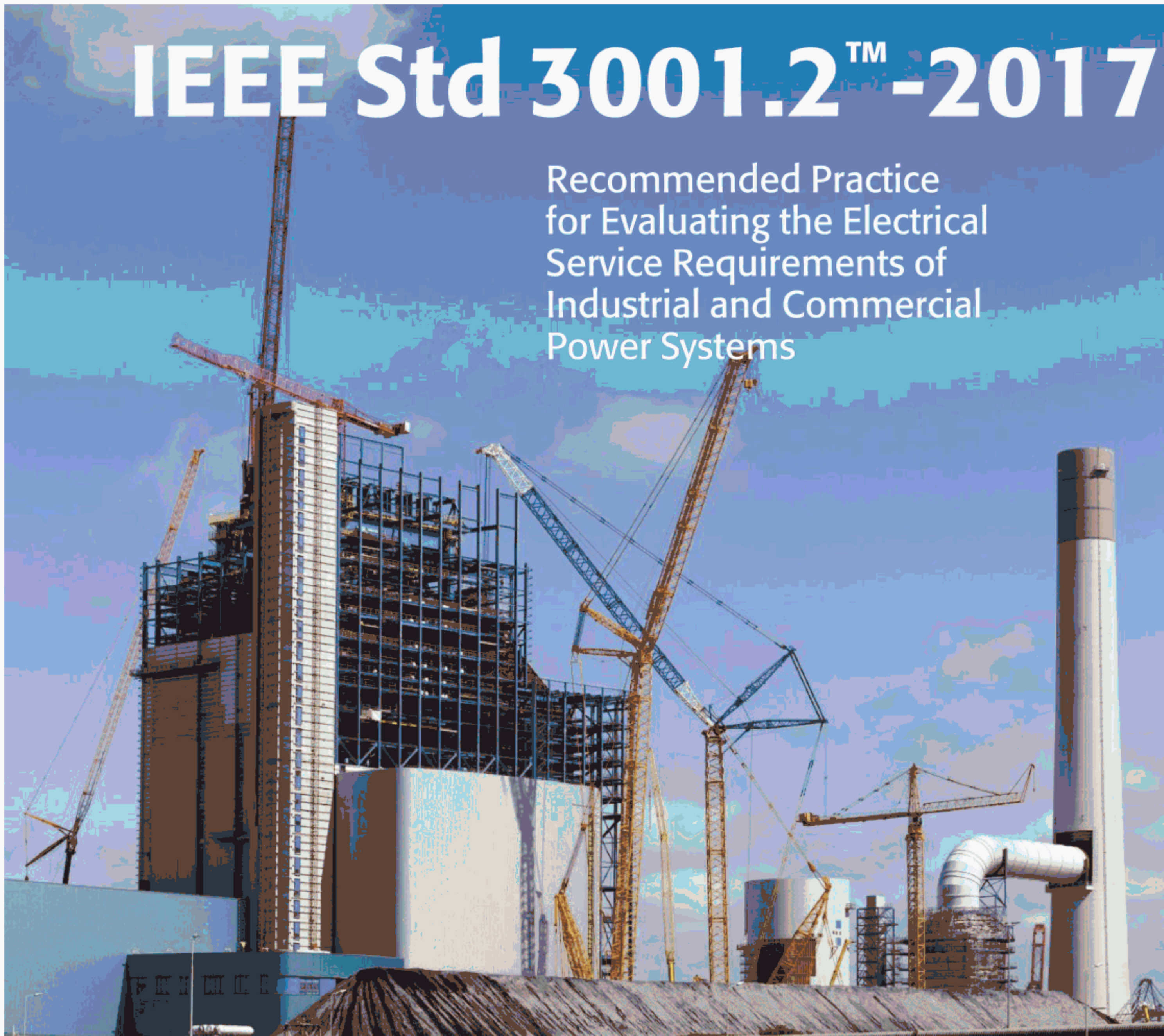


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IEEE 3001 STANDARDS:
POWER SYSTEMS DESIGN

IEEE Std 3001.2™-2017

Recommended Practice
for Evaluating the Electrical
Service Requirements of
Industrial and Commercial
Power Systems



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IEEE Recommended Practice for Evaluating the Electrical Service Requirements of Industrial and Commercial Power Systems

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**Technical Books Coordinating Committee
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IEEE Industry Applications Society**

Approved 6 December 2017

IEEE-SA Standards Board

Abstract: Commercial, institutional, and industrial design of electrical services, interconnecting with a utility distribution or transmission system is explored. The electrical system information needed by the designer concerning the utility's system characteristics, and the electrical load information needed by the utility to design a satisfactory electrical interface between the serving utility and the premise electrical distribution system is considered.

Keywords: electric rates, IEEE 3001.2, service, service entrance, substation, utility metering, utility billing, vaults

The Institute of Electrical and Electronics Engineers, Inc.
3 Park Avenue, New York, NY 10016-5997, USA

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PDF: ISBN 978-1-5044-4513-9 STD22890
Print: ISBN 978-1-5044-4514-6 STDPD22890

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Introduction

This introduction is not part of IEEE Std 3001.2™-2017, IEEE Recommended Practice for Evaluating the Electrical Service Requirements of Industrial and Commercial Power Systems.

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This recommended practice was developed by the Technical Books Coordinating Committee of the Industrial and Commercial Power Systems Department of the Industry Applications Society, as part of a project to repackage IEEE's popular series of IEEE Color Books®. The goal of this project is to speed up the revision process, eliminate duplicate material, and facilitate use of modern publishing and distribution technologies.

When this project is completed, the technical material included in the 13 Color Books will be included in a series of new standards—the most significant of which will be a new book, IEEE Standard 3000™, IEEE Recommended Practice for the Engineering of Industrial and Commercial Power Systems. The new standard will cover the fundamentals of planning, design, analysis, construction, installation, start-up, operation, and maintenance of electrical systems in industrial and commercial facilities. Approximately 60 additional dot standards, organized into the following categories, will provide in-depth treatment of many of the topics introduced by IEEE Std 3000™:

- Power Systems Design (3001 series)
- Power Systems Analysis (3002 series)
- Power Systems Grounding (3003 series)
- Protection and Coordination (3004 series)
- Emergency, Standby Power, and Energy Management Systems (3005 series)
- Power Systems Reliability (3006 series)
- Power Systems Maintenance, Operations, and Safety (3007 series)

In many cases, the material in a “dot” standard comes from a particular chapter of a particular color book. In other cases, material from several color books has been combined into a new “dot” standard.

The material in this recommended practice largely comes from Chapter 2 and Chapter 15 of the *IEEE Red Book*™, IEEE Std 141™-1993, Recommended Practice for Electric Power Distribution in Industrial Plants, and Chapter 4 and Chapter 7 of the *IEEE Gray Book*™, IEEE Std 241™-1990.

IEEE Std 3001.2

This publication provides a recommended practice for the electrical design of commercial and industrial facilities. It is likely to be of greatest value to the power-oriented engineer with limited commercial or industrial plant experience. It can also be an aid to all engineers responsible for the electrical design of commercial and industrial facilities. However, it is not intended as a replacement for the many excellent engineering texts and handbooks commonly in use, nor is it detailed enough to be a design manual. It should be considered a guide and general reference on electrical design for commercial and industrial facilities.

Tables, charts, and other information that have been extracted from codes, standards, and other technical literature are included in this publication. Their inclusion is for illustrative purposes; where technical accuracy is important, the latest version of the referenced document should be consulted to assure use of complete, up-to-date, and accurate information.

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IEEE Recommended Practice for Evaluating the Electrical Service Requirements of Industrial and Commercial Power Systems

1. Scope

This recommended practice explores commercial, institutional, and industrial design of electrical services, interconnecting with a utility distribution or transmission system. Close coordination between the facility electrical designer and the serving utility are critical for a successful service connection. This recommended practice considers the electrical system information needed by the designer concerning the utility's system characteristics and the electrical load information needed by the utility to design a satisfactory electrical interface between the serving utility and the premise electrical distribution system. It describes various ways to take power from the serving utility. It also covers the specific requirements for utility metering on service entrance equipment, as well as service equipment rooms, vaults, and pads.

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

Accredited Standards Committee C2™, National Electrical Safety Code® (NESC®).

IEC 61936-1-Ed.1.0, Power installations exceeding 1 kV ac—Part 1: Common Rules.¹

IEEE Std 80™, IEEE Guide for Safety in AC Substation Grounding.^{2,3}

IEEE Std 142™, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems (*IEEE Green Book*™).

IEEE Std 693™, IEEE Recommended Practice for Seismic Design of Substations.

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³IEEE publications are available from The Institute of Electrical and Electronics Engineers (<http://standards.ieee.org/>).

IEEE Std 979™, IEEE Guide for Substation Fire Protection.

IEEE Std 980™, IEEE Guide for Containment and Control of Oil Spills in Substations.

IEEE Std 998™, IEEE Guide for Direct Lightning Stroke Shielding of Substations.

IEEE Std 1127™, IEEE Guide for the Design, Construction, and Operation of Electric Power Substations for Community Acceptance and Environmental Compatibility.

IEEE Std 1402™, IEEE Guide for Electric Power Substation Physical and Electronic Security.

NFPA 70®, National Electrical Code®(NEC®).⁴

3. Common relationships with electric utilities

The most common relationship that exists between the industrial or commercial facility and a connecting electric utility is that of a seller and buyer. That is, the electric utility supplies electric energy to the facility based on a rate typically regulated by a state agency as the utility will typically have a monopoly over serving a given geographic area. Considering this, the industrial or commercial user may be referred to as the *customer*. The relationship between a utility and its customer has become more complex based on the following developments.

- Wholesale power agreements that allow a user to purchase energy from entities other than the connecting utility. The connecting utility is not the direct seller of energy. However, the connecting utility will usually still be compensated for the use of their distribution system through *wheeling charges* that are added onto the user's monthly energy invoice.
- Community Choice Aggregation programs that allow users within the geographic boundaries of the program to secure alternative energy supply agreements by working in aggregate, typically through a city or county agency.
- The capability to generate power onsite, typically through cogeneration or renewable energy sources such as wind turbines or photovoltaic panels. Diesel engine or gas turbine sources may be used. The onsite generation may simply reduce the overall facility demand, or the user may be permitted to export power when the user's onsite source capacity is greater than the user's own load demand. The utility should be consulted to determine whether they are willing to accept any exported power, and any special requirements they have for users who install onsite power sources that may be connected to the utility distribution system.

4. Planning for utility service

4.1 Introduction

It is the responsibility of the engineer to understand the serving utility's electric service requirements and service tariffs to develop an efficient and economical means of receiving electric power and distributing it to each area to be served. This function can be carried out in many ways. Selection of system arrangements, components, and voltages should be engineered to function reliably and safely, and to deliver the power at correct voltages without hazard to personnel or the facility.

⁴NFPA publications are published by the National Fire Protection Association (<http://www.nfpa.org/>).

4.2 Utility/designer communication

Each utility differs in its service policies and requirements. Therefore, establish communications with the major account representative, or service design professional of the supplying utility so that their requirements can be incorporated in the facility's plans, equipment specifications, and commissioning documents. This is a two-way path of communications. The utility needs information about the proposed loads to be connected (refer to 5.4). The facility's electrical designers need information about the utility's electrical distribution system characteristics (refer to 5.5). The designer should obtain from the utility company a range of possible available fault current at the point where the utility connects. Obtaining only the maximum theoretical value is not adequate for the eventual analysis of arc flash on the user's distribution system. It is important to also know what is the possible minimum fault current available, as well as the maximum worst case available fault current.

4.3 Service availability

4.3.1 Service voltage

The service voltage selected and its characteristics for primary or secondary service are based on the utility's distribution standards and the voltage grids in the specific area of the facility. The utility should be contacted to determine the available voltages based on the load to be served and, in some cases, the geographic location of the load. The designer may become aware of service voltages provided to customers in the service area that are no longer available. Such services continue to be offered only to existing facilities and are not typically offered to new facilities.

Service is usually available at the utilization voltages, such as 240 V delta (3-phase/3-wire), 120/240 V high-leg delta (3-phase/4-wire), 208Y/120 V, 480Y/277 V, or 600Y/347 V. Utilities may have kilowatt demand limitations for each specific voltage. When the facility's load becomes too large to be supplied at the utilization voltage, due to excessive cost or excessive voltage drop, the facility should be supplied at a distribution voltage, typically, but not limited to, 4.16 kV, 12.47 kV, 13.2 kV, 13.8 kV, 26 kV, or 34.5 kV. In the case of large facilities, it may also be economically feasible to connect to the utility transmission line system. A primary substation is used to step the voltage down from transmission line levels to medium-voltage levels. Refer to 8.6 and Clause 11.

If the customer owns the medium-voltage distribution system, then the associated equipment, including transformers, should be purchased and installed by the customer. The exception would be if the utility provides all or part of the medium-voltage distribution system, in return for the right to sell power directly to tenants, or when the utility and the authority having jurisdiction (AHJ) permit more than one service in the building. In the latter case, the utility may consider each service as a separate customer, and usually the bills will be higher than a single bill.

4.3.2 Service type

The designer should discuss the type of services available in the service area supplying the facility with the utility service design professional. Services may be underground, open wire aerial, or lashed aerial cable. In addition, the utility may offer dual-service options or dedicated lines for special customer load requirements.

4.3.3 Reliability considerations

4.3.3.1 Introduction

Consistency in maintaining needed reliability throughout the entire electric system is essential. A careful evaluation of each part of the design, for reliability and maintainability, as well as that of the utility feeders and their sources is needed. For instance, the incoming feeders might have taps for other customers; be exposed to hazards; or have a history of power quality problems, including substation or line circuit breaker and recloser operations that indicate a need to be reinforced, or supplemented with an alternate set. When planning for

redundant incoming feeders, this evaluation may uncover that the two feeders are sourced from the same utility transformer or substation bus, whose failure would compromise that reliability. Resolving such issues may have large impact on project cost and/or schedule, or in worst case the resolution may not be feasible.

4.3.3.2 Facility reliability design options

The design professional should consider all possibilities of planned and inadvertent outages to determine the justification for reinforcements, such as alternate feeders or feeders from separate substations. Plan, specify, and design into the distribution system the ability to connect mobile standby generators to the incoming service switchboard in the event of a total loss of utility service. Designing in the ability to connect portable generation can be omitted when:

- Permanent standby generators are required by code or otherwise incorporated into the design
- The time to obtain a mobile generator is too long for operational conditions

Onsite generation using renewable sources (photovoltaic, wind, etc.) may enhance the reliability of the power system somewhat; they are limited by the availability of the source from which they derive the energy. Renewable sources are often intermittent; in addition, the design of the inverters of such sources may not allow for islanded operation. When this is the case, the renewable source needs to be complemented by some other type of onsite generation or stored energy source.

4.3.3.3 Utility system design

The reliability of utility service depends on generating facilities, the exposure of the transmission system from the generating plant, and more importantly on the design of the utility's distribution system. The reliability of the electric service also depends on the other loads on the same distribution system. For instance, a facility supplied at the same voltage level and on the same lines as a rock-crushing operation may incur power quality and reliability issues compared to a facility supplied from lines supplying a shopping mall or office building. Utility tariffs usually have requirements to limit the impact of customers with special loads on other customers. Distributed generation connected to the distribution system may increase reliability through the voltage support it provides. However, these sources cannot be counted upon to support adjacent loads in the event of a complete utility outage.

4.3.3.4 Utility reliability measurement criteria

Utility reliability is usually measured and reported to public utility commissions as SAIFI (System Average Interruption Frequency Index—number of interruptions exceeding five minutes in duration per year) and CAIDI (Customer Average Interruption Duration Index—average system wide interruption duration in minutes). Some utilities also measure MAIFI (Momentary Average Interruption Frequency Index). These indices are usually for the utility's entire system. The facility designer should request these indices for the specific distribution circuit that will supply the facility, or request a list of momentary and sustained interruptions on the circuit over a three- to five-year period. This will provide a more realistic expectation to design the facility's electrical system to provide the reliability needed for specific load areas such as computer data servers, cash registers, and controls for critical loads. Such measures may include, but are not limited to, uninterruptible power supplies, or standby generation.

4.3.4 Operating staff

One of the most important, and often neglected, considerations is the ability of facility staff to operate and maintain the proposed systems. Commercial buildings often have a very limited number of staff. This can be the case for industrial plants as well. This staff might be unqualified to properly and safely maintain medium-voltage systems, protective-relaying systems, or complex switching arrangements. However, a limited staff may be augmented by contracting with third-party service providers or electrical contractors if local resources can provide qualified personnel on a timely basis.

4.3.5 Electric service protection

In addition to the overcurrent and disconnecting means requirements of the National Electrical Code (NEC), articles 230 and 240, Canadian Electric Code (CEC), [section 6](#) and section 14, or local codes, facility services should be protected against electrical anomalies that may result from impacts to the electric utility's distribution or transmission system. These may include but are not limited to:

- Motor control and protection: Utility tariffs usually state that they assume no responsibility for failures, equipment, or operations due to use of the electrical energy. The utility requirements specify that customers are responsible for equipping motor controllers with protection.
- Undervoltage protection: Tripping devices to prevent sustained under-voltage operation. The under-voltage protection should be of a time-delay type to avoid unnecessary tripping during momentary disturbances or service interruptions.
- Phase protection: Tripping devices to switch off motor controllers as protection from single phasing, improper rotation due to phasing, and overheating due to current unbalance.
- Protection required for interconnecting onsite power sources to the utility system: Setting source protective devices to provide voltage and frequency support as long as possible, but tripping off devices to prevent continuing to power the utility system after utility power has been removed from the line to which the industrial or commercial facility is connected.
- Protection required for interconnecting to the utility transmission line system: High-speed fault detection and clearing is imperative to prevent a fault on the customer's system from degrading the transmission line system and reducing the levels of safety and reliability that the network provides to other customers.
- Arc flash and or other protection that enhances maintenance and operational safety: Protection to mitigate electrical hazards may be more than that required to meet the minimum requirement of installation codes, how it should be considered within the context of safety-by-design principles, and the hierarchy of hazard-control measures provided in NFPA 70E, CSA Z462, and ANSI Z10.

4.3.6 Economic considerations

4.3.6.1 Utility cost to provide service

The designer should investigate any utility interconnection costs associated with the service to the facility. Most utilities have a *line extension policy* to provide revenue credits toward utility construction costs to provide a service. If the load is not sufficient to cover costs, a customer contribution to construction may be levied on the project. Other utility costs may be levied for special or nonstandard service requests, such as dual services or dual services from separate substations, or non-standard voltages.

4.3.6.2 Other utility economic considerations

Discuss and negotiate with the utility account representative the rules and tariffs on such items as:

- a) Consideration of a more beneficial rate structure
- b) An alternative incoming voltage
- c) Location of the property line boxes or incoming service
- d) An alternative transformer winding connection, such as requesting a primary delta to grounded-wye secondary transformer instead of a transformer with a grounded-wye primary to grounded-wye secondary
- e) Use of a feeder with a history of increased reliability

The utility account representative may request:

- a) Limiting motor-starting currents, voltage dips, and flicker
- b) Providing more convenient access to routes for service or specific locations where utility metering or communication components need to be installed
- c) Installing switchgear with special features or higher ratings
 - 1) Specific manufacturer and models of equipment or components
 - 2) Protection, control, and communication requirements, for example, transfer trip via power line carrier, fiber-optic media, or microwave
- d) Installing harmonic control equipment
- e) Installing power-factor improvement equipment

4.3.7 Point of delivery

The utility should provide, in writing, the service point for the facility. This is the demarcation between utility-owned facilities and customer-owned facilities, and usually determines which party is responsible for maintenance or repair. The actual point of delivery may be the last utility pole location, utility transformer secondary terminals, or the terminals of a disconnect switch. The design engineer should consider minute details associated with the actual point of delivery, such as the scope of supply for termination hardware and field work. The requirement for manholes, handholes, or end boxes will also be included. The design should also consider whether a splice at the point of demarcation is required. If a splice is not required, details should be listed as to which party will extend conductors to meet the other, and which party is responsible for the splice or terminations for medium-voltage services.

4.4 Facility load information

Prior to discussing power costs and availability with the utility, load data for initial and future requirements should be estimated as accurately as possible. (Refer to ANSI C84.1 [B4], Chapter 3 of IEEE Std 141 [*IEEE Red Book*TM] [B24], and Chapter 3 of IEEE Std 241 [*IEEE Gray Book*TM] [B26]). If the utility has to install additional facilities to achieve the service quality needed, then a charge for these additional facilities may have to be paid by the owner. The annual operating cost can be ascertained from the utility tariff. If facility expansion is likely, check the ability of the utility to supply the increased load. The utility may need the following information:

- a) Plot plan of the area, which shows the buildings (both present and future), roadways, and other structures. Underground and overhead utility lines should be documented. Identify area allocated for utility substation when applicable.
- b) Preferred point of delivery for electric service.
- c) Estimated connected load, maximum demand and power factor, and any requirements for future increases including life-cycle load growth margins.
- d) Preferred voltage.
- e) Harmonic producing equipment, including variable frequency drives, large motors, electric boilers, welders, and X-ray apparatus, which may disturb the supply system.
- f) Any requirements for alternate, emergency, or standby service.
- g) A single-line diagram of service equipment. For medium-voltage service, show the distribution system including the sizes and ratings of fused load-interrupter switches, metal-clad or metal-enclosed circuit breakers, surge arrestors, and relaying, including current transformers and potential transformers.

Transformer descriptions should include the basic impulse insulation level (BIL), voltage taps and tap changing method (de-energized or on-load type), transformer winding connections, system grounding, and phase rotation.

- h) A load tabulation for the peak summer and winter seasons that indicates the contribution of each of the following loads to the peak demand:
 - 1) Central systems/utilities: water chilling, water heating, ventilation, air handling, humidification, space heating
 - 2) Data processing: computers and peripherals, air conditioning
 - 3) Telecommunication information centers, servers, and air conditioning
 - 4) Food service
 - 5) Lighting
 - 6) Refrigeration
 - 7) Room air conditioning
 - 8) Water heating
 - 9) Welders and compressors (e.g., maintenance shop)
 - 10) Receptacles
 - 11) Heating
 - 12) Transportation: elevators, escalators, people movers, conveyors
 - 13) Miscellaneous power: radio and television broadcasting, etc.
 - 14) Process or manufacturing loads
 - 15) Residential loads (i.e., for mixed-used commercial buildings)
- i) Rating of standby and emergency generator(s).
- j) The electrical load information should be separated by voltages and whether single-phase or three-phase. The largest motor in each category should be shown by rating (kilowatt or horsepower), together with its locked-rotor and full-load amperes. Advise when reduced voltage starting is planned for limiting motor-starting currents.
- k) Considerations for parallel operation of generation: Utility requirements for protective relaying and transformer connections should be considered if generation (i.e., synchronous, induction, or inverter connected) is to be paralleled with the utility service.
- l) Considerations for automatic bus transfer schemes (refer to 11.6.4.8).
- m) Load factor, i.e., daily and monthly.
- n) Schedule data:
 - 1) The date service and preliminary construction schedule will be required
 - 2) The dates when full estimated initial load and full load will be required
 - 3) Temporary construction service requirements

4.5 Information from the utility

When requested, the utility may provide the following information:

- a) Tariffs.

- b) Voltages available.
- c) Power factor requirements.
- d) Range of the nominal voltage and the voltage unbalance and any power quality–related parameters (refer to ANSI C84.1 [B4]).
- e) For medium voltages, insulation-coordination data:
 - 1) Basic impulse insulation level (BIL) of equipment
 - 2) Ratings of surge arresters:
 - i) Front-of-wave test data
 - ii) Lightning protective level (impulse protective level)
 - iii) Switching protective level
 - 3) Lightning protection methods employed (e.g., “skywires”), if any
- f) Point of delivery of electric service, when preferred point is not acceptable.
- g) Line route from the property line to the point of delivery for any portion of the line installed by the utility.
- h) Any charges for service, including cost of any underground portion of the line.
- i) The utility may provide options for the underground service: direct burial cable, or conduit and manhole system.
- j) Electric service requirements, including:
 - 1) Metering
 - 2) Service equipment specifications
 - i) Protective relay specifications
 - ii) Station battery specifications
 - 3) Transformer vault and network specifications
 - 4) Service transformer specifications
 - 5) Specifications for transfer switches and other types of transfer schemes
 - 6) Fire pump connection specifications
 - 7) Fire alarm and exit lighting connection specifications
 - 8) Emergency operations facility connection specifications
 - 9) Operation and maintenance of service equipment specifications
 - 10) Protection of motors specifications
 - 11) Motor-starting inrush current specifications
 - 12) Power quality specifications including voltage flicker, telephone interference factor (TIF), and total harmonic distortion limitations
 - 13) Communication and power system data interface requirements
 - 14) Harmonic limitation requirements for variable frequency drives
 - 15) Power factor improvement capacitor/harmonic filter connection requirements
 - 16) Phase load balance requirements

- 17) Electrical identification of wiring
 - 18) Phase rotation at each voltage level
 - 19) Single-phase equipment (for example, welders, etc.) inrush current limitations
 - 20) Surge protection and equipment basic impulse insulation level requirements
 - 21) Tree trimming and vegetation control specifications around service equipment
 - 22) Distributed power generation connection and protection requirements
 - 23) Automatic transfer scheme requirements between two utility feeders or between utility feeder(s) and owner's generator(s)
 - 24) Requirements for customer-owned substations
- k) Available minimum and maximum short-circuit capacity of the supply system, accounting for likely future changes to the utility distribution system (maximum values are used for determining suitability of interrupters applied in the system while arc flash incident energy calculations should use these and minimum values to determine maximum arc flash energy conditions). Information for single-line-to-ground faults should also be obtained for medium-voltage services.
 - l) Protective device time current coordination information.
 - m) Any special local exception to the NEC, which applies to utility-associated equipment.
 - n) Recommended ratios and taps for transformers provided by the customer.
 - o) Availability and cost of an alternate or standby electric supply.
 - p) Historical as to the reliability of substation transmission and distribution feeders (SAIFI yearly and CAIDI, refer to IEEE Std 493™ [\[B32\]](#)).

Prior to requesting short-circuit data, the user must consider the purposes for the data. The major uses of utility supply short-circuit data are for determining the following:

- *Withstand and interrupting ratings of equipment.* The maximum available fault current values are required.
- *Settings of protective devices.* The range of probable fault values is required, although sometimes only the maximum fault currents are considered by some users.
- *Prospective arc flash incident energy.* The range of probable fault values is necessary, as emphasized in IEEE Std 1584™.
- *User system design.* This includes motor starting criteria, transformer taps, and other load issues. This assessment must consider the range of relevant utility data. For example, if two utility lines are available, any one of which will support the load, but both of which are required to start a large motor, this range of data becomes important. If, however, the same motor must be started with only one utility line available, a different range of utility data is required.

For industrial and commercial projects, it is normal to attempt to determine the “maximum and minimum fault currents,” and use that information to determine arc flash incident energies. Sometimes the minimum fault current is also used for other aspects of the design of overcurrent protection, but often the designers of these systems forget about this consideration. When the “minimum fault current” is requested, the utility engineer providing the information may consider scenarios that are not applicable to the power system being designed.

The electrical supply utility engineer starts with the present system configuration. He routinely determines the fault currents (three-phase, single-line-to-ground, and occasionally line-to-line and double-line-to ground) for this configuration. He often will have an anticipated future configuration, perhaps a 10-year “look-ahead”

model, and will determine the probable fault currents for that condition. However, when asked for a “minimum fault,” the methodology varies widely. Sometimes the “minimum fault” provided is actually a single-line-to-ground fault. Usually the utility engineer considers N-1, N-2, etc., cases. N-1 means any one element is taken out of service. In practice, there will need to be a large number of N-1 cases run, each taking a different element out of service, to determine the range of available fault currents for *N-1*. Similarly, *N-2* means two different elements are simultaneously taken out of service. In some cases, the configuration which corresponds to “minimum fault” cannot support the user’s load currents. These are very important calculations for the utility, because they are used in assessing protective relay settings. However, they may not be applicable to the user’s system because it is not a practical operational condition.

Another consideration is the fault contribution from large motors connected to the systems of adjacent users. If the user is located in an industrial complex where adjoining users connected to the same power supply network have large motors in operation, the fault contribution from these motors will often be ignored. This may not be significant if the motors in question are separated from the user’s fault location of interest by two or more power transformers. However, it could have an impact on some supply infrastructure (such as circuit breakers), which may be within the scope of the user or the supply authority, depending on details of the proposed utility connection.

In order to obtain appropriate fault current values from the supply utility, the user needs to discuss present and probable future network configurations which will support the user’s loads. Some of these configurations may not permit a large motor to start, but configurations which can realistically maintain the user’s running load need to be considered. Situations where load curtailment is required should be addressed separately, if relevant. (Load curtailment is not feasible for some facilities, and very practical for others.)

From this set of agreed network configurations, the maximum and minimum three-phase and single-line-to-ground fault currents and impedances need to be determined at the agreed point of connection between the supply authority and the user. The range of normal operating voltages at this point of connection should also be requested.

Any potential fault contributions from other connected user’s motors need to be discussed. If this is a likely condition, but not included in the supply utility’s data, some assessment of the order of magnitude of these possible contributions needs to be determined, whether by the supply utility, the user, or a third party.

4.6 Interrelated utility and project factors that influence design

Other factors that may influence the facility’s interconnection with a utility service are:

- a) Type, size, shape, and occupancy purposes of the building or buildings
- b) Voltages and voltage ranges that are available at the site [refer to Chapter 3 of IEEE Std 141 (*IEEE Red Book*TM) [B24] and Chapter 3 of IEEE Std 241 (*IEEE Gray Book*TM) [B26]]
- c) Electrical rate plans available
- d) Availability of aerial or underground service and of network sources
- e) Type and rating of building utilization equipment
- f) Economics of utilization voltage distribution
- g) Necessity of changing the service voltage, e.g., from 480Y/277 V to a medium service voltage i.e., 4160Y/2400 V or 12 470 V, 13 200 V, or 13 800 V
- h) Complete or partial replacement of equipment in a modernization project
- i) Application of energy-conserving projects

- j) Intent to use fuel cells, microturbines, photovoltaics, or other onsite sources of electric energy that can be connected to the utility system
- k) Reliability and maintainability of supply
- l) Utility outages and shutdown planning
- m) Future planning: Learn the utility's plans for maintaining the local distribution system or possibly replacing or upgrading it in the future
- n) Economics of the distribution system as a consequence of available fault levels of utility services and customer-furnished fault current limiters, such as transformers, reactors, system neutral grounding, and current-limiting protective devices
- o) Coordination with other utilities such as natural gas, sewage, and water

5. Electric rates

5.1 Demand and fixed charges

Demand charges cover all generally predictable utility costs, such as depreciation, interest, and insurance. Capital investments for land, buildings, generating equipment and switchgear, transmission lines, and structure transformation and distribution equipment are depreciated over the estimated or specified life of the equipment. Demand charges reflect the investment required by the electric utility to serve the customer's maximum rate of consumption (demand). The demand is determined by a demand meter. In most cases this is a standard kilowatt-hour meter with demand interval registers that record the kilowatt-hour consumption over the demand interval period. In electro-mechanical meters, the demand is determined by multiplying the kilowatt-hour registration times the number of demand intervals in one hour. For a 30-min demand interval, this would be the kilowatt-hour registered in an interval multiplied by 2. Digital meters can calculate this using software algorithms and have capabilities for multiple types of interval periods (i.e., fixed or sliding. Refer to 7.6).

5.2 Energy and variable charges

Utility rates include cost items such as fuel, operating labor, maintenance, raw materials, etc. There may also be a *fuel adjustment clause* to compensate the utility for the market price of fuel above its long-term contract base rate. Some states in the United States, and some provinces in Canada, have de-regulated their electric utilities, resulting in competition to supply energy. These utility tariffs provide separate costs for variable distribution charges, transmission system charges and energy charges. Customers in these service territories may shop the market for third-party energy suppliers. The serving utility provides "wire" or "delivery" service charges, which may still be based on kilowatt demand and kilowatt-hour energy delivered. Most de-regulated utilities remain a "last resort" supplier of energy, if the customer does not select a third party energy supplier. The resulting energy rates are published in their tariffs. Customers in these de-regulated markets should research an alternate supplier. They should provide expected kilowatt demand, expected kilowatt-hour consumption, an estimated load factor, and inquire about the impact of power factor. To arrive at the most economical tariff, the design professional should evaluate the following tariff conditions:

- a) Characteristics of service:
 - 1) Voltages and types of systems available
 - 2) Maximum demand in kilowatts or kilovolt-amperes
 - 3) Demand interval: 15 min, 30 min, or 60 min
 - 4) Energy consumption in kilowatt hours
 - 5) Power factor: minimum required and recommended

- 6) Voltage unbalance
- 7) Power quality: total harmonic distortion, allowable voltage dips and flicker due to motor starting
- b) Installation and maintenance of overhead and underground facilities
- c) Space for transforming and other utility apparatus
- d) Interior distribution arrangement
- e) Service equipment
- f) Customers wiring and equipment
- g) Metering: special meters, submeters, tenant meters
- h) Billing: minimum bills, terms and conditions
- i) Load adjustments by the Independent System Operator at times of emergency
- j) Conjunctional billing
- k) Off-peak rates, seasonal rates, time-of-day rates
- l) Incentive rates
- m) Real-time pricing
- n) Emergency service, auxiliary service, standby service, backup service
- o) Interruptible service
- p) Purchases of installed generating capacity
- q) Charges due to excess load above “standard load density” for building type
- r) Charges or credits associated with power factor or other power quality requirements
- s) Fuel cost adjustment clause; taxes; nuclear plant decommissioning fee
- t) Charges for multiple supplies from different substations for reliability
- u) Charges for utility-installed and operated uninterruptible power supply systems
- v) Availability and costs for electrical distribution equipment maintenance and repair services
- w) Guaranteed outage duration
- x) Credit for inability to deliver service
- y) Compensation for failing to meet in-service date
- z) Compensation for metering system failure

5.3 Power factor credits and penalties

The power factor of the load may be required to be 85% or 90% with a credit for a higher power factor and a penalty for a lower power factor.

6. Electric utility metering and billing

6.1 Introduction

An understanding of utility metering and billing practices is important for evaluating service arrangements. The design, usage, and load characteristics for a given application should be carefully weighed before selecting service voltage and metering characteristics. When momentary high demand loads, high seasonal loads, or

low power factor loads are present, billing penalties may also be incurred. High load factor or high power factor loads may merit a billing allowance or credit.

6.2 Metering by type of premises

6.2.1 Introduction

The availability of a specific metering and billing arrangement depends on the characteristics of the business premises, type of load involved, and utility tariffs.

6.2.2 Single-occupancy building

A single-occupancy building will be metered by the utility with a watt-hour-demand meter. With multiple services, watt-hour-demand meter readings may be added together to take advantage of lower rates, and the demands on two or more services may be totaled to benefit from the diversity of their demand.

6.2.3 Multiple-occupancy building

Multiple-occupancy buildings are typically equipped with an individual meter for each customer (owner and tenants), except in cases where light and power are included in the tenant's rent, in which case a master metering may be utilized. In some localities, buildings may be submetered so the utility's customer buys wholesale power on a utility master meter, and then resells it to the tenants at legally prescribed rates using private meters.

6.2.4 Directly-metered multiple-occupancy building

Where the tenants are directly metered, by the utility or by submeters, provide sufficient flexibility in the metering arrangement to facilitate changes, for example, a change of tenant.

6.3 Metering by service voltage characteristics

Metering of incoming electric service may be located on the high-voltage or low-voltage side of the transformer, depending on the tariff. When the metering is on the high-voltage side of the transformer, the transformer losses will be metered and charged to the customer. Where the service point is on the high-voltage side, but the meter is on the low-voltage side, then the utility may add a fixed percentage to the bill, such as 2%, to cover the transformer losses. In some cases, the customer is given a discount to offset this loss.

6.4 Meter location

Since all meter locations are subject to utility approval, review the meter locations with the utility at the preliminary design stage. Utilities require accessibility for meter reading and maintenance purposes, and suitable meter protection. Where remote meter reading is performed, the utility may require a dedicated telephone line. Where the customer has distributed generation or a contract to generate electricity upon order of the utility during emergencies, then an additional, separate meter may be required to be installed at the generating set together with remote reading capability and a requirement for a dedicated telephone line. Utility requirements for meter heights above the standing surface may differ depending on whether the location is indoors or outdoors.

Meters installed indoors may be applied in:

- Secondary distribution points
- A suitable meter room

- A separate control building that may also contain control, relay, and associated primary service switchgear

Possible outdoor locations include:

- Pole-mounting
- Exterior wall attachment
- Pad mounting

6.5 Meter mounting, control, and associated equipment

Utilities tariffs include rules and standard specifications for meter mounting, control, and associated equipment. Utility meters are commonly installed on the supply side of the main service disconnect in single-occupancy applications. This is referred to as *hot-sequence metering*. Utility metering located on the load side of the service disconnect is referred to as *cold-sequence metering*. In multiple occupant applications, the tenant meter is hot-sequence paired with a tenant main. A main service disconnect is required by the NEC 230.71 when there are more than six tenant mains or other disconnects supplied by the utility lateral. Some local jurisdictions require main service disconnects regardless of whether the number of disconnects in the service equipment is fewer than six. The presence of overcurrent protection associated with a disconnect ahead of the utility meters can have an influence on the type of meter that can be applied in situations where the available short-circuit current is very high, as noted below.

Utility metering may be grouped into the following three categories:

- a) Self-contained metering: Meters are connected directly to the system wiring being metered. The customer is required to furnish and install meter-mounting equipment or a socket and its associated wiring, conduits, devices, fittings, and bonding. This metering is normally used up to a maximum load of 400 A for low-voltage systems. Meter sockets have a maximum short-circuit withstand rating of 30 kA peak per UL 414 [B75]. This withstand is protected and/or limited by the overcurrent device associated with the service disconnect, which may be either a circuit breaker or fuse. In high available short-circuit applications, such as those associated with spot network sources, the overcurrent device selection cannot necessarily depend simply on having a symmetrical rms short-circuit rating that is greater than the available short-circuit current. The selection should also determine that the fault current through the meter is reduced to less than 30 kA peak as a result of a current-limiting effect by the overcurrent device.
- b) Instrument transformer metering: The utility will require the use of instrument transformers between system wiring and meter wiring when the service rating exceeds currents or voltages on the order of 200 A or 480 V. The customer is required to furnish and install the instrument transformer cabinet or mounting assembly, meter box, conduit, fittings, and bonding. The utility furnishes instrument transformers that are installed and the meter-wiring connections made by the utility or the customer, according to utility requirements. Current transformers are usually installed on the line side of the service disconnect and within 10 ft of the associated metering. The saturation characteristic of current transformers will generally limit the peak current seen by the meter socket to less than 30 kA peak.
- c) Special metering: Includes totalized metering, impulse metering, telemetering, reactive component, or power factor metering, etc. For complete requirements in all such cases, the utility should be consulted.

6.6 Metering equipment guidelines and types

Demand metering can be performed by fixed or sliding measurement periods. With fixed period demand, the demand is totalized during fixed periods beginning and ending at fixed times of day. Sliding demand measurements are performed by continuously analyzing the demand and capturing the maximum demand during any demand interval, that is, any 15-min, 30-min, or 60-min interval per schedule. There is no predetermined synchronizing pulse that the demand is measured against since it is a continuous analysis. Electronic meters record all the pertinent information within memory. Some data is displayed, and all data can be retrieved via an optical reading device or telecommunications if the meter is equipped with a modem, see ANSI C12.1 [B2], or sent via the Internet. Guidelines on the metering facilities to be installed are listed in Table 1.

Table 1—Metering guidelines

Service type and voltage	Requirements	
	Self-contained meters	Transformer-rated meters
Single-phase 120/240 V	Four- or five-jaw meter socket	Six-jaw socket
Three-phase 208Y/120 V	Seven-jaw meter socket	13-jaw socket
Three-phase 480Y/277 V	Five- or seven-jaw meter sockets may be used depending upon the three- or four-wire load wiring, respectively.	13-jaw socket
480Y/277 V with line-side loads	May require use of a bottom-connected watt-hour meter and current transformers. Exit lights are an example of load on the line side of the service disconnect. When line side connected loads are present, a caution notice should be provided at the service disconnect to make operating personnel aware of this.	

NOTE 1—Meter-bypass facilities are installed for health care facilities and places where continuity of service is important. Bypass provisions are also sometimes required on commercial occupancies.⁵

NOTE 2—Meter sockets are usually required to be installed on the line side of the customer's disconnect facilities. Also, taps for fire pumps and photovoltaic connections are other common things connected ahead of the main disconnect.

NOTE 3—Meter mountings for bottom-connected, self-contained meters are usually installed on the line side of the customer's disconnect facilities.

NOTE 4—Fifteen-jaw sockets may be acceptable where 13-jaw sockets are required.

The types of meters are (refer to [B21]):

- a) Watt-hour metering: Measures energy consumption only. Quantities on analog meters are indicated on a dial or on a cyclometer register. Digital electronic watt-hour meters may have numeric displays that use either light emitting diodes (LEDs) or liquid crystals (LCDs). Watt-hour meters are available with special features, such as:
 - 1) Differential watt-hour metering: Kilowatt-hours from loads up to a certain value are registered on one dial, and kilowatt hour for loads in excess of the preselected value are registered on another dial or register.

⁵Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.

- 2) Time-of-day, time-of-use watt-hour metering: Consumption for certain periods of time is registered on one dial and other periods on other dials or register.
- b) Demand metering: Kilowatt demands are measured by several types of meters. Indicating demand meters of the mechanical type have a pusher arm that remains at the maximum demand of the period, until reset by the meter reader. Dials or cyclometer registers are accessory devices that accumulate the maximum demands. Electronic meters are also available and becoming more popular as they provide excellent communication capabilities as well as a combination of features at affordable prices. They offer user and especially utilities flexibility for convenient meter read out:
 - 1) Integrating demand meters: Energy consumption for a specific time (usually 15 min, 30 min, or 60 min) is accumulated and shown as a rate of use. A 15-min demand interval means the meter is accumulating kilowatt hours for 15 min and multiplying by the ratio of 60 min to 15 min (by means of gears in mechanical meters) and displaying the result as kW:
 - i) $\frac{60 \text{ min}}{15 \text{ min}} = 4$
 - ii) $4 \times \text{kW in a 15-min interval} = \text{kW integrated demand (15-min basis)}$
 - 2) Cumulative demand meters: The maximum demand reading that is stored in the register is added, after reset, to the prior stored reading total. The demand is obtained by subtracting the prior reading from the present reading and applying the appropriate multiplier.
 - 3) Electronic hybrid demand meters: Electromechanical watt-hour meters equipped with electronic registers to measure and display energy and demand. The electronic register is supplied energy pulses from the meter disk and integrates it with its timing function to obtain the maximum demand.
 - 4) Electronic demand meters: Self-contained electronic meters widely used today to measure energy and demand in an integrated product. These meters can be made more functional to add time of use, profile, or telephone modem capability by adding optional circuit boards or by software keys provided by the supplier.
- c) Kilovolt-ampere demand:
 - 1) Ammeter and nominal voltage: An ammeter calibrated to read kilovolt-ampere for the nominal supply voltage
 - 2) Reactive kilovolt-ampere (kVAR): A kilowatt meter with the voltage element shifted (lagged) 90 electrical degrees can measure the reactive component
 - 3) Reactive kilovolt-ampere hours (kVARh): Average power factor rates-use meters for kilowatt hours and reactive kVAh
- d) Master metering: This is a single-metered electric service to multiple-occupancy premises. Tenant service costs are included in the rent as a flat charge or determined by submeters, depending upon local utility regulations.
- e) Multiple metering: A separate meter is established for each tenant's requirements in a multiple-occupancy building. Each tenant is separately metered and billed by the utility.
- f) Transmission metering: Associated with service connected directly to a utility transmission line system. The customer owns and maintains the high-voltage substation that typically steps the voltage down to a medium-voltage distribution level. Meters are applied via voltage transformers and current transformers to the transmission line side of the step-down transformers. Primary disconnects on the supply side and the load side of the metering transformers may be required by the utility. The secondary conductors of the instrument transformers may be required to terminate to a metering location inside a small building on the perimeter of the substation yard, and arranged to provide free access to utility personnel for reading or servicing the meters, and without the necessity of entering the substation yard itself.

- g) Primary metering: Medium-voltage metering applied on system with nominal voltage ratings greater than 600 V and up to 34.5 kV is primary metering. The service entrance equipment may be supplied from a tap off a utility distribution feeder, or the utility may locate a dedicated substation on property adjacent to the facility. The customer generally owns and maintains service meter-mounting equipment. Metering is generally owned and maintained by the utility.
- h) Secondary metering: Under 600 V, the utility usually owns and maintains service transformers, metering transformers, and meter wiring. Meter-mounting equipment may be owned by the utility, however, often it is associated with the service entrance equipment.
- i) Totalized metering: Coincident demand of multiple services is metered by pulse or integrating demand metering to provide diversified demand registration that is equivalent to that of a single meter. It is usually required by the utility when the service to a single switchboard or panelboard is impractical.
- j) Pulse metering: This is used to determine coincident demand. Meter registration is affected by the use of electric pulses. Each pulse is a function of load and time. Pulses are received from several sources (that is, metering points) and counted by a totalizing meter. The totalizing meter integrates the received pulses over a given period of time (characteristically, the demand interval) to provide a readout of the total demand. Printed tape, magnetic tape, electronic totalizers, and electronic profile recorders utilize pulse metering.
- k) Compensated metering: This is applicable to primary metered service to a single transformer bank. Rather than primary metering, secondary metering together with a transformer loss compensator is calibrated to compensate for the service transformer losses equivalent to that of a primary meter, saving the cost of high-voltage instrument transformers. Electronic meters with internal compensation factors are also in use.
- l) Profile metering: This records the customer's energy demand consumption for specific time elements, (15 min or 30 min) for the entire billing period. These devices are usually read via telecommunications or by electronic reading devices.
- m) Submetering: Additional metering is installed on a building distribution system for the purpose of determining demand or energy consumption, or both, for certain building load subdivisions, and where the same metering is preceded by a master billing meter. When submetering is required for billing tenants of a commercial building, the metering may be at the medium- or low-voltage distribution point when all loads on the feeder are for one customer. When a feeder supplies more than one customer, or when power costs are to be accurately apportioned among various departments, the metering should be installed at each unit substation or low-voltage feed.
- n) Subtractive metering: An application of submetering where readings of submeters are subtracted from associated master meter readings for billing purposes. Subtractive metering permits the determination of the load taken by an unmetered area when the total energy into the applicable system is known and all other services are metered.
- o) Coincident demand [refer to item i)]: For totalized service without coincident demand, the demand is known as *additive*.
- p) Telemetering: Metering pulses are transmitted from one location to another for meter reading at a remote location. It may also be used to totalize two or more distant locations.
- q) Power factor metering: Reactive kilovolt-amperes (kVAR), or kilovolt-amperes and kilowatts are metered to determine the power factor for utility billing purposes. Coincident or cumulative metering is used, depending upon the utility rate schedule.
- r) Multi-function electronic metering: Revenue metering by use of electronic meters is preferred when tariffs contain complex schedules, such as loss compensation, time-of-day, four quadrant metering, and power factor penalties.

6.7 Metering for energy conservation

Check metering (customer-supplied metering in addition to utility revenue metering) is recommended [refer to Chapter 17 of IEEE Std 241 (*IEEE Gray Book*TM) [B26] and IEEE Std 3001.8TM [B48]]. In some states, energy efficiency regulations in the building codes require check metering on services (CEC 400 2012 004-CMF-REV2 [B11]). Check metering may be permanent or portable. For safety reasons, permanent metering is recommended. Where portable metering is to be used, permanently installed front-accessible terminal blocks with removable covers mounted on the switchboard or panelboard are recommended. The removable covers are normally secured with replaceable retaining wires to avoid unauthorized access to the terminal block posts. To connect the meter to the switchboard terminal block, the voltage and current connections from the meter are wired to a plug that connects to the terminal block. Preferred metering is a permanently installed kilowatt-hour-demand meter, with a wired connection to the facility building automation system or power-monitoring system. Examples of check metering are:

- a) Permanently mounted socket-type or switchboard-type kWh-demand meters with display.
- b) Watt-type transducers, with analog output signals (e.g., 4 mA to 20 mA) to the building automation system.
- c) Kilowatt-hour-type transducers, with pulse outputs to the building's automation system.
- d) Portable instrumentation: Current readings are obtained from clamp-on or split-core current transformers. Voltage readings are obtained from voltage transformers or direct reading. Readings saved over a period of time may be uploaded from the meter to a personal computer through a serial connection.
- e) Portable instrumentation plugged into switchboard or switchgear current and voltage test blocks: The current test plugs are connected in series in the current transformers' secondary circuits so that a portable instrument will read the same current as an installed ammeter. The voltage test plugs are connected in shunt to any installed voltage transformer and voltmeter.

6.8 Utility billing

6.8.1 Introduction

Rates include fixed and variable costs. Hence, rate schedules take the form of a block rate, wherein incremental service costs vary as a function of usage. Rates comprise two components: the demand charge and the energy charge. Rates for small customers include only a block meter rate that specifies a certain price per kilowatt hour, which decreases for succeeding blocks.

6.8.2 Hopkinson demand rate

The *Hopkinson demand rate* applies to that method of charge which consists of a demand charge based on demand or connected load plus an energy charge based upon consumption. The demand charge, or the energy charge, or both, may be in block form. A rate in this form is called the *block Hopkinson demand rate*.

6.8.3 Wright demand rate

The *Wright demand rate*, or *hours-use rate*, or *load factor rate*, applies to that method of charge which was the first to recognize load factor conditions. Under this rate, the consumer pays a different charge for each successive block of consumption. The consumer's demand is a factor in the determination of the block size. Effectively, this produces demand and energy charges and thus recognizes the load factor. Variable cost factors that may be added to the rates include purchased fuel differential, real estate tax differential costs, government gross receipts taxes, and other charges.

6.8.4 Rate metering and billing

Examples of utility metering and billing methods are:

- a) Master metering, rent inclusion: Offers a saving to the owner in first cost for metering equipment. Savings in operating costs depend on the type of multiple-occupancy building and applicable utility rates. The owner has to determine tenant electric service costs, usually as a flat sum for purposes of incorporation in the tenant's lease or rental agreements. The flat rate encourages excessive power usage by the tenants.
- b) Multiple metering and billing: Generally requires a higher first cost to the owner for multiple-occupancy buildings over the cost of master metering. The utility collects all tenant electric service costs.
- c) Conjunctional billing: Large commercial or institutional customers that have multiple facilities within a utility franchise area should explore the availability of conjunctional billing. This consists of adding together the readings of two or more individual billing meters for a single billing. Due to the usual practice of decreasing rates for larger demands, conjunctional billing can result in lower billing than individual billing. Conjunctional billing will generally result in a higher bill than a master or totalizing meter reading because the maximum demand readings on the individual meters rarely occur simultaneously, so that the arithmetic sum will be greater than the simultaneous sum, unless a provision is made for coincident demand measurement.
- d) Power factor billing: If the type of load to be installed in the facility will result in poor power factor, e.g., less than 90%, then an evaluation should be made to determine when power factor improvement could be justified to avoid penalties.
- e) Flat billing: Certain applications involve service to the load of a fixed characteristic. For such loads, the supplying utility may offer no-meter or flat-connected service. Billing is based upon time and load characteristics. Examples include outdoor and sign lighting.
- f) Off-peak billing: Reduced billing for energy consumed during off-peak periods, such as water heating and ice making loads. The utility may monitor such off-peak usage through control equipment or special metering. Off-peak billing is also based upon on-peak and time-of-day, or time-of-use, metering for all billing loads.
- g) Standby service billing: Also known as *breakdown* or *auxiliary service*, is applicable to customers whose electric requirements are not supplied entirely by the utility. In such cases, billing demand is determined either as a fixed percentage of the connected load or by meter, whichever is higher. This applies to loads that are electrically connected to an alternate supply source and for which this service is requested.
- h) Backup service billing: This service is provided through more than one utility circuit, solely for a utility customer's convenience. The utility customer customarily pays for the additional circuit and associated supply facilities. Each backup service is separately metered and billed.
- i) Demand billing: This service represents a significant part of electric service billing. The demand meter measures the average rate of use of electric energy over a given period of time, usually 15-min, 30-min, or 60-min intervals. A demand register records the maximum demand since the last reading. The demand register is reset when recorded for billing purposes.
- j) Minimum billing demand: A minimum demand billing consisting of a fixed amount or a fixed percentage of the maximum demand established over a prior billing period may be charged. This applies to customers with high peak demands, resulting in low load factors, such as users of welding or X-ray equipment, customers whose operations are seasonal, customer with frequent starts of large motors with full-voltage starters, or those who have contracted for a given service capacity. Review operation of equipment to avoid such charges.

- k) Load factor billing: The ratio of average kilowatt demand to peak kilowatt demand during a given time period is referred to as the *load factor*. A credit for high load factor usage may be available. An example of such a credit: The utility may provide a reduced rate for the number of kilowatt-hours that are in excess of the maximum (metered) demand multiplied by a given number of hours (after 360 h for a 720-h month or a 50% load factor).
- l) Interruptible or curtailable service: A peak-load shaving technique is interruptible or curtailable service. This rate is available for facilities with defined loads that can be readily switched off. The tariff gives a billing credit for the capability of requesting a demand reduction to a specified contract level during a curtailment period. The monthly credit is determined by applying a demand charge credit to the excess of the maximum measured demand used for billing purposes over the contract demand. Should the customer fail to reduce the measured demand during any curtailment period, at least to the contract demand, severe financial penalties may be incurred. An alternative to switching off loads is to supply the loads from on-site generation.

7. Distribution circuit arrangements

7.1 Introduction

Recognize that the medium-voltage circuits and substations might be owned by the utility, or the customer, depending upon the electric tariffs and local practices. Proper design considerations, including fault protection, safety interlocking, automatic or manual control, personnel training, experience, availability, and capability need to be fully evaluated when developing a safe and reliable system. See IEEE Std 242™ (*IEEE Buff Book*™) [B27] for a discussion of electrical protection. Influencing the system design and circuit arrangement are these characteristics:

- a) Supply available at the facility or building site
- b) Load demand
- c) Required power quality
- d) Facility or building size and configuration
- e) Economics

7.2 Network systems

Electric service is available from secondary-network systems in the downtown areas, usually at a nominal voltage of 208Y/120 V, where a network grid is installed, or at 480Y/277 V where a spot network would be installed. A spot network may be established to serve the entire building, or spot networks may be established, above flood level, at the main service on the ground floor, or on the intermediate electrical equipment floors.

7.3 Small commercial buildings

Service for small commercial buildings is recommended to be at the secondary or utilization voltage. This allows the utility to own, operate, and maintain the transformer station.

7.4 Medium and large commercial buildings

Service for medium and large commercial buildings is also recommended to be at the utilization voltage whenever possible, leaving it to the utility to own, operate, and maintain the medium-voltage distribution.

7.5 Large industrial facilities

Services for large industrial facilities are more typically served by dedicated industrial substations that can be designed, constructed, and owned by the utility, by the industrial plant, or by joint arrangements as determined by the utility operating and rate policies, the plant management's desires, and in some cases, negotiation between representatives of the utility and plant. Likewise, operating and maintenance responsibilities can rest with the utility and/or the industrial plant, depending on ownership. Large services and substation design is covered in Clause 11.

7.6 Medium-voltage distribution

It may be necessary for power to be purchased at the utility medium-voltage distribution level under the following conditions:

- The building facility is too large to be supplied from a single secondary unit substation, or spot network.
- The facility consists of multiple buildings similar to a campus environment where distances cause voltage drop problems at low voltage.

The electric power is then distributed through or around the facility to supply secondary unit substations or spot networks that provide utilization voltage. Only those building facility owners with experienced and qualified staff to operate and maintain medium-voltage equipment should consider the responsibility of installing their own substations and medium-voltage equipment. For this reason, a customer contemplating providing the medium-voltage equipment in return for a rate reduction needs to justify the risk and economics of the installation.

7.7 Multiple services

Utility tariffs and the NEC generally require that there be only one service to a building on low-voltage services. Exceptions may be permitted, particularly when the building load exceeds the available current rating that the utility is willing to supply from a distribution transformer, or when services rated for different voltage levels are required. Refer to 10.2.

7.8 Multiple tenants

If the commercial building has more than one tenant, some utilities will furnish the medium-voltage system and secondary unit substation transformers, or install spot network transformers, in return for the right to meter the tenants directly.

8. Incoming lines and service laterals

8.1 Introduction

Incoming lines and service laterals are an extension of a building's electric distribution system, connecting the facility to the serving utility's service point. The operating voltage, ownership, maintenance, and burden of installation cost for this portion of the electric system will vary from region to region. When planning, it is important to route the incoming circuits to avoid clearance conflicts with existing or future underground or overhead structures. Poles located in areas subject to vehicular traffic may require curbs or barriers for protection. When open-wire lines pass near buildings, adequate clearances should be provided to avoid accidental contact by occupants, maintenance or inspection personnel, and emergency responders. Some considerations for medium-voltage services are different than those for low-voltage services, such as qualifications for operating and maintenance personnel, and utility requirements. In many states, because of the potential hazard of electric conductors to the general public, services are required by law to meet minimum

construction standards. Underground and overhead services are normally built in accordance with local electric utility standards and the requirements of the following list. The utility may assign responsibility for this construction to the commercial customer.

- a) National Electrical Safety Code® (NESC®) (Accredited Standards Committee C2)
- b) National Electrical Code® (NEC®) (NFPA 70)
- c) Or state codes such as these California rules:
 - 1) General Order 52, Rules for Construction and Operation of Power and Communication Lines to Prevent Inductive Interference (GO-52) [B18]
 - 2) General Order 95, Rules for Overhead Electric Line Construction (GO-95) (FEMA [B19])
 - 3) General Order 128, Rules for Construction of Underground Electric Supply and Communication Systems (GO-128) [B20]

8.2 Overhead service

8.2.1 Introduction

For small buildings supplied at utilization voltages, the overhead service lateral is generally terminated at a bracket on the building at sufficient height to provide the required ground clearance given in provisions of the NESC and the NEC. NESC rules apply to utility systems and to commercial systems if it is a *utility interactive system*, defined in the NESC as operating in parallel with the utility and capable of delivering energy to the utility. Larger buildings facilities may be served by open-wire lines terminating at a transformer step-down substation outside the building facility, or at a cable terminal pole where the step-down substation is either pad mounted outside the building facility, or inside the building facility in a transformer vault or electrical room. An alternative method is to use aerial cable (insulated cables, shielded where applicable, supported by a grounded messenger) attached to poles. Open-wire lines may consist of copper, copperweld, aluminum, or aluminum conductor, steel-reinforced (ACSR) conductors attached to insulators, supported on pins mounted on wood or epoxiglass crossarms or on pole brackets attached to wood poles set in the ground. Metal, reinforced concrete, or fiberglass structures are also sometimes used. The conductors may be suspended from crossarms on suspension-type insulators, or clamped to horizontally mounted post-type insulators bolted to poles. The NESC and the NEC spell out all clearances. This construction should meet the applicable voltage and BIL of the service and is subject to acceptance by the serving utility. The design of an open-wire line depends on the factors described below.

8.2.2 Overhead service safety

Safety to the public, providing the necessary clearances from the line to buildings, railroad tracks, driveways, walkways, and other areas.

Safety to personnel who may operate and maintain the line, involving adequate climbing and working space on the pole, spacing between conductors on the crossarm, and interphase spacing between items of equipment on the pole. Spacing requirements should consider the effects of wind-induced galloping of conductors.

Mechanical strength, involving consideration of wind and ice loads, diameter of the pole, the size and strength of wire, etc. Margins of safety for power lines are given in the NESC for construction grades B, C, and N. Grade B is the strongest.

8.2.3 Insulation

8.2.3.1 Protection against lightning surges

This is achieved by shielding the line from direct strokes (refer to IEEE Std 998™) and induced surges through the use of surge arresters, one or more shield wires installed above the power conductors, and by greater insulation. System and pole grounds conduct lightning currents from the line following a lightning stroke. Proper grounding will help minimize lightning damage.

8.2.3.2 Protection against voltage surges caused by power switching

The above-mentioned preventive measures against voltage surges also apply for switching surges. For guidance on overhead line design, refer to the local electric utility company and to the following references:

- a) US. Rural Utilities Service bulletins on distribution design, operation, and maintenance:
 - 1) Rural Substations, Bulletin 65–1 [B61]
 - 2) Mechanical Design Manual for Overhead Distribution Lines, Bulletin 160–2 [B62]
 - 3) Specifications and Drawings for Underground Electric Distribution, Bulletin 1728–803F [B67]
 - 4) Electric System Operation and Maintenance, Bulletin 1730–1 [B68]
- b) US. Department of Defense MIL-STD-3007 [B54]

Flashover characteristics of insulators can be obtained from manufacturers' catalogs. However, this does not necessarily provide the coordination of the insulation level required.

8.2.4 Rights-of-way

Rights-of-way grants may be required from the owner for lines on private property, and permits are required from the responsible governmental authority for lines on public property.

8.2.5 Service lines over and on buildings

Although the NESC and the NEC provide clearance requirements, the installation of open-wire lines over buildings should be avoided because it is poor practice. They interfere with the activities of fire fighters and maintenance or security personnel, and present a safety hazard. Use of fully-insulated cable, with a grounded metallic sheath for medium-voltage cable, is an alternative to open-wire construction over or near buildings. When attached to a building's exterior, the service conductors should be in grounded metallic conduit. If this conduit is mounted on the roof or other flammable building material, the conduit should be encased in 50 mm (2 in) of concrete. If open wire is installed over buildings, minimum clearances for personnel should be maintained over all areas accessible to personnel. Clearances should meet provisions of the NESC and the NEC or rules of the AHJ. Tree coverings applied to bare overhead conductors, for voltages up to and including 15 kV, do not have adequate insulation values to prevent injury from accidental contact. These coverings are used to reduce interruptions caused by momentary tree branch contact with the wire. All conductors operating above 2000 V to ground should be fully insulated and shielded or considered as bare conductors. Bare conductors should be guarded by height or barriers meeting requirements of the NESC or the NEC.

8.2.6 Weather and environmental considerations for overhead services

In designing any outdoor structure, weather forces should be considered. A building is designed to withstand wind on its walls and a snow or water load on its roof. Similarly, an overhead electric line should be designed to withstand a wind load on the poles and conductor, as well as an ice load on the conductor. The severity of the weather factor varies by location throughout the United States, and reference may be made to the General Loading Map in the NESC. In damp, foggy, or polluted atmospheres, contamination of insulator surfaces

becomes a problem, and special insulators having an unusually long leakage distance should be used to prevent leakage currents across the surface of the insulators. Resistance grounded insulators may be used to control the effect of atmospheric contamination on insulator performance.

8.2.7 Information sources for environmental design and security

Consideration should be given to Federal Emergency Management Administration (FEMA) guidance on mitigation techniques for these hazards: dam safety, earthquakes, extreme heat, fires, floods, hazardous materials, hurricanes, landslides, nuclear safety, terrorism, thunderstorms, tornadoes, tsunamis, volcanoes, and winter storms. Refer to the information found in *Natural Hazards Mitigation* [B57], *What Is Mitigation?* [B16], and the following references:

- a) National Institutes for Occupational Safety and Health (NIOSH): Guidance is provided for protection from airborne chemical, biological, and radiological attacks (NIOSH [B56]).
- b) National Climatic Data Center (NCDC): Weather records for all weather stations in the United States. The data are useful for determining the extremes of weather that determine the capability of current carrying conductors exposed to the weather and the ventilation needs of enclosed spaces. Refer to the NCDC website (NCDC [B55]).
- c) US. Geological Survey (USGS): Seismic hazard maps, earthquake hazard maps, and landform hazard maps (USGS [B76]).

8.3 Underground service

Certain conditions may require underground construction. Examples of the conditions include: conflicts with overhead structures that cannot be bypassed with aerial construction, load density, local ordinances, or regulatory requirements governing construction in new residential subdivisions. Aesthetics may also be a factor to consider. An underground system is relatively free from any of the problems associated with an overhead system. However, in case of failure, the repair time and expense of an underground system is considerably greater. Underground systems usually cost substantially more than equivalent overhead systems. This is especially true of conduits and manhole underground systems. The use of direct-burial-type underground systems, such as underground residential distribution (URD) and commercial and industrial park underground distribution (CIPUD) yields a considerable cost saving for new developments over the cost of an equivalent conduit-and-manhole system.

URD is a direct burial, single-phase distribution system used by utilities for new residential developments. Organic insulated and jacketed cables are used together with premolded or encapsulated splices and termination devices. Pad-mounted transformers may be utilized, or transformers and switching devices may be installed in prefabricated fiberglass or epoxy resin “box pads” or in cast manholes.

CIPUD is a direct burial, three-phase system used by utilities for commercial/industrial park distribution. The cable system is looped through pad-mounted transformers or switchgear installed above ground, or installed in suitable below-grade boxes or vaults. CIPUD and URD cable systems are generally run behind curbing in grassy areas to minimize paving costs as well as to provide accessibility. Conduit or duct sleeves are generally installed under paved crossings to eliminate the need for breaking and restoring paving when installing or removing cable or making repairs.

Fault indicators assist in enabling rapid determination and repair of faults on CIPUD and URD cable systems. Installed at cable termination locations, the fault indicator displays a signal whenever fault current has passed through its sensor. The device either resets automatically after the system is re-energized or is reset manually.

Maintenance and operation of CIPUD and URD systems should be entrusted to the utility or to specially trained contractors or facility personnel for both safety and operational reasons. These systems are not suitable

for the high-density loads of urban centers because of the direct burial aspect and the limited load and fault-handling capability of the equipment.

8.4 Service entrance conductors within a building

If service conductors (defined in the NEC as the conductors from the point of connection with the facilities of the serving utility to the service disconnecting means of the premises wiring) have to pass through the building to the service equipment, a safety hazard presents itself because that part of the circuit in the building is not generally protected against short circuits, overloads, or arcing faults. However, when the distance is as short as possible, the hazard is considered to be minimal. Consult the AHJ and the serving utility if the intention is to install the service conductors beyond the point immediately adjacent to the building wall. If the AHJ and the serving utility agree, then permission may be granted to extend the conductors inside the building beyond a location immediately adjacent the building wall, provided it is a metallic raceway system installed within 50 mm (2 in) of concrete, and other measures may be required. The greater additional protection is provided by the use of metallic conduit suitably encased in concrete, which is considered by the NEC as “outside the building.” This protects the building by confining any possible fire or arcing (because of a short circuit) within the concrete envelope. The safety of property and life is always enhanced by encasing the service entrance conductors in concrete inside the building. Concrete-encased raceway may be installed along ceilings, under the basement floor, or on the roof. Although busway is sometimes used for service entrance conductors, it is very difficult to provide protection for arcing faults. Bonding of the neutral to ground, normally employed at both the main switchboard and the service transformer(s), makes fault detection complicated. From services fed by spot networks, primary sensing is generally ineffective. Overtemperature detectors that are located frequently over the busway have proven valuable; but cooperation from the serving utility to interrupt the utility protection devices at their equipment is necessary.

The City of New York recognizes the use of a service entrance cabling system [B12] consisting of: UL 2-h fire-resistive mineral insulated cables, designated service entrance cable termination kits, and NEMA Class 12B galvanized steel ventilated cable tray with louvered covers. When installed in accordance with the manufacturer’s specification and subjected to special inspection after installation by the manufacturer’s technician, the system is allowed to be used to route service entrance conductors inside the building. This application is useful for renovation of older buildings.

Cable limiters (cable protectors) are often installed on large commercial building services at both ends of all phase cables whenever three or more cables per phase are utilized. These limiters isolate faulted cables, allowing for a maximum continuity of service until they can be replaced.

Service entrance conductors within buildings should be installed to meet or exceed the minimum requirements of the NEC as modified by the AHJ. Consult with the AHJ regarding any questions concerning the application of these rules. It should be recognized that most of these codes cover minimum requirements and are not intended to be recommended design criteria.

Cable systems should be routed to avoid high ambient temperature that is caused by steam lines, boiler rooms, or over the roof where conductors are subject to direct sunlight, or re-radiated or convective heat. Precaution should be taken with polyethylene, cross-linked polyethylene, and other organic jacketed cables to prevent chemical degradation of the jacketing when hydrocarbons may be present, such as in fueling areas, marshland, landfill areas, and similar locations. Cable systems should be protected from oils and chemicals that are used as preservatives in wood poles by suitable barriers on the riser pole, and enclosed in a raceway at a suitable distance from the pole. Manholes and pull boxes are recommended in long duct runs to facilitate pulling and splicing the cables, and where more than 360° bends occur. Spare ducts should be considered to provide for the contingency in which a faulted cable becomes frozen in a duct and cannot be removed for replacement. This also simplifies installation of future cables that may be required for load growth. A duct system should not be laid in the same trench with gas or sewer service. When installing an underground duct line for medium-voltage conductors, it is recommended that metric designator size 103 be used as a minimum and metric designator size 129 is preferred. At least two spare conduits should be installed. The duct bank should have a

minimum slope of 75 mm per 30 m (3 in per 100 ft) away from buildings and toward manholes. The conduit should be run in straight lines except where a change in direction is necessary. Except at conduit risers, accomplish changes in direction exceeding a total of 0.175 rad (10°), horizontal or vertical, by long sweep bends having a minimum radius of curvature of 7.62 m (25 ft). Manufactured bends should be of the large radius type. Conduits should be rated for the temperature of the enclosed conductors, such as 90 °C for Type MV-90, or 105 °C for Type MV-105 conductors, as may be selected for the project. Further information on underground facilities is available in MIL-STD-3007 [B54]. Further information on cable systems is available in IEEE Std 3001.5™ [B47].

9. Service entrance installations

9.1 Introduction

Service entrance conductors comprise that portion of the system between the client-owned service equipment and the utility's service drop or lateral, sometimes referred to as the *service point*. Service equipment includes the main service control or disconnect for the electric supply, and consists of one or more circuit breakers, or fusible switches, and accessories as well as the metering equipment. Service entrance conductors and service equipment are generally paid for and owned by the customer. Design features are frequently influenced or controlled by the utility. Billing metering instruments are nearly always owned and maintained by the utility. Current and voltage transformers used exclusively for billing metering purposes may be furnished by the utility at either the customer's or the utility's expense. Refer to 5.6 for details on utility metering. The relationship of service entrance equipment design and characteristics to the incoming lines or feeders, and to the distribution switchgear or switchboard are of vital importance to the customer and to the utility. Therefore, it is important that the engineer serve both the client and the utility by developing a design that satisfies client requirements without interfering with the quality of the electric service to the utility's other customers.

9.2 Number of services

The number of services supplied to a building or a group of buildings will depend upon several factors:

- a) *The degree of reliability required for the installation as related to the reliability of the power source:* When service reliability is important, multiple services or standby service, with load transfer arrangements between various parts of the building distribution system, may be indicated. In some cases, economic considerations may indicate acceptance of reduced service availability and the interruption of nonessential loads during an emergency. If more than one service is required by a client, an additional charge may be assessed by the utility.
- b) *The magnitude of the total load:* Since the capacity of an individual service is limited by the utility to a maximum current value, additional services may be provided, as required, to meet building demands.
- c) *The availability of more than one system voltage from the utility:* If more than one voltage is available, the utility may, for example, supply 208Y/120 V for lighting and receptacles at one or more service entrance points, and 480Y/277 V for power.
- d) *The physical size of the building or the distances separating buildings comprising a single facility:* Tall buildings, occupying a large ground area, and widely separated smaller buildings will often be supplied from multiple services.
- e) *The NEC and local code requirements,* including items such as fire walls.
- f) *Additional capacity to serve future loads:* The initial design should consider requirements for future services and feeders. If service capacity is determined by the NEC (partially illustrated in Chapter 2 of IEEE Std 241™ (*IEEE Gray Book*™) [B26]), service capacity will generally be more than adequate to serve major load additions. Service equipment design, however, should be such that additional feeder protective devices may be added.

In all instances the AHJ should be appraised in the event governmental permission is necessary. NEC Section 230.2 should be consulted as to when the AHJ needs to be involved.

9.3 Physical arrangement

The physical arrangement of the service entrance will vary considerably, depending upon the type of distribution system employed by the utility and the type of building facility being served. In some cases, the utility will supply service from one or more transformer vaults located directly outside the building with bus stubs through the basement wall. This is the usual arrangement for buildings of moderate height in heavily loaded areas of many large cities. Transformer vaults are sometimes located within the building itself in the basement and on the upper floors of tall buildings. Underground service, by means of cable from a manhole or a pole in the street, is sometimes provided. In other cases, overhead services may be available. In all cases, service entrance equipment rooms should be easily accessible to qualified persons, be dry, well lighted, and should comply in all respects with the requirements of the electric utility and local code authorities that have jurisdiction. Plans should be made for possible future replacement of equipment. Provision for smoke exhaust should be considered in the event of an electrical fire.

9.4 Service design considerations

9.4.1 Introduction

Service entrance equipment is one of the most important parts of the electric supply system for buildings because it is through this equipment that the entire load of the building is served. The service entrance equipment that is installed initially should either be adequate for all future loads, or be designed such that it can be supplemented or replaced without interfering with the normal operation of the building that it serves. Because the service entrance is part of the building and involves equipment that is important to the utility company, the choice of service equipment and service voltage should be a cooperative decision between the building's electrical design engineer and the local electric utility. This should be accomplished early in the design phase in order to allow the building designer to adapt the design to the present and future supply plans of the utility, and to enable the utility to supply power to the building in a manner that considers both present and future requirements. The electrical design engineer should furnish load and other data to the electric utility company to assist it in determining the effect of the building load on its system and, where necessary, plan for the expansion of its facilities. The utility will, at this time, inform the design engineer as to the type of services available, their voltages, and the options of overhead or underground electric service. The building engineer should assist the electrical designer in determining, with the help of the utility, the service point and its termination. Other data pertinent to the system design, such as short-circuit current or the kilovolt-ampere available at the service entrance; service reliability; costs; space requirements for poles, substations, transformer vaults, metering equipment, inrush current limitations, and design standards; and similar information should be obtained from the utility. The following is a checklist of items to be considered in connection with the design of an electric service:

- a) Service entrance details: Physical and mechanical requirements of the service entrance include:
 - 1) Number of locations at which service may be supplied.
 - 2) Type of service: overhead or underground cable, or bus.
 - 3) Points of service termination, including information as to which parts of the service installation will be owned, installed, and maintained by the utility.
 - 4) Location and type of metering equipment, including provisions for totalizing demand and for submetering, where permitted, and provisions for mounting and wiring the electric utility's meters and metering transformers. Access to the meter by utility personnel for purposes of meter reading. The utility may have requirements for remote metering/monitoring.

- 5) Space and other requirements for utility vaults, poles, and similar equipment, and access provisions for its installation, maintenance, testing, and meter reading.
 - 6) Avoidance of structural interferences (particularly critical when using busway).
 - 7) Equipment: Construction may have to meet special requirements of the utility for the isolation of and blocking for utility system maintenance.
 - 8) Service cable should meet the utility's specification for the ability to handle return ground-fault currents. Sizing conductors to match the utility's standard sizes may prove beneficial in facilitating emergency replacement of the cables or terminations.
 - 9) Consideration for fire pump motor connections, where required (refer to 10.4.2).
- b) Service equipment requirements: Electrical requirements for service entrance include:
- 1) Equipment voltage level, BIL, and coordination of surge protection.
 - 2) System capacity and fault capability, both present and future (future may be defined as "foreseeable").
 - 3) Requirements for the coordination of overcurrent protective devices: Types, sizes, and settings should be acceptable to the serving utility.
 - 4) Utility-approved types of service and metering equipment, utility isolation and/or grounding methods, and requirements for the coordination of ground-fault protection for grounded service systems.
 - 5) Requirements for owner instrumentation: Check metering is used regularly in facilities to identify and account for cost of energy. Power metering is installed on the service main to provide immediate access to power and energy data of the entire facility. Additional metering elsewhere in the facility may be used to monitor, control, and trend the cost of production and other activities.
 - 6) Determine arc flash boundaries and post warnings at all locations where extra precautions are to be taken. Follow NFPA 70E, NFPA 70, and prevention-through-design principles. Determine arc flash boundaries (IEEE Std 1584 and NFPA 70E Art. 130.4) and post warning labels according to ANSI Z535.5 and NFPA 70E Art 130.5(D) at all locations where precautions are to be taken.

9.4.2 Fire pump motors connected to services

When present, the fire pump may be connected using one of three methods below. The utility should be consulted to confirm that a particular method is allowed.

- a) A tap-off is made for the fire pump motor between the utility meter and the main disconnect. The fire pump motor is metered along with the other loads connected to the service.
- b) A tap-off is made for the fire pump motor within the utility pull section of the service entrance equipment and cables are routed to a service switchboard that is dedicated to the fire pump load. These cables may be supplied and maintained by the utility.
- c) The fire pump cables are supplied from a dedicated utility meter located on the service entrance equipment. Note that the fire pump disconnect is not permitted by NEC 697.4.(B)(3) to be located at the meter when other service disconnects are in the same equipment.

The fire pump may need to be individually metered for utility billing purposes in multiple-tenant occupancies. Note that only the fire pump disconnect must be rated for the fire pump motor locked-rotor current and the utility meter need only be rated for the fire pump motor full-load current. The fire pump disconnect location must comply with NEC 697.4.(B)(3). That is, it cannot be located in the same switchboard as the disconnects that supply other loads, and it must be located "sufficiently remote" from other disconnects to avoid inadvertent

operation. Confirm that the disconnect type being used can be locked in the closed position. Circuit breakers that utilize spring-charged closing mechanisms with pushbutton mechanical actuators for closing and opening (commonly applied for current ratings greater than 1200 A) can present challenges in complying with this requirement. Some form of padlockable cover-limiting access to the trip pushbutton should satisfy this requirement.

9.5 Medium-voltage services

9.5.1 Introduction

Many utilities are offering medium-voltage services to moderate and large commercial and industrial facilities. Although the higher voltages pose unfamiliar problems to the commercial facility's electric distribution system, there are many benefits to both the facility and the serving utility. Planning a medium-voltage distribution system within a building requires more time and effort, but affords the design engineer a greater degree of flexibility in selecting equipment and designing electrical facilities within the building. The utility saves considerable capital investment in switching and transformation equipment, which should be reflected in a lower electric rate structure for services at these voltages. Most utilities that provide medium-voltage services will only require the service equipment to meet their requirements for interconnection. This allows the design engineer to have complete control over the design of medium- and low-voltage distribution systems throughout the building. Local codes, the NEC, and, in some cases, the NESC will govern the design of the medium-voltage installation.

9.5.2 Medium-voltage system design flexibility

The advantages of this design flexibility include the following:

- Medium-voltage risers can be designed as feeders. Fully protected at the service equipment, concrete encasement is no longer required. Standard wiring practices can be used. All medium-voltage conductors and raceways should be adequately marked to indicate their operating voltage.
- Unit substations can be installed in electrical rooms rather than utility vaults. The design of the rooms can be more flexible with the selection of proper equipment. Transformer insulation types can be specified to suit the design of the electrical rooms, reducing fire-resistance construction features.
- Transformers can be selected and located to optimize kilovolt-ampere size and floor space, which is valuable to the facility's owner. The designer has complete control of the transformer specifications to control voltage, connection configuration, and impedance to optimize voltage drop and the short-circuit contribution to the low-voltage overcurrent devices. The design engineer should, however, review transformer primary-voltage ratings, voltage taps, and transformer connections with the utility company for compatibility with the utility's system voltage and variations. The configuration of the transformers can also be controlled to allow for redundancy in the system with primary and/or secondary transfer between multiple medium-voltage supplies.
- Medium-voltage distribution may provide a solution to voltage drop problems associated with low-voltage distribution systems that must span long distances. Such situations may occur in high-rise building designs that serve high-density loads and the utility service point is limited to the ground floor or basement.

9.5.3 Medium-voltage service costs

Although medium-voltage services provide benefits to both the utility and the facility, the facility should bear the cost of installation, operation, and maintenance of the medium-voltage service equipment, which usually includes the cost of transformer losses. These additional costs should be offset by the rates offered by the serving utility. An economic analysis should be performed to substantiate the initial investment as well as expected long-term costs to determine whether the expected initial savings are consumed by normal operating

conditions over a reasonable time period. In some cases, the electrical requirements of the facility may not meet the low-voltage service characteristics of the serving utility, forcing the facility to a medium-voltage service to take advantage of the flexibility that it affords. Maintenance and operation of the system will require special training of the facility's maintenance personnel, or engaging a qualified maintenance contractor to operate and maintain the medium-voltage installations. A contractor experienced with medium-voltage systems should be identified in the event of equipment malfunction, replacement, or system expansion.

9.6 Vaults and pads for service equipment

9.6.1 Indoor vaults

Service transformers and associated switching and protective equipment are often located in vaults. When providing a vault for utility-owned equipment, consult with the utility on their requirements. These requirements may include such items as minimum access dimensions, minimum vault dimensions, oil containment (if applicable), lighting, and ventilation.

Special precautions should be taken to remove the heat given off by the transformers. Equipment vaults should be located so that they can be ventilated to the outside atmosphere without the use of flues and ducts, where practical. Natural ventilation is considered to be the most reliable means of ventilation. The total net area of the ventilator should not be less than $1936 \text{ mm}^2/\text{kVA}$ ($3 \text{ in}^2/\text{kVA}$) of installed transformer capacity. Additional ventilation may be required by local codes or electric utilities. Where the load peaks in the summer and where the average outdoor temperature during 24 h periods in the summer exceed 30°C , the ventilator area should be increased, or an auxiliary means of removing the heat from the vaults, such as fans, should be used. If long vertical ventilating shafts from the vault to the top of the building should be used, it is necessary to have a larger vent area to compensate for the added resistance to the flow of air. The long vertical shaft should also have a divider (air-in/air-out) with the air-in portion carried down to just above the floor in the vault to better promote circulation. For such shafts to overcome air friction, a fan should be installed with its discharge directed toward the shaft air-out opening to increase the velocity of the air through the ventilation shaft. The fan should have a cord and plug to facilitate its replacement, and it may be single-phase or three-phase. A signal light at the entrance door should indicate fan failure. Controls for the fan should not be permitted in the vault and should be accessible only to authorized personnel. Suitable screening should be used to prevent birds, insects, vermin, or rodents from entering the shaft.

The ceiling, walls, and floor should be of fire-resistant construction. NEC Article 450.42 requires a minimum fire resistance of 3 h for the walls and roof, as well as floors that do not have contact with the earth. Floors that have contact with earth are required to be concrete with a minimum thickness of 100 mm (4 in). In all cases, the floor must have sufficient structural strength to support the equipment load that will be contained inside. Local authorities should be consulted on this as local codes can vary on these requirements. Reinforced concrete is preferred. When oil-insulated transformers are used and persons occupy the area adjacent to the vault wall, or when an explosion may otherwise damage a building wall, the vault walls should be sufficiently strong to withstand an explosion. The hazard may also be reduced by limiting the ratio of vault volume to net ventilated area. Any opening from a vault into a building should be provided with a tight fitting 3 h fire door that is listed by a Nationally Recognized Testing Laboratory (NRTL).

The vault should be free of all foreign pipes or duct systems. A sump, with protective cover or grate, should be provided in the vault floor, to catch and hold any oil or liquid spillage. The floor should be pitched to the sump. The floor should be sealed with an adequate coating before installing equipment. Doorsills should be of sufficient height to retain all of the oil from the largest transformer. Fire dampers may be required at air duct openings.

Grade-level gratings are suitable for underground vaults and will also suffice for a combination access hatchway and ventilation well when the vault is in the basement of a building and adjacent to an outside wall. Gratings for sidewalk service vaults should be made strong enough to support the wheels of trucks and should satisfy local code requirements. Gratings of net free-air area equal to 63% to 70% of gross grate area

are available commercially to meet various loading requirements. Grating for roadway service should comply with AASHTO Class H20 highway loadings [B1].

If multiple banks of transformers supplied from different sources are used, they should be installed in separate compartments to prevent fire in one compartment from affecting adjacent transformers. Switchgear associated with the transformers should also be separately enclosed so that a failing transformer can be isolated without entering the transformer compartment and to prevent transformer trouble from involving the switchgear. Consult local codes; Part III, Transformer Vaults, of NEC Article 450; CEC section 26; insurance underwriters; and the local utility for specific vault construction requirements.

9.6.2 Outdoor pads

Pad-mounted, three-phase transformers and switching equipment are installed in many applications. Designed for installation on surface pads, pad-mounted components are an economical and safe means for providing service. Cables enter and leave via the bottom of the component, hence presenting no energized parts to create a hazard.

Care should be taken to ensure that there is sufficient vertical clearance from the pad to the terminals to permit training and termination of the cables. Spacers can be specified with the transformer or switchgear to provide adequate working space. Vaulted pad installations are also common. This system comprises a precast vault with a lid. The vault is buried in the earth with the lid serving as the equipment pad, at grade. Cables and or conduits enter the vault area. Cables are free to enter the bottom of the equipment through cutout sections in the lid, reducing the congestion of conduits penetrating the lid in the equipment connection compartments. This system provides excess cable slack for phasing corrections and is especially convenient for large services where four or more conductors per phase are to be terminated on pad-mounted transformer secondary terminals. The vault is also required for medium-voltage low-profile switching equipment that incorporates elbow connectors. The vault area provides sufficient slack cable to permit the medium-voltage elbow connectors to be disconnected and moved to parking stations within the equipment enclosures.

Pad-mounted equipment is usually designed as complying with ANSI construction standards for tamper resistant enclosures (ANSI C57.12.28 [B3]) and can be located in areas accessible to the general public. An enclosure may be provided for unusual or aesthetic purposes.

Traffic protection posts should be provided in areas that are accessible to vehicles. If placed in a vault, provision for the insertion and withdrawal of the pad-mounted unit by crane should be allowed. Landscaping or architectural fencing may be used for concealment.

Operation of pad-mounted medium-voltage equipment requires special grounding and working space considerations. Recommendations for grounding of outdoor substation equipment, including the pad mounted equipment, are contained in the IEEE Std 142™ (*IEEE Green Book*™) [B25], IEEE Std 80™, and IEC 61936-1-Ed.1.0. Testing and operating the equipment requires the use of insulated sticks, some as long as 2.5 m (8 ft). Enclosures, shrubs, or other architectural treatments must be at least 3 m (10 ft) from the front of the operating side of this equipment. In addition, the counter-poise ground ring must extend around the equipment to encircle the operator's feet. Utility working space requirements for such installations should be consulted when designing the arrangement of such equipment.

9.6.3 Safety, security, and environment

Except for outdoor, pad-mounted equipment, which meets the requirements of the NESC, Article 380, and CEC section 26, outdoor substations should be enclosed by walls or fences. Adequate aisles should be provided for safe operation and maintenance. Proper clearances, both vertically and horizontally, should be maintained. Fence safety clearances should be maintained. All equipment, operating handles, fences, etc., should be adequately grounded. See IEEE Std 142 (*IEEE Green Book*™) [B25], for a complete discussion of grounding requirements and methods. High-voltage warning signs should be prominently displayed.

Enclosures, equipment, operating handles, etc. should be locked. Substations should not be located near windows or roofs where live parts may be reached, or where a fire in the substation could be transmitted to the building (refer to IEEE Std 979™). Local utilities, authorities, and insurance underwriters may require liquid-filled transformers to be located not less than certain minimum distances from building openings unless suitably baffled (refer to IEEE Std 980™). AHJs may also refer to other NFPA Standards. Indoor substations should have the same general safety considerations as an outdoor substation, even though they are usually metal clad or enclosed. They should have a separate enclosure or should be placed in separate locked rooms, and should be accessible to authorized personnel only. Multiple-escape means to the outdoors or to other parts of the building should be provided from vaults, and located in front of, and to the rear of, switchgear and the rows of transformers. These emergency escape means should be hinged doors with panic bars on the inside of the doors for quick direct escape in the event of trouble with clear identification by signs and/or painted escape routes which are visible in low-light conditions. Security of the facilities needs to take into account the recommendations in IEEE Std 1402™. Capability to continue in-service following an earthquake or seismic event can be designed into the facilities by adherence to the recommendations in IEEE Std 693™.

9.7 Network vaults for high-rise buildings

9.7.1 Introduction

The electric demands generated by large offices or commercial high-rise buildings almost invariably require the installation of a multiple number of transformers in close proximity to the structure or within the structure. Each transformer is connected to a common low-voltage bus through a network protector. Many new buildings have power supplied at two or more locations, one beneath the sidewalk and others in the building, or perhaps on the roof. Typically, these installations could provide up to 6 MVA at 208 V, or up to 15 MVA at 480 V at one point of service. The design of major network installations divides naturally into two parts. First, it is necessary to establish a utilization voltage, the number of transformers, and the number of service points. It is then necessary to match utility standards with clients' building designs. The design should satisfy client and utility requirements and also meet municipal regulations, all within a framework of economics. The ability to install, maintain, or replace a component of the supply system without interruption of service is the backbone of network design.

9.7.2 Network principles

To more fully appreciate the subject of specifying and designing network installations, it is first necessary to understand the principles of a network system. The network is designed to meet power demands on a contingency basis, which is to say that, with a predetermined number of components (for example, transformers) out of service, full-load capability is maintained. This is accomplished by operating the remaining equipment above its nameplate rating and allowing slightly reduced service voltage levels. Networks are generally designed as first or second contingency systems. *First contingency networks* generally utilize two or three primary feeders. *Second contingency networks* may utilize three, four, six, or more primary feeders. If full-load capability can be maintained with two sets of components (that is, primary feeders) out of service, the system is defined as a *second contingency network*. If full-load capability can be maintained with only one set of components out of service, the system is defined as a *first contingency network*. True contingency design also requires that the primary feeder supply system, as well as the substations and switching stations ahead of them, be built and operated with the distribution system in mind. The last implication in contingency design is that all network equipment, including the associated high- or low-voltage cable ties, is sufficiently isolated. As a result of this, the failure or destruction of a single component in the system will cause only first contingency operation until repairs or replacements can be effected.

9.7.3 Preliminary network vault design

The initial step is to prepare a simple sketch of the proposed installation by means of a standard vault equipment arrangement showing any adaptations required in the building structure or any interference with

existing obstructions located beneath the sidewalk. The standard designs are similar for subsidewalk or in-building locations. Designs should include the following considerations:

- a) Sufficient space should be available with reasonable proximity to customer load centers.
- b) Subsurface conditions should be favorable. It is desirable to avoid the added expense of pilings or footings.
- c) Installations should be designed so that environmental factors (for example, water) present no serious problems. As an example, underground transformers may be cooled by natural convection with an all-welded construction and corrosion-resistant finish. Interior transformers may be of the ventilated-dry-type with natural and forced air-cooled ratings, providing for the safety of non-explosive, nonflammable equipment.
- d) Conformance to municipal regulations should include:
 - 1) General structural design with sidewalk loads that may have requirements equivalent to that of highway loads.
 - 2) Location and size of ventilation and access panels: These factors provide only for the basic adequacy of an installation at a particular location.

9.7.4 Detailed network vault design

Many other specific considerations are involved in the safe and reliable design of network installations. Major considerations for properly designed vaults follow:

- a) *Ventilation*: Ventilation should be directed to the atmosphere and sized at not less than 1936 square mm (3 square in) of net open area per 1 kVA of transformer capacity. The electric utility and local codes should be consulted for more stringent requirements. Forced ventilation, if required, should be a minimum of 1.4 L/sec per 1 kVA of transformer capacity, unless a higher rating is required by local codes or the utility.
- b) *Ventilation ratio*: The ventilation ratio relates to the construction and ventilation discussion above. To avoid excessive pressure in the event of a secondary explosion in a vault containing oil-filled equipment, the ratio of vault volume to net ventilation area should be as small as practical. Such a ratio should be less than 15.2 m³/m² of open ventilation area, typically 9.13 m³/m².
- c) *Construction*: Below grade, vaults shall be reinforced concrete for strength and explosion confinement. Vaults are constructed to be as watertight as possible; but drainage (when permitted and practical) is also provided to eliminate stagnant or casual water accumulation. Concrete floors should be coated with a suitable sealant to prevent concrete dust from being convected into the core and coils of dry-type transformers and onto circuit breaker parts.
- d) *Access*: Direct, rapid access is required at any time for maintenance or emergency operating personnel. An acceptable access route should be included for replacing transformers. Removable slabs or walls are sometimes considered acceptable.
- e) *Isolation and protection*: The effects of equipment failure can be reduced by either isolation or protective relaying, or both. In the extreme, the following effects may result from such failure:
 - 1) *Oil-filled equipment*: Explosion, tank rupture, fire, smoke, danger of secondary explosion (re-explosion of volatile vapors generated by destruction of Class A and B materials)
 - 2) *High-flame point liquid (when permitted by applicable codes)*: Violent tank rupture, a form of explosion
 - 3) *Ventilated dry type (open)*: Smoke with very limited fire possibilities; very limited possibility of secondary explosion

4) *Sealed dry type*: Normally not considered hazardous

While such failures are rare, the possibilities cannot be neglected. Of course, the location of the equipment in relation to people will determine the overall degree of hazard. For example, a transformer failing in a sidewalk vault may be relatively innocuous compared to a similar failure in an electrical room adjacent to a public area. Some utilities depend almost entirely upon isolation for safety. At the higher voltages, utility practice may preclude the use of protective relaying, which would detect low-level faults. In these instances, strong masonry vaults that are vented to the outside are depended upon to contain the effects of a fault. In larger installations, transformers are placed in individual vaults, and the network protectors and collector buses may be similarly isolated. Any ducting may negate the venting provided. If the vaults or network area are part of the building distribution system rather than utility owned, protective relaying that will cover all zones is required. Such protection will include, as a minimum, overcurrent and ground-fault protection. It may, in addition, include differential protection, transformer liquid level, liquid temperature, winding hottest-spot temperature, pressure/vacuum and sudden pressure trip, or alarm. Heat- or arc-sensing, or smoke-detection devices in the room or vault, or even inside larger pieces of equipment, may be provided. None of these, however, can relieve the need for physical isolation, which may be required to protect the building's occupants and the public from the effects of failure. The use of machine room floors or other heavy equipment areas for the location of the electrical rooms or vaults further enhances the afforded protection. Great care should be exercised that no smoke or fumes could, under any foreseeable condition, enter the normal building ventilation system.

9.7.5 Apparatus arrangement

It is important to provide adequate working space around electrical equipment for the operation and maintenance of the following:

- a) Drawout of circuit breakers and rollout trays switchgear
- b) Replacement of fuses, cable limiters, or cables
- c) Access to equipment accessories
- d) Cleaning
- e) Air circulation
- f) Access to equipment for replacement purposes without disturbing other equipment
- g) Cable pulling and installation

9.7.6 Miscellaneous

The following are further considerations regarding the design and location of vaults:

- a) Heavy-duty roof structures for vehicular traffic (AASHTO Class H20) loading.
- b) Interference by curb cuts or driveways.
- c) Future street widening or grade changes.
- d) Improved drainage.
- e) Spare conduits within buildings.
- f) Duct arrangement for separation of primary and secondary feeders.
- g) Effects of unnecessarily long cable ties on voltage regulation.
- h) Balanced equipment loading.
- i) Access for heavy test sets to the vault switchgear.

9.8.4 Ventilation

Ventilation should be provided to limit the ambient temperature of the room to maintain operating temperatures within ratings and to minimize the accumulation of dust and airborne contaminants. When a transformer other than a signal-type transformer is installed in an electrical closet or room, some local codes require that a system of mechanical ventilation be provided. Refer to [10.6.1](#) and [10.7.4](#) for mechanical ventilation requirements.

9.8.5 Foreign facilities

Electrical rooms and closets should only contain the facilities necessary for the electrical installation's operation and maintenance. NESC Rule 110.B.1. prohibits rooms or spaces containing electrical equipment to be used for storage or other purposes, whereas working space required by NEC 110.26(B), which is generally in front of equipment or anywhere there are access covers, must not be used for storage. Verify if local codes prohibit a raceway, wiring panel, or device of a telephone system from being installed in this area. The same codes would even be more stringent on the running of water, gas, or other nonelectrical pipes or ventilating ducts through electrical rooms or closets. If local codes are not specific about this, the dictates of good judgment or practice should apply. NEC 110.26(F)(1)(b) requires protection of the dedicated electrical equipment space from foreign facilities. Condensation can drip from cold water pipes and ventilating ducts. Sleeves and slots or other openings should be provided for cable and busway entrances. Those that are not in use should be sealed with pipe caps, plugs, or barriers. All openings with cables should be sealed with approved duct sealer or other materials. Fire stops should be provided in accordance with code requirements where busways or wiring troughs pass between floors or fire-rated walls. Sills or elevated sleeve openings may be used to prevent seepage of liquids around cables or busways. When facilities are used for other purposes, unqualified personnel who enter become exposed to an unfamiliar environment. This could result in an electrical injury or in accidental or malicious tampering with the electrical equipment. Some jurisdictions require sprinklers to be located in electrical rooms. In such cases, the electrical equipment should be specified as NEMA 2 (driptight) or NEMA 4 (intended to protect from splashing water, seepage of water, falling or hose-directed water, but not intended for submersible applications).

10. Large services

10.1 Introduction

This clause provides an outline of the interface considerations for the planning, design, construction, and operation of substations that typically supply either large industrial plants or campus-style facilities such as hospitals, universities, and military sites. These substations commonly are supplied from utility systems with voltages operating between 69 kV and 230 kV.

10.2 Purpose

A substation is typically used to transform a higher utility transmission system voltage to a plant's lower distribution or utilization voltage level. [Figure 1](#) provides an illustration of an industrial substation. Such substations are normally dedicated to serve a single facility with loads greater than 5 MVA and commonly include one or more transformers. Industrial-type substations may also be used to interconnect a utility with an independent power producer. The interconnection requirements of such facilities could add a significant degree of complexity to the interface considerations and are beyond the scope of this chapter. The planning, design, and construction of a substation often take about two years. An approximate overall schedule of the activities involved is discussed in more detail in [11.6.10](#) and throughout this clause. This clause assumes that the utility has the design, construction, and ownership responsibility. Even if this is the case, plant personnel should still monitor all aspects to confirm that plant requirements are met. If the plant has any of the design, construction, or ownership responsibilities, then the activities outlined here must be assumed by the plant personnel or other designated parties.

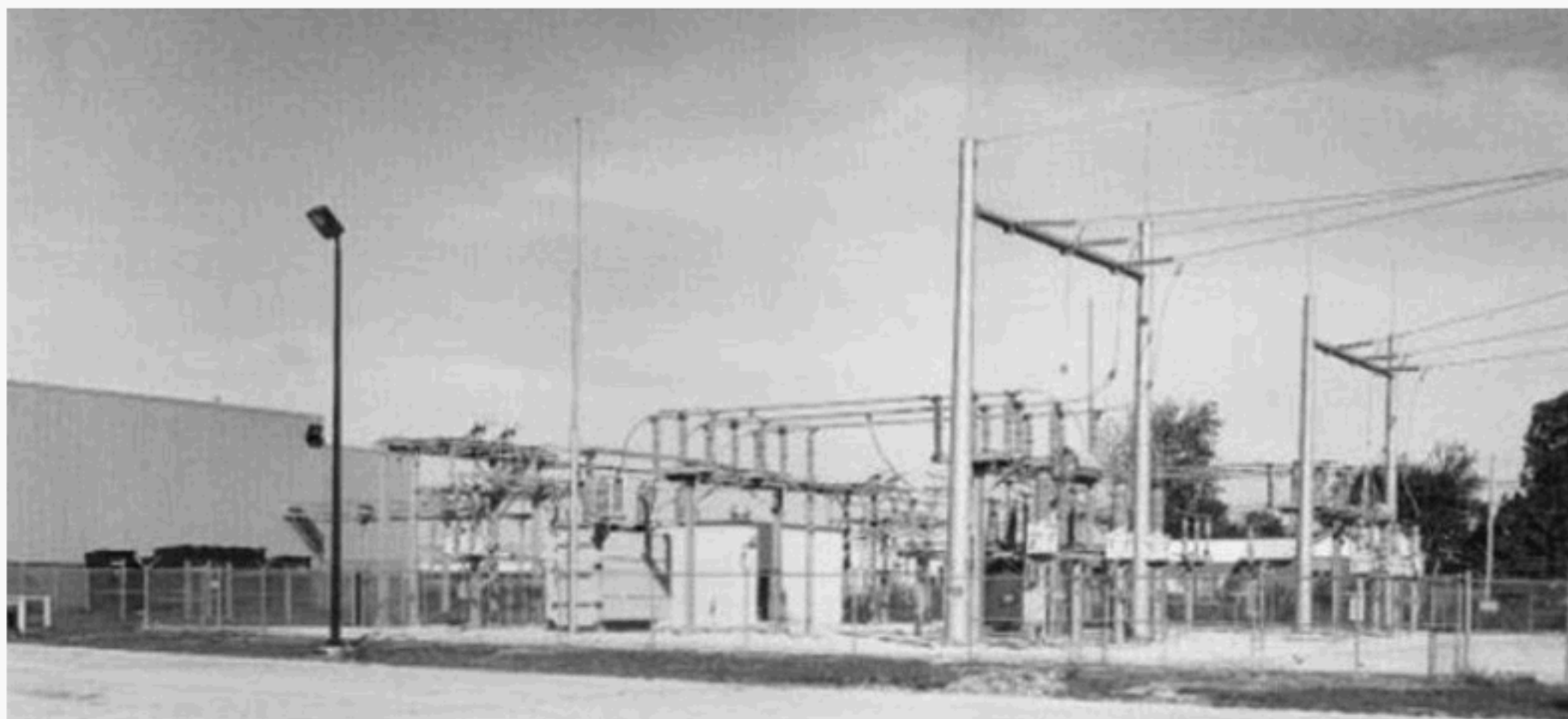


Figure 1—An industrial substation

10.3 Substation justification

A new or upgraded substation may be needed for any of the following reasons:

- a) A new facility is to be constructed, or an existing plant is increasing its load to a level that cannot be adequately served from the utility's existing system.
- b) The facility's operation causes, or may cause, voltage fluctuations that may disturb the utility's other customers and/or the plant's own operations.
- c) The facility has special power-quality service requirements that are best served by such a substation.
- d) The installation of on-site plant generation requires new or modified substation facilities for the utility to provide back-up supply service, and/or for the facility to deliver power to the utility.
- e) It is more cost-effective and practical to serve the facility's load at a different voltage level.
- f) The utility system in the area of the facility is being modified to meet the utility's other area needs.

10.4 Development stages

The four basic developmental stages of a substation project considered in this clause are as follows:

- a) *Planning:* Includes the determination of the needed capacity, evaluation of alternative methods of service, selection of the service voltage and required facilities, and related financial requirements. This stage concludes with a contract between the utility and the facility.
- b) *Design:* Includes development of detailed engineering drawings, finalizing of facility requirements, bidding documentation, and specifications for the facilities and changes required. This stage concludes with the letting of construction contracts.
- c) *Construction:* Includes the construction and energizing of the substation facilities.
- d) *Operations:* Includes the development, implementation, and documentation of the procedures for operating and maintaining the substation. These procedures are typically developed during the design and construction stages, and completed prior to energizing the substation.

10.5 Project participants

10.5.1 Planning stage

In the planning stage, personnel representing the plant and the utility should conduct preliminary discussions regarding the project scope. In addition to using the facility's staff, the facility management should usually engage a competent engineering consultant to assist in developing the design scope and applicable criteria. Project design criteria developed during the planning stage should be suitable for later use by the same, or another, engineering consultant for developing the design specifications and other construction and equipment-purchase documents. The utility personnel involved in the planning stage are generally the customer account representative, the system planner, and the substation project engineer. The utility design engineers, relay protection engineers, and possibly others assigned to the project should also be involved in the planning stage to assure consistency of the conceptual plans of the project with the evolving design and operating requirements of the project. Large projects may require significant infrastructure in form of construction offices, fabrication yard, staging areas, etc., which will require a temporary electrical power supply for the duration of construction. Some of these facilities installed ahead of the main construction schedule could later become part of the permanent distribution system. Such temporary power, often referred as *construction power*, may require significant engineering and design efforts upfront. The construction power is supplied at either low voltage or medium voltage from the serving utility. The temporary power deserves the same considerations as that of a permanent power supply of a similar scope, and must be addressed in the planning stage as it may have significant economic impact. Remote locations may require the use of temporary portable generators to provide construction power.

10.5.2 Design stage

In the design stage, the facility management typically uses the services of a consulting engineer to assist in the development of the technical requirements for the facility's system since the facility does not usually have sufficient technical in-house resources. This consultant should identify changes and new requirements in the facility's electrical distribution system made necessary by any supply changes. For example, the consulting engineer may determine that the increased capacity created by the new substation increases the available fault current to levels that are greater than the ratings of existing equipment, and must then develop a plan to resolve those issues.

10.5.3 Construction stage

During the construction stage, the utility and facility representatives will most likely work with the owner's construction crew and/or utility construction crews. All parties are typically involved in the day-to-day activities, construction schedule, work progress, and resolution of any problems. The consultant may also assist with the technical liaison and interface with the utility.

10.5.4 Operating and maintenance stage

The specific participants in the operating and maintenance functions will depend on the owner of the facilities and on the availability and expertise of the owner's personnel.

10.6 Planning stage

10.6.1 Introduction

This stage develops and resolves technical interface and conceptual planning considerations so that the project scope and criteria can be adequately defined. The various conceptual aspects typically involved and considered in the planning process are discussed below.

10.6.2 Definition of load

The projected facility load requirements and characteristics should be defined and provided to the utility. During the planning stage, the utility may only require an estimate of the initial and future electrical demand plus a statement about the type of operations anticipated in the facility (e.g., steel rolling mill, metal fabrication, chemical or petroleum processing, university campus, etc.). When firm information about load is not available, reasonable conceptual estimates must be made because certain load characteristics can affect the project scope and requirements. For example, the way in which the facility operates large motors or other loads could influence the basic design. Chapter 2 of IEEE Std 141™ (*IEEE Red Book*™) [B24] deals with these planning considerations.

10.6.3 On-site generation

Consideration should be given to both the immediate and future possibility of installing on-site generation since it could affect the substation design. It is almost always less expensive to incorporate design provisions at this stage than at a later date. Some basic consideration, such as allocating a plot of land for future on-site generation, usually has minimal cost associated with it and would provide significant savings in the future when generation is added. Cogeneration of electric power may be desirable if certain economic, thermal, and electric system conditions are met. Chapter 2 of IEEE Std 141 (*IEEE Red Book*™) [B24], IEEE Std 1001™ [B37], and IEEE Std 1109™ [B40] provide more detail of the technical issues and considerations for the interconnection of a facility-owned generator with a utility. Facility representatives should also obtain the specific written interconnection requirements of the utility for on-site generation in order to properly make an evaluation.

10.6.4 Conceptual planning considerations

10.6.4.1 Introduction

The following specific conceptual supply and facility planning aspects should be evaluated and resolved between the utility and the facility during this stage.

10.6.4.2 Capacity/reliability/power quality

These aspects are commonly interrelated. Larger MVA capacities generally require higher utility voltage levels, which are built with higher insulation levels and a stronger grade of construction. This more secure construction typically results in service with increased reliability. Usually, power quality is also perceived to be better at higher utility voltage levels in a given area; mainly because voltage sags, probably the most common cause of plant disruption, are typically less frequent and less severe in terms of duration on higher-voltage systems (Martzloff and Gruzs [B52], Wagner, Andreshak, and Staniak [B77]). It should be noted, however, that the switching of long higher-voltage lines could produce disruptive voltage transients. Also, steady-state voltage on higher levels may not be regulated to the extent that some lower levels are. For a given voltage level, reliability and power quality may be inversely related. For example, service from three lines may be more reliable than from two lines. However, three lines increase exposure to line disturbances. Similarly, utility supply systems that have many grid lines to a given area provide more reliability (and lower system impedance) to the industrial plant. However, these interconnected systems may have more voltage variation because disturbances can easily be transmitted long distances across the grid. The utility supply arrangement should be carefully evaluated since there are often system trade-offs available between reliability and power quality. Considerations that should be made include the following:

- a) Single-line radial service.
- b) Two-line (or multiple line, if available) service, which could be either radial or loop. This service may not provide full service with the outage of the single largest capacity component. The normal and emergency loading limits on facilities and the basis for these limits should be discussed.
- c) Separation of the supply sources, i.e., different utility buses or substations.

- d) Configuration, type, and coordination of protective devices and associated isolation switches. Chapter 2 of IEEE Std 141 (*IEEE Red Book*TM) [B24] provides additional details on these service arrangements and the associated considerations.

10.6.4.3 Utility-supplied information

The utility should help define levels of power capacity, reliability, quality, and their associated costs to enable the facility personnel to perform a meaningful cost/benefit analysis. The facility personnel should estimate the cost of a shutdown, and evaluate the utility's system quality to ascertain if it meets expectations, or if changes might be warranted. Aspects that should be evaluated (for the last 3- to 5-year period and the future if possible) include the following:

- a) The frequency, duration, and causes of outages. (Note that a line outage may not result in a service interruption depending on the substation primary and secondary breaker configuration and operating procedures. This subject is discussed later in 11.6.4.8.)
- b) Mean time to repair.
- c) Supply voltage variations: Steady-state and deviations such as sags, surges, harmonic content, etc. Refer to Chapter 3 of IEEE Std 141 (*IEEE Red Book*TM) [B24] for more information.
- d) Impact on, and effect of, other customers on the supply lines.
- e) Utility tariffs that apply to the point at which the facility is metered, especially when the substation is owned by the customer and the facility is metered at the transmission voltage. Refer also to 11.6.7.

10.6.4.4 Supply voltage variations

Facility personnel should, when possible, evaluate the tolerance of various facility equipment to supply voltage variations. There is a wide range of susceptibility and ride-through capability in facility equipment manufactured today, and there are no recognized standards that apply to this equipment. IEEE Std 1100TM (*IEEE Emerald Book*TM) [B38] provides valuable information on the powering and grounding of sensitive equipment.

10.6.4.5 Orderly process shutdown

Another aspect that should be evaluated is the safe shutdown of processes for system disturbances outside of the tolerable operating range of specific facility equipment. These considerations will allow the facility management to evaluate the extent of any future problems and determine the need for special equipment, line conditioning, or other devices.

10.6.4.6 Service voltage

The utility supply voltage level is usually determined by the utility based on the facility's load requirements. The facility personnel may have a role in selecting the utility supply delivery voltage if more than one level is available. Selection should be made based on a cost/benefit analysis together with careful consideration of both present and future service, capacity, and service quality expectations and requirements.

10.6.4.7 Facility distribution system design

The facility's primary utilization or distribution voltage level will usually be determined by the facility engineer after considering immediate and future load requirements. The amount of load to be served, its characteristics, the size of the facility to be served, and the equipment available, will usually dictate the choice of utilization voltages. When considered necessary, substation transformers can have automatic voltage regulating capability that maintains steady-state voltage at the substation secondary typically within + 1 V on a 120 V base. However, the reaction time of these mechanisms is usually set between 20 s to 60 s to

avoid excessive operations. If a more responsive regulated-voltage supply is required for certain applications, consideration should be given to installing different types of fast-regulation equipment. IEEE Std 1100 (*IEEE Emerald Book*TM) [B38] and IEEE Std 519TM [B34] provide more information on such devices.

10.6.4.8 Facility bus configuration

Consideration should be given to the configuration and operation of the facility's bus. Alternative approaches to guard against bus and/or breaker failure and promote service continuity include such arrangements as the double bus, double breaker; main transfer bus; double bus, single breaker; and breaker-and-a-half schemes. Refer to Beeman [B6] and Fink and Beaty [B17]. Closed bus tie operation will provide enhanced continuity of service as well as higher available fault current, which the facility's system must be designed to handle. It is possible to ride through or minimize service interruptions with closed bus tie operation if the voltage collapse is not too severe and the facility does not experience subsequent utility system faults. Closed bus tie operation is typically contingent on the utility system requirements, facility operating preference, and fault current impact on the facility's system. Note that utilities commonly have the need for certain control requirements over the facility's service switchgear, including mains and bus tie breaker(s). Typically, the utility will require access to open and lock out these protective devices for certain system conditions and faults (i.e., such as for repairs of a line or transformer following a fault or alarm). There are also other facility bus switching and operational approaches that may be considered for unusual circumstances. One unique approach is an automatic bus transfer scheme controlled by logic controllers that implement a mechanically fast load transfer to an alternate supply in the event of an interruption on one supply line. This approach is particularly dependent on the existing motor load and its ability to sustain voltage during the transfer operation (Hornak and Zipse [B22]). A *static* or electronic load transfer is also possible with two synchronized feeds, and this system is relatively independent of load type. Static transfer systems are typical for uninterrupted power supply systems and certain critical loads, such as those in pharmaceutical and food industries.

10.6.4.9 Supply system fault/voltage flicker/harmonic distortion

10.6.4.9.1 Introduction

Generally, the higher the fault current available, the more tolerant the utility system will be to currents that may cause voltage flicker and/or harmonic voltage distortion. Higher available fault current levels to the substation secondary will result from using larger capacity transformers, lower impedance transformers, or by operating the transformers in parallel. Careful evaluation must be made by the facility representatives to confirm that available fault levels, including contributions from the facility's motor loads, do not exceed the facility's primary and secondary system interrupting and momentary, close-and-latch equipment ratings. This analysis must be done for all normal and emergency system operation configurations. Refer to Chapter 2 of IEEE Std 141 (*IEEE Red Book*TM) [B24] regarding these types of evaluations and Chapter 4 of IEEE Std 141 (*IEEE Red Book*TM) [B24] for information on fault calculations.

10.6.4.9.2 Voltage flicker limitations

Many utilities have voltage flicker standards. Such standards are intended to protect other utility customers because a facility may negatively impact the quality of power for other nearby utility customers. Flicker generally evolves from large inrush currents caused by starting large motors, metal melting, or welding operations. Typically, these standards are established internally by the utility and are not usually approved by the utility's regulatory agency (for regulated utilities). However, utilities are also typically granted service rights by their regulatory agency with respect to the handling of facilities that have caused utility system problems or service problems to other facilities. Refer to Chapter 3 of IEEE Std 141 (*IEEE Red Book*TM) [B24] for more information on voltage flicker considerations.

10.6.4.9.3 Telephone interference

Some utilities may also have telephone interference factor (TIF) standards, typically established in a manner similar to flicker standards. Again, these standards are intended to protect both the utility and the users.

Depending on the location of the utility distribution feeder and service point, the facility owner may be able to negotiate with the utility to relax their TIF requirements.

10.6.4.9.4 Harmonic distortion

While harmonic distortion concerns are justified, development of standards and applicable criteria are relatively new. Several aspects must be considered, including voltage distortion in the utility's supply; facility-load harmonic-current requirements; conditions under which to measure harmonic distortion (e.g., heavy- and light-load conditions, supply-line service status, power-factor-correction capacitor status, system-switching status, etc.); means of measurement (e.g., single-phase, three-phase, etc.); harmonic-system interactions; severity and duration of harmonic distortion, and various other related conditions. Refer to Chapter 9 of IEEE Std 141 (*IEEE Red Book*TM) [B24] and to IEEE Std 519 [B34] for more information on harmonic considerations.

10.6.4.10 Short-circuit and protective-relaying coordination analysis

An analysis should be performed for normal and emergency-system operating configurations to determine the adequacy of new or existing equipment and to define the ratings necessary. A formalized and definitive study needs to be performed (refer to 11.7.4.9) to determine proper settings and time-current coordination. Refer to Chapters 2, 3, and 4 of IEEE Std 141 (*IEEE Red Book*TM) [B24], IEEE Std 242 (*IEEE Buff Book*TM) [B27], and IEEE Std 399TM (*IEEE Brown Book*TM) [B28] for further discussions of short-circuit and protective coordination. The utility's protective-relaying scheme and its interface with the facility's protective-relaying scheme should be reviewed.

If a facility is fed by a loop system, facility personnel should understand utility requirements, if they exist, to automatically reclose facility breakers to test if a temporary line fault has cleared. Preferably, the utility can test the line for integrity from a remote breaker prior to re-closing facility breakers; thus, perhaps avoiding an additional unnecessary disruption. Manual reclosure is generally preferred for the facility's breaker operation because of simplicity in control requirements. Any automatic reclosing that may affect substation operations should be very carefully considered as it can impact the facility's operations and create system safety concerns. Typical utility protection requirements include line protection, bus protection, single- or dual-channel tripping, breaker-failure backup, and utility transformer protection. Protection of the facility system, including primary mains, ties, buses, and feeder cables, must coordinate with protection of the utility's high-voltage supply and transformers, whose protection is generally governed by utility policies.

Facility representatives should be provided with the specific requirements of the utility in cases where the facility relays must be coordinated with the utility relay system. These requirements include types of relays, terminations, connections, and other acceptable equipment.

Utility- and facility-control requirements for voltage, fault isolation, service restoration, and metering should be determined.

Careful evaluation should be made of the possible impact of the utility's relaying scheme on critical facility operation, especially if facility generation is involved. The utility's relaying scheme may have some objectives that are contrary to those of the facility management for its more critical operations.

10.6.5 Specific considerations for substation facilities

There are many considerations related to building the substation facilities that need to be recognized, but not necessarily resolved in the planning stage, such as the following:

- a) Location of the substation and rights-of-way on the facility site:
 - 1) In general, the facility management provides land to the utility at no cost

- 2) Entry and routing of utility lines
- 3) Location of the primary switch house (or switchgear enclosure), based on a balance between the costs of the facility's and the utility's facilities
- 4) Proper clearances from existing or future utility services, new building construction, or modification of existing buildings, fences, etc. (e.g., avoid overhangs of buildings, etc.) (IEEE Std 1119™ [\[B42\]](#))
- 5) Need for fire-protection barriers or clearances (IEEE Std 979)
- 6) Minimizing interferences for facility land use, including future site development
- 7) Rebuilding an existing substation in lieu of opening a new site
- b) Site determination and preparation requirements:
 - 1) Topographical survey of the surrounding area
 - 2) Clearing, leveling, and rough grading to standards acceptable to the utility
 - 3) Soil tests to determine if the site is environmentally acceptable, and boring tests to determine if the soil will support the required loadings. Tests should be performed for the specific substation location recognizing associated requirements
 - 4) Seismic concerns (IEEE Std 693™)
 - 5) Soil-resistivity measurement as required (IEEE Std 80)
- c) Location of equipment (if required), including the following:
 - 1) Entrance towers for overhead lines
 - 2) Entrance stands for underground lines
 - 3) Circuit breakers
 - 4) Disconnect switches
 - 5) Grounding switches
 - 6) Current and voltage transformers
 - 7) Line-coupling capacitors and line traps
 - 8) Lightning protection (including surge arresters)
 - 9) Power transformers
 - 10) Reactors (shunt or series)
 - 11) Resistors/reactors (neutral)
 - 12) Capacitors (shunt or series)
 - 13) Buses
 - 14) Metering facilities
 - 15) Grounding grid
 - 16) Control house
 - 17) Fencing
- f) Substation and supply-service electrical parameters, including considerations of the following aspects:

- 1) Selection of initial installed transformer capacity to allow for some reasonable load growth without additional changes (e.g., selection of a 24/32/40 MVA rated transformer or transformers to serve a load of approximately 24 MVA where the potential exists for the load to increase to some 30 MVA to 40 MVA over time). Lower transformer temperature rise ratings applied on designs otherwise designed for 65 °C rise (55 °C/65 °C rise) may be used to obtain some 12% additional capacity at little increase in equipment cost. The additional cost is usually minimal and it provides a greater safety margin in capacity. Refer to IEEE Std 3001.5 [B47] for more information.
- 2) Selection of transformers that are standard in specification and ratings to those typically used by the utility, if the facility organization is responsible for providing and installing them. Standardizing facilitates coordinating any future repairs, replacements, testing, use, and maintenance requirements with the utility.
- 3) Determination to use voltage control on the transformers. Typically, load tap changers (LTC) are used for new transformers. Substation regulators may be used for retrofitting small installations but are expensive, bulky, and can present maintenance problems. Therefore, their use is generally not desired if there is a choice.
- 4) Selection of transformer impedance(s) that are the utility standard or higher impedance units to limit fault current. Lower than standard impedance units may be used to address large welding or large motor-starting concerns. Refer to IEEE Std 3001.5 [B47].
- 5) Determination of BIL for substation equipment, including transformer high- and low-voltage windings and station high- and low-voltage surge-arrester levels. The lightning activity in the area and environmental contamination (e.g., airborne pollutants) may dictate the need for higher BIL ratings. Refer to Chapter 6 of IEEE Std 141 (*IEEE Red Book*TM) [B24] and IEEE Std 3001.5 [B47] for more information.
- g) Space considerations in substation for primary and secondary power-factor correction capacitors or harmonic filters (utility and/or facility owned), current-limiting reactors, and system neutral-grounding resistors or reactors.
- h) Equipment delivery/removal access, loading, and clearances to the substation yard. Access considerations include rail, truck, and crane. Loading considerations include rail, roadway, and bridge load-bearing limits. Clearance considerations include overhead and side clearances and roadway/rail turn radius requirements. Provisions for equipment maintenance, repair, replacement, and station-expansion provisions are all required.
- i) Future planning provisions in the substation, including the following:
 - 1) Allowances for future expansion of the utility's service, the primary switchhouse, and the substation facility, including upgrading to larger-sized transformers. Considerations include provisions for adequate foundations, structural steel, and physical clearances, access, loading requirements, etc.
 - 2) Allowances for any utility supply voltage conversion that might take place. Clearances, insulation levels, foundations, and access all should be considered.
- j) Protection from exposure of the substation and utility facilities to facility or public vehicular traffic.
- k) Allowances for utility metering, communication, controls, and alarms for the substation yard.
- l) Location, type, and ownership of batteries (dedicated or shared use by facility and utility). (Refer to IEEE Std 484TM [B30], IEEE Std 485TM [B31], IEEE Std 1106TM [B39], and IEEE Std 1115TM [B41]).
- m) Underground obstacles, such as water and sewer mains, storm water drains, steam services, electric services, or other obstacles.
- n) Environmental considerations related to the following:

- 1) Station physical configuration (profile, height, etc.)
 - 2) Oil-spill controls and containment provisions and compliance with federal, state, and applicable local spill-containment requirements for oil-filled electric devices (e.g., transformers, circuit breakers, capacitors, etc.) (refer to IEEE Std 980)
 - 3) Requirements for record-keeping or disposal related to equipment containing SF₆
 - 4) Proper station storm water drainage and runoff
 - 5) Station noise and any other local zoning requirements or restrictions
 - 6) Industrial or other known contamination that would affect insulators and outdoor switches (e.g., their location should not be downwind from open coal handling or cooling towers)
 - 7) Bird, snake, and other animal protection and control requirements
 - 8) Aesthetic considerations related to location, color, profile, and consistency with the design of existing or planned facility facilities
 - 9) Adequate and legal authorization for land use (easement or license agreement) provisions, including rights-of-way from property belonging to other owners and necessary construction permits, and rights-of-way for the utility facilities and for the substation
- o) Provisions for easy access to authorized personnel and restricted access to others.
 - p) Connection arrangement from transformer(s) low-voltage bushings to the facility's switchhouse (e.g., outdoor bus, bus duct, underground or above ground cables, etc.). Refer to IEEE Std 525™ [B35], and IEEE Std 3001.5 [B47] for more information.
 - q) Grounding of the substation mat and the primary switchhouse and consideration of connecting the two. Refer to Chapter 7 of IEEE Std 141 (*IEEE Red Book*™) [B24], IEEE Std 80, and IEEE Std 142 (*IEEE Green Book*™) [B25] for more information.

10.6.6 Facility's primary switchhouse

The same considerations previously discussed regarding land use and availability apply equally well for the facility's primary switchhouse. Specific additional considerations include the following:

- a) Type of construction: Concrete, cement block, or prefabricated-type construction is generally preferred. Access can be easily restricted with this type of building to protect both the facility and utility equipment (if located in the facility's switchhouse) and the environment can be easily controlled and equipment maintained. In some cases, all equipment can be housed in metal-clad gear.
- b) Provisions for equipment, such as the facility's primary metering, relaying, main buses, control transformer, main and bus tie circuit breakers, and the facility's primary feeder breakers. Requirements for obtaining metering information from the utility's facilities should be discussed.
- c) Requirements for telephone, relaying, telemetry communications, and alarming provisions, including fault-isolating equipment.
- d) Provisions to restrict access to facility's switchhouse and to provide space in the switchhouse for utility controls, metering, and related equipment accessible only to utility personnel.
- e) Consideration for special ambient air treatment requirements due to unusual environmental circumstances, such as airborne contamination or ambient temperatures above equipment ratings. Elevations higher than equipment ratings may also need to be considered.
- f) Access for the addition, removal, or replacement of equipment. A roll-up door or removable panels are options.
- g) Construction and maintenance power receptacles (120/240 V).

- h) Provisions for future expansion to meet the ultimate facility load.
- i) Space provisions for maintenance and testing equipment.
- j) Fire suppression and limiting the extent of fire propagation.

10.6.7 Facility and substation ownership

The ownership demarcation between the utility and the facility should be determined. Specific ownership of the substation and associated equipment may be a complicated issue that may be determined by a number of conditions and factors. The chief considerations are the rate structure and operating philosophy of the utility, the operating philosophy and return on capital of the facility owner, and the particular situation that may determine such policies.

Once all these factors are considered, ownership and lines of demarcation can be determined. The ownership point may vary for utility-owned substations. The transformer low-voltage bushings or low-voltage terminations at the facility's switchhouse are typical points of ownership demarcation. [Figure 2](#) indicates some of the various ownership boundaries for a typical substation configuration. Should the utility provide the option of ownership to the facility, the facility management should then consider various other factors to determine the best course of action. High-voltage rates (tariffs) should be carefully evaluated if they are available. In this case, the economic advantage gains from the rates should be evaluated against the added cost of substation ownership, including capital, operation and maintenance, and repairs. These costs should be compared to the utility's policies to provide an equivalent substation and any financial requirements that the facility management might still be responsible for paying to the utility for some or all of the facilities.

In some cases, the facility management may have an option for payment, depending on utility policies and tariff. The utility tariff should be carefully scrutinized in this regard. In some cases, arrangements can be made with the utility to perform the necessary maintenance, operation, and repairs at a reasonable cost. There are specific issues associated with substation ownership that the facility management should understand and resolve. These include design and construction of the substation (if performed by facility representatives), economic savings obtained from high-voltage rates, maintenance, operations, and switching, especially for high-voltage equipment, substation repairs, and any potential future substation capacity expansion requirements. Insurance coverage is commonly provided by the facility and the utility for their respective facilities as part of their normal course of doing business. If facility substation ownership is involved, the facility management must include insurance for the facility.

In the case where underground duct systems are involved, ownership can change at a manhole on either side of the facility's property line. Splices inside the manhole may or may not be the utility's responsibility. The cable and ducts connecting to the substation may or may not be the customer's responsibility, generally depending upon the voltage level. Cable termination at the substation may or may not be the facility's responsibility.

The delivery voltage level may also determine the point of ownership change. The ownership point issue may also vary for customer-owned substations. In this case, possible change of ownership may be at a termination of utility services at towers near the facility's property line, at the facility's substation property line, or at the high-voltage terminations in the facility's substation yard at either the high-voltage breakers or the transformer high-voltage bushings.

Since the high-voltage protective devices in the yard may be an integral part of the utility's transmission system, utilities may often retain ownership and control of this equipment. In this case, the ownership point may be at the transformer high-voltage bushings. In some cases, partitions in the substation yard may be required to separate areas of ownership for security and safety reasons.

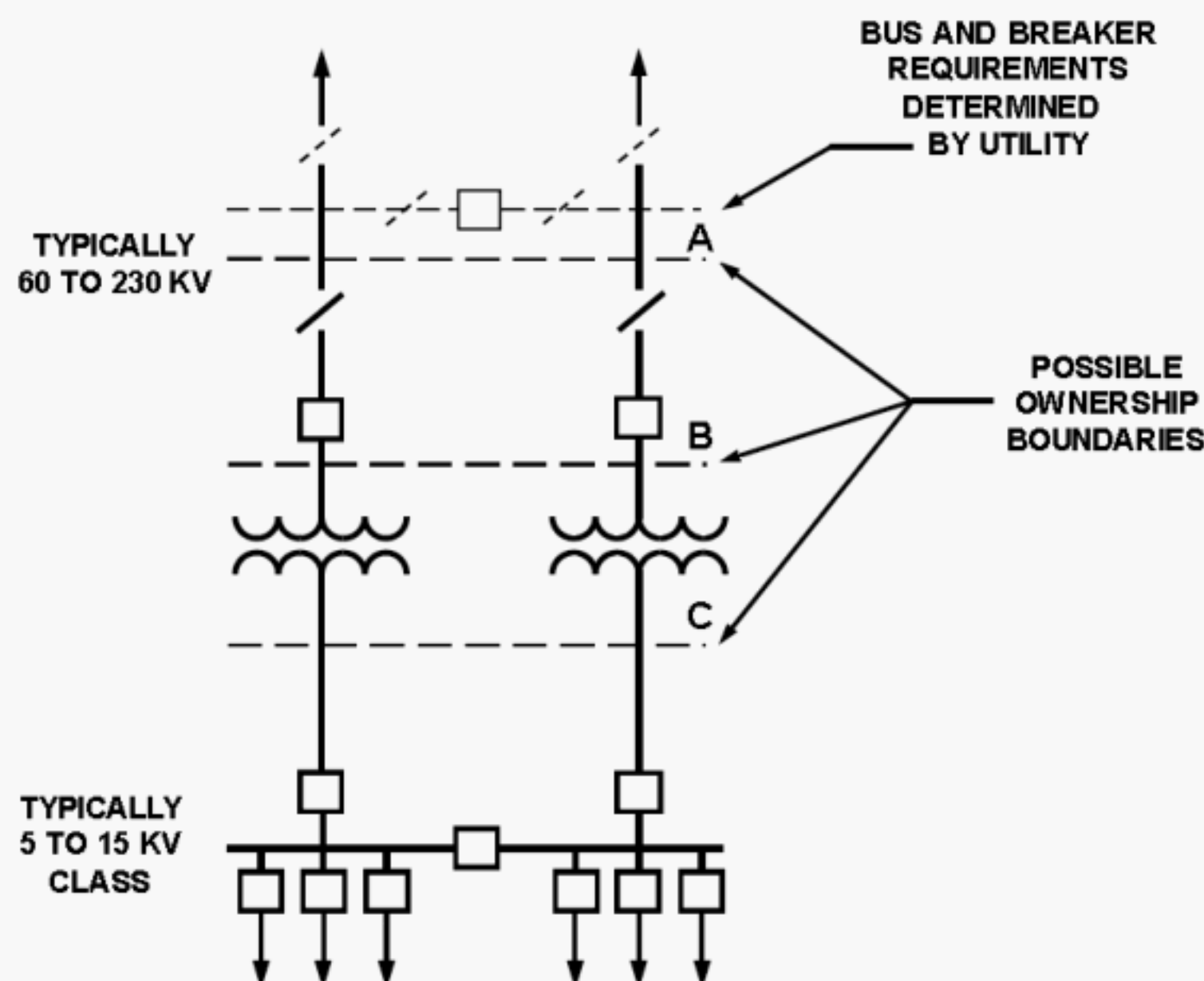


Figure 2—Typical industrial substation one-line diagram showing possible ownership boundaries A, B, or C

10.6.8 Substation operation and maintenance

The facility management should resolve responsibility for performing the substation maintenance, calibration, operation, repair, and periodic tests in the case of a customer-owned station. These requirements, particularly those involving calibration, testing, and repair, should be performed by personnel experienced in high-voltage equipment, practices, and safety. Most often, such requirements are beyond the facility's personnel resources. The utility may be willing to provide such services at a nominal cost, or a qualified high-voltage contractor (specialized in electrical testing) may be hired to perform such work.

10.6.9 Administrative considerations

Administrative and policy requirements contained in the utility's approved tariff, standard terms and conditions, and service rules should be carefully reviewed with the utility. The particular issues reviewed should include substation design, construction, maintenance, and ownership responsibilities, financial requirements, and the facility's options (if any) with respect to any financial requirements and payment options. These policies vary by utility and may be highly defined or quite vague. Cooperative negotiation should be pursued to resolve issues of concern. The owner's legal and financial departments should be involved in this review.

10.6.10 Time requirements

A typical substation project can be developed and engineered, and have equipment purchased, installed, and energized, in approximately two years, which may not include the time associated with land acquisition. This schedule includes allowances of six months for planning; six months for basic engineering and specification preparation; 12 to 14 months for bid inquiry, major equipment purchase, fabrication, and delivery; and some three to six months for construction (weather permitting), starting some two to three months before major equipment delivery. It should be recognized that if line construction on public or private property is required for the service, additional time could be required to obtain the necessary rights-of-way. Refer to [Figure 3](#) for a sample of a typical schedule.

The substation schedule must be coordinated with other related facility project activities. For example, for a greenfield site, the substation schedule must be coordinated with the overall facility design and construction schedule. The substation schedule may need to accommodate the need for the substation to supply temporary construction power prior to full facility operation. In the case of a service upgrade, the coordination of transferring load from the existing service to the new substation must be considered.

10.6.11 Finalizing conceptual planning requirements

The planning stage should conclude with the resolution and definition of the following aspects:

- a) Agreement on a preliminary single-line diagram, equipment plot-plan, project schedule for the required facilities, and relaying system configuration. Basic equipment ratings should be indicated on these drawings.
- b) Resolution of ownership requirements with a definition of the “utility” and the “facility” portions of the facility.
- c) Agreement in the areas of facility responsibility related to design, construction, operation, maintenance, repairs, etc.
- d) Preliminary review of the conceptual plans by utility and facility design and operating personnel to ascertain that conceptual planning criteria and scope are consistent with all design and operating requirements.
- e) Agreement on the administrative requirements related to contractual and financial responsibilities (including construction and operating budgets).

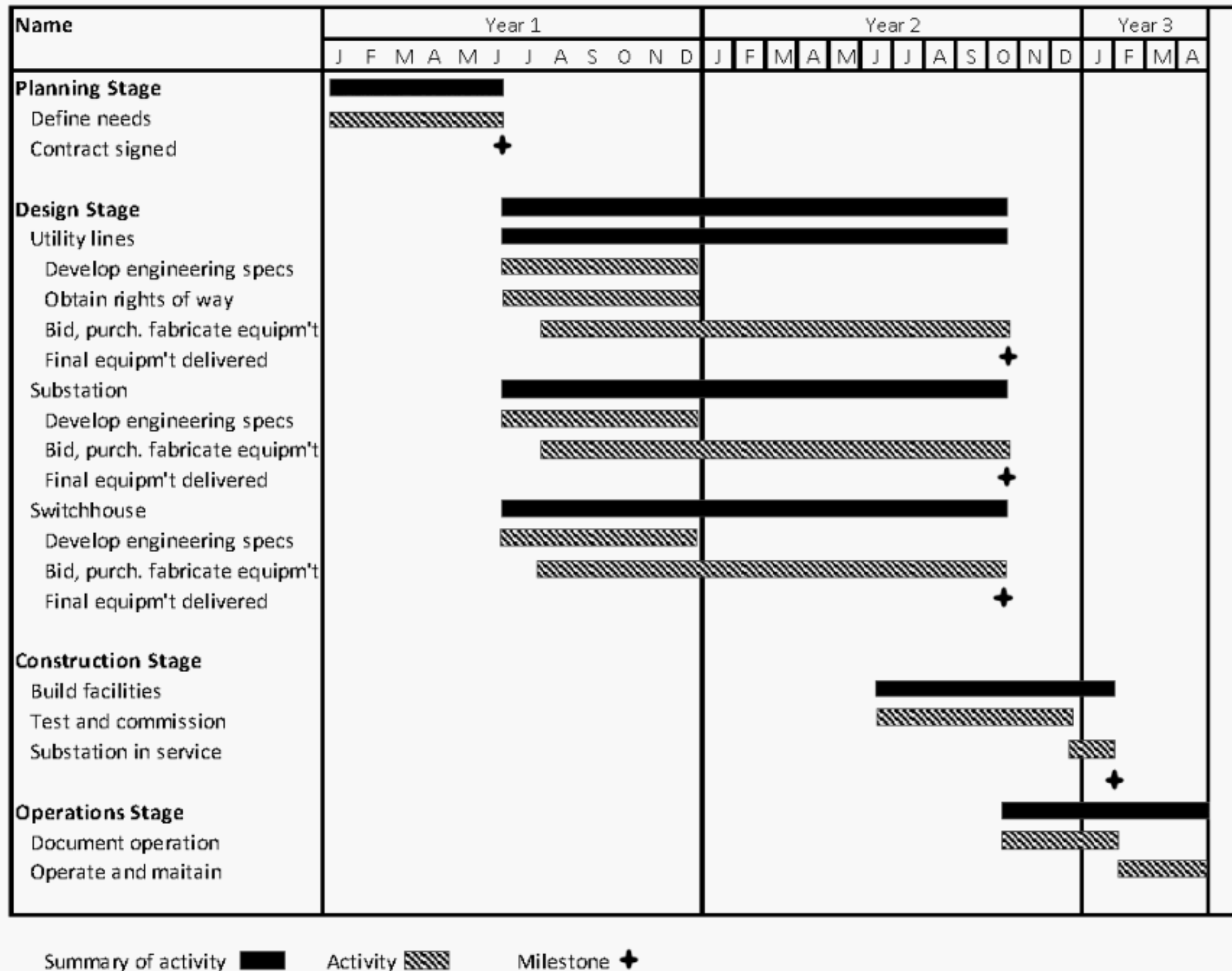


Figure 3—Illustration of overall project schedule for an industrial substation

10.6.12 Contract

Resolution of the items in 11.6.11 will lead to the contract between the facility and the utility signifying the end of the planning stage and start of the design stage.

10.7 Design stage

10.7.1 Introduction

This stage is the detailed follow-up to all previous work in the planning stage. While industrial plant substations are often designed and built by the utility, in certain cases the facility management may be required, or may be allowed the option, to design and build the substation. In such cases, the facility representatives then perform most of the functions indicated here for the utility, although the utility personnel will probably review and approve certain aspects related to the interconnection and protective relaying with its system. The design stage starts by using the preliminary single-line diagram developed and agreed upon in the planning stage. From this and other related design parameters developed in the planning stage, detailed design and engineering drawings and specifications, along with construction cost estimates, are developed (refer to Chapter 16 of IEEE Std 141 (*IEEE Red Book*TM) [B24]).

10.7.2 Detailed schedule

A detailed engineering design and construction schedule should be prepared in this phase, based on the preliminary schedule prepared in the planning stage.

10.7.3 Site testing

Site testing should be done (at locations specified by the substation designer) to determine the load-bearing strength of the ground. While preliminary testing can be performed at an early stage, it is more useful if a plot plan layout is available and equipment weights are known. This testing is generally performed by specialized soil boring and test companies. Soil boring companies can take sufficient test borings to determine the design parameters for foundations needed for the utility's incoming towers, circuit breakers, transformers, and the facility's primary switchhouse. Land that has been filled even 15 or 20 years ago may not have developed sufficient load-bearing capabilities; installing caissons or piles to support the foundations may be necessary, especially for a large substation. If the ground has been used for other purposes, such as a waste disposal site, or contains fill of unknown origin, it is necessary to take soil samples and have them analyzed and certified to be non-hazardous and non-toxic, although this is often performed as a matter of policy regardless of any identified previous site use. Test of soil resistivity should be conducted by a qualified electrical contractor in accordance with Chapter 7 of IEEE Std 141 (*IEEE Red Book*TM) [B24] and the utility's practices.

10.7.4 Site design

10.7.4.1 Introduction

Since site selection has been determined in the planning stage, the following design factors now can be addressed.

10.7.4.2 Grading

The final substation grade should be flat with only enough slope for water to drain naturally from the facility's switchgear, building, and substation area. If regrading becomes necessary, areas must be filled using clean structural fill that can be properly compacted in layers. All foundations, basement, and duct banks should preferably be poured before the backfilling is started. Typically, substation foundation pads are raised to achieve natural drainage. Scraping soil from the high spots and dumping it at the low spots is not recommended since correct soil properties required for good compaction may not then exist.

10.7.4.3 Drainage, sewer, and water

Most industrial substations do not require a sanitary sewer system or a potable water supply as such facilities are typically accessible nearby at the facility. The substation owner has responsibility for ensuring that the roof and the area around the facility's substation building are properly drained to prevent water or ice buildup. Considerations should be given to avoid adversely affecting adjacent areas or properties that may not be owned by the facility owner. If the substation has an associated basement or cable vault, the foundation must have drains and possibly sump pumps to prevent any unwanted water buildup around the footings. Basement sumps are also advisable to carry away any seepage from around the incoming cables. If a storm sewer system is not available, it may be necessary to provide an area to dispose of the drain water.

10.7.4.4 Oil containment

The area around oil-filled transformers and other equipment (i.e., circuit breakers, capacitors, etc.) should be constructed in such a way that will contain leaks. A common pit, sized adequately to collect the oil from a group of transformers, may also be allowed. The system must be designed to contain the oil, but at the same time allow rainwater to drain naturally and freely away. If the water and oil can be drained or pumped to the industrial sewer system, many problems are eliminated (IEEE Std 980). However, it may be necessary to construct an American Petroleum Institute (API) separator with oil skimmers for that rare occasion when a transformer develops a major leak. Some containment systems retain all the rainwater until an operator

temporarily opens a bottom drain to dispose of the water. In other cases, special absorption beads may be used in containment-area reservoirs. These beads allow water to pass under normal conditions, but swell upon oil contact to choke-off all fluid flow when spills occur. In any case, these requirements are subject to local law or statute, and are typically the responsibility of the substation owner.

10.7.4.5 Yard stone

A layer of crushed stone with a specified resistivity, or equivalent, helps support vehicles and provide high resistance critical to providing safe step-and-touch potential. It is also helpful for drainage, helps reduce ice accumulation, and prevents small animals from readily digging under the fence.

Typical crushed stone resistivity varies from 10 000 Ω -m for clean granite to 2000 Ω -m for some types of clean limestone in wet locations. An assumed stone resistivity greater than 3000 Ω -m can be used as long as the measured value is greater than the assumed value. When selecting the type of surface material for substation grade finish, refer to Table 7 of IEEE Std 80 for surface material resistivity guidelines, and also refer to the geotechnical report. Preferred rock types are granite and limestone.

10.7.4.6 Landscaping

Landscaping and visual or acoustical screening may be required to maintain consistency with the design approach of the industrial plant. In most cases, this is a minimal requirement. Such requirements may be more pronounced for certain “high-tech” plant facilities, such as computer or electronics plants. In some cases, a low-profile substation configuration may be required (refer to IEEE Std 605™ [B36] and IEEE Std 1127™ [B43]). There may be state or local requirements for particular screening requirements in certain locations.

10.7.4.7 Airborne contamination

Airborne contamination in an industrial plant may be a serious problem and may require cleaning the transformer(s) or switch insulators on a regular basis or after an unplanned emission from a plant process. Sufficient space must be allowed around the substation to bring the cleaning equipment close enough to the equipment. If major releases of contaminants are possible, additional protection may be obtained by specifying a higher BIL for all outdoor insulators. The higher BIL will give a longer creepage path and a greater effective resistance when partially contaminated. Special insulator coatings may also be applied to maintain BIL in contaminated areas. Gas-insulated switchgear, which can be enclosed in a building, could provide a more practical and cost-effective solution in areas where airborne contamination is severe.

10.7.4.8 Animal intrusion

Animal screening is usually adequate if the area is well fenced and the ground within the fence and several feet beyond the fence is heavily stoned. Consideration should be given to overhead line or structure design in cases where large birds known to inhabit the area could cause a risk to flashover of exposed conductors.

10.7.4.9 Environmental considerations

Environmental concerns should be addressed, especially when the location is other than a rural setting. Issues with audible sound, excessive visible light, and aesthetics may be concerns of adjacent landowners or city/county officials. Refer to IEEE Std 1127 [B43] for further details.

10.7.5 Relaying and control design

10.7.5.1 Introduction

The installation of a dedicated substation to serve a facility inherently involves an interface between the utility and the facility. Close coordination between utility and facility personnel is essential so that relaying, control, and other related requirements are identified and proper responsibilities assigned. This may include

requirements that the facility provide equipment or space for the utility's relaying, control, metering, data acquisition, and other related equipment.

Consideration should be given to connecting protective relaying and instrumentation to a supervisory control and data acquisition (SCADA) system. The system can gather and store historical load data and capture the sequence of operations of devices. This information is invaluable in responding to and diagnosing trouble on the power system. It can also facilitate ongoing monitoring of the substation, and reduce the response time of service personnel by the ability to remotely monitor the substation from elsewhere in the facility, such as the chief engineer's office. This is especially useful when the substation is located well away from the facility's center of operations.

There are three general areas where protection requirements must be coordinated to promote a safe and reliable system:

- Utility supply line protection, see 11.7.5.2
- Transformer protection, see 11.7.5.3
- Facility main bus and feeder protection, see 11.7.5.4

10.7.5.2 Utility supply line protection

Typically, line faults may be detected and isolated using overcurrent, distance, pilot wire, or differential relaying protective techniques. Several factors influence the choice of line protection, including circuit type (e.g., underground cable, overhead line, single circuit, parallel circuit, multi-terminal lines, etc.) and the line's function and importance (e.g., impact on service continuity and the amount of time needed to detect and isolate faults). As a practical matter, the line(s) supplying the substation are part of a larger utility system and the applicable line protective-relaying scheme(s) are usually selected by the utility for compatibility and coordination with other protective devices upstream from the substation within the utility system. It is important to understand that the utility scheme used may well impact facility operations. Any conflicts in objectives between the utility protective scheme and maintenance of critical facility operations should be resolved. Refer to Chapter 5 of IEEE Std 141 (*IEEE Red Book*TM) [B24], IEEE Std 242 (*IEEE Buff Book*TM) [B27], IEEE Std 1001 [B37], and IEEE Std C37.95TM [B50] for various viewpoints on protection of incoming lines.

10.7.5.3 Transformer protection

The protection schemes for transformers depend on several factors, including system configuration, method of grounding, speed, coordination, operation, cost, etc. Some of the more commonly used protective schemes for industrial substation transformers are shown in Figure 4 through Figure 7. Typically, they include one or more of the following:

- Overcurrent protection using either fuses or circuit breakers controlled by overcurrent relays
- Ground-fault relays (typically indicated by either 51G if applied on the transformer neutral connection, or 51N or 51GS if applied on the phase conductors)
- Current differential protection
- Differential ground protection (typically provided on secondary windings and connecting conductors)
- Sudden pressure devices (Buchholz relays)
- Liquid temperature alarms
- Winding temperature alarms
- Liquid level alarms

Figure 4 shows how a primary breaker can be used for transformer protection. The basic protection is provided by the 87T transformer differential relays. Device 50/51, overcurrent relay with instantaneous unit, provides primary protection for phase faults; either Device 50G or 50N/51N can be used as backup protection for ground faults. Transformer overload, low-voltage bus, and feeder backup protection is provided by Device 51 on the secondary side. Since the low-voltage side is resistance-grounded, a ground relay (51G-1) should be used to trip Breaker 52-1 for low-side ground faults between the transformer and the secondary breaker, to provide protection against internal secondary winding ground faults not covered by the 87T differential protection, and for resistor thermal protection. Device 51G-2, which trips Breaker 52-11, provides bus ground-fault protection and feeder ground backup, while Device 63 offers highly sensitive detection of low-magnitude transformer faults. Devices 50/51, 51, 51G-1, 50G, and 51G-2 require coordination to provide zones of protection, which will aid in fault location.

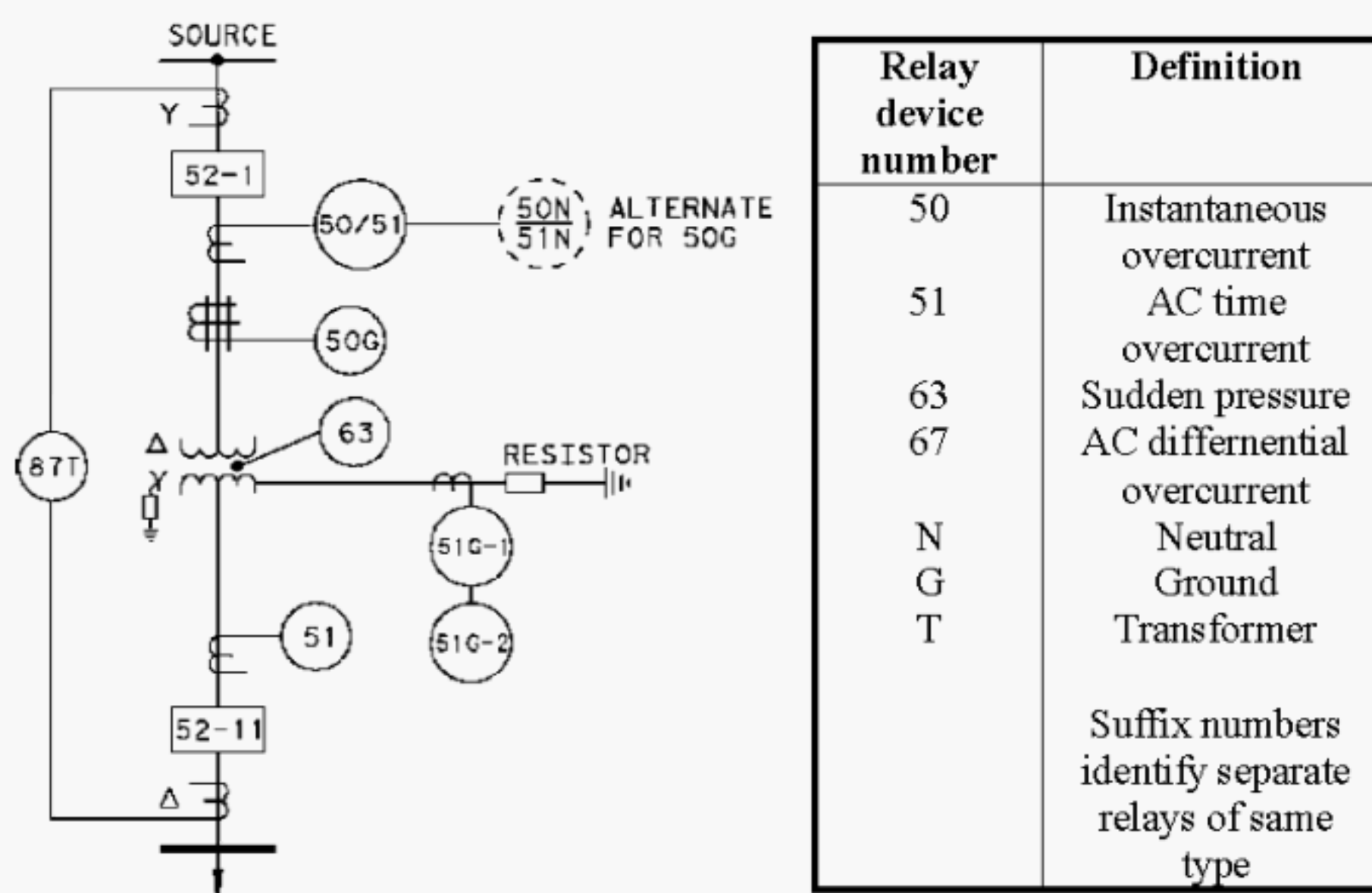


Figure 4—Transformer protection with primary breaker (load and metering circuits not shown)

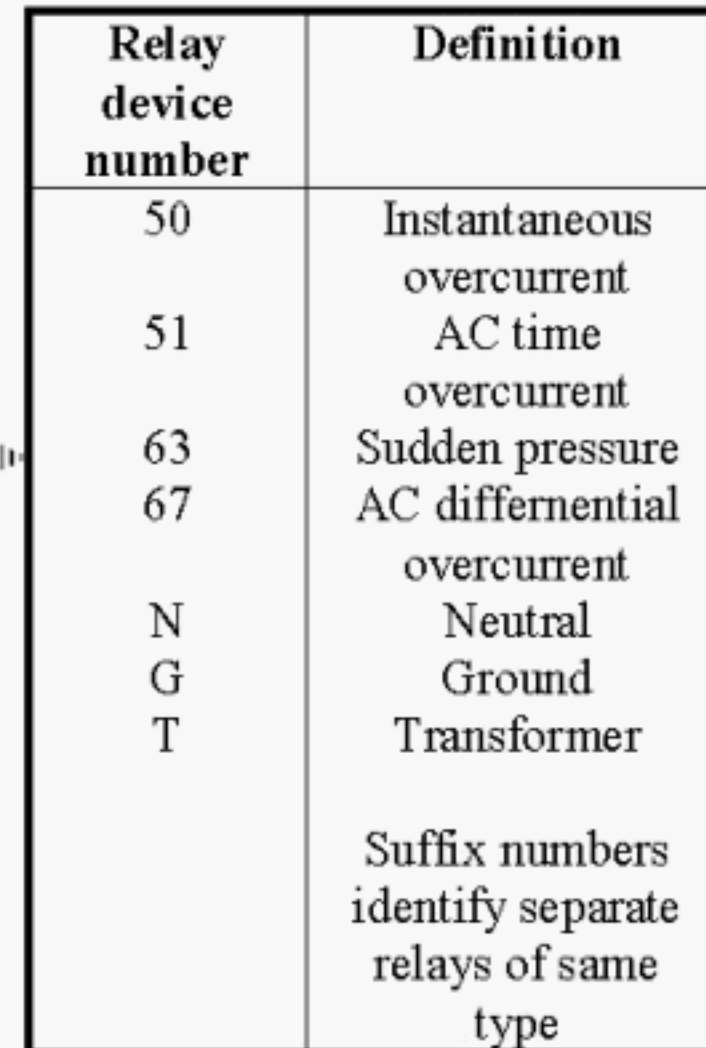


Figure 5—Paralleled transformer protection with primary breaker (load and metering circuits not shown)

When a normally closed secondary bus tie is used for paralleled transformer protection (Figure 5), there are several differences from the primary breaker scheme shown in Figure 4. First, Device 87TG provides selective and sensitive protection for ground faults within the secondary circuit of the differential zone. In addition to Devices 51G-1 and 51G-2 shown in Figure 4, a 51G-3 relay is used to trip Breaker 52T on ground faults. The trip sequence of these three ground relays is as follows:

- 1) 51G-3 trips 52T
- 2) 51G-2 trips 52-11
- 3) 51G-1 trips 52-1
- 4) 87TG trips 52-1 and 52-11

Device 67 provides directional overcurrent protection.

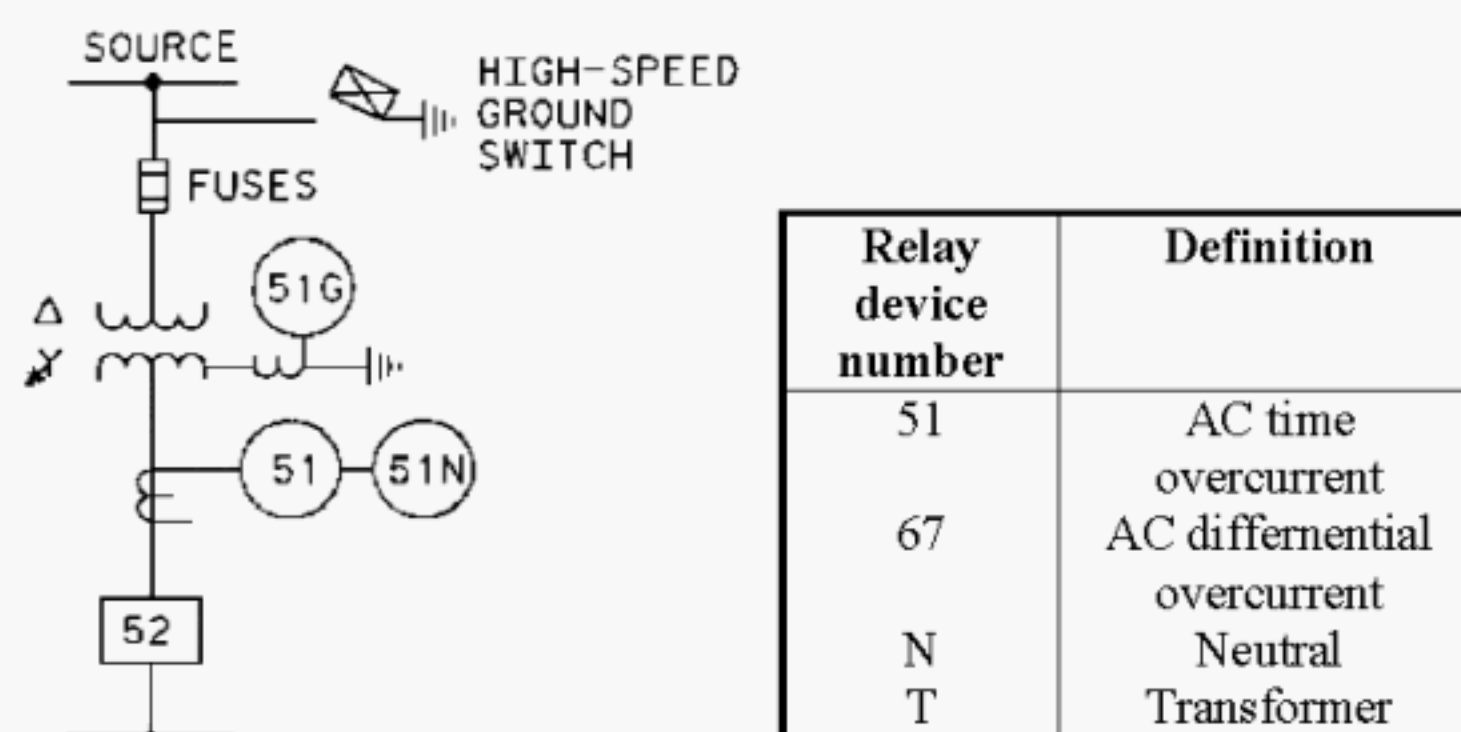


Figure 6—Transformer protection with primary fuses (no load or metering circuits shown)

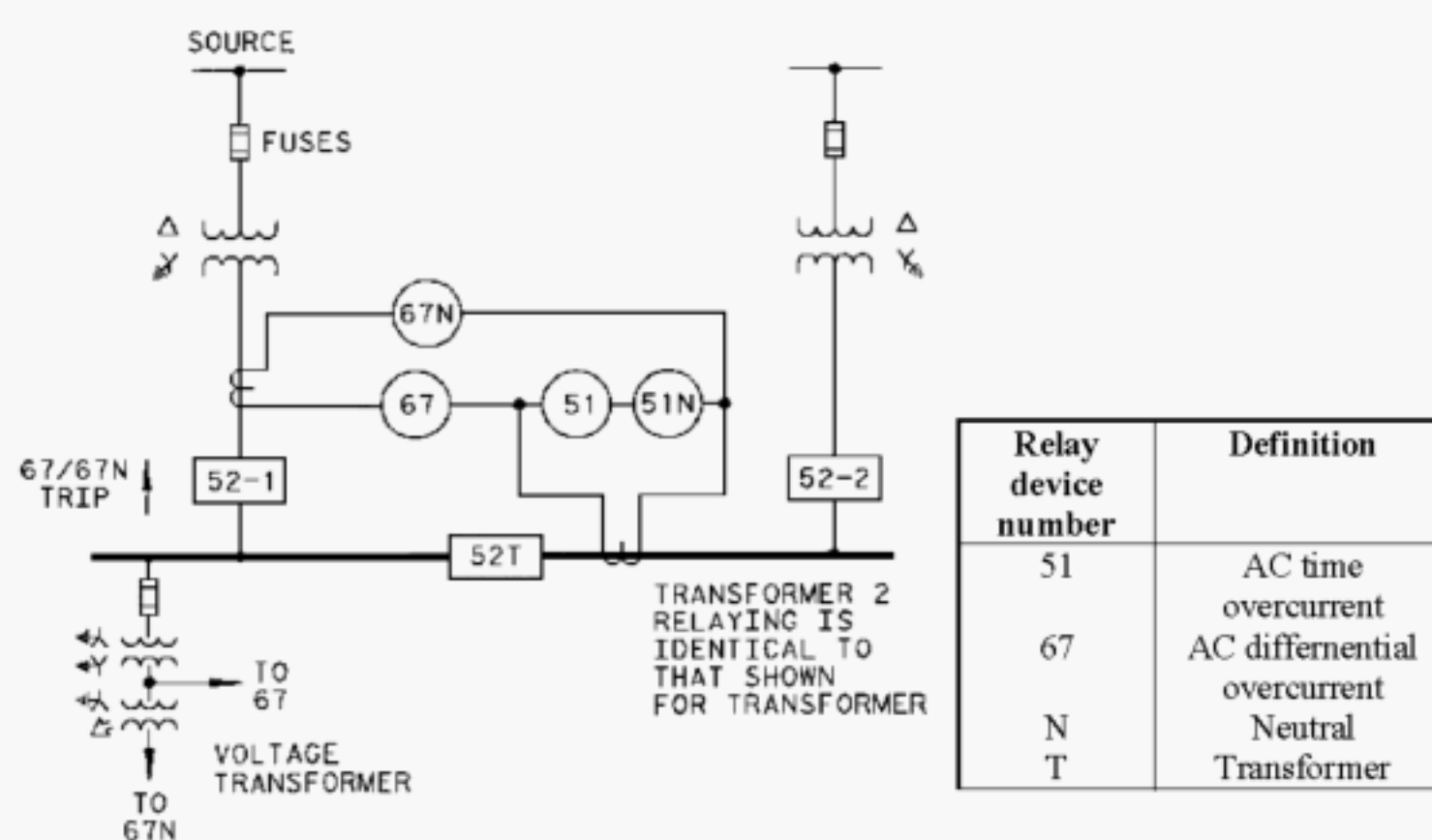


Figure 7—Paralleled transformer protection with primary fuses (no load or metering circuits shown)

If the transformer size does not warrant the basic schemes described above, the schemes shown in [Figure 6](#) and [Figure 7](#) may be used. Here, fuses provide the primary fault protection. Solid grounding will assure sufficient primary phase fault current to open the fuses for most secondary ground faults. In cases where secondary ground faults do not produce enough fault current to open primary fuses, a 51G relay may be used to trip a high-speed ground switch, as shown in [Figure 6](#). The opening of a single primary fuse will result in single phasing of the transformer secondary system. This may be difficult to detect, particularly at light loads, and appropriate precautionary measures should be taken. If the utility source is grounded and there is a power source on the secondary side, a ground fault on the incoming line will be interrupted by the utility breaker. The secondary breaker, however, will not be relayed open because no ground-fault current will flow through the delta primary transformer connection. Failure of the secondary breaker to open can result in hazards to personnel, possible damaging transient overvoltages produced by an arcing-type fault, and prevention of automatic reclosing of the utility breakers. Several schemes can be used for opening the secondary breaker under these conditions, including pilot protection of the incoming line, transfer-trip, reverse-power relaying, or potential ground-detection-relaying schemes on the transformer primary. The utility will prevent automatic reclosing of its breaker if the facility's secondary breaker is not open. Note that certain fusible switches are available that will automatically open all three phases should a fuse open on single-phase. In some cases, it is appropriate to specify Type 60, voltage or current balance/negative sequence, relay protection on the secondary of transformers with fused primaries to provide single-phase protection.

When a normally open bus tie is used, as in [Figure 5](#) and [Figure 7](#), Devices 67 and 67N are not required. Where transformers with no high-side breakers are applied as part of a line section, transfer tripping or the application of high-speed ground switches or circuit switchers operated by the transformer protective relays may be used for transformer protection. With a high-speed ground switch, a ground fault is initiated on the transmission line near the transformer location, provided that there is adequate fault current for the remote ground relays to trip the remote breaker and isolate the faulted transformer. This system is slower, but is widely used and is fairly simple and straightforward. It does not require any secure communication medium. For this type of application, the remote ground relays can be set to operate for 100% of the line and not overreach the low-side bus at the transformer location. The use of high-speed ground switches is not desirable where power quality is a major concern.

10.7.5.4 Facility main bus and feeder protection

Facility main bus protection may be provided by overcurrent or differential protection schemes. Overcurrent protection should be coordinated with that provided for transformer protection. When applied for bus protection, the partial differential scheme is most commonly used for protection of facility main buses. In this scheme, only the source circuits are differentially connected, using an overcurrent relay with time delay. The relays protecting the feeders or circuits are not in the differential. Essentially, this arrangement combines time-delay bus protection with feeder backup protection. Where some or all of the feeder circuits have current-limiting reactors, a partial-differential circuit is used with distance-type relays. These distance-type relays are set into, but not through, the reactor impedance. The reactor impedance is used to select between faults on the bus and external faults on the feeders. The scheme is both fast and sensitive. Feeder circuits are almost universally protected with time overcurrent relays for both phase and ground-fault protection.

Ground-fault relaying may be connected in the residual circuit of the current transformers, or may be connected to zero sequence (toroidal-type) current transformers. However, zero sequence type ground-fault protection, especially those involving time overcurrent relaying, should be limited to low-resistance grounded systems and not be applied on solidly grounded systems due to the susceptibility of the ground sensor current transformer to saturation at the high current levels associated with solidly grounded systems.

Prior to specification of equipment, short-circuit and protective-device coordination studies must be performed. The coordination effort is intended to produce a complete record of protective-device ratings and settings and suitable time current curves, etc., to promote proper and coordinated operation of all protective devices with the utility supply and for facility system faults. For more discussion, refer to Westinghouse Electric Corporation [\[B78\]](#), Chapters 4 and 5 of IEEE Std 141 (*IEEE Red Book™*) [\[B24\]](#), Chapter 15 of IEEE Std 242 (*IEEE Buff Book™*) [\[B27\]](#), and IEEE Std 1127.

An arc flash evaluation should be conducted using the short-circuit current values and protective device settings determined by the power system studies. Procedures for estimating the arcing current and arc flash incident energy are provided in IEEE Std 1584 [\[B46\]](#). The results of this evaluation are needed for the preparation of arc flash warning labels that must be affixed to electrical equipment in compliance with NFPA 70E [\[B58\]](#).

10.7.6 Primary switchhouse

Where a facility's switchhouse is required, it should be developed in conjunction with the substation arrangement and configuration since it is an equally important integral part of the service facility. The switchhouse contains the facility's medium-voltage switchgear, main bus, and related equipment. The switchhouse is typically located adjacent to the substation switchyard on the secondary side of the primary transformers in order to minimize expense associated with the secondary bus or cable connections from the transformer secondary to the facility's medium-voltage main breakers. The switchhouse is generally provided with heating, lighting, and ventilation services (or air conditioning) and with locked access to restrict entry to authorized personnel. For utility-owned substations, the utility will most likely require space in the facility's switchhouse for utility metering, station controls and batteries, data acquisition and monitoring, and protective relaying. This is often accomplished by partitioning a section of the switchhouse from the facility's portion

and restricting access to that section to the utility. Details need to be coordinated early so adequate space allowances are made.

The switchhouse may be constructed using traditional building methods where most fabrication is performed onsite. Another popular method is to employ an equipment power center (EPC) as a switchhouse. EPCs are prefabricated structures that are constructed off-site and then moved to their final location, in multiple modules if required for the size and transportation limitations. All electrical equipment is installed at the EPC fabricator premises, as well as all other ancillary equipment: HVAC, lighting, station batteries, etc. The only site work required is to prepare a suitable foundation with allowances for any required underground conduits, anchor the EPC to the foundation upon arrival, followed by pulling and terminating all interconnecting power and control circuits. An EPC can provide several advantages:

- The EPC enclosure can be fabricated from corrosion-resistant materials, such as stainless steel, when required for the environment in which it is located.
- Total cost to install can be less because onsite labor is minimized.
- The EPC design is very flexible in its ability to adapt to a variety of support structures: concrete slabs, piers, mezzanines, etc.
- The footprint of an EPC can be minimized by locating rear-access type equipment against an exterior wall that has doors or covers to access the rear of the equipment.

10.7.7 Drawing approvals

The utility will probably require that specifications and drawings for all of the facility's primary equipment and relaying that is an integral operating part of the utility grid be submitted to the utility for its approval before equipment purchase by the facility representatives. The drawings may need to be reviewed and sealed by a licensed professional engineer. Carefully prepared specifications and an approved vendor list that meets with utility approval will increase the chance that the equipment selected is acceptable to the utility. The utility should identify its areas of responsibility with respect to the facility's system and indicate which related manufacturer's drawings they wish to review for both the preliminary and final designs. The utility should send copies of substation drawings, especially the grounding drawings and relay schematics, to the facility representatives, who may need to review them for certain interface items.

10.8 Construction stage

10.8.1 Project management

Although owners may not have the in-house or resident engineering resources available for all planning and design tasks, the facility management should provide a project manager to oversee the facility's responsibilities and to provide coordination between the facility, the utility, and the engineering consultant. Periodic meetings between the various parties are recommended during the construction stage to facilitate proper coordination and to ensure that all problems and concerns that arise are promptly addressed and resolved.

10.8.2 Inspection during construction

In the utility-owned portion of a substation, the utility will, of course, have major inspection responsibilities. In the facility-owned portion of a substation, the utility will have relatively little concern with the construction phase, except to periodically review the construction schedule to determine if the project is on time, and to make sure facility crane or digging operations do not take place too close to utility power lines. It is the responsibility of the facility representatives and the engineering contractor to inspect and make reasonable checks of the major equipment during manufacture and factory testing to assure that the product is delivered consistent with specifications. Some utilities may choose to witness the high-voltage equipment performance test, although certified test results are usually sufficient.

10.8.3 Final testing

The facility's construction contractor should have responsibility for installing all the equipment as defined by the drawings and scope of work. The contractor is then responsible for checking all connections in the wiring between units. Verification that the contractor has correctly interpreted the drawings and that the drawings are correct should be done by an outside testing company or engineering consultant that has experience testing high-voltage substations (refer to IEEE Std 510™ [B33]). For utility-owned transformers, the facility representatives may want to witness final testing. For facility-owned transformers, the facility representatives, along with the facility's technical consultant, should witness and verify all final tests. The utility will require, as part of its acceptance review, which tests and/or calibrations it plans to witness. Calibration and setting data must be provided in sufficient time for proper review by the utility. The testing or commissioning contractor should be involved in the project to witness the general contractor continuity test. Commissioning activities commonly include the posting of arc flash labels on electrical equipment owned by the customer. Final tests should, at a minimum, include the following:

- a) Transformer and switchgear polarity tests on potential and current transformers. For multiple taps on current and voltage transformers, a determination that the proper taps are selected and the unused connections are properly secured. All current and potential circuits should be suitably tested to verify continuity, proper phasing, and polarity, and grounding.
- b) Calibration and testing of all relays, timers, trip circuits, and closing circuits, etc. These tests should be possible since control voltage is available from the station battery. Voltage-sensitive relays may be tested separately, and it may be necessary to block or bypass this control until the station is online. Protection systems tests may include the following:
 - 1) Remote trips to and from the utility
 - 2) Line trips back toward the utility
 - 3) Transformer differentials, sudden pressure relays, ground backup and step (time-delay) tripping
 - 4) Breaker failure
 - 5) Trip and close modules
 - 6) Tie breaker controls
 - 7) Reactor shorting controls
 - 8) Automatic reclosing controls
 - 9) Bus-differential and bus-backup tripping
- c) Operation of all disconnect switches and circuit breakers, including operation of any mechanical and electrical interlocks. Air break switches and grounding switches should be carefully checked for contact and alignment.
- d) Resistance of the ground loop to a remote ground (refer to IEEE Std 81™ [B23]).
- e) Ratio test on power transformer at all tap changer settings. Set fixed taps to requirements.
- f) Insulation power factor test or tan delta test on power transformers.
- g) Complete transformer oil tests.
- h) Insulation tests on switchgear.
- i) High-potential dc tests on cables (refer to IEEE Std 400™ [B29], IEEE Std 1242™ [B44], and IEEE Std 3007.2™ [B49]).

10.8.4 Plan for energizing

After all the relays and circuits are tested and the proper settings made, the utility may wish to review the test results unless they have already witnessed the testing. At this point, the utility and facility representatives should prepare a schedule or sequential plan for energizing the substation. Typical steps for station energizing include the following:

- a) Locking out incoming switch or circuit breaker.
- b) Connecting incoming lines to utility system. This work is customarily the responsibility of the utility. This connection will probably require an outage by the utility.
- c) With transformer secondary and feeder breakers open, closing the primary switch or breaker. This operation should be repeated several times to assure that good contacts are made.
- d) Checking secondary voltage, adjusting de-energized tap changer as needed (after opening primary switch or circuit breaker), and set automatic tap changer (if applicable). Verify correct phase rotation.
- e) Closing transformer secondary main breaker to energize bus.
- f) For dual-source substations, checking phasing across tie breaker and all lock out and transfer schemes.
- g) The substation will be ready to receive load after the usual equipment no-load waiting period recommended by most manufacturers.
- h) Upon application of load, verifying and recording currents in the protective-relaying circuits.

10.8.5 Operating stage

10.8.5.1 Introduction

This stage involves the planning for the operation and maintenance of the station and the documentation of all required tests, inspections, calibration, and coordination data necessary for proper station operation. Operation and maintenance plans should be prepared and available before the substation is placed in service.

10.8.5.2 Operating requirements

Even if the utility does not own and cannot maintain the substation, their typical substation operating and maintenance practices and procedures manuals for their similar or equivalent substations should be reviewed and used as a basis, as appropriate, for developing applicable procedures. These utility practices can provide invaluable guidance to an outside contractor that may be hired to perform the maintenance work and prepare the operating and maintenance manuals for the substation. The operating data involved includes the test results for final station testing, relay and protective service settings, station operation and switching procedures, normal and emergency operating conditions, repairs, switching conditions, and an operational record of the substation commissioning.

Occupational Safety and Health Administration (OSHA) regulations should be considered, since it may be that the utility's practices are not allowable on an industrial system due to differing governmental regulations. The owner's electrical safety program documentation will need to be updated to reflect the hazards and procedures that must be followed that are associated with the substation operation. Whether work is performed by customer employees or by qualified contractors, owners are ultimately responsible for all safe work practices on their premises.

10.8.5.3 Documentation

The operational sequence, operation and maintenance procedures, practices, conditions, and schedules are generally compiled in the operation and maintenance manual for the station. This manual outlines the various tests and inspections, and their frequency, equipment repairs, and other work to be performed for the

periodic maintenance of the substation. A sufficiently detailed description of the protective-device sequence of operation should be included in the manual. This should include the utility's supply protective-device operation, interconnections with the facility protective devices, and the facility's protective devices. The operation and maintenance manual should be supplemented by as-built record drawings of the substation. The as-built drawings are an important reference document for maintenance, troubleshooting, servicing, and future planning activities.

10.8.5.4 Maintenance

Generally, for facility-owned substations, a third party is contracted to perform substation maintenance work since most facilities lack the resources and experience to properly maintain high-voltage equipment. This third party may be an independent high-voltage electrical testing contractor, or the utility may be hired to perform the work. The substation maintenance work is generally based on the inspection and maintenance performed by the utility for its own similar substations and/or recommendations from the independent contractor hired to perform the work if the utility cannot or will not perform it. This maintenance program typically entails a one-time inspection of the entire substation, thereby establishing a baseline reference for periodic checks and inspections. This one-time inspection should include fencing; structure steel; electrical equipment; foundations; checks on all liquid and gas pressures, levels, and temperatures; fluid and gas sampling of all liquid-filled equipment; various operation tests as applicable; protective relaying; thermographic surveys; and electric equipment tests. A program of periodic checks and inspections is then developed, which includes routine daily, weekly, quarterly, and annual inspections and other less frequent routine inspections, such as those of relaying, circuit breakers, transformers, and infrared equipment.

10.8.5.5 Spare parts

A recommended spare-parts inventory should be developed for the station. The equipment and parts should be purchased as part of the original purchase contract and maintained on hand to take care of any unforeseen emergency problems. Specific spare-part recommendations depend on the substation configuration and local operating practices and experiences. Sources for spare part recommendations include the facility's utility who may have operating experience with the same equipment and the suppliers of the purchased equipment. An independent high-voltage electrical testing contractor that might be retained to perform maintenance work on the station can also provide recommendations. The typical spare parts maintained might include such items as close and trip coils for high-voltage circuit breakers, high- and low-voltage surge arresters for the station, and items for the primary transformers, such as high- and low-voltage bushings, valve sockets, stationary, moveable LTC contacts, control fuses, and spare batteries. Some spares that have a limited shelf life, such as cable termination kits, electronic cards for protection relays, and components for automation systems, etc., must be clearly identified in the inventory.

Annex A

(informative)

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²⁰Available online at <http://www.gsa.gov/p100>

²¹Available online at <http://www.coned.com/es/electricbluebook.pdf>

²²USDA Rural Utilities Service Bulletins available online at http://www.rurdev.usda.gov/RDU_Bulletins_Electric.html. To obtain copies of bulletins that are not available online, contact Adam Miller by email at adam.miller@wdc.usda.gov or by phone at (202) 720-8674 (not toll-free)

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²³Available online at https://www.wbdg.org/ccb/ARMYCOE/COETM/ARCHIVES/tm_5_811_6.pdf

²⁴Available online at http://armypubs.army.mil/eng/DR_pubs/dr_a/pdf/tm5_811_1.pdf

²⁵Available online at <http://www.pge.com/en/mybusiness/services/nonpge/electrictransmission/contractstariffs/handbook/index.page>

²⁶Department of Defense Unified Facilities Guide Specifications available online at http://www.wbdg.org/ccb/browse_cat.php?c=3.

²⁷UL publications are available from Underwriters Laboratories (<http://www.ul.com/>).

²⁸Available online at <http://earthquake.usgs.gov/earthquakes/map/>

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