and SF_6 is considerably reduced. Moreover, the requisite quality control can be obtained by means of tests and modern diagnostics. In conclusion, it can be said that the on-site high-voltage quality control and the diagnostic tools used have proved to be very successful. The GIL in Geneva went into service without problem.

18.8 Corrosion Protection

For applications where aluminum pipes are used in air aboveground or in a tunnel, aluminum generates an oxide layer that protects the enclosure from any kind of corrosion. The oxide layer of an aluminum pipe is very thin, only a fraction of a micrometer, but it is very hard and very resistive against a gaseous environment like the atmosphere. In most cases it is not necessary, even in outdoor applications, to protect the aluminum pipes against corrosion with, e.g., coloring.

Going underground for directly buried systems, the situation regarding corrosion changes and a corrosion protection is required. Two basic methods are used today: a passive corrosion protection and an active corrosion protection. The passive corrosion protection is an added layer of non-corrosive materials, e.g., polyethylene (PE) or polypropylene (PP), whereas the active protection system uses voltage protection to direct corrosion from the protective aluminum enclosure toward a loss electrode.

18.8.1 Passive Corrosion Protection

Passive corrosion protection is used widely for all kinds of metallic underground systems that have direct contact with the soil, e.g., electric power cables, oil or gas pipelines, and all kinds of other pipes.

There are several different technologies available on the market to add a coating to a pipe as a passive corrosion protection. In all cases, the processes used and the materials are similar. The surface of the metallic aluminum enclosure needs to be degreased, and the oxide layer needs to be removed. Acid fluids or mechanical brushes can be used to accomplish this. In some cases, both of them are used. If fluids are used to prepare the enclosure for the coating process, the pipe is run through a curtain of fluid acid. If mechanical treatment is used, then brushes treat the surface accordingly, sometimes together with a fluid. These processes are the same for steel and aluminum pipes and are run with the same machines. After the surface of the aluminum pipe is prepared, a first layer of a corrosion-protection fluid is brought onto the pipe to stop corrosion. This first layer is the active part of the passive corrosion protection and is only a few micrometers thick. On top of this layer, a 3–5-mm layer is added mainly for mechanical protection reasons. For this protective layer, two basic processes are applied: the extruded-layer and the tape-wrapped-layer methods. The use of these passive corrosion-protection methods has a long history and thousands of kilometers of experience as well as years of operating experience.

Figure 18.28 shows a GIL with passive corrosion protection. In the middle of the photo the blank aluminum enclosure is shown, prepared for the welding process. To the right and left of the blank, the small dark bands are the active corrosion-protection layer. Finally, to the far right and left, is the white cover for mechanical protection, which is a PE or PP coating 3–5 mm thick.

After the pipe segments are welded together, it is also necessary to protect the welded area. There are various corrosion-protection processes available that can be applied on site. Figure 18.29 shows how one such on-site corrosion-protection method is applied. In this case, a corrosion-protection system based on a shrinking method is used. Other methods involve granulates or tapes and are also widely used in the pipeline industry.

FIGURE 18.28 GIL with passive corrosion protection. (Courtesy of Siemens.)

FIGURE 18.29 On-site corrosion protection of the welding area—shrinking method. (Courtesy of Siemens.)

18.8.2 Active Corrosion Protection

With an active corrosion-protection method, the induced current generates a voltage potential of the metallic enclosure toward the soil. If this voltage level is at a potential of around 1 V toward a loss electrode, then the loss electrode corrodes instead of the aluminum enclosure. The active corrosion-protection system is a backup to the passive corrosion-protection system. It is installed as an additional quality insurance system if the passive corrosion protection fails. Failures in the passive corrosion protection can occur over the lifetime of the system by outer damage through other earthworks or by cracks or voids in the protective material. If necessary, the active corrosion-protection system prevents corrosion in the event of cracks and voids in the passive corrosion-protection system.

Experience with installed, directly buried pipe systems worldwide shows that, over the decades, some cracks or voids in the passive corrosion-protection system can occur, which increases the induced current of the active protection system. The positive effect of the active corrosion-protection system is that each passive corrosion-protection failure need not be repaired immediately, and a guaranteed lifetime of the passive corrosion-protection system of 50 years can be extended by many more years. Repairs of passive corrosion-protection systems can be planned and concentrated on troublesome segments. Experience with oil and gas pipelines shows that the lifetime can be extended significantly without opening the pipe.

The active corrosion-protection system, also called cathodic corrosion protection, uses an induced current to adjust the protective voltage of approximately 1 V against the lost electrode. To reach this 1-V protective voltage, an induced current of approximately 100 μA is needed. The induced current is related to the total of the surface to be protected and increases with the length of the system and the numbers of failures. In practice, several kilometers can be protected with only one dc-voltage source because the current is low.

To obtain cathodic protection, the buried GIL must be a non-earthed system, which means that it must be insulated toward the ground potential. To allow the 1-V protection potential, the ground system is coupled with the GIL through a decoupling element, which could be a battery or a diode. This battery or diode ensures that a protective voltage of about 1 V is applied to the aluminum shield. If an earth fault of the electric system occurs, the failure current is conducted to the ground potential through the diode or battery.

Active corrosion protection can be easily installed along with the electrical transmission system, with no interferences between electrical transmission and the corrosion-protection voltage potential. Such electrical transmission systems have been operating for many years with no failures reported. The high reliability observed for pipelines and cables also applies to GIL systems.

18.9 Voltage Stress Coming from the Electric Power Net

18.9.1 Overvoltage Stresses

Two typical GIL applications are represented by the connection of 400-kV overhead lines to a GIL with a length of 1 and 10 km. The overhead line is protected by two shielding wires along its full length. The height of the last three towers is about 65 m, and the maximum footing resistance for the towers is about 7.5 W.

18.9.2 Maximum Stresses by Lightning Strokes

Based on these configurations of the overhead lines and the lengths of their insulator strings, the following maximum stresses by lightning strokes were evaluated and used to calculate the maximum overvoltage stresses on the GIL:

Remote stroke: 2000 and 2100 kV
Nearby direct strokes: 35 and 18 kA
Stroke to towers: 200 kA

18.9.3 Modes of Operation

The basic arrangement allows calculation of lightning strokes on the GIL for the following modes of operation:

Transport:
Overhead line connected by the GILs of 1- and 10-km length
Overvoltage stresses caused by lightning strokes to the overhead line
Open end:
GILs of 1- and 10-km length connected on one end to the open bay of a substation
Overvoltage stresses caused by lightning strokes to the overhead line

18.9.4 Application of External and Integrated Surge Arresters

To protect the GIL against high lightning and switching overvoltage stresses, external surge arresters located at the last towers of the overhead line, as well as encapsulated metal oxide surge arresters immediately connected to the GIL at certain locations (integrated surge arresters), can be applied. For 400-kV systems with an earth-fault factor of £1.4, the special integrated surge arresters have the following characteristic data:

Rated voltage, Ur = 322 kV
Continuous operating voltage, Uc = 255 kV
Residual voltage at 10 kA, U10 kA = 740 kV
External metal oxide surge arresters commonly used in German 400-kV systems—those with Ur = 360 kV, Uc = 288 kV, and U10 kA = 864 kV—were taken into account.

18.9.5 Results of Calculations

For each mode of operation, for both lengths of GIL, and for the different possibilities of surge-arrester application, the maximum overvoltage stresses (depending on the distance from the left-hand-side end of the GIL) have been calculated for all kinds of possible lightning strokes. In all cases, the maximum stresses are caused by nearby direct strokes to line conductors. For the various possibilities of surge-arrester application, the maximum lightning overvoltage stresses are listed in Table 18.11 for the GIL of 1-km length and in Table 18.12 for the GIL of 10-km length.

18.9.6 Insulation Coordination

At least up to a length of some tens of kilometers, lightning overvoltage stresses are decisive for the insulation coordination of a GIL, since stresses by switching overvoltages at those lengths will be much lower than on overhead lines because of their lower surge impedance (60 W compared with 300 W for

TABLE 18.11 Maximum Overvoltage Stresses Depending on Mode of Operation and Number of Surge-Arrester Sets for a GIL of 1-km Length

	Number of Surge Arrester Sets at		Maximum Overvoltages in kV Caused by Nearby Direct Strokes to	
Mode of Operation	GIL	Tower L1/R1	N2 (35 kA)	N3 (18 kA)
Transport	2	—	1013	913
	2	2	952	890
Open end	2	—	1066	958
	2	2	989	938

— > 990 kV
--- > 904 kV
Source: Courtesy of Siemens.

TABLE 18.12 Maximum Overvoltage Stresses Depending on Mode of Operation and Number of Surge-Arrester Sets for a GIL of 10-km Length

	Number of Surge Arrester Sets at		Maximum Overvoltages in kV Caused by Nearby Direct Strokes to	
Mode of Operation	GIL	Tower L1/R1	N2 (35 kA)	N3 (18 kA)
Transport	2	—	996	904
	2	2	983	890
	4	—	867	837
	4	2	842	829
Open end	2	—	1048	950
	2	2	1035	940
	4	—	902	883
	4	2	893	877

—— $>$ 990 kV
---- $>$ 904 kV
Source: Courtesy of Siemens.

an overhead line). The insulation coordination of a GIL of up to 10-km length considered here is therefore based on the maximum stresses by lightning overvoltages.

Given the large amount of experience already gained with design tests and on-site tests of huge GIS, the following procedures are proposed for selecting test voltages for on-site tests on GIL sections of up to 1-km length and of type tests on a representative length of GIL:

18.9.6.1 On-Site Tests

On-site tests are designed to verify that the GIL is free of irregularities after laying and assembling. Taking into account the safety factor of Ks = 1.15 (according to IEC 60071-2), a withstand voltage of Uw $\geq$ 1.15 ULEmax—with ULEmax = maximum overvoltage stress from the calculations—should be verified by these tests.

18.9.6.2 Type Tests (Design Tests)

On the other hand, the on-site test voltage corresponds to 80% of the required rated lightning-withstand voltage, Urw, when type testing a representative length of GIL. At these tests, single flashovers on self-restoring insulation are permitted according to the applicable IEC standard 61640.

18.10 Future Needs of High-Power Interconnections

18.10.1 Metropolitan Areas

Metropolitan areas worldwide are growing in load density, mainly at their centers. Demand for power has grown because of the construction of huge residential and tall office buildings with air conditioning and lots of electronic equipment, leading to increases in electric loads of up to 10% per year in metropolitan areas [28]. The following short historical overview explains how the power supply of metropolitan areas has developed over the last 30 years.

Figure 18.30 shows the principle for power supply in a metropolitan area. Power generated in a rural area is connected to a metropolitan area by 420- or 550-kV overhead lines with a short-circuit rating of 40 kA. Several substations are placed around the city as overhead towers using a bypass or a ring structure around the metropolitan area, from which 110-kV cables transport electrical energy into the center of the city, where medium-voltage energy is distributed.

In Fig. 18.31, the metropolitan area has grown, with more tall buildings in the center. Most cities still have a 420/550-kV ring around the city, but the short-circuit rating has been increased to 50 kA or, in some places, to 63 kA. Note the second connection to the ring from another rural power generation area. More

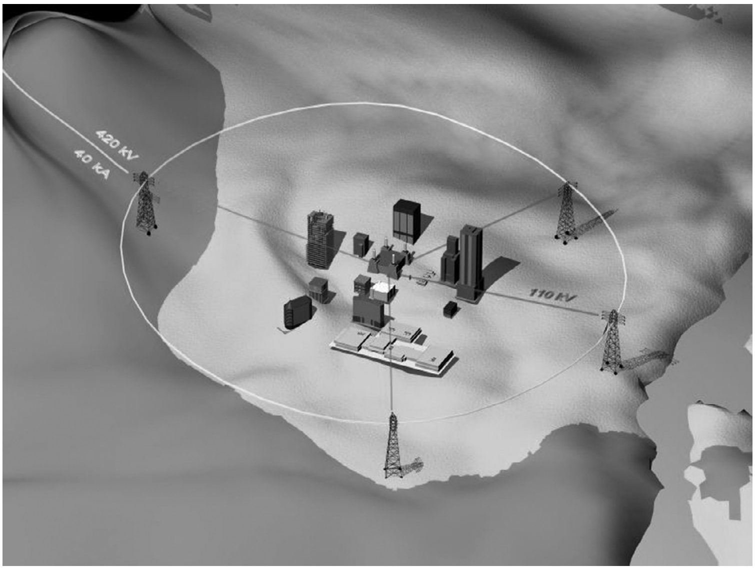

FIGURE 18.30 Power supply of metropolitan areas in 1970. (Courtesy of Siemens.)

110-kV cables are connected to the ring to transport the energy to the substations in the city for distribution. To increase the power transportation into the center of the city, it is not possible to increase the voltage to 1000 kV because of dielectric problems. Moreover, worldwide experience with very high short-circuit ratings shows that short-circuit rating values cannot go far above 63 kA because of mechanical problems. So the only way to increase the power transportation into the city is to lay 400-kV underground bulk-power-transmission systems right into the center. In such cases, the GIL offers the best solution.

Figure 18.32 shows the metropolitan area as it may appear in 2010. The same metropolitan area with more buildings has grown further, and a 420/550-kV, 63-kA, double-system GIL was built as a diagonal connection underpassing the total metropolitan area. This GIL could have a length of 30–60 km. The solution illustrated here allows splitting of the short-circuit ratings of the ring into two half rings and to

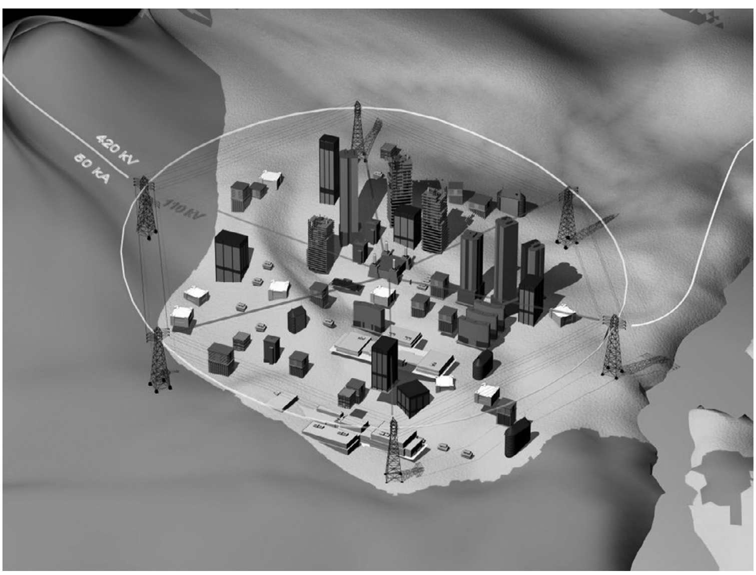

FIGURE 18.31 Power supply of metropolitan areas in 2000. (Courtesy of Siemens.)

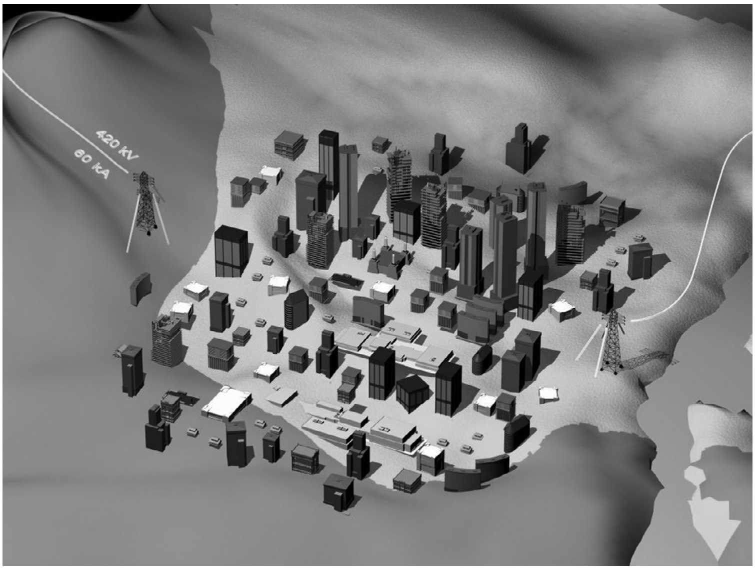

FIGURE 18.32 Power supply of metropolitan areas in 2010. (Courtesy of Siemens.)

connect directly to the 400-kV high-transmission-power GIL in the center of the metropolitan area. The underground connection is a tunnel for GIL, as discussed in Chapter 4.

18.10.2 Use of Traffic Tunnels

GILs can safely be routed through tunnels carrying traffic on rails or streets. This new application for electrical transmission systems with solid insulated cables was not possible until today because of the risk of fire or explosion. The GIL has a solid metallic enclosure and does not burn or explode, as explained in Chapter 4. The combinations of GIL and street or railroad tunnels are shown in Fig. 18.33. Three

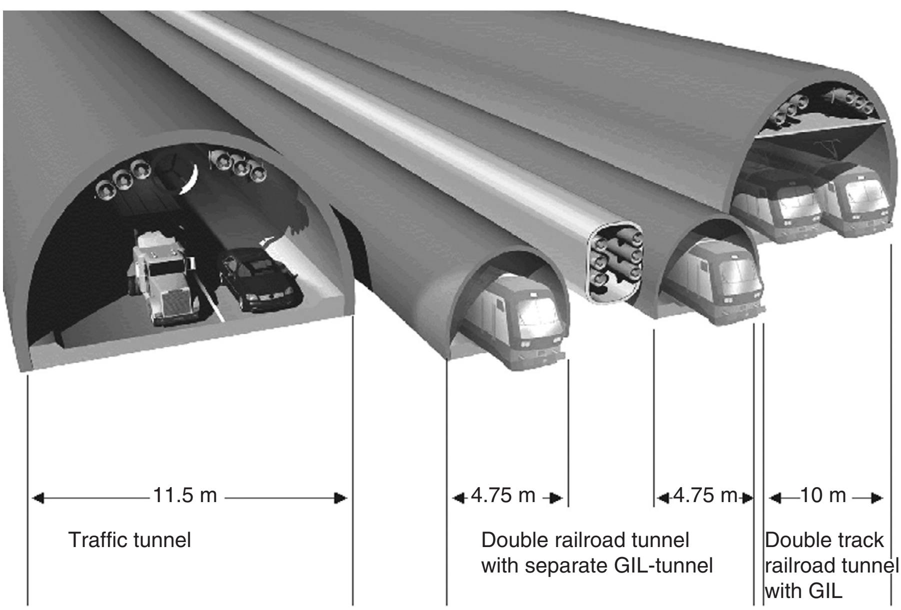

FIGURE 18.33 Different types of traffic tunnels to be used for GIL. (Courtesy of Siemens.)

examples are given. The first one is a traffic tunnel with cars and a GIL mounted on top of the tunnel; the second is a double railroad tunnel system with a separate GIL tunnel; the third example is a double-track railroad tunnel with a GIL included.

The use of such traffic tunnels with GIL is now under investigation in different parts of the world. In the European Alps, interconnections between Germany, Austria, Switzerland, Italy, and France are now planned to improve the traffic flow and to allow trade of electric energy. In China and Indonesia, interconnections between the mainland and islands or between outlying islands are under investigation. In the near future, GILs will become economically viable and will be widely used as high-power, long-distance transmission lines.

18.11 To Solve Bottlenecks in the Transmission Net

18.11.1 Introduction

The European Transmission Net has a regional development history. In the beginning of the transmission net the highest voltages were used to connect larger electrical load areas with large scale power generation in fossil and nuclear power plants. These connecting lines had a regional structure inside national country borders. The main power-flow was from the regional power generators to the regional power consumers [29,30].

In a next step of the development of the transmission net, line connections were made to connect regional transmission networks with the neighbor. The main reason for such transmission lines was the need of emergency power supply if the own power generation was not high enough. With interconnecting transmission lines between the regional networks also the reliability was improved by redundancy.

These interconnecting transmission lines were built to connect regional transmission network inside national country borders and sometimes are also cross border connections. For all regional power suppliers it was the first goal to generate the electricity inside their own network to be sure to have control onto the power generation costs, which was seen as essential for the usually public utility. In most cases the power transfer on interconnecting transmission lines in and out of one regional power supplier was balanced.

The interconnecting transmission lines were typically not the strongest in power transmission capability, because of their function as an emergency back-up connection. These solutions were found long before the deregulated market was found, and trading with electrical energy was normal.

Strict contracting with regional monopolistic structures ensured the status of regional power transmission and distribution. This regional transmission and distribution network structure reached its final stage in the late 1980s and in the 1990s, but is still in operation today.

The deregulation of the energy market in Europe in the 1990s until today caused big changes in the way how the transmission net will be used and what are the new requirements. This transmission process from a closed and protected regional electrical energy market to an open, competitive one is still ongoing today and in the near future. Changing requirements to the transmission net of tomorrow ask for new solutions to avoid costly and reliability decreasing bottlenecks.

18.11.2 Transmission Net Requirements

The transmission net follows the requirements that are coming from the user and public. First the user needed an economical (low cost, high reliability) technical solution that was developed and manufactured by the industry in the form of the overhead line.

The overhead line for transmission networks uses high voltages of 400 kV in Europe or 245/550 kV in other regions in the world. Typical technical values are shown in Table 18.13. With the technical layout of four aluminum wires in a bundle of 240 mm^2 with a 40 mm^2 steel core the transmission

TABLE 18.13 Technical Data

	Overhead Line 4 × 240/40 Al/St	GIL
Thermal load limit (MVA)	1800	2000
Thermal current limit (A)	2600	3000
Resistance per kilometer (mΩ/km)	30.4	9.4
Capacitance per kilometer (nF/km)	14.2	54.4

rating is for the thermal limit about 1800 MVA. This requires a current of about 2600 A, also a thermal limit value.

The low capacitance of the overhead line of 14.2 nF/km allows to build long lines without the need of phase angle compensation. A mean maximum length of overhead line without compensation is around 1000 km.

The resistance per km of the overhead line is relatively high due to the reason of the limited cross section of the conductors or wires possible with overhead line structures. With typical values of 30.4 mΩ/km the losses in the upper part of the transmission capability cumulate to high transmission losses. In Table 18.14 the losses of such a line are shown.

The GIL offers instead a higher transmission capability of 2000 MVA and a thermal current limit of about 3000 A. The lower resistance of 9.4 mΩ/km produces much less thermal transmission losses compared to an overhead line (OHL) as it is shown in Table 18.14 [11–13].

The requirements to the transmission net in the past were solved best with the overhead line if erection cost and operation cost were evaluated in an $n-1$ system environment. That means. if the transmission of 2000 MVA was needed between two points the overhead line was built following the $n-1$ rule with two systems of 2000 MVA transmission capability each. In case of one failing system the second is able to carry the full current. That means if both systems are in normal operation the current in each system is half and below to grant the full redundancy, and in consequence the transmission losses are relatively low. This changes with the current increase close to the thermal limits. The driver of today for using the assets much more close to the limit are asset management and an open trading market. This will result in higher ratings for power transmission lines.

A second change of the requirements for power transmission is coming from the public and the low or non-acceptance of overhead lines in most places in Europe. The reasons are purely aesthetic or related to health concerns because of the electromagnetic fields.

A third driver in Europe that is changing the requirement for power transmission is coming from regenerative energy source like wind, solar, or bio power. The strongest increase today and in the near future is coming from wind energy land installed, and in the near future also from off-shore wind parks of large scale units. The consequences to the transmission net are the increase of load in general, the possibility of bottlenecks and the loss of the $n-1$ redundancy.

A fourth influence of changing the requirements for the future transmission network in Europe is coming from the open, competitive electricity market. Large scale of electricity flow changes in the transmission net will require reinforcement and new transmission lines to fulfill the needs of the future.

These four influences will come simultaneously with influences to each other, and will cumulate in the effects. The weakest point in the transmission net is often called the "bottleneck." This weak point will come up first and will cause transmission net problems. All large area outages in the world of the last

TABLE 18.14 Transmission Losses

Transmitted current (A)	500	1000	1500	2000	2500	3000
Transmitted power (MVA)	350	700	1000	1400	1800	2100
Losses overhead line	20	91	205	364	570	820
Losses GIL	5	28	63	112	176	254

years like Italy in 2004 or in U.S. and Canada in 2003 can be technically connected to these bottlenecks of electrical power transmission which finally causes the blackout.

18.11.3 Technical Solutions

There are several possibilities to solve bottlenecks in the transmission network [31,32]. Bottlenecks are typically local overloads of the transmission net which finally can cause a large area outage.

The influences of one bottleneck or congestion in the transmission net can reach large areas if the load on the single lines is high and an $n-1$ criterion is not fulfilled anymore. One trip of one branch then can end in regional blackout.

Increasing the transmission capability, e.g., with an underground GIL may improve this complex transmission net situation. This should be part of net studies, to bring understanding of overload situations in the net. Various cases need to be studied and simulated by computer software.

The first and mostly done in the past is the reinforcement of overhead lines by upgrading the voltage, e.g., from 245 to 420 kV, or the current by adding more wires to increase the current rating to the thermal limit at 2600 A. In this case a bundle of four wires is needed. Besides upgrading, new overhead lines could also be built to solve the bottleneck problem.

The second principle solution is to control the power flow by use of electronic equipment in the transmission net using FACTS and HVDC equipment. FACTS stands for Flexible AC Transmission System, which is able to control via electronic valves (thyristors) the power flow on a transmission line. HVDC stands for High Voltage DC and is using also electronic valves for power flow control with a DC transmission line between the two HVDC converter stations at its ends. This electronic control can prevent outages in cases when the power flow can be rerouted without creating new overload sections, bottlenecks, and other locations.

A third way to solve the bottleneck problem is to go underground at the regional overload sections to reinforce the transmission capability. This underground solution offers the possibility to use the way of rights of OHL and to reduce the time for getting the permission by authorities. It is clear that the cost of underground lines is higher.

There are three technical principle solutions: solid insulated cables, gas-insulated lines and superconductive cables.

Solid insulated cables are used for underground power transmission since the very beginning of the installation of the transmission network. Mostly used in cities or other applications where overhead lines cannot be used. The use of solid insulated cables is limited in length and current rating, even if these values have been increased in the last years.

Gas-insulated lines are used for more than 30 years worldwide, many projects offering a very high-power transmission capability like the overhead line, and are practically not limited in length.

The superconductive cable is still in a stage of industrial implementation with a few projects, mainly in the USA. It will need some more time before a wide use will come. A bottleneck is usually in a limited region, limited to some kilometres of length. An existing overhead line is in operation and under normal conditions close to the thermal limits of the transmission capability.

The way of right is given and limited to the line built. In Europe in most cases it is not possible to reinforce the line by upgrading to higher voltages without a new commissioning process with the authorities. This process may last very long, before the first work can be started. In some cases, the public opinion might be so strong that an overhead line cannot be built or reinforced.

The underground solutions for solid insulated cables and GIL have much higher investment cost but show advantages in operation during the lifetime. Transmission losses are lower, maintenance and repair expenses are lower, reliability is higher, public acceptance might be higher, commissioning time might be shorter, and the impact to the public, e.g., reduced value of the property, is lower.

All the single points do have different impacts and values in the single region where the bottleneck problem is to solve. How to evaluate the single points is depending on the individual situation. But some calculations can be made.

TABLE 18.15 Cost Comparison of GIL and Overhead Lines

		OHL	GIL
Transmission power	(MVA)	2100	2100
Losses per km	(kW/km)	820	254
Losses per 50 km	(MW)	41	12,7
Cost of losses		24,682,000	7,645,400
(0,1 €/0,7*8600 h*losses)	(€)		
Savings in losses using GIL	(€)	13,036,600	
Investment cost for GIL (1 system)	(€)	175,000,000	

18.11.4 Cost of Transmission Losses

Transmission losses can be calculated and evaluated with the cost per kWh of the non-delivered energy that cannot be sold to the customer. Taking the losses of Table 18.14 for the rated current of 2000 A in comparison of GIL and Overhead Line, and a 0.10 €/kWh, the values are given in Table 18.15.

18.11.5 Conclusion

The impact of blackouts can reach very large areas and effect millions of people, as we have seen during the last years.

One reason for these blackouts is coming from the fact that the existing transmission network is higher loaded than decades ago, creating bottlenecks and then in consequence the blackouts.

The public situation is that overhead lines are not welcome and the net situation is that power flow directions are changing with new power generation plants and distributed generation. The GIL is one technical solution to overcome bottlenecks in the transmission net.

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19

Substation Asset Management

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Asset management is a way of making spending decisions throughout an organization that aligns all asset-level spending with high-level business objectives. Generally, this means that spending decisions are made with the explicit objective of maximizing business performance while proactively managing risk, budgets, resources, and key performance indicators. By its very nature, asset management applies to all aspects of a business. For a vertically integrated electric utility, true asset management must span generation, transmission, substations, distribution, and all company-owned retail and wholesale customer systems. Therefore, one cannot talk about "substation asset management" per se. Instead, one must talk about how substations are affected by and fit into an overall asset management utility organization. However, there are several concepts of asset management that can be applied specifically to substations and groups of substations. For the people who operate, design, engineer, plan, or manage substations, asset management means a shift from past perspectives and practices about the role of the substation, how budgets are allocated to substations, and what is expected from both the substations and the people who manage and operate them.

19.1 A Business-Driven Approach

Asset management is a management paradigm that seeks to maximize an organization's business performance in a rigorous and data-driven manner with regards to multiple considerations like profitability, risk tolerance, cash flow, regulatory relations, reliability, environment, customer satisfaction, employee satisfaction, and safety. In other words, strategic business goals directly drive engineering and operating decisions (Fig. 19.1). As used within the power industry the term "asset management" has slight variations in interpretation. However, invariably it means a strategy, decision-making, and prioritization system that includes a closer integration of capital and O&M planning and budgeting that was traditionally the case, with the goal of managing the life cycle of equipment while considering system perspectives, throughout aimed at achieving an overall "lifetime optimum" business case for the acquisition, use, maintenance, and disposal of equipment and facilities (Center for Petroleum Asset Risk Management).

Conceptually and strategically, asset management is a *business-driven paradigm*, but functionally it is a fact-based, *data-driven process* that requires more data than utilities, traditionally used in planning and operations, applied in a more comprehensive and rigorous decision-making structure than they traditionally used (Brown and Humphrey, 2005). This is the fundamental reason that, when done well, asset management yields improved performance when compared to traditional approaches (Morton, 1999). The power industry is gradually moving to asset management for several reasons. First, asset management methods provide executives and financial managers with more and better information about how much budget is enough and on exactly where and how spending should be directed. It makes the needs of T&D systems more visible to financial decision makers, including the role of substation investments. In addition, when applied comprehensively, asset management can simultaneously increase profitability, reduce risk, and improve customer satisfaction.

Finally, asset management is being adopted now because it can now be done. It is not a new concept, having been used for decades in industries that could afford the data and information costs to apply it within their venue (Humphrey, 2003). But it is only in the last decade that power systems and business technologies have permitted asset management to be economically applied to a business that operates a network of many very geographically dispersed but heavily interacting technical equipment units and resources. Modern automation and control technologies, enterprise information systems, and computerized engineering analysis methods can support the more data-driven, customized decision-making approaches required to apply asset management. Decades ago, when equipment could not be monitored

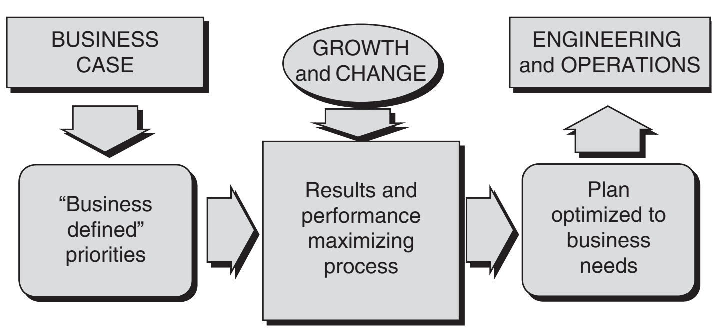

FIGURE 19.1 Asset management is a business-driven approach, in which multiple priorities, which may conflict or interact, are balanced and leveraged to create the maximum possible performance.

routinely, when SCADA system measurements were not archived and analyzed by comprehensive advanced algorithms, when photocopiers and faxes did not permit wide dissemination of information throughout an organization, and where different departments and functions within a utility could not share information at near-real-time on an enterprise level, asset management was simply not a viable management paradigm (Philipson and Willis, 2005).

19.1.1 Asset Management Framework

Asset management incorporates all of the following into a comprehensive analysis, planning, and execution framework: business driven, multiple objectives, and risk management. A description of these three aspects is now provided.

Business driven. Asset management makes business performance, rather than engineering and operations measures, the "standard" by which success is measured. All decisions about what the company owns, how it uses and takes care of (or neglects) what it owns, how it invests in new assets it wants to own, and how it operates those assets and uses its human and other resources are made on the basis of if and how they contribute to the overall business performance. From an asset management perspective, substations are part of an investment portfolio that are (a) competing for resources and (b) expected to contribute cost-effectively to corporate goals.

Multiple objectives. "Business performance" does not mean a focus only on financial profit (even purely financial businesses must consider both profit and risk exposure). The need to consider multiple objectives is especially true for regulated utilities, where it is the job of regulators to determine acceptable levels of profit. The job of the utility is to provide adequate service to all customers within its service territory for the lowest possible rates. Profitability will always be a major goal, but there are other considerations that are quite important such as well-managed risk, high customer satisfaction, high reliability, low environmental impact, employee safety, public safety, full compliance with all laws and regulations, being a good corporate citizen, and so forth. Table 19.1 shows the key performance indicators (KPIs) used by one utility, including the metric measurement used for each utility and the targets desired. It is representative of the comprehensive nature of KPIs used in the asset management approach, but not necessarily typical of most utilities. Goals and needs vary widely. Most of the KPIs are self-explanatory, but several are not. Here, "DivBSpl" is the largest deviation among the company's many operating divisions from the ratio of budget spent in the division to revenues collected in the division in the year. DivBSpl is a measure of the "fairness" of spending. Big bad outage measure (BBOM) is a KPI, aimed at reducing the likelihood of "outages that get into the newspapers" and will be discussed in more detail later in this chapter.

TABLE 19.1 Key Performance Indicators Used by One Asset Management Utility

KPI	Meaning	Metric	Target
CAPEX	Capital spent in the year	Dollars	<\$135M
OPEX	O&M spend in the year	Dollars	<\$340M
Total \$	Sum of CAPEX and OPEX	Dollars	<\$450M
DivBSpl	Divisional budget split	Max Δ	<10%
SAIFI	Ann. avg. customer inter. events	Events per customer	<1.3
SAIDI	Ann. avg. customer inter. duration	Minutes per customer	<95
$CEMI_3$	Customers with more than 3 inter.	% of customers	<3%
BBOM	"Big bad outage" contribution to SAIDI	% of SAIDI	<4%
PSAFE	Public safety	Nonemployee accidents	0
ESAFE	Employee safety	OSHA events per million hours	<1
LGL	Compliance with legal, codes, etc.	Number of outstanding violations	0
PWOM	PW of future O&M spending	Dollars	as low as possible
PWCR	PW of future capital spending	Dollars	as low as possible

All but two of the KPIs are *targets* (there is no compelling reason to spend money to go beyond it). The remaining three KPIs are *objectives* (areas where the utility desires to drive performance as far as possible). Overall, this set of KPIs can therefore be interpreted to mean:

> Spend no more than \$450 million in the year, distributed so that CAPEX is no greater than \$135 million and OPEX no more than \$340 million, with spending by division no more than 10% out of proportion to corresponding revenues. Achieve a SAIFI less than 1.3, $CEMI_3$ less than 3%, a SAIDI below 95 min with less than 4% of that caused by widespread (big bad) outages, have no public safety events, no more than 1 OSHA reportable accident per 100,000 h of company labor, and no deviations from legal and regulatory requirements. Subject to achieving those targets, minimize the present worth of future capital and O&M spending.

Financial asset management is about balancing risk vs. return. Infrastructure asset management is more complicated, and must balance performance, cost, and risk. Sometimes the need to balancing act is obvious, as when considering whether to spend money on a substation to reduce the risk of a catastrophic failure. A utility can spend a lot of money and have low risk, spend no money and have high risk, or do something in between.

Most utilities are not perfectly efficient when it comes to performance, cost, and risk. In this situation, an asset management utility seeks to *finesse* rather than balance competing targets and objectives. It may be possible through synergy, leverage, optimization, and efficiency gains to improve all KPIs simultaneously, but not to the initial target levels that have been set. In this case, a utility may find that it makes more sense to focus on certain KPIs before others. A utility may also find that it could slightly worsen a few KPIs so that other KPIs can substantially improve. In the end, a utility should have a set of KPI targets that can all be reached. Much of the asset management process involves the finessing of these targets into an acceptable spending plan.

The utility that used Table 19.1 effectively told its asset management planning process to

- Spend up to \$450 million next year. CAPEX and OPEX can vary a bit, but keep each one and the spending allocation to divisions, within set limits.
- Satisfy all of the KPI targets, but there is no need for improvement beyond the target. It is all right to further improve any KPI in order to get other things done that need to be done.
- To the extent possible within the two previous requirements, minimize the present worth future CAPEX plus OPEX.

When asset management portfolio planning is done well, it will either (a) determine ways to achieve these goals or (b) show utility planners why this set of targets cannot be achieved.

Risk management. Risk involves uncertain knowledge about the future. For targets, risk is associated with the probability of not achieving the target. For objectives, risk is associated with the uncertainty surrounding the expected outcome of the objective. Uncertainty stems from unpredictable or uncontrollable external and internal factors.[1] Asset management seeks to quantify and manage risk through explicit, fact-based consideration of the uncertainties and application of investment and decision principles that minimize risk impact and balance it against expected gain. Approaches to risk management vary, but must always involve the quantification of risk and the weighing cost of mitigation to its impact on expected performance and expected cost.

Common approaches to risk management are the use of probabilistic techniques, multiscenario analyses, or a mixture of both. In a probabilistic approach, while one does not know the eventual outcome of a particular factor (e.g., weather) one can characterize the uncertainty with a probability

[1]An external factor is something "outside" of the utility, anything from future tax rates (set by politicians, not utility managers) to the weather, which no one can control or forecast. Internal factors of concern to the risk management process are variance from budget and completion time (not all projects are brought in on time and on budget), etc.

distribution that is known. In a scenario approach, one studies the implications of some large event or shift in conditions with respect to the entire plan.

Traditionally, electric utilities have been very risk-averse. The move to risk-based approaches is motivated by a growing recognition that often this risk aversion is not in alignment with overall corporate objectives. Instead, risk-based asset management seeks to balance risk (the likelihood bad outcomes) against the cost of avoiding them. Consider the experience of a one large IOU in the central U.S. The capacity requirements and design standards at this utility required a minimum ratio of substation capacity to projected peak demand for substation equipment. A risk assessment showed that these criteria resulted in about 4% of capital substation spending and would only be useful less than once every 40 years. A risk perspective revealed two important points about this expenditure:

1. *This spending was effective.* It did assure that the bad outcomes it was meant to prevent (outages due to insufficient substation capacity) would be avoided. However, not spending it did not necessarily mean that the outcomes would always happen: operating measures and emergency reactions in many cases might avoid them.
2. *There were more effective ways to spend the money.* The utility could buy much better *overall performance* for its customers and stockholders with 4% of the substation capital budget by spending it elsewhere. This includes items such as automation and monitoring that would provide improvement more often than every 40 years and that would improve more than just customer reliability.

Thinking in terms of risk management is often a difficult adjustment for organizations that have institutionalized a dislike risk, as have many traditional electric utilities. However, risk management is fundamental to all businesses subject to substantial uncertainty, and sound asset management is impossible without risk management. A utility using a risk-based approach might set the KPI targets shown in Table 19.1, and then set *probabilistic targets* for their achievement: Probability of budget exceeding limits will not exceed 5%, nor that of failure to meet any one target exceed 10% or all targets simultaneously, 20%). Probabilistic analysis then looks at the probability distribution of uncertain and uncontrollable events and factors, as well as stochastic factors such as how much project cost varies from forecast, etc., and how all the factors influence the KPIs to determine if a spending plan meets these probabilistic criteria. Proper numerical methods can optimize the problem, finding the best spending plan to meet the KPI targets within the desired level of confidence.

19.1.2 Coordinated Cross-Functional Decision Making

Asset management calls for all policies and decisions about the use of existing assets, investment of new capital, and application of O&M resources, to be coordinated so that they maximize their joint contribution to achieving goals and managing risk. This is related to the pursuit of synergy and leverage between projects when attempting to achieve all targets at once. Synergy and leverage can only be managed through the close coordination of investments, resource allocations, and policies. At many utilities, asset management starts with an initiative to prioritize only large-capital projects using some sort of cost-to-benefit ratio ranking method. This is a good first step. Large-capital projects are an important budget and performance category, and asset management principles can be easily and effectively applied. Further, there is typically good data. Last, the cost analysis for each large and important project can be separately justified. However, true asset management links all spending decisions into a coherent whole. It does not consider only all large-capital projects. Rather, asset management looks at small-capital projects, large-capital projects, inspection projects, maintenance projects, and operational policies together with full consideration of their positive and negative interactions.

For an electric utility, this means that capital spending, maintenance spending, and operational policies must all be coordinated and managed through the asset management process. Asset management means substantially more communication and cooperation among departments and across the disparate functions scattered throughout the utility through a common asset management process. The hope is that all departments and functions mutually work toward broader corporate goals. For substations, this means that a substation asset management process must include substation planning, substation design, substation equipment standards, substation operating guidelines, and the inspection and maintenance of all substation equipment.

19.2 Important Functional Elements of Asset Management

Many functions within an asset management process already exist within the existing utility framework. However, asset management has several important aspects that are distinct from traditional utility planning and engineering. This includes portfolio management, multi-KPI assessment, multi-KPI prioritization, and probabilistic risk management.

19.2.1 Portfolio Management of Projects and Resources

The term *portfolio* has long been used within the investment community to refer to the set of investments that a person or institution has made. In utility asset management, the portfolio is best thought of as the set of investments and resource commitments that the utility makes in order to get the business results it wants (Fig. 19.2). A utility obtains its KPI targets buy "buying" its portfolio of assets.

A point often missed about portfolio selection is that the portfolio is selected as an integrated whole. All the projects within a portfolio are selected simultaneously, or in a way that effectively accomplishes the same result. This is a large departure from past practices. In the traditional utility, all projects were approved simultaneously or at least within the same process in the same budget year. However, each project was typically created to address a particular "problem," and this was done in relative isolation from other projects related to other problems. In contrast, asset management links not only the decision about whether to approve a particular project to the approval of other projects, but also the decision about what to do in each instance to what is decided to be done in every other instance.

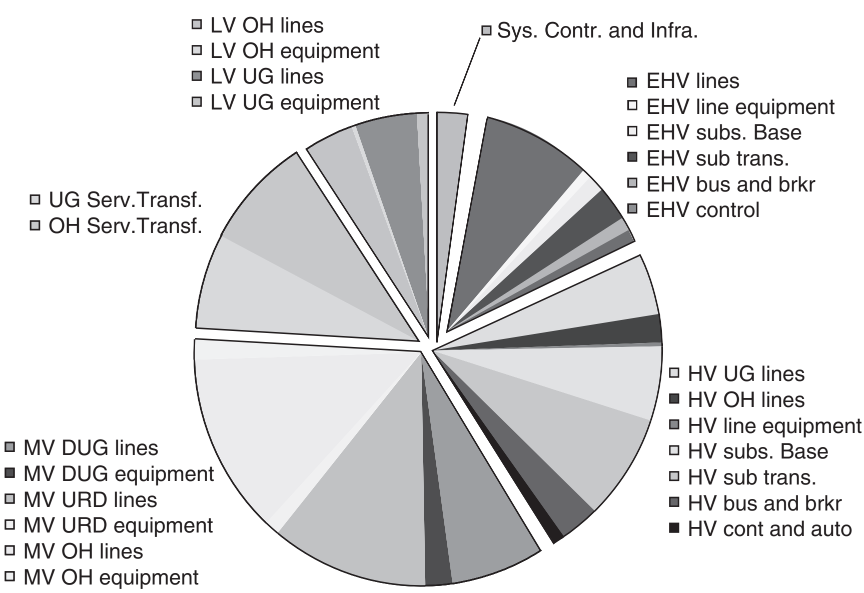

FIGURE 19.2 The "portfolio" is the distribution of "investment" by the utility in order to obtain the results it wants. This pie chart shows the asset value of the T&D system owned by an invested-owner utility in the SE U.S.

The integration of project identification and selection is much tighter than in traditional utility planning and management. All projects are effectively part of a single, broader decision.

Consider an old substation transformer that is showing signs of deterioration. Ways to address this issue include: do nothing; do weekly visual inspections; install on-line condition monitoring equipment; do minor maintenance; do a major overhaul; transfer load away; replace the unit; and many other possibilities. The traditional approach would examine each option and select the "best." Asset management does not pre-judge the answer. Instead, all options are provided to the portfolio optimization process and the choice is made in full coordination of all other projects with all of their associated options.

19.2.2 Evaluation of Projects Based on Multi-KPI Contributions

Table 19.1, discussed previously, highlights the multi-KPI nature of asset management's focus. Functionally, this means that in the evaluation, planning, and approval stages, the merits of any particular project option are assessed on how it contributes to all business goals, and on whether improvement in each of those KPI areas is needed (i.e., a particular project may provide a good deal of improved reliability, but none may be needed). Not every project contributes to every KPI, and some projects will actually have negative impacts on certain KPIs. Many projects will incrementally contribute to several KPIs, and asset management explicitly recognizes this by evaluating projects based on their value overall.

19.2.3 Prioritization Based on Total KPI Contribution

A key concept of asset management is that projects and options the utility could select for approval are assessed based on their total KPI contributions and those with the highest overall contribution are selected. This is often called "bang for the buck" prioritization because projects are evaluated on the "results" (bang) they provide rather than to their cost (bucks). At its simplest, asset management assembles a single-valued "score" for each project based on the KPIs and a scoring or conversion formula. For example, if the KPIs were as listed in Table 19.1, these formulae would be something like that shown below:

$$\text{Score for a project} = \text{project value/project cost} \tag{19.1}$$

$$\begin{aligned}\text{Project value} = {} & A \cdot \Delta\text{SAIDI} + B \cdot \Delta\text{SAIDI} + C \cdot \Delta\text{CEMI}_3 + D \cdot \Delta\text{BBOM} + E \cdot \Delta\text{PSAFE} \\ & + F \cdot \Delta\text{ESAFE} + G \cdot \Delta\text{LGL}\end{aligned} \tag{19.2}$$

$$\text{Project cost} = \text{PWC} + \text{PWOM} \tag{19.3}$$

where

$A \rightarrow G$ are scalar weighting factors proportional to the importance of each KPI
PWC is the present worth of the project's capital cost
PWOM the present worth of O&M

Projects are then ranked on the basis of their score, and selected "from the top" moving down the list until either budget or resource constraints are reached, or all KPI targets are achieved. Once a particular target is reached, no additional value should be placed on further improvement of that KPI. Therefore, value scores for additional projects should be recomputed with a zero weight associated with any KPI that has reached its target. The list can then be "reranked" in a dynamic reevaluation manner each time another KPI is achieved, and the selection process continues.

The portfolio (group of selected projects) should meet all KPI targets for the minimum possible present worth cost, regardless of the weighing factors that are used. One should note that the "value" score and the weighting factors used are only a means to an end, and not of material importance or even particularly meaningful. They are used only to enable a simple solution methodology to work.

If a solution that does not violate any constraints cannot be found, the asset manager must relax one or more constraints, generate a new portfolio, and repeat this process until an acceptable solution is found. Methodologies that use a ranking approach, even those that use dynamic reevaluation and reranking (as described above), are simple to implement but are generally not able to find optimal solutions, for several reasons. First, the solution will generally be dependent upon the weights chosen for the ranking formula, although this is generally a small concern as long as all KPI targets are reached. But a weighting-factor ranking method that finds a solution may not find the best solution.

More important, ranking methods have difficulty in handling practical constraints (e.g., you can select project X only if you have previously selected project Y or project Z; you cannot do both M and N in the same year; you must do one but only one of U, V, or W). Last, it is nearly impossible to properly consider the interdependencies of project benefits with simple methods (e.g., project A will deliver more value if project B is also done; project C will deliver less value if project D is also done). In practice, the authors have found it is impossible to accommodate more than a handful of such issues with customized reranking methods.

For complicated project portfolio selection problems, the use of rigorous optimization algorithms is generally preferred. These algorithms can automatically address any shift in values as KPIs are achieved one by one, can handle any number of practical constraints, and can simultaneously select projects while considering interdependencies. However, the concept of ranking based on total contribution to business goals is central to asset management, and is useful as an intuitive guide in understanding its goals and methods.

While tools and techniques vary from utility to utility, all asset management approaches decide which projects or options to select for the portfolio (i.e., which to approve for funding) in a simultaneous manner, where all are effectively in competition with one another for funding. In general, projects selected for funding (i.e., to be included in the portfolio) contribute broadly to many KPIs for which improvement or performance gain is needed. Few approved elements of a plan will have "single criterion" expenses that achieve or contribute to only one aspect of the business goal set.

An example from an actual asset management plan for a large IOU in the central U.S. is shown in Table 19.2. In the interests of space, only a few KPI columns and a few project rows in a very big table are shown. The actual plan involved 18 KPIs and over 430 different potential strategic project options, 108 of which were selected for the portfolio. The approval optimization determined the best set of projects meeting the specified KPI targets, and ranks projects based on a benefit-to-cost score. The entire set of 108 projects from which this list is taken is the optimum portfolio to achieve the KPI goals the utility has set.

19.2.4 Probabilistic Risk Management

Asset management methods in the financial industry are based on sophisticated risk quantification based on probabilistic techniques. The goal is to identify the maximum expected return that can be achieved for each level of risk (defined as the standard deviation of expected return). The topic is vast, but the point is that there are many mature probabilistic techniques that have been developed and proven to work well. Many of these also work when applied to utility asset management and substation asset management.

Probabilistic risk management falls into two categories: cash and noncash. Cash flow uncertainty related to a project is reflected in the present value calculations for the project. Projects with cash flow risk that is similar to the overall cash flow risk of the company should use the weighted average cost of capital (WACC) for the discount factor. Projects with cash flow risk that is higher to the overall cash flow risk of the company should use a higher discount factor.

Noncash risks generally relate to nonfinancial KPIs. Consider a utility with a SAIDI target of 110 min, but SAIDI will vary from year to year depending upon unpredictable factors such as weather and the stochastic nature of equipment failures. It may not be enough to target SAIDI at 110 min on average. Should the 110-min target, or better, be achieved in four years out of five? Nine years out of ten? Ninety-nine years out of 100? A deterministic asset management methodology that works with numerical KPI

TABLE 19.2 Ranked List of Projects from a Utility Asset Management Plan for 2005

#	Project Name	Project Option	CAPEX	OPEX	SAIFI	SAIDI	NPV-$	Utility/$	Cum. Cost
1	Dist. sub transfs >10 MV	−10%$ I&M., cond. based	$15	−$523	317	57060	$2,458	870.9	($520)
2	Dist. sub transfs <10 MV	+10%$ I&M, cond. based	$18	$484	8004	960526	$3,667	837.0	($33)
3	MV OH lines	+15%$ perf. based sch. 3	$22	$674	32193	2961756	$4,779	813.7	$644
4	EHV breakers >115 KV	Repl. 50 bad @ 10/yr	$2,110	$780	11035	1986300	$6,070	713.7	$1,783
5	MV breakers <34 KV	+10%$ I&M., cond. based		$284	4002	80044	$1,716	549.0	$2,067
6	3-Ph pad. serv trans	Replace units rated <S	$1,637	$281	350	63015	$1,608	513.2	$2,626
7	Dist. sub transfs <10 MV	Monitoring@remote sites	$1,180	$24	4803	864474	−$757	487.2	$2,851
8	EHV sub transformers	Full 8-gas moni. & alarms	$8,967	$56	4911	206262	−$283	487.2	$4,431
9	HV breakers (35 and 69 kV)	−10%$ I&M., cond. based		−$345	−1252	−11780	$2,255	399.9	$4,086
10	OH serv trans TLM	TLM Repl. prog. on-going	$234	$71	154819	270000	$20	389.2	$4,197
11	HV circuits (35 and 69 kV)	Fault Red. Focus Program	$84	$196	32018	1344756	$900	371.2	$4,407
12	MV circuits (<69 kV)	Fault Red. Focus Program	$84	$996	40022	3682018	$7,740	342.2	$5,418
13	MV UG lines Circuits	−20%$ I&M., cond. based		$180	−3200	−576000	$1,012	323.7	$5,598
14	EHV breakers >115 KV	−20%$ I&M., cond. based		$134	−2087	−1789	$484	270.6	$5,732
15	EHV OH lines	0%$ I&M., cond. based	$84		1252	22536	$680	256.8	$5,746

targets essentially assumes that they are expected values. As such, it is about 50% likely that expected values will not be achieved in a particular year due to random chance. A probabilistic method is needed to determine how often the utility will achieve the target. A probabilistic methodology can determine a statistical confidence level for all noncash KPI targets (e.g., achieve a SAIDI of 110 min with 90% confidence). A probabilistic portfolio optimization requires probability distribution functions for key inputs (such as expected project benefit) and use of Monte Carlo techniques that are able to compute the probability distribution functions for key outputs (e.g., KPIs).

Consider a potential project portfolio consisting of five projects, with the goal of improving SAIDI. The impact of each project on SAIDI is described as a probability distribution, typically a triangular distribution consisting of a minimum benefit, a most likely benefit, and a maximum benefit. A Monte Carlo simulation will use random numbers to determine the benefit that each project has on SAIDI in a particular year, with the sum of the benefits of the five projects equal to the total SAIDI benefit. This process can then be repeated many times. The percentage of times that SAIDI is lower than the target is equal to the confidence of achieving the target. Assume that the Monte Carlo simulation is performed 1000 times, and the SAIDI target is met in 850 of these simulations. The probability of meeting the SAIDI target is $850 \div 1000 = 85\%$. If the SAIDI confidence level is set higher than 85%, the portfolio is unacceptable. If the SAIDI confidence level is set lower than 85%, the portfolio is acceptable.

19.3 Asset Management in an Electric Utility

19.3.1 Shift from Standards-Driven to Business-Based Management

Traditionally, utility planners recommended, and management generally approved, projects and resource commitments based on minimizing the cost of satisfying planning criteria, engineering standards, and operating guidelines (Seevers, 1995). Typically, this was carried out on a department level (e.g., transmission, substation, distribution) with a "standards-driven approach," in that a set of guidelines determined when and how the utility would commit spending and resources (Fig. 19.3). For example, a utility might have an equipment loading standard stating that a substation transformer should not be loaded past 80% of its nameplate rating under normal (weather adjusted, no contingencies) peak demand conditions. If load growth forecasts predicted that the 80% loading limit would be exceeded in the future, capital planners would determine what and how and when to change the system. This might include the addition of transformer capacity so the loading limit would no longer be violated, while spending the least amount of money possible. Similarly, the company's O&M guidelines would call for medium voltage breakers to be inspected and serviced at specified intervals regardless of the condition of a breaker and regardless of the importance of a breaker to overall system performance.

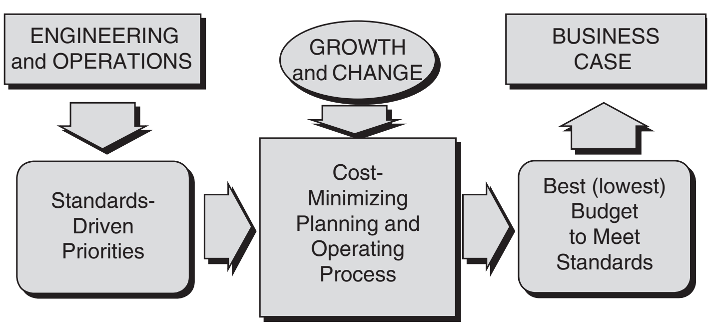

FIGURE 19.3 Many of the priorities and most decisions to spend money in a traditional electric utility were driven by "standards" on what and how "things should be done." When followed, standards typically resulted in low levels of risk and operational stability. Compare this approach to Fig. 19.1.

Such standards and guidelines were developed, fine-tuned, and proven over time. For the most part, they led to the desired results. The lights stayed on. Equipment usually lasted a long time. And there was little drama with respect to operation of the utility system. But the traditional engineering and operating guidelines (standards) were, in effect, "one size fits all." They assured that performance would be satisfactory, but they did not always spend money and use resources and existing assets optimally. Occasionally they called for projects that had very high marginal costs for very low marginal benefit. Sometimes they passed up opportunities where a small additional expenditure could provide a large business benefit outside of the mainstream context of the standards. Such situations were exceptions to these "one size fits all" rules. But there were enough exceptions that a more case-by-case approach like asset management can improve cost-effectiveness and overall results by noticeable amounts.

While good planners generally did minimize the cost of each project within the traditional standards-driven framework (e.g., planning all substation upgrades so that the loading guideline would no longer be violated), each project was considered in relative isolation to other projects being studied, other decisions being made, and how those decisions and plans might interact with other goals the organization had. As a result, the traditional paradigm did not necessarily minimize the overall cost of achieving the ultimate result (e.g., satisfactory service and equipment lifetime). Projects and expenditures were not selected based on being "put together" in an overall optimum plan. Then, too, only capacity-based KPIs were considered, leaving other KPIs to be dictated implicitly by design standards. Asset management goes beyond the traditional paradigm by considering all KPIs explicitly and considering all projects simultaneously in the same way. It provides improved business performance and improved cost-effectiveness because it seeks to achieve satisfactory overall performance at the lowest possible overall cost by looking at the ultimate goal, not at subsidiary goals such as loading standards, and by considering how projects, programs, and policies "fit together" into a coordinated portfolio.

Finally, standards-driven process did not fully exploit opportunities for leverage, nor drive synergy among different functions and departments. Certainly, good managers and planners at traditional utilities were aware of, and tried to create synergy and cross-functional leverage where they could. But the process, and the institutionalized framework within which they worked, typically did not encourage this type of behavior. This is especially true of departments and budgets. It was often perceived that a bigger budget means a more important department. Asset management, ideally, is quite the opposite. Importance of departments is measured not by budget, but by contribution to.

Asset management is a different way of making spending decisions and requires a dramatic change in corporate culture. This culture change is perhaps the most difficult aspect of implementing an asset management strategy. For substations, this culture change will primarily be a shift away from engineering and "equipment stewardship" mindset toward a business and risk management mindset.

19.3.2 Pareto Curves and the Efficient Frontier

As discussed earlier, asset management strives to identify a coherent set of achievable KPI targets. Optimization methods cannot, by themselves, determine the recommended portfolio or the recommended plan. What they can do is analyze thousands of possible portfolios and compare results. A simple way to do this is to plot the present value of CAPEX and OPEX for each portfolio against the weighted KPI improvement, as shown in Fig. 19.4. Each circle, whether shaded or unshaded, represents one possible portfolio consisting of a set of projects prioritized to perform over a 5-year period. Each circle is plotted based on its "bang" (KPI improvement) vs. its cost (bucks).

Most of the project portfolios (asset plans) in this diagram are not optimal in the sense that other portfolios exist that are both less costly and result in more KPI improvement. For example, portfolio "A" costs the same amount as portfolio "B," but provides noticeable less bang. Clearly, "B" and "C" are better choices than "A." Since there are no projects that are unambiguously better than "B" or "C," they are referred to as efficient. Their KPI improvement level cannot be achieved without higher cost and cost reduction cannot be achieved for either without sacrificing some of their KPI improvement.

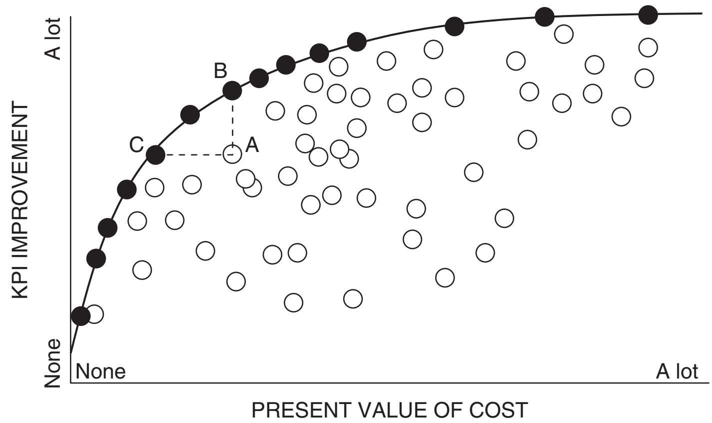

FIGURE 19.4 Potential portfolios (asset use and spending plans) can be plotted by their cost and performance results as shown here and explained in the text. Only the best portfolios like on the efficient frontier, also called the Pareto curve, which denotes the maximum performance possible at every budget level. Optimization used in asset management finds only the portfolios on the efficient frontier and draws the curve for the utility planners.

The *efficient frontier* is the set of all efficient solutions and can be thought of as the upper boundary of this set of portfolios. The efficient frontier represents the set of choices the utility has with regard to how much performance it wants to buy. It describes how much performance can be purchased for various levels of spending and is a cornerstone of asset management in all industries (Markowitz, 1952). Conversely, it describes how much a utility must spend to achieve various levels of performance improvement. This efficient frontier is also known as a Pareto curve, since it identifies a set of optimal solutions based on the same efficiency concepts used by the Italian economist Vilfredo Pareto when he examined issues related to social welfare (Pareto, 1906).

Other graphs similar to the efficient frontier are often useful. Consider a portfolio of projects where inside the portfolio, projects are ranked based on the ratio of total KPI contribution to the present value of cost. For budgeting reasons, a utility may want to plot KPI improvement vs. budget impact rather present worth. Projects are still ranked based on present worth, but the plot is based on cash requirements. Another useful approach is to plot the improvement of each KPI separately. Projects are still ranked based on total KPI contribution, but results show improvement for each KPI vs. various levels of spending.

Figure 19.5 shows an actual Pareto curve from the asset management study for a large investor-owned electric utility in the central U.S. The curve was formed by a constrained optimization method that started with "zero budget" and then determined optimum portfolios (sets of approved projects) for every 5-year budget level up to $1,500,000 million, in even increments of $1 million. The optimization worked on multiple KPIs, but Fig. 19.5 shows only SAIDI result. Characteristics worth noting here are

1. *Must-do region.* Starting at the origin and up to about $122 million, SAIDI improves one by about minute only for each $20 million spent. But beyond $122 million, the slope of the curve increases dramatically. From there to $250 million SAIDI increases an average of one minute for each $2.5 million spent. The initial low slope and poor performance in buying SAIDI is due to a number of "must do" projects. These projects must be funded for $122 million, but do not contribute greatly to SAIDI. In the optimization process, "must do" projects are approved before anything other than spending. But once these are funded, the algorithm can search for the most efficient ways to buy SAIDI, and slope increases dramatically as it begins spending beyond $122 million.

It is rare to see a "must do" slope depicted in theoretical descriptions of optimization and asset management. However, must-do projects are a reality in any practical utility situation and are often

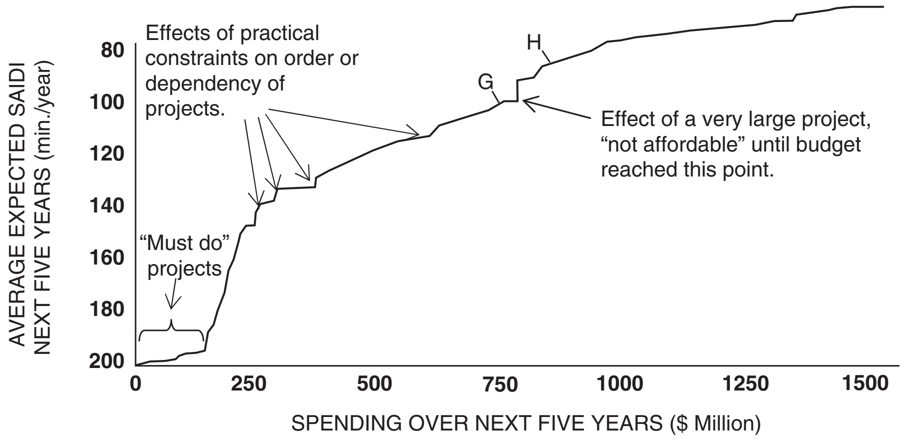

FIGURE 19.5 Actual Pareto curve for an electric delivery and retail utility in the central U.S. shows characteristics common to actual, practical applications. See text for details.

quite an important part of the corporation's focus and its potential KPI performance achievement. Accommodating them well is a key success factor in any practical asset management approach.

2. *Decreasing marginal return.* After the "must do" project is approved, the Pareto curve is concave. This means that each subsequent dollar spent results in less KPI improvement. Early spending has relatively high benefit-to-cost, and later spending has relatively low benefit-to-cost. This characteristic is inherent and indicates a correct analysis: an optimum "performance buying process." The optimization process starts with the most effective (highest bang for the buck) projects and saves the rest for later. For example in Table 19.2, the first project bought has an effectiveness (bang/buck) of 870 per dollar, the next has 837 per dollar, the next has 813 per dollar, the next 713 per dollar, and so forth.
3. *Bumps and small shifts in slope.* Figure 19.5 is not a smooth curve like the one shown in Fig. 19.4. It has several end points where, despite the general condition of concavity discussed above, the slope increases briefly as spending is further increased. Discontinuities and deviations from a strictly decreasing slope are due to the facts that: (a) real projects are being optimized and (b) constraints are being used. Deviations from the gradual smooth decrease in slope like that occurring at $760 million in Fig. 19.5 are due to "big projects," as will be described in the paragraph below.
4. *Portfolios on the curve are not cumulative as a function of cost.* In other words, the portfolio (set of projects) on the curve that costs $800 million (point H) does not necessarily consist of all the projects included in the lesser-cost portfolio (G, $700 million) with an additional $100 million of projects included. In fact, in this particular case, H contains only $630 million of overlap with G. With $800 million to spend rather than $700 million, the optimization took a different approach, which the discontinuity indicates. When the optimization reached $760 million, it "dumped" $70 million in other projects it had bought up to that point, to spend $71 million on a system-wide substation automation system that it could not previously afford, while still meeting all other requirements and constraints it had to meet, at any lesser budget. This $71 million project provides much better SAIDI impact than the $70 million in "dumped" projects did, hence the nearly straight upward slope at that point. Curve behavior like this is common in real, practical utility planning situations.

19.3.3 Use of Risk-Based Asset Management Methods

Asset management principles are most effective when applied with an explicit consideration of risk management, as discussed earlier. The purpose of asset management is to maximize business

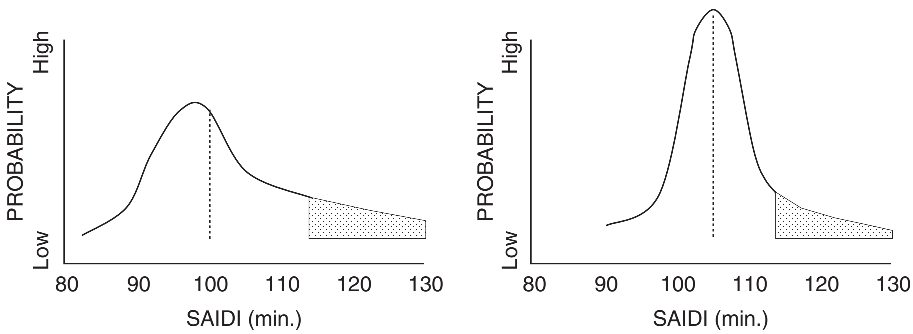

FIGURE 19.6 Left—probability of SAIDI for a plan optimized to a deterministic target of 100 min. There is a 28% likelihood of exceeding 115 min in any year. Right—distribution of a plan optimized to minimize the likelihood of SAIDI exceeding 115 min. The probabilistic plan leads to a higher probability of success for the utility.

performance. While this can be interpreted to mean "maximize" the expected of performance, it can also be interpreted to mean "minimize" the likelihood of failure (Brown and Spare, 2004, 2005). A mature asset management process will explicitly consider all risk factors in a balanced manner. Risk management is particularly important for substations since utilities are often concerned more about avoiding large but rare event rather than just the contribution of substations to broader customer-level KPIs such as SAIDI.

Risk exists whether the planning method used by utility considers it or not. Deterministic (non-risk-based) asset management methods do not evaluate, display, or allow planners to deal with uncertainties and the risk they create, but the risk is still there. As an example, the left side of Fig. 19.6 shows the probability of SAIDI corresponding to an investment plan that was deterministically optimized to an expected SAIDI of 100 min. The authors calculated the shown probability distribution based on analysis of the probabilities for factors such as weather, load growth, on-time completion and budget compliance of large projects, large equipment failures, etc. The average expected SAIDI is 100 min, but as shown, the utility can expect it to exceed 115 min in about 3 out of every 10 years.

An alternate plan was developed using a risk-based methodology that did not optimize based on average SAIDI. Rather, the objective was to minimize likelihood of SAIDI exceeding 115 min (the utility's regulatory definition of "poor performance" in this KPI). The risk-based plan spends the same budget but directs spending in a way that will minimize performance-based rate penalties in "bad luck" years (Brown and Burke, 2000). The resulting expected SAIDI is 106 min, a 6% increase over the first plan. However, the likelihood of SAIDI exceeding 115 min is less than 8%, a nearly fourfold reduction in the likelihood of poor performance when compared to the first plan.

Risk-based asset management methods typically look at sources of uncertainty in the utility's performance that cannot be precisely predicted or controlled (Table 19.3). Independent stochastic events such as equipment failures are analyzed probabilistically and their impact minimized in the

TABLE 19.3 Factors Typically Analyzed as Risk Sources in Utility Asset Management

	External Factors	Internal Factors
On a probabilistic basis		
	Weather	On-time completion of projects
	Load growth	On-budget completion of projects
	The economy	Field force response time and quality
	Price of power/fuel	
	Cost of money	
On a scenario basis		
	Regulatory relationship	Labor union–utility relationship
	Change in regional employment base	

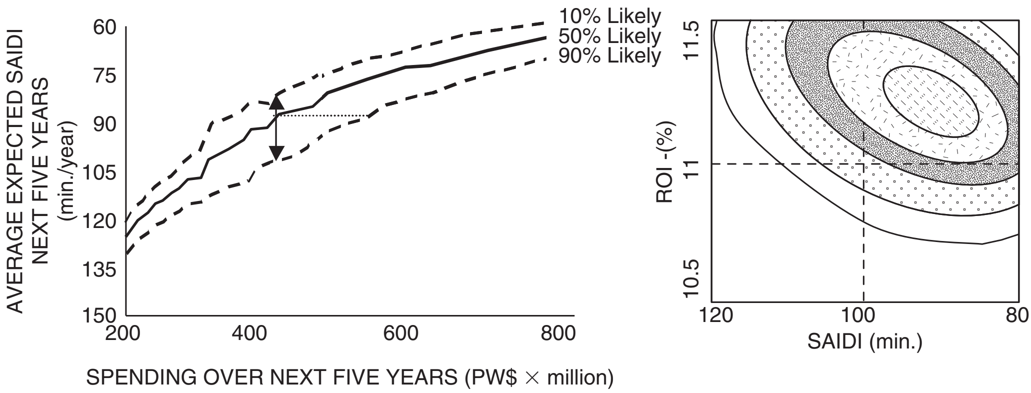

FIGURE 19.7 Information developed by a utility in the western U.S. during studies for its asset management strategy, which was targeted at 90-min SAIDI and an 11.2% return of investment. The left graph shows a Pareto curve of spending vs. SAIDI, including 10, 50, and 90% confidence levels. The right graph shows the probability of SAIDI and ROI outcomes for the selected plan. It is seen that SAIDI and ROI are negatively correlated, mainly due to the probabilistic effects of weather: hot summers are good from a profit standpoint (high revenues) but put additional stress on system and equipment (harmful from a SAIDI standpoint).

portfolio optimization. Major stochastic events are analyzed on a scenario basis with the goal of developing plans that are robust in a variety of alternative scenarios (Willis, 2004).

Risk-based asset management methods perform analysis of projects and portfolios on a probabilistic basis, providing indications of the probability of success rather than deterministic evaluations (Figs. 19.6 and 19.7). Figure 19.7 shows information developed by a utility in the western U.S. A $400 million budget gives an expected SAIDI of 90 min. However, to be confident that it will achieve a SAIDI of 90 min or better 9 years out of 10, it would have to target an expected SAIDI of 80 min and spend $520 million (dotted line). The diagram shown is for a plan developed deterministically. A probabilistic optimization eventually developed a plan that spent $470 million and had the same probability of SAIDI exceeding 90 min. Information derived and presented in this manner is used to support decisions on both spending and forecasts, i.e., executive management uses risk-based methods both to study what targets they can achieve and the likelihood of their success (i.e., set realistic, achievable goals) and to manage to those targets on a strategic and operational basis.

19.4 Asset Management Project and Process Example

The following example highlights the difference between a traditional utility approach and asset management. Suppose Big State Electric's Eastside distribution substation has two 40-MVA transformers, two low-side buses (each fed by one of the two transformers), and a total of eight feeder circuit breakers (four per bus). These transformers, buses, and breakers have been cared for according to well-established guidelines. All equipment are visually inspected annually. Breakers are completely serviced every 6 years or so-many operations, whichever comes first. The substation currently serves a 57-MVA peak demand, balanced fairly well between the two transformers/bus combinations, and among the eight circuits.

19.4.1 Substation Example

The utility's guidelines call for no more than 75% loading of transformers in any two-transformer substation at normal peak demand, which means a limit on the substation load (when balanced between the two units) of 60 MVA. This guideline is meant to limit the stress on substation power transformers, and thus ensure a long service life. Other guidelines call for no more than four breakers per low-side bus (so that a bus outage does not cause too many circuit outages) and no more than 8-MVA loading per feeder (based on the present size of feeder getaway cable). All of these guidelines have their justification in analytic technical evaluations done in the past and have been proven over time. These guidelines seem to work well when they are followed.

Suppose that peak demand at this substation is expected to rise to 68 MVA in the next four years, continuing over the next decade to 78 MVA. Under the traditional paradigm, utility planners would evaluate options and select the best (least-cost) one so that the substation did not violate this or any other guideline as this load growth occurred, in a process diagrammed in Fig. 19.8. The options studied would include transferring load to neighboring, less-loaded stations, as well as more capital intensive options involving addition and replacement of equipment. The planners would pick the option with the lowest total cost, usually meaning the option with the lowest net-present value (NPV) of capital and future O&M costs.

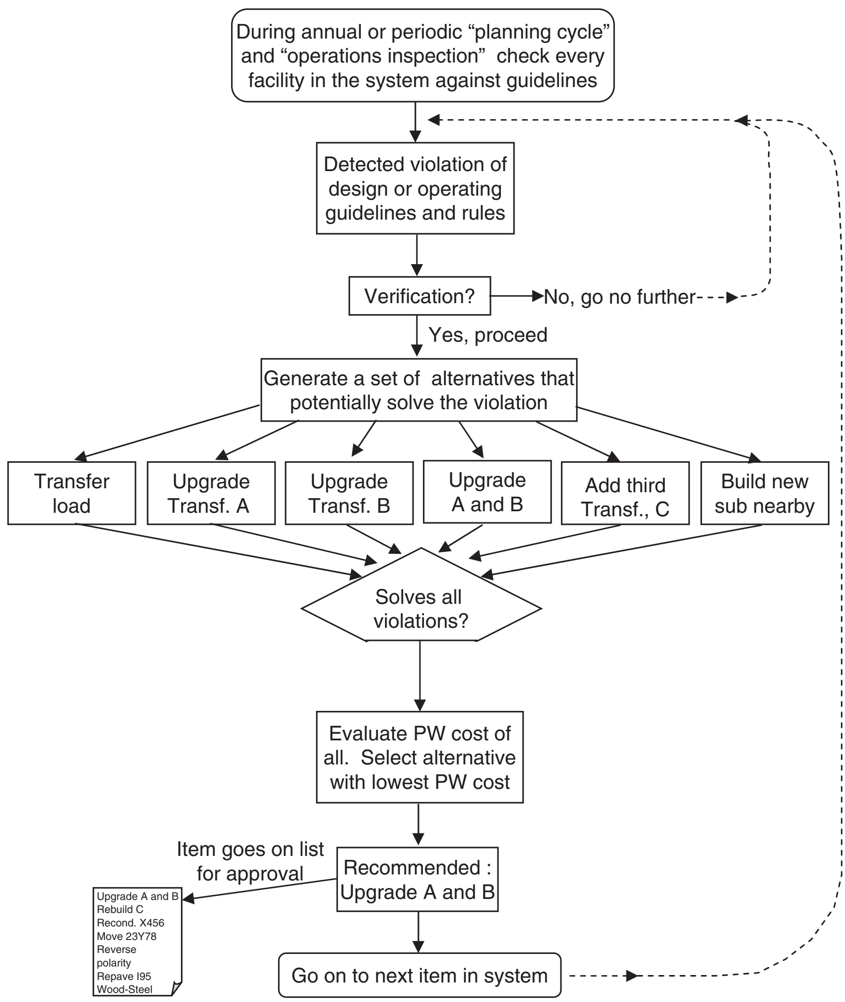

FIGURE 19.8 Traditional process of "spending" by a utility is initiated by either planning studies of system capability against forecast, or condition assessment of equipment. Expenditure is triggered by detection of a possible guideline (standards) violation. This initiates something like the process shown, a search for a project that will fix the deviation (and cause no more) at the least possible cost.

In this example, the least-cost option that is selected includes (a) the transfer of what will eventually be 6 MVA to circuits out of neighboring substations, (b) the replacement of the two existing transformers with 50-MVA units (thus serving the 72 MVA of remaining projected peak within the utility's standard), and (c) the upgrading the two buses and all eight feeder getaways so that the circuits can each carry 8 MVA (i.e., so all other aspects are within other standards). To justify these projects, the planners have provided documentation that among all options examined this is the one with the lowest cost that satisfies all the relevant guidelines.

Asset management would decide what to do in this case by looking at a wider set of considerations, with a focus on the ultimate business outcomes the utility desires, and without absolute adherence to the substation design guidelines. The decision about if and what should be done at Eastside substation would be made in conjunction with evaluation of other needs and opportunities, and with it in "competition" with possible projects to be done elsewhere in the system. While this represents a significant departure from the traditional approach, it recognizes that the utility is not really interested in adhering to design guidelines per se. Rather, the utility is interested in good customer-service quality, satisfactory and sustainable equipment condition, and a low-spending level overall. Traditionally, design guidelines were indirect means of achieving those overall goals.

Some engineers and planners will be concerned that asset management has the potential to lower the utility's standards. Although, this may seem true from a narrow perspective, it is important to realize what issues traditional approach did not consider. It did not take into account the condition of the substation's equipment. Perhaps much of Eastside substation's equipment is old and worn, certain to require expensive maintenance and expected to provide marginal reliability in the future, and likely to fail without warning and need replacement in the foreseeable future. Or perhaps this substation is new, in very good condition, and of a particularly robust design that can take a lot more stressful service, particularly if selected equipment is inspected a bit more often and serviced more frequently in proportion to the greater wear and tear that higher loading creates.

Furthermore, the tradition process did not consider the impact that substation outages would have on KPIs, and their interaction with other resources and assets. Perhaps the feeder network around Eastwood substation is old, worn, and prone to frequent failures. Because of operational restrictions in the area served by the substation, it may be difficult and time consuming to restore customers after an outage. As a result, customers served by this substation service reliability somewhat poorer than system average to begin with, regardless of any substation-related issues. With this broader perspective in mind, a new substation along with feeder upgrades might solve the loading violation and provide a needed reliability boost for the region. Or perhaps the opposite is true. The circuits out of this station, and their tie points to circuits from neighboring stations, could be automated, so they can detect problems during emergencies and switch load very quickly. In this case, reliability of the substation and adherence to the strict standard would be less important, because substation outages could be quickly and effectively mitigated.

Although substation guidelines are still useful as guidelines, asset management recognizes that broader considerations should affect the decision about what needs to be done at the Eastside substation, as well as how Big State Electric intends to spend money and assign priorities elsewhere throughout its system. When all this and perhaps other factors are taken together and depending on the specific situation for Eastside substation, the utility might decide to

1. Do exactly what would be done in the traditional case: upgrade the substation and feeder getaways, at considerable capital expense.
2. Do nothing at all.
3. Do nothing to upgrade the substation or its feeder system, but only increase the frequency and comprehensiveness of inspection and service. This is in recognition of increased equipment loading and the potential increase in failure probability.

4. Do nothing to upgrade the transformers, buses, or existing breakers and feeders, but add two additional 8-MVA breaker/circuits (one per bus). This is in violation of the traditional four-per-bus limit, but allows the 72-MVA peak demand to be served within the 8-MVA limit. This plan would also increase the frequency and comprehensiveness of transformer and bus inspections.
5. Do nothing to upgrade the substation or its feeder capacity, but automate and upgrade selected feeder tie points in the substation area so that dispatchers can monitor loading and switch remotely during emergencies. This plan will also increase the frequency and comprehensiveness inspections.
6. Build a new substation and feeder network nearby.
7. Do something else entirely.

All of these options, and any others evaluated, should be assessed on a multi-KPI basis within the context of a broader project portfolio. Whether a particular option "solves" the loading projected, loading violation is only important to the extent that these loading levels, in conjunction with other system characteristics, will impact the utility's KPIs. In addition, an asset management approach should apply a risk assessment to this decision. This would typically begin with an evaluation of the load forecast. It might be high, so there really will not be a loading violation. It might be low, so the situation will be worse than forecast. The risk assessment should (as much as possible) identify the probability of extreme outcomes and the cost to address these outcomes. This allows the utility to make an informed decision about how much money to spend to mitigate specific sources of risk.

19.4.2 Implementing Project Evaluation and Portfolio Selection

Many utilities making the transition to asset management see project evaluation and portfolio selection as its most important element. However, the changes in how and why people work together for project evaluation and portfolio selection and in learning to think asset management are just as or more important. These *cultural changes* results will improve the way engineers and planners throughout the utility make business decisions. This will improve the quality of spending focus in itself, even without a sophisticated project evaluation, and portfolio selection, and risk management process.

Figure 19.9 shows that portion of the decision-making process as it applies to Eastside substation under an asset management approach, drawn in a manner as similar as possible to the traditional steps shown in Fig. 19.8. The reader must bear in mind that the final selection in this case is not done in "isolation" as it is shown in Fig. 19.8, but instead through portfolio prioritization, using optimization, as depicted in Fig. 19.10. There, the decisions about what to do at Eastwood substation, as well as the decisions about how to best address all other needs and opportunities throughout the utility system, are made simultaneously. This includes a comprehensive consideration of all costs and business impacts needed to achieve the aggregate KPI targets set (e.g., Table 19.1). The decisions about what will be done at this example substation, and in all those other situations, are made in a way where each potential project competes against others based on benefits, costs, and uncertainties.

When addressing an issue or a problem, traditional planning and asset management both strive to generate a number of options to address the issue or problem. In traditional planning, the best option is typically identified as part of the problem assessment and this best option is recommended for implementation. Asset management is completely different. The same project options may be identified, but all options are retained during the optimization process. Some options may be low cost and low benefit, while others may be high cost and high benefit. Without looking at all other spending decisions simultaneously, it is not obvious whether the low-cost or high-cost option is superior from a broader KPI perspective. In asset management, all asset-related spending decisions must be made at the same time and at the same place and within the same process.

19.4.2.1 Constraints are a Key to Practical Success

For the asset management process shown in Fig. 19.10, the identification and proper use of the constraints is a key factor and warrants further discussion. The thoughtful use of constraints is largely

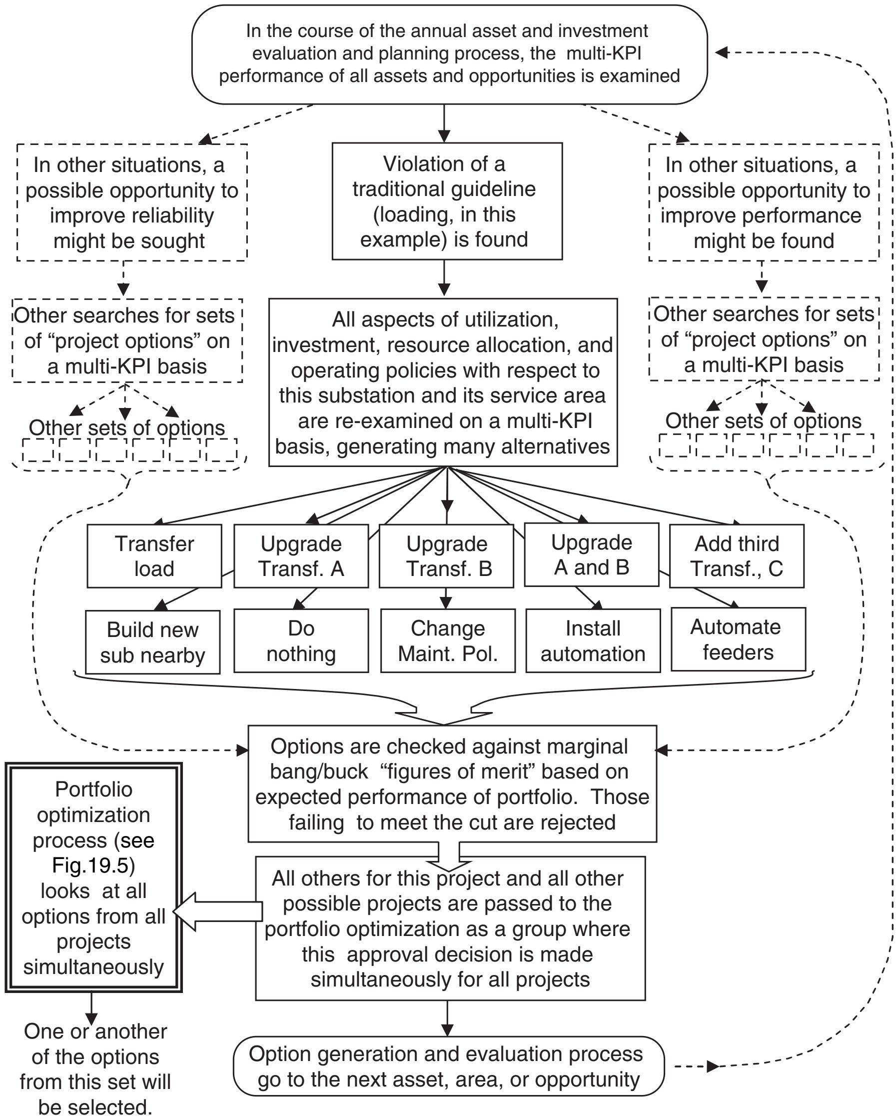

FIGURE 19.9 Like the traditional utility process, asset management periodically looks at the entire system for deficiencies that need correcting, as well as for opportunities to invest well or improve performance. Options, not selected recommendations, are passed to the portfolio optimization.

what determines how practical an asset management portfolio plan is, and proper use greatly increases overall value of the plan. Even if constraints are properly identified, ranking algorithms tend to have difficulty in finding optimal solutions subject to these constraints. This is the reason that in the portfolio selection step, mature asset management processes will increasingly turn toward rigorous optimization algorithms instead of ranking algorithms.

In any practical utility asset management process, there are many constraints, not just a few dozen. As a rough rule of thumb, there will be more constraints than projects, but not more than the total number of project options. For example, one utility which have 582 projects with 1480 options had more than 900 constraints in the portfolio planning set up. Most of these constraints are of the "common sense" nature, generated automatically by the optimization algorithm so that it will find only reasonable

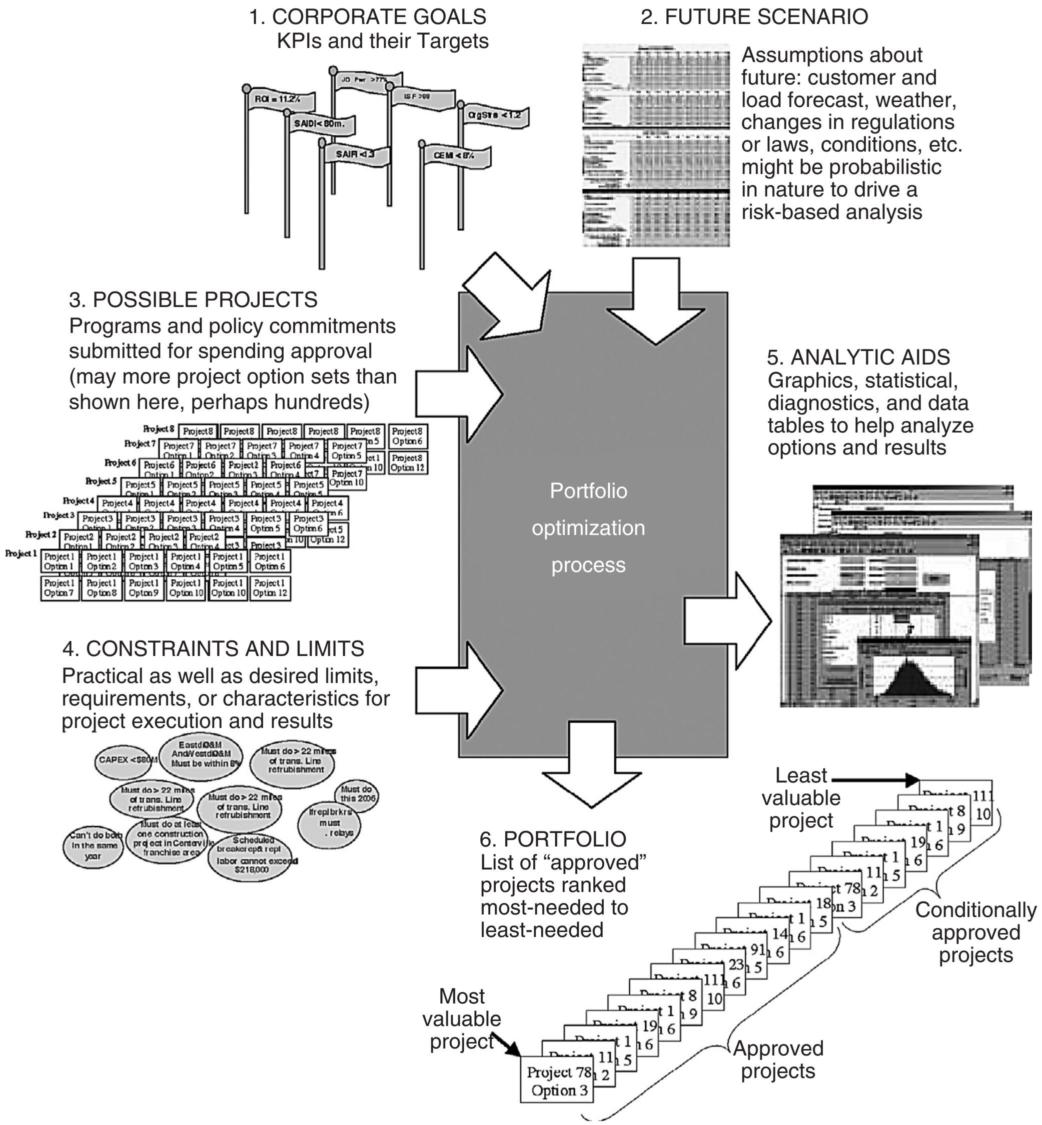

FIGURE 19.10 Asset management's portfolio optimization process evaluates all the options for all the projects in order to select the portfolio (set of project options) that achieves all performance targets and maximizes objectives. It has two strategic inputs, the corporation goals expressed as KPI targets and values (1) and a scenario description giving trends and conditions and assumptions about the future (2). "Tactical" inputs include (3) the options for all projects (from Fig. 19.4), and a set of constraints (4) which set practical limits ("You can do project A or B but not both.") and preferences. Outputs include graphs, diagnostics and statistics to aid planners in understanding their options, the portfolio and why items were selected, and the overall performance result (5), and the portfolio (6), the set of project options recommended for implementation (many more options were not selected and are not shown). Conditionally approved project set is explained in the text.

solutions. An example is a constraint for each project that has more than one option requiring that only one option be selected (e.g., only one of the project options shown in Fig. 19.9 for Eastwood substation can be selected). Beyond this, the utility asset management planners can enter additional constraints to represent goals they know they must achieve in the execution of their plan, or limits they know they face. Examples might be:

- You can only pick one of the project X options if you have first decided to do project Y option 2 or 3 (e.g., the utility can only build new feeders out of Eastwood substation if you have first picked an option that builds the new bus needed to connect them to the system).
- Capital construction projects in Area 7 must be at least $250,000. (The utility promised local politicians that it would make this much improvement during its franchise renewal hearings.)
- No more than $12.4 million in breaker projects can be done. (There are only so-many qualified breaker-crew hours available.)
- At least $7.8 million in breaker projects must be done. (Internal breaker crews will be fully utilized on breaker work.)

Setting up constraint represent a good deal of the practical work in asset management planning, and the ability to use them effectively will increase with experience and study.

Overall, the process depicted in Figs. 19.9 and 19.10 might decide to do absolutely nothing at Eastwood substation, despite the traditional guidelines. It might decide to spend more, or to spend in a different way, than the traditional paradigm would dictate. The important point is that asset management selects the project and expected performance for this project based on the needs and priorities of the entire portfolio. This project is only one of a set of selected options that in combination would:

- Stay within the corporate budget limits and constraints.
- Achieve all of the KPI performance targets. In each case the target would be met, but not necessarily exceeded.
- Minimize the present worth of CAPEX and OPEX.

In selecting the recommended portfolio, optimization seeks to find project options that cumulatively achieve all KPI targets while being cost-effective over time. In some cases, a utility's initial "optimization run" will spend up to its budget limits without achieving all KPI targets. In this case, there is no viable solution and either budgets must increase, KPI targets must be reduced, or more cost-effective project options must be identified. Understanding the interrelationship of KPIs to budgets, KPIs to themselves, KPIs to available spending, and project options to all of these is critical when adjusting set up. This is where diagnostics and graphics aids (item 5 in Fig. 19.10) are invaluable.

19.4.2.2 Conditional Approval in Risk-Based Planning

Figure 19.10 shows the optimized portfolio (item 6) as including two classes of approved projects, those approved outright and those that are conditionally approved. This second class includes several subcategories of projects or programs that might be approved, or needed, depending on if and how any number of probabilistic outcomes occur, in order to reduce risk. For example, if the utility experiences a very hot summer, revenues will probably exceed expectations for an "average year," but expected stress on substation and other major equipment will also be higher than average (see right side of Fig. 19.7). The conditional project set would contain one or more projects to mitigate the negative outcomes of this hotter-than-average weather (e.g., perhaps a project to inspect equipment thought to be at jeopardy during a hot summer, the money coming from the additional revenues, to be approved only upon seeing that the summer in fact turns out to be hot). Similarly, the conditional project set would contain one of more projects that effectively say, "If load growth is above expectation, we would spend this additional money on connecting the greater-than-expected number of customers." Such projects permit the risk-based portfolio plan to have the necessary probabilistic elements to control risk.

19.4.3 "Half Measure" Approaches Fail to Deliver Good Results

A number of utilities have attempted to apply asset management, risk-based or otherwise, using a "half-measure" approach to portfolio selection that is between the traditional and full portfolio selection approach outlined above. In this method, instead of passing all the project options (the product of Fig. 19.9) as input to the project data set (item 3 for the portfolio optimization in Fig. 19.10), they select and pass only the one option that would be traditionally selected for each planning or operating study (i.e., the product of Fig. 19.8 in the case of the example) to the prioritization/optimization. Utilities that take this approach do so because it simplifies and reduces the amount of data that must be prepared and input into the portfolio optimization, greatly reducing the work required. In addition, it permits a simpler algorithm to be used (simple spreadsheets in most cases). This approach assures that only projects that adhere to the traditional cultural "comfort level" are considered for inclusion in the project portfolio. Almost always, only projects meeting traditional standards, or something like them, make it into the process. This renders the move to asset management much easier to accept throughout the organization because the "answer" looks pretty much like business as usual.

The problem of this approach is that the resulting portfolio is essentially what would have been planned in the traditional approach. With this "half measure" approach, performance and bang for the buck increase only slightly, if at all, when compared to the traditional paradigm. If the process concludes that KPI targets cannot be achieved, management will likely conclude that all possible trade-offs have been considered when this is definitely not the case. In practice, asset management is only effective if it has the ability to spend a little less on one project and shift the savings to other projects. In the authors' experience, good results come only from asset management approaches that apply to all of the following in the portfolio selection process:

1. Use of multiple KPIs covering all major interests of the utility, with only quantitative targets.
2. Use of rigorous optimization algorithm (as opposed to simple ranking).
3. Use of constraints to define limits and requirements for execution.
4. Use of project options that provide a range of results and costs for each potential project.

An asset management process that applies these concepts will likely recommend a portfolio of projects that is significantly different than those that would have come out of the traditional approach. Since this can create a certain amount of discomfort for traditionalists, there is always a need for strong executive championing to anticipate and manage culture change, at least in the early stages of the transition. Executive involvement is warranted because asset management can make a significant positive impact on the utility's performance for customers, stockholders, and employees alike.

19.4.4 Limiting "Must Do" Projects

Any successful practical optimization process will need to recognize a project designated as "must do," which means that regardless of project KPI contributions or cost, it will be selected and approved. From time to time every utility has projects that are truly "must do," and so this feature is needed in any practical decision-making process. Furthermore, there are reasons why planners want to have this feature available just because of the study capability it provides.[2]

But for asset management to be successful, "must do" projects cannot represent a large percentage of spending. The utility must make every effort to minimize project options identified as "must do" to the portfolio optimization process. Failure to address this particular point has been the downfall of many asset management initiatives, particularly those using a half-measure approach.

Many utilities taking up asset management for the first time end up labeling far too many projects "must do." This is particularly the case when a hybrid or half-measure approach is used as described in the above subsection. It is not uncommon for utilities taking that approach to end up with upwards of 70% of their total capital budget committed to "must do" projects.

What happens is that with regards to a particular need (for change to the system, as when an area of new growth needs to be connected to the system), something must be done and since only one project is to be submitted into the portfolio optimization to address this need, and that project seems reasonable (particularly from the traditional perspective), it is clearly "must do." Consider the following example.

[2] A project can temporarily be designated as "must do" to force the optimization to select it—thus showing the planner what other projects and decisions it would or would not make given that this project will be done.

There is a vacant field that will be developed to serve 300 homes being built-in what will be "Valley Oaks" subdivision. Traditionally, the utility would look to its design standards and submit a project calling for the extension of a distribution feeder and construction of laterals and service drops. If the utility was not using project options, and had entered only this one option for the Valley Oaks project, very likely it would label that project as "must do" "because the new customers have to be connected." Likewise, something similar would be done in many other situations. The result is that the portfolio optimization is presented with a plethora of "must-do projects," which give it no flexibility to pick and choose so it can achieve synergy and optimization, and which use up most of the available budget. Asset management carried out in this process produces little, if any, improvement in performance.

In an options-based approach (Figs. 19.9 and 19.10) planners would instead enter a set of options for this project along with a must perform constraint. The options might include the feeder extension project described above, as well as other projects. One option might be to build a new substation near the subdivision, another to use different construction standard for the feeder, another to extend other circuits from other stations, yet another to use distributed generation, and still another to do a combination of these things, and so forth. These options would provide a range of KIP-impact and price variations to the portfolio optimization, allowing it to mix and match its plans to maximum bang for the buck. But none of these would be a "must do" project. Each would have a KPI or contribution tag identifying it as "serves new Valley Oaks customers" and the optimization would be given a constraint that one project option meeting this requirement must be included in the portfolio.[3] As with the use of options in general, this provides more flexibility to the portfolio selection algorithm and greatly improves the likelihood of performance improvement and/or cost reduction. There is no doubt that this approach represents more work, in identifying and inputting options to the optimization, but most of this can and should be automated (to both reduce labor and improve consistency) and that is what computers and modern technology are all about.

19.5 Changes in Philosophy and Approach

To engineers, operators, and managers in an electric T&D utility, asset management means their company will undergo a philosophical shift in its concept of why the power system exists and "what it is there to do." Under asset management, the system exists to achieve the company's business goals, rather than deliver power to customers. Over time, this leads to subtle but significant differences in attitudes and values throughout the organization. It will also mean some differences in how people work.

First, nearly everyone will have to work "together" to a greater extent than in the past. Comprehensive and balanced integration of all decisions requires that managers, planners, operators, and executives communicate more, share more information, cooperate, and "compromise" more than in the past. For some, there will be only a small change in their work practices and responsibilities. For others, their entire function and purpose will be transformed. Regardless, information systems will become more central, both in their ability to make data available to decision makers and in their ability to facilitate communication and coordinate work processes. Sophisticated information systems in themselves do nothing without changes in the mindset of employees. However, asset management, by nature, is a data-driven process that requires support for information systems to be successful.

Second, more of a business-case approach permeates all decisions and processes. Even traditionally "pure-engineering" venues like substation equipment specifications may have an element of business-case evaluation, with all decisions having to be written in a business-case manner before gaining approval.

[3]Another way to do this is to enter the options, each of which connects to the 300 customers somehow, as a group and require the program to select one of them.

Third, there will be a company-wide "standardization" of the way project documentation and justification is required for approval and performance tracking. In the traditional paradigm, it was relatively easy for planners to show that their plans satisfied their goals by adhering to the company standards (e.g., loading is within the 83% limit. Maintenance was performed within guideline periods.). Often, this was done through department-specific analysis and documentation. In an asset management organization, everyone documents a more diverse set of business attributes, as well demonstrates that their proposal optimizes, and not just satisfies, company requirements. Furthermore, an asset management utility puts much more emphasis on tracking results against targets. In the past, it was straightforward for the traditional utility to check that it was in fact keeping substation transformer loading within guidelines once the money was spent to upgrade the substation. By contrast, the asset management utility focuses on a more difficult set of measures: "Did we get the maintenance cost reduction, customer-service quality improvement, and capital cost containment we expected?"

Asset management represents a big change from the traditional utility framework for managing, budgeting, planning, prioritizing, and operating. However, if implemented correctly, asset management leads to improved system performance, reduced costs, and better managed risk.

To be successful, asset management must be applied across the entire utility, covering capital, inspection and maintenance, and operating budgets and priorities in all departments and for all functions. For utility personnel involved in the management and operation of electrical substations, asset management means that the performance expectations their company has and the decisions they make will become more business based, and that over time they will have to work within a wider range of considerations and communicate and cooperate with a broader base of coworkers in the utility.

19.5.1 Asset Management Does Not Lower Standards

Like any organizational change, resistance is expected when shifting away from the traditional approach to the one utilizing asset management. Many people will insist that the organization is lowering its standards because asset management considers "cheap alternatives" and might not decide to do as much as the traditional approach would have in many cases. This is a narrow and misleading view. In reality, the utility is not lowering its standards, but it is changing them to be more directly linked to business objectives. From an executive perspective, this represents a raising of standards.

Regardless, culture resistance to the change is to be expected. Some of this resistance is due to the natural resistance to change in general. However, there is an additional driver. Some of the work required for asset management is more difficult and requires additional skills. Planners and engineers may feel like technical experts within a traditional approach, but may initially feel insecure about their abilities within the context of a business-driven approach (many engineer may also be genuinely uninterested in business issues).

If change management is effective and asset management principles are implemented well, a utility will be assured to two results:

1. *Planning and decision making will be more difficult and costly.* In the past, hard-and-fast rules dictated what was done "Do this. Period. Then move on." Now, the utility must gather and use a wide range of information to make multi-KPI decisions that are often not as black-and-white as in the past. In addition, planners must generate and consider within this broader context a wider range of options and alternatives. Finally, the utility must track this expected multi-KPI performance against its expectations to validate and improve assumptions and models. All of this takes additional data, additional analysis, and modern information systems to make it all work.
2. *Business* p*erformance will improve.* Why? Because, asset management can always pick "the traditional solution" when it is best from the standpoint of buying performance (but not necessarily just adherence to arbitrary standards). But it selects different alternatives whenever they provide more business performance or less risk exposure per dollar spent.

Management needs to be honest with employees throughout the organization about the added skills and effort required by asset management. Management must also reinforce the message that the end (better performance on all fronts) more than justifies the added cost and organizational disruption.

19.5.2 Asset Management Is Not Necessarily Trying to Reduce Spending

Asset management methods can be and have been used by utilities striving to reduce costs (Brown and Marshall, 2000). These utilities could not afford to do everything that it had previously done in the past, and looked for asset management to prioritize spending and "minimize the pain." As a result, asset management has gained a reputation in some parts of the industry as a cost-cutting measure. There is no doubt that asset management can help a financially challenged company determine how to spend what it has in the best-possible manner. But asset management can just as easily be used for utilities looking to increase spending, or to more effectively allocate existing levels of spending.

In fact, asset management often leads to better recognition of the consequences of not spending than the traditional approach provided. This can directly lead to spending increases, especially in the area of risk mitigation. In addition, there is a supply side effect in the longer term. Because the cost of improving performance is reduced, the laws of supply and demand dictate that more spending will sometimes be warranted, especially in areas that are shown to be highly cost-effective.

19.5.3 Changes in Perspective and Culture Specific to Substation Personnel

An asset management approach will bring about a further change in perspective and organizational culture for those engineers, managers, and operations personnel most closely associated with substations: a broadening of their role within the organization to one of enterprise-level monitoring and information management. Traditionally, substations have been regarded as important and allocated some degree of priority in attention within a utility purely because of their role in power delivery: they are key "way stations" in the transportation and control of power transmission and distribution. It is certain that this role will be no less important in the future.

However, as Section 19.6 will explore, a combination of asset management priorities and modern technological advances is almost certain to lead to utilities using substations as "data hubs" for corporate enterprise information technology (EIT) systems. In the future, substations will be regarded not just as key hubs in the power delivery chain, but as the cornerstones of a distributed data gathering system, which the utility maintains to monitor its assets and performance, and share throughout company-wide data warehousing systems, where it can be used in a wide variety of applications, many of which will be outside the substation, or even power delivery, part of the corporation. This second, IT, function for substations will become, in many ways and to many people in other parts of the company, as important as the original function of power delivery. Substation personnel will have to work in an environment where this second function of the area of their responsibility is as important, in many regards and to many people, as the power delivery role with which they have long been familiar.

19.6 Substation Asset Management

By its nature, asset management spans all elements of a utility since it is interested in overall business performance. However, the concepts of asset management can, to a certain extent, be applied effectively to substations in an approach commonly called "substation asset management." Basically, this approach will look at all spending decisions spent on substations, look at their impact on substation-related KPIs, and look at areas of risk that are specifically related to substation performance. Substation asset management will typically mean more flexible decision making, much more data collection and usage, and much more rigor in the decision making process. Overall, most utility personnel associated with substations will like the results of the change.

This section looks at what utilities can one expect with regard to the substations when they use an asset management approach to strategy and decision making. Example results are from a U.S. utility and represent a typical situation. However, many utilities differ from the norm in some way: service area topology, climate, customer demographics, regulatory environment, employee base and internal skill sets, system design and age profile, power pool requirements, or business goals. Therefore, the example results are difficult to generalize since specific results for specific utilities can vary widely.

19.6.1 Utilization and Life Cycle Management

Asset management generally spends slightly more on the care of major power equipment and switching facilities than was the traditional practice in the industry, but then uses equipment (loads it, operates it) more heavily than traditional practice. Asset management process will try to finesse (balance one against the other while trying to create and leverage synergy) O&M, remaining lifetime, and utilization rates to maximize the business case for ownership of the equipment. There are certain obvious trade-offs. Cut inspection and maintenance too much and (a) performance will suffer due to breakdowns, and (b) equipment lifetime will decrease due to outright failures. Either way the value derived from the assets will drop. Conversely, if the utility spends too much on inspection and maintenance the payback is diminished since there are other areas where that money can be spent to buy more KPI performance.

Similarly, high utilization policies throughout the utility will "use equipment fully" and therefore increase the business value obtained from it today, but these policies could seriously erode remaining lifetime. On the other hand, low loading or usage will result in longer equipment lifetime but will mean that the equipment provides less business value everyday it operates. Finally, business needs of the corporation will dictate how these trade-offs are viewed. In every case, asset management (at least if done well) will attempt to optimize these trade-offs from a slightly broader perspective than the traditional paradigm. It will look at them and their secondary and unintended consequences, in aggregate, as they affect overall business performance.[4]

Usually, a multi-KPI perspective will look at these trade-offs and recommend slightly more spending on preventive substation inspection and maintenance than the utility did traditionally. However, the recommended expenditure may not be for traditional types of "O&M." For example, instead of increasing the frequency of maintenance, an asset management process may recommend the capital addition of on-line condition monitoring equipment for critical pieces of equipment assessment.

The reason asset management often leads to increased spending on substations is that substations influence a broad range of KPIs. First, substations involve a good deal of very expensive equipment. For this reason alone, there is a business case for taking good care of substations. But beyond this, substations affect most of the KPIs listed in Table 19.1, including all of the reliability-related metrics and the BBOM. The only KPI listed in Table 19.1 in which substations are not as involved as some other part of the T&D system is public safety, which is mostly concerned with the distribution system. As a result, substations and their equipment tend to receive slightly higher priority from a multi-KPI approach than under the traditional utility paradigm, where spending priorities were typically based mostly, if not exclusively, on equipment-care considerations alone.

While asset management tends to take good care of the substation equipment, this business-driven approach will also want to "get its monies worth" by loading that equipment to high levels. A pure return-on investment business analysis of loss-of-life as a function of loading often will conclude that the "optimum" utility use of a transformer is to load it to where its expected lifetime is only 25 years (Willis, 2004). Results vary from utility to utility and from case to case, but usually the optimum loading sought

[4]For example, high-loading limits not only will reduce equipment lifetimes but also are almost certain to drive up annual unexpected maintenance needs in certain equipment categories, too. Thus high-loading policies and somewhat increased maintenance costs go hand in hand. On the other hand, higher loading and stress on equipment increases the marginal value seen from scheduled inspection and maintenance. Good asset management planning processes take such interactions into account.

by asset management will be higher than what the utility had been using traditionally. It is worth nothing that some utilities dramatically increased the loading levels during financially troubled times in the late 1990s. Asset management may actually reduce these “recommended” loading levels.

In addition to normal loading levels, asset management will tend to increase acceptable levels of loading during emergency conditions, a result of risk balancing. A business-case study of probabilities, costs, and expected outcomes often leads to a decision not to spend money in many cases where a traditional utility would have bought capacity or facilities to mitigate exceptionally high loading during a major equipment outage. Asset management will often reduce this type of spending with the following thinking, “the additional capacity may never be needed, I will not purchase it and accept the fact that I will have to load equipment to extraordinarily high levels if certain rare situations happen to occur.”

19.6.2 Overall, a Subtly Different Philosophy on Equipment Stewardship

While asset management’s approach to valuing and funding maintenance will be welcome, many long-time utility personnel are often uncomfortable with the bigger context of change. Traditionally, many utilities and many utility personnel viewed loading and operating guidelines as part of a broader equipment stewardship mentality. As equipment stewards, a utility should take “good care” of power transformers and other major equipment by keeping loading at levels where loss of life from thermal or other stresses in minimal. Failures of equipment are failures of the utility. Equipment should last for a very long time.

Asset management takes a far different view. Equipment is there to be utilized in full, at least in the context of overall business performance (Fig. 19.11). Loading levels and the interaction with expected lifetime should be managed, realizing that remaining equipment life of 40 years into the future is worth very little to a utility today from a present worth perspective. The the-only-reason-it-is-here-is-so-we-can-use-it-up perspective represents a major departure from the traditional equipment stewardship

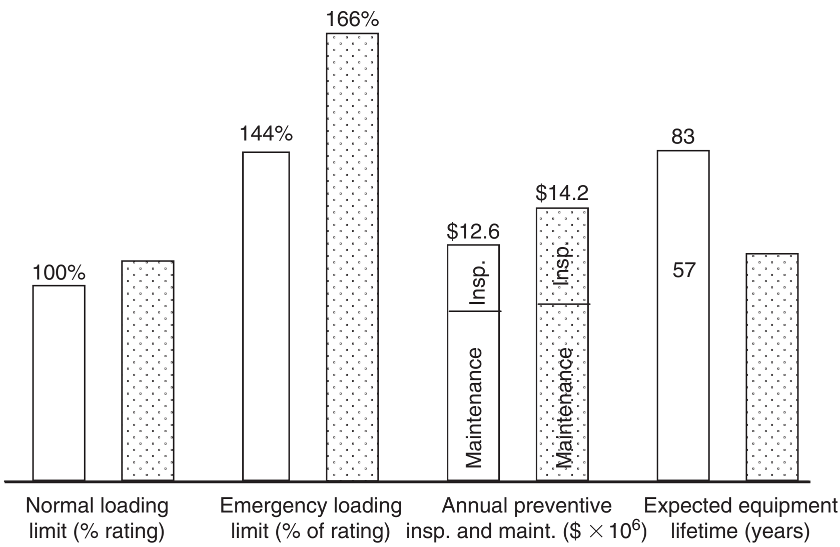

FIGURE 19.11 Comparison of distribution substation transformer ownership and operating policies at one utility prior to and after implementation of multi-KPI asset management program. Unshaded blocks show the standards and practices prior to asset management, which were fairly typical of the U.S. industry in the mid 1980s and early 1990s. Afterward (shaded), much more was expected of the equipment but more was spent on preventive maintenance and service. Despite the more intense care given the equipment, the expected service lifetime of the units decreased to what asset management viewed as an optimum from a business standpoint. Breakdown of inspection and maintenance bars shows amount of spending devoted to each. See text for details.

culture that still prevails in traditional utilities. The transition to an asset management perspective in this area will make many equipment experts uncomfortable and resistant to change. These people are the same who will ask "why don't we just built it and put it in the rate base?" This is flawed thinking, and antithetical to a successful asset management culture.

19.6.2.1 Asset Management and Aging Infrastructure

For substations, asset management seldom recommends the replacement of old or aging equipment just because it is more prone to fail. A business-case valuation of outcomes nearly always dictates a "run to failure" ownership policy—gets every possible day of use out from the equipment up until failure occurs or is incipient. For old equipment, asset management may dictate that greater care, particularly more frequent inspection, is given in order to better manage the end of life, but rarely will it call for outright replacement. The only exceptions are where replacement with new equipment will reduce O&M cost significantly and/or enable greater performance. Among the few types of equipment that fall into that category are replacement of older circuit breakers with newer low-maintenance designs, replacement of older electromechanical protective relays with digital systems, and replacement of old RTU and automation systems with new, more capable automation systems.

19.6.2.2 Condition-Based Maintenance

The use of asset management over a period of several years invariably moves a utility closer to some sort of condition-based, reliability-centered, or performance-oriented maintenance approach (van Schaik et al., 2001). Each of these leads to more emphasis on inspection and use of inspection data. Bang for the buck is enhanced whenever the utility can direct maintenance activities where they are truly needed, and avoid or defer maintenance activities on equipment for which it is not needed (Ostergaard and Jensen, 2001). For example, suppose Big State Electric owns 1600 medium voltage breakers. Among them there may be 150 that are much more in need of maintenance than average, either because they are in poor condition or because they are in especially critical positions, or both. Similarly, there may be 150 that are less in need of attention than average. Asset management will spend much more on inspection and maintenance for the former group of breakers than the latter.

Big State Electric may need to maintain and service far more than just 150 breakers in any year. But regardless of the number it decides it should service, it will probably not see much value in doing service on the 150 that do not need attention. Therefore, it should find a way to exclude them from scheduled maintenance activities. Conversely, it should make certain it does include those 150 most in need of attention. Taking both these steps will significantly improve the cost-effectiveness of its maintenance program.

Inspection and the use of inspection data are the keys to effective condition-based maintenance (Butera, 2000). In order to focus maintenance where needed, the utility needs to know something about the condition of those 1600 breakers. There is more here than just inspection. It is the use of inspection results for tracking and targeting that is needed. Therefore, inspection programs (institutionalized processes that include inspection, retention of inspection records, and use of that archived data for condition assessment) are among the highest priorities for substation asset management.

19.6.3 "Big Bad Outages" and Setting Priorities for Substations

Several large investor-owned utilities in the U.S. use a KPI factor in their planning that is a measure of the likelihood or severity of expected "big bad outages." These are typically defined as unexpected outages that are less severe than a regional blackout, but more widespread than typical outages and is likely to make headlines in the local newspapers. One of these utilities even refers to its measure as BBOM. Specifically, it defines a big bad outage as any nonstorm or nonblackout related event that takes every year 30,000 customers or more out of service for 4 h or longer. Its BBOM is the expected customer-minutes per year due to this class of outage and is computed for various plans or policies using probabilistic reliability assessment methods (Brown, 2001).

TABLE 19.4 Spending Allocation across the System—Millions of Dollars

System Level	Attain All Goals but BBOM	Attain All Goals Incl. BBOM
EHV (345–230 kV)	$63	$64.3
HV (161–69 kV)	$81.3	$88.7
Distribution (>69 kV)	$163.5	$160.9
Service trans. and secondary	$65.3	$61.1
New customer connections	$75	$74.8
Total spending	$448.2	$449.8

Most utilities consider a widespread interruption to have a higher cost to the utility per affected person than a more limited interruption. Thus, the avoided cost of a minute of BBO customer interruption is deemed higher than that of less widespread outages. Additionally, big bad outages garner media and public attention, which is bad for the utility's public image and raises the cost of public, municipal, and regulatory interaction. More limited outages, even if far more frequent, do not "get in the newspapers." The use of a BBOM KPI and target focuses decision making on reducing these types of outages, and not just on driving down broad measures of reliability performance such as SAIDI and SAIFI.

The use of a BBOM pushes spending priorities toward substations, particularly higher voltage and large capacity substations. Few, if any, elements of the distribution system, and many elements of smaller electrical substations, have an impact on a measure requiring a minimum of 30,000 customers, or on any similar measure. Therefore, use of a BBOM will focus a certain amount of spending on large substations and transmission facilities and their control systems, as shown in Table 19.4.

In many cases it costs very little for a utility to add a big bad outage focus to its reliability program. In the case illustrated here, a hypothetical case run by the authors using data from the utility in Table 19.1 (which did use BBOM) with and without the measure, the overall difference in spending required to address BBOM is only $1.6 million. The reason is that BBOM's major effect is to shift $7 million (2.3%) in spending away from distribution and service level spending, where it worked down SAIDI and SAIFI, to the high-voltage and very-high-voltage levels, where it helps work down SAIDI, SAIFI, and BBOM. Much of this money goes for enhanced substation investment and maintenance. The additional $1.6 million in spending is required because the shifted spending, focused on BBO, is slightly less effective at reducing SAIDI and SAIFI, so a bit more must be spent to cover that small shortfall.

19.6.4 Advanced Substation Technology

One characteristic of many asset management portfolio plans is that a good deal of capital is devoted to improved control and monitoring systems rather than to the purchase of raw-equipment capacity. Current trends toward wider use of automation, particularly in substations, are not driven predominately by an industry shift to an asset management perspective. A good deal of advanced technology monitoring, control, and information systems would be adopted regardless of the decision-making methods being used by utilities. Among other improvements, on-line condition monitoring can reduce failure rates and level of damage sustained from failures of major components like transformers (McCullough, 2005; Timperley, 2005).

But beyond those benefits, a decision-making framework seeking broad, multi-KPI impacts can often derive great value from certain types of substation automation and systems. First and foremost, condition monitoring systems can help lower breakdown and failure rates and extend equipment lifetime. In conjunction with automated switching, condition monitoring can also shorten customer-service interruptions caused by equipment failure or storms. Thus, substation automation improves performance in a number of KPI areas.

Additional value can be derived if the substation automation system is linked into corporate-wide enterprise systems, allowing decision makers throughout the company to use data gathered in the substations during the asset planning process. For these reasons, many utilities making the transition to an asset management approach see themselves also moving more quickly than they had expected into substation automation.

19.7 Summary

Asset management is a fact-based process that strives to link all asset-related spending decisions to their impact on corporate objectives. The result is a more effective way of making decisions, one that is more rigorous and that cuts across traditional functions and budgets. For substations, asset management means a move away from standards-based decisions based on equipment-level considerations and toward multi-KPI-based decisions based on system-level considerations. When a utility pursues substation asset management, the following are likely to occur:

- Increased focus on data collection
- Increased focus on risk management
- Increased ability to trade-off capital spending with maintenance spending
- Increased focus on developing options for projects
- Increased ability to quantify the impact of projects on KPIs
- Ability to prioritize projects and project options
- Increased loading of equipment
- Less focus on periodic maintenance and more focus on condition-based and reliability-centered maintenance
- Increased usage of data collected from substation automation systems

Since asset management concerns itself with overall corporate objectives, asset management activities relating to substations must ultimately be considered within a broader context. Regardless, many of the concepts and techniques of asset management can be directly applied to substations so that performance can be better managed, spending can be more efficient, and risks can be better managed.

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20

Station Commissioning and Project Closeout

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Baltimore Gas & Electric Company

Once the construction is complete, its time to determine if all the systems work as specified, connect to the system, straighten out any site issues, and close out the project and accounting. This chapter will take us through the various issues that should be addressed in order to finally complete the project.

20.1 Commissioning

Final tests of the completed substation work in a partially energized environment are required in order to determine the acceptability and conformance to customer requirements under conditions as close as possible to normal operating conditions. Coordination should be achieved with other entities in order to successfully connect to the electrical system and all outstanding site issues have to be finalized in order to provide the operating staff with a functional product. Additionally, there are a number of public and utility organizations that should be made aware that the facility is ready for operation.

20.1.1 Testing

- Power supplies
- Relays
- Protection schemes
- Communications
- Grounding
- Fire protection
- Major equipment
- Security systems

Although testing had been performed on individual items during the construction phase, functional testing should be performed on all subsystems in order to ensure proper function. Verify that all the factory acceptance and site acceptance tests have been satisfactory and then proceed to the process of checking the functionality of the entire package. It is possible that vendors and consultants will have to be involved at this stage in order that warrantees and specifications might be accommodated.

All AC or DC systems providing power for subsystems or major equipment should be checked. This includes any batteries, transformers, generators, switches, breakers, panels, chargers, hydrogen sensors, and associated fans or ventilation. Off-site power may also be involved if the substation is required for black start of the system or if the station is a new generation switchyard.

Verification is required that all relay devices, instrument transformers, transducers, meters, and IEDs, located at both the major equipment and control house, provide the intended control and monitoring functions as well as provide the proper inputs to the protection, automation, and communication schemes. As stated in an earlier chapter, the key to a commissioning test plan is to make sure that every input and output that are mapped in the system is tested and verified. The systems that operate, monitor, and protect the substation equipment should be verified to function according to the functional diagram. The interface with SCADA and other communication systems should also be tested as well as the operator interface. In addition to the proper communications between components with the substation, the communications with the energy control center and other utility elements should also be tested. This may also involve communications with other utilities or interconnection entities such as a non-utility owned power plant that seeks connection to the electric system. It may also be necessary to include systems to monitor or advise customers and suppliers.

It is necessary to determine the integrity of the station ground grid prior to connection to the system. The grid resistance must be measured prior to connection to the rest of the system in order to verify that the grid will provide the proper operation of the electrical equipment and the protective relays as well as the personnel safety margins that were intended.

The various fire or smoke detectors located at the equipment or within buildings or other enclosures should be functionally tested. Their interface to control, communication, and alarm systems should be checked along with any pumps, valves, and spray systems. Alarm systems should be found to be functional along with the interface to the necessary utility entities and the fire department. If direct alarming of the fire department is not provided, the proper notification scheme needs to be verified. Since this scheme has probably been negotiated with the fire marshal, several entities may be involved.

Major items of electrical equipment with their own controls, and monitoring should be successfully operated. Power transformers need to be properly charged prior to applying load. Breaker and switch operation needs to be verified both locally and remotely. It is not uncommon to involve manufacturer, vendor, or consultant personnel in this verification.

The integrity of any walls, fences, locks, or any other personnel barriers should be checked along with the function of any intrusion detection systems such as motion sensors, video cameras, and door alarms. This is also the time to verify the functionality of the notification process for corporate security and the police department.

20.1.2 Coordination

- Generation
- Interconnection
- Distribution
- Public sector

In the case of power plant switchyards, it is necessary to coordinate testing of the interface between the substation and the plant as well as the timetable for final energization. This may involve off-site power if black start of the plant is involved. If there is separate ownership of these facilities, the coordination will also involve legal and contractual issues. Bulk power substations and power plant switchyards must not only integrate into local utility systems, but must also properly interface with regional interconnection entities. Communications systems for monitoring and control should be tested not only for proper function, but also verified that they provide the features necessary to meet the contractual obligations of the interconnection. Area supply substations must properly interface with energy control center, but also with distribution automation schemes. Also, the availability of incoming and outgoing feeders must be coordinated so as to meet the agreed service dates.

The police and fire departments will be involved in the testing of any security and fire detection systems. Public works departments will be involved in issues associated with water mains, drains, and traffic. It may also be necessary to advise the general public of activity that may impact the neighborhood.

20.1.3 Site Issues

- Permits
- Roads
- Aesthetics
- Landscaping
- Drainage
- Storm-water management

The preponderance of permits are usually associated with the construction of the facility, but there may also be permits necessary for occupancy or operation. Now is the time to make sure that the requirements have been met for these permits. Also, the procurement of any special use permits should be verified, for example, Federal Aviation Administration clearance for any high structures or communication towers. Paving for driveways, roads, turnarounds, and any other vehicle access needs to be completed. This may also include deceleration or merge lanes associated with public roads along with any required curbing. Any stone covered access or parking area should be final dressed. Final touches need to be applied and final inspection undertaken of any features of the installation that serve special aesthetic purposes in order to obtain community acceptance. Decorative walls, special fences, fence inserts, custom coloring, or any other treatments need to be finalized. The final landscaping arrangement needs to be checked against the approved landscaping plan to ensure compliance. Due to drought or seasonal requirements, it may be prudent to delay some plantings until conditions are optimal. Should this be the case, it may be necessary to advise the appropriate public agencies that plantings will be delayed. In any case, care should be taken to comply with any warranty requirements.

Cleanup should be conducted on all drainage systems, including removal of all silt fences and installation of stone cover at the outfall of trenches. Should any grading have been necessary for drainage, the final stone layer must be installed or turf repaired. Check valves need to be tested and protective facilities such as fences around storm-water management ponds need to be verified. The function of any oil–water separator systems also needs to be tested. Should direct connection to public storm drains be involved, these connections should be checked for proper function.

20.1.4 Notification

Once the facility has been made available for service, various elements within the utility organization need to be notified. Besides the obvious notification of the operating departments, planning organizations, corporate security, general services, and legal staff need to be advised. In addition, the accounting group needs to ensure that the facility is now included in the rate base.

Public safety organizations, such as the police and fire departments, need to be advised of the operation of new infrastructure. In addition, legal notification of the local political district and several state agencies may be required along with federal entities, such as the Federal Aviation Administration, Corp of Engineers, etc. Regional interconnection entities may need notification along with special customers, for example, a power generator.

20.2 Project Closeout

20.2.1 Final Walk-through or Inspection

20.2.1.1 Owners or Customers

A final walk-through or inspection of the completed substation project is undertaken as a beneficial measure that allows the substation owner or customer the opportunity to view the finished product first hand. On internal utility substation projects, the typical owner or customer of the project is the area of the company that possesses both the authority and ability to operate the station. On most internal utility substation projects, the system operating area is broadly familiar with the project intent and deliverables. Yet the final walk-through or inspection can provide the opportunity for these operating personnel to unquestionably verify their full understanding of the project objective or perhaps it can provide the opportunity for a learning experience when new technology was implemented to achieve a familiar deliverable. On substation projects that are pursued by the utility to meet an explicit external customer need and where final ownership of the substation falls outside the boundaries of the utility, the final walk-through or inspection can take on a broader customer satisfaction dynamic. In these cases, the owner or customer may not be thoroughly familiar with the substation business; therefore, the final walk-through serves as a key opportunity for the owner or customer to begin their education and training process.

20.2.1.2 Contractors

It is quite necessary to include in the final walk-through and inspection of all the contactor disciplines that were involved in the project. Since these were the entities that directly executed the project deliverables, they are partly accountable with respect to ensuring that the project deliverables were provided as engineered. Due to the contractor's role and responsibility on the project, they would be a primary contributor during any question and answer session with the owner or customer that may ensue. The walk-through activity is also beneficial to the contractors from the standpoint that it can provide internal learning and training opportunities for their additional staff that may not have been directly involved in the project.

20.2.1.3 Vendors

Equipment and material vendors are also necessary participants to include in the walk-through and inspection activity. Their on-site participation allows them to see their various products in service first-hand. This visual observation opportunity provides several unique benefits for the equipment and material vendors. It offers the ability to verify that what they are providing indeed meets their customer's expectation and it perhaps provides for the forum to learn of improvement opportunities from the contractors or stakeholders that are also on site. These learning opportunities, if implemented, can not only provide better products for that same utility on future projects, but perhaps the improved products can also be beneficial to the vendor's additional customer base. Finally, along with the contractors, the vendors can also serve as key contributors during any question and answer session where they can provide immediate and comprehensive feedback on their products.

20.2.2 Punch List

20.2.2.1 Development and Ownership Establishment of Specific Items

A key purpose of the need to conduct a final walk-through or inspection of the completed project, with all pertinent members of the project team, is to develop a punch list of project items that require full closure. The punch list is primarily a compilation of construction related issues that, although typically have no bearing on the ability to energize the deliverable of the substation project, require additional attention in order to bring all elements of the project to a thoroughly safe and acceptable closure. Typically, the project manager, responsible engineer, or the construction manager leads the punch list development exercise. The punch list items can involve all engineering and construction disciplines and can range from nominal issues to significant project elements that must be addressed immediately in order to eliminate their possibility to negatively impact the project deliverable at a future date. Punch lists routinely include such items as site erosion issues, insignificant equipment problems, minor material corrosion issues, as well as various unsafe conditions that require immediate and full closure. However, the final punch list can be comprised of any and all project issues that are either collectively agreed upon, by all involved in the punch list development exercise, as being worthy of inclusion or issues seemingly insignificant in nature that are deemed worthy of inclusion by the punch list development leader.

Full completion of the punch list is customary prior to the primary project stake holder, project sponsor, or customer accepting formal ownership of the completed project. Prior to accepting ownership, all elements of the project must be completed in their entirety in a fully functional, operationally sound, and quality manner. The punch list and the corresponding ability to verify the completion of its contents are the necessary control mechanisms that are put into place in order to protect the project stake holder, project sponsor, or customer from accepting ownership of an incomplete project. An additional control mechanism to ensure the timely completion of the punch list items is the practice of identifying firm ownership of each punch list item. In leading the punch list development exercise, the project manager, responsible engineer, or the construction manager has the responsibility of soliciting and identifying a specific owner who is singularly accountable for ensuring the acceptable completion of a particular punch list item. This ownership establishment practice is commonplace and allows for the ability to expand the responsibility of the completion effort throughout the team membership, thus increasing the success rate of punch list item completion as well as improving the timeliness of completion.

20.2.2.2 Ensure That Each Item Is Properly Completed

As mentioned, the effort to identify and verify firm ownership of each punch list item is an important practice that seeks to establish accountability for ensuring specific item completion. This ownership identification approach allows for the establishment of working relationships between the punch list item owner and the project manager, responsible engineer, or the construction manager. This approach streamlines the completion accountability verification process in that direct lines of communications can be established and clear performance expectations can be set. The need for a follow-up walk-through or inspection of the project site, to ensure the completion of all punch list items, is a function of the complexity of the overall punch list in addition to being contingent upon the successful performance of the communication links. Although the need to revisit the site to verify the completion effort firsthand will vary on a project by project basis, overall the ownership identification approach dramatically increases the completion performance while significantly improving the ability to indirectly ensure completion fulfillment. All of which is necessary prior to the primary project stake holder, project sponsor, or customer accepting formal ownership of the completed project.

20.2.3 "As-Built" Information

20.2.3.1 Construction Drawings

Although every effort is typically put forth to produce perfectly engineered construction drawings, site conditions, situational unknowns, and incorrect original record documentation issues are routinely encountered that require the construction process to deviate from what was specified on the guiding construction documents. These deviations range from slight in nature, which require no approval to implement, to recommended changes whereby implementation is only pursued upon the approval of the project manager or responsible engineer or both. Construction document changes can be encountered throughout the construction life cycle of a project within all involved engineering disciplines. Regardless of the magnitude of the change implemented, it is necessary to capture and record the change via what is known as the as-built process. The as-built process is usually a manual effort of documenting the construction changes and deviations from the original plan onto a hard copy of the construction drawings. The as-built process is typically initiated and completed by the construction forces involved in the project. The manual effort consists of using a red or other conspicuously colored writing instrument to record the acceptable changes onto the original construction drawings.

Upon completion of the as-built drawings by the construction forces, the as-built package is forwarded to the responsible engineering discipline for their use to permanently transfer the as-built information onto the original construction documents. This information transfer practice is necessary for appropriate legacy record keeping purposes. This will help to ensure that any future use of these record documents will accurately reflect the field conditions expected to be encountered. The transfer of the as-built information onto the permanent record drawings should be completed as soon as possible following the completion of the project. This timely completion effort will help to eliminate future drawing confusion issues that may perhaps surface if the lingering as-built information were to be inadvertently overlooked or mistakenly discarded. It is customary for the original engineering personnel who created the construction documents to be involved in the as-built transfer process. This back-end involvement offers the engineering personnel an opportunity to perhaps learn from their own mistakes and misjudgments or it can serve as a reminder that a seemingly perfectly engineered product can sometimes encounter unforgiving field conditions that warrant an acceptable deviation from the desired product.

20.2.3.2 Equipment Manuals and Operations Instructions

In addition to the as-built construction documentation, it is necessary to ensure that other forms of important project information are disseminated to the appropriate project stakeholders. Both equipment manuals supplied by the equipment vendor as well as any substation operational instructions fall into this category of vital information. This information may not be utilized during the construction or commissioning phase of the project, but rather it becomes a necessary tool for future equipment maintenance needs or during times when the station requires an operational change or modification that deviates from the station's normal mode of operation.

The equipment manuals are typically provided by the equipment manufacturers and, upon their dissemination, are usually stored in a central office environment where they are readily accessible to the appropriate equipment maintenance personnel. These manuals become very useful in that they provide the necessary technical guidance during trouble shooting events as well as during future maintenance cycles. Advancing and evolving equipment technology along with routine workplace attrition issues can present challenges with trying to maintain a fully educated and proficient equipment staff. The equipment manuals provide for a safeguard to ensure that all recommended maintenance practices are thoroughly followed and at the same time they offer a comprehensive education on the equipment being serviced. The substation's operational instructions, typically created during the engineering phase by appropriate members of the engineering team, are routinely stored on site within the energized substation. On location at the substation, the instructions are readily accessible by operational stakeholders to provide the oversight necessary to guide one through a safe operational change or modification exercise.

20.2.4 Invoices

20.2.4.1 Resolve Outstanding Issues or Conflicts

As the substation project enters the closeout phase, the processing and payment of service and product invoices typically represents the primary final project activity that may require firm oversight. Invoice issues or conflicts can involve any of the consulting or contracting service entities involved in the project as well as involve any of the vendors involved that provided equipment and material. Effective project management techniques, if implemented throughout the life cycle of the project, generally result in a minimal number of adverse invoice issues or conflicts to resolve. Yet, there are times when a detailed invoice analysis is required to ensure that a service or product invoice is accurately reflecting the proper and fair charges that are required to be rendered by the utility. If the project is executed according to its original plan, and thorough scope of work plans were developed and broadly communicated, the invoicing process is ordinarily administered in a successful manner as expected. On projects, with complex deliverables, where scope of work changes were routinely encountered and perhaps project site nuances caused a deviation from the original work plan, the resulting invoice process can become somewhat complicated, especially in the absence of implementing effective project management techniques.

Since many of the same engineering and design consultants, contractors, and vendors will provide a duplication of the services and products on future substation projects, in the spirit of team unity and in the effort to retain successful working relationships with these entities, it is in the best interest of all parties to effectively and fairly resolve the invoice issues. It is not uncommon for many utilities and selected service or product providers to establish alliance relationships. These alliance relationships essentially provide the means for the utility to retain the continued ability to procure services and products at the most economical cost possible. These alliance relationships are equally attractive to the service and product providers in that they are routinely and continually contracted for substation projects in a non-competitive bid manner. These mutually beneficial business partnerships lend themselves well to establishing effective invoice validating processes that are rooted in a give and take approach that serves as a win–win outcome for all vested parties.

20.2.4.2 Complete All Payments

The contractor, consultant, or equipment vendor invoicing process is not complete until the utility renders full payment to those entities. Rendering full payment is important to help ensure that the final project cost accurately reflects the thoroughly relevant and factual cost to complete the project. This cost knowledge is essential for not only providing an accurate picture of the estimate's performance, but it is also vital historical, financial information to capture that will serve as a useful reference when estimating future similar projects. A final activity involves the effort to verify, with the utility accounting personnel, that the invoice payments have been officially surrendered to the invoicing company. This verification activity should be pursued prior to formally closing the project's charge accounts, thus to ensure that the invoice payments will be captured in their appropriate project charge account numbers.

20.2.4.3 Submit Invoices for Reimbursable Items or Services

Typically, substation projects are initiated by utility companies to meet an exclusive internal need of that utility. Therefore, the utility remains the primary customer on routine substation projects and services by others, outside of the utility employment arena, are rendered to the utility rather than by the utility. This would translate into the fact that, generally, the utility company would not be submitting an invoice for a reimbursable item or service for their routine projects. Yet there are times when rare projects are pursued by the local utility to institute a change or modification to an existing substation that is required to ensure the operational integrity of the interconnection grid between itself and a neighboring utility or perhaps a merchant independent power provider (IPP). These types of projects are initiated by either the IPP or neighboring utility with oversight by the regional grid interconnection entity, otherwise known as an independent system operator (ISO), to address transmission system and substation operational impacts between all involved entities. Since the local utility is not the originator of this type of project, and would not otherwise engage in the work, the cost of the work performed locally by the utility is categorized as a reimbursable expense to be rendered by the IPP or neighboring utility. In these cases, the local utility would submit an invoice for full reimbursement following the completion of all work and after capturing all associated project costs. The ISO is usually the recipient of the invoice and manages the reimbursement payment process.

20.2.5 Closure of Outstanding Permits, Sureties or Bonds

20.2.5.1 Permits or Sureties Required

- Grading
- Storm-water management
- Landscaping

Utility substation projects that fall into the categories of either entirely new substation installations or existing substations, whose scope of work entails an extensive modification or significant expansion effort, typically require some type of local governing agency permit to be secured. The need for a certain permit depends directly upon the nature and scale of the proposed substation work. Each governing agency interprets a project's nature and scale differently; therefore, exact permit mandates and requirement thresholds can vary between governing jurisdictions. The types of substation permits that are usually required range from building permits for foundation work to more extensive types of permits such as those for site grading activities and storm-water management implementations.

When certain permits are necessary, it is customary for the governing agency to require that the permit requestor also secures a surety to be linked directly with a certain permit. In the case of a substation project, the surety is a control mechanism that endeavors to ensure that the utility complies with the permit requirements and performs the substation's project scope of work to the full satisfaction of the governing agency. Having ownership of the surety, the governing agency would invoke their fiduciary authority on the utility to require them to indemnify the governing agency in the event of a permit non-compliance classification. Also, by requiring the surety, the governing agency is protecting itself from any financial loss in the event that it must assume ownership of various substation construction activities to make certain that project deliverables result in sound engineered products from both a general public and environmental protection perspective. Generally, for substation projects, the permits that require a surety to be obtained are site grading permits, storm-water management permits, as well as landscaping permits.

When a surety is required, the specific financial instrument utilized can vary dramatically between governing jurisdictions. The financial instruments that are typically authorized range from bonds, certified checks, letters of credit, to letters of guarantee. Each jurisdiction has the independent authority to determine which instrument is necessary for the specific permit purpose. Although there are several unique financial instruments that can be utilized, they all equally grant the governing agency firm fiduciary authority to render the utility financially responsible for a permit violation. In each case, the financial instrument is submitted to the governing agency, along with the permit application, where the governing agency retains ownership of the surety while the substation work is pursued.

20.2.5.2 Permit Closure Process or Final Governing Agency Inspections

Although all secured permits require some type of proper closure process, the permits that have associated sureties necessitate a more stringent procedure to bring those permits to full closure. These types of permits are appropriately viewed as covering project elements that require strict governing agency oversight to ensure that project deliverables adhere to acceptable engineering practices. In bringing those permits to proper closure, the agencies have established a firm policy that requires a final on-site inspection to be performed by an agency representative for the purpose of reviewing first hand the completed project element. This final governing agency inspection is routinely initiated by the permit applicant and represents the first step in the effort to secure the release of the submitted surety.

Final governing agency inspections are usually required for site grading permits, storm-water management permits, as well as landscaping permits. It is not uncommon for the actual completed field construction work, pursued under these permits, to deviate from the design product. Sometimes the deviation from the design is appreciable. For example, it is virtually impossible to perform the site grading or construct the storm-water management facility to perfectly match the engineered design. Various unknown conditions and other site nuances typically arise during the construction phase and contribute to the finished product being different from what was originally engineered. In these cases, another control measure invoked by the governing agency is the requirement to create and submit as-built documentation of the completed site grading and storm-water management facility. In receiving this as-built documentation, the governing agency endeavors to prove that, although the final actual site product deviates from the engineered design, it will still adequately perform as engineered. If the design performances of the actual conditions still prove to be acceptable, then the permit's surety is rendered unnecessary and the surety release process proceeds to its final administrative phase. Eventually the surety, regardless of the financial instrument utilized, is returned to the utility for their archive record purposes.

20.2.6 Archive Records

In an effort to perpetually retain key project documentation, a hard copy archive file of the project should be created upon its completion. The archive file exists for the primary purpose of offering both an engineering and financial history of the completed project. The archive file serves as a repository of vital and sometimes esoteric project knowledge that must be retained for future awareness needs. This historical information can be useful or even necessary at a future date for perhaps gleaning lessons learned for a similar project or possibly utilized for a research analysis of the archived project.

Key data to be stored in the archive file should be limited to items of information that cannot be readily reproduced via another storage mechanism or information that is perhaps already being stored elsewhere, as a normal practice, in the office environment. The archive file data should typically include documentation that centers on key customer communications and agreements, original zoning, permitting or surety information, as well as the final analysis of estimate and schedule performance. In addition, the archive file should contain any lessons learned documentation and any project nuances that are deemed unique and valuable engineering experiences that warrant legacy capture.

The archive file creator is typically the project manager or the responsible engineer or both. In being appropriate stewards of the project file documentation, it is important that the archive file creator possesses the level of experience necessary to effectively differentiate between project documentation that requires archiving and project documentation that can be readily discarded. The historical archive file should not be merely a full collection of the project working file, but rather a conscientious recovery effort of vital documentation only. All project archive files should be stored in hard copy format in a central and accessable area of the office environment. However, in establishing the archive area, some thought should be given to the ability to secure the files when considering their significance from a homeland security perspective. Electronic historical archive file efforts should be discouraged due to continuing technological advances that may render current recovery efforts obsolete.

20.2.7 Develop Unit Costs

In support of the never ending pursuit of improving project estimate performance, it is customary to develop unit costs, derived from actual project labor hours consumed as well as actual project cost data. The computation of unit costs allows for the establishment of detailed estimate building blocks that can be used to better develop accurate estimates for future projects with similar activities. This building block approach enables elements of a complex project scope to be fragmented into quintessential project activities in order to allow basic cost and labor hour components to be developed. Future estimates based on actual derived unit costs enable the estimate to be built utilizing these discrete building blocks, thus usually leading to significant improvements in estimating accuracy. In addition, the unit costs can also serve as achieved performance measurements that can be established as successful benchmarks or target performance goals on future similar projects.

Unit costs can be developed for each of the engineering disciplines associated with a project as well as for each of the construction trades that are involved. Examples of unit costs that can be derived are as follows: labor hours per pound of steel erected, labor hours per yards of concrete poured, labor hours per length of underground duct bank constructed, labor hours per length of cable installed, and labor hours per construction drawing developed. Essentially, unit costs can be derived for almost any singular project activity whereby it is possible to clearly differentiate the labor hours and expenses that were consumed to complete that specific activity. These unit costs become the essential estimate building blocks for future projects that possess similar scope activities, thus contributing immensely to the continued effort to improve overall project estimate performance. As project estimates continue to be built with these unit cost building blocks, repeating the process of computing unit costs at the completion of the project serves as a calibration tool to verify the accuracy of the base data, further improving the accuracy of the future estimating activity.

20.2.8 Closeout Project Accounting

20.2.8.1 Cancel Charge Numbers

A timely and key activity to pursue shortly following the completion of the project involves the complete closure of the project's dedicated accounting charge numbers. The timely closure of the charge numbers is important in order to avoid the inadvertent or inappropriate charging of the project's account numbers, for unrelated work, that would directly result in the distortion of the project's estimate performance. The closure of the charge numbers can be pursued in a segmented fashion. This approach allows certain charge numbers to be closed immediately or shortly after project completion, while other numbers remain active while they wait final charges from project activities or invoices that may linger. This segmented closure strategy is a successful project estimate control practice routinely followed by the project manager or the responsible engineer as an added measure that limits the availability of active charge accounts. This strategy directly endeavors to minimize the inadvertent or inappropriate over-charging of a specific account number, thus generally improving the project's estimate performance.

20.2.8.2 Verify Invoices Have Been Paid

Typically, second party invoices for contractor services, purchased equipment, and material represent the category of outstanding financial responsibilities that remain following the completion of the project deliverable. The effort to properly process the payment and full accounting of this category of invoices can often linger for a few months following the project's completion. The project's charge numbers should only be closed upon the verification that all appropriate project financial responsibilities have been fully and completely satisfied.

20.2.9 Notify Stakeholders

20.2.9.1 Project Completed

A formal project completion announcement should be appropriately and thoroughly disseminated shortly following the accepted completion of the project. The announcement should be widely circulated to all levels of the project team as well as to all project stakeholders or project sponsors. Prior to the announcement, stakeholder or sponsor acceptance of the completed deliverable should be verified to avoid any false or inaccurate claims of completion. The thorough and fully disseminated successful project completion announcement provides all interested parties with the knowledge that the project has been brought to a successful closure. Equally, the completion announcement provides various team members with the completion awareness that may perhaps initiate their own associated project activity closure processes. The project completion announcement should include commentary that centers on schedule performance, estimate performance, as well as scope and quality performance. Thus, the announcement serves as a direct performance feedback mechanism to all project team members and project stakeholders.

20.2.9.2 Charge Numbers No Longer Valid

At the appropriate time, a follow-up announcement should be widely disseminated that declares that the project charge numbers have been closed and are no longer valid. The announcement serves as a final reminder that the project is considered 100% complete and can no longer accept any financial responsibility for the project. The announcement is typically offered as a courtesy to provide the full awareness that the project charge numbers have been rendered invalid, which serves as a project control mechanism to eliminate the inadvertent or inappropriate charging of the project's account numbers for unrelated work.

20.2.10 Development of Lessons Learned

Although many projects can seemingly be categorized as routine pursuits or perhaps basic in nature, most projects offer possibilities to glean some type of lessons learned that can be successfully leveraged on the next project opportunity that possesses either a similar scope or duplicate activities. The quantity and quality of the lessons learned and developed are not necessarily a function of the complexity of the project. Although, typically the greater the project complexity, the more the opportunity exists to develop quality lessons learned, all projects can usually offer learning experiences worthy of noting in order to be implemented on future projects. In general, many project lessons learned are identified during the final walk-through or inspection phase of the completed project and speak uniquely to the construction phase. However, the full project life cycle should be thoroughly examined to discover these improvement opportunities. The derived and implemented lessons learned generally endeavor to improve upon both the construction practices and safety performance of a project; however, all project phases and disciplines involved can benefit directly from this lessons-learned identification task. Effective project management techniques call for the lessons-learned to be identified during the planning phase of a future project, thus typically leading to appreciable improvements in the project's estimate performance, quality of the project deliverable, and safety performance as the project moves through the construction execution phase.

The process of developing or identifying lessons-learned opportunities can be accomplished in a variety of forums. These forums can range from personal notations based on individualized experiences, informal conversations amongst limited project team members, or sometimes the process can consist of engaging in a formal meeting setting. The formal meeting setting option is usually held for projects of a very complex or unique nature, which required the contribution of several engineering disciplines and involved a wide range of construction trades. The meeting would be attended by all pertinent project-activity owners and is customarily facilitated by the project manager or the responsible engineer who follows a structured agenda. Essentially, a lessons-learned item can be anything that either an individual derives or a project team identifies that is considered a worthwhile implementation on future projects to continually improve towards achieving higher levels of project success.