IEEE Std 1109-1990

IEEE Guide for the Interconnection of User-Owned Substations to Electric Utilities

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Substations Committee of the
IEEE Power Engineering Society

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IEEE Std 1109-1990

Published by the Institute of Electrical and Electronics Engineers, Inc., 345 East 47th Street, New York, NY 10017, USA.

July 17, 1990 *SH13409*

IEEE
Std 1109-1990

IEEE Guide for the Interconnection of User-Owned Substations to Electric Utilities

Sponsor

Substations Committee
of the
IEEE Power Engineering Society

Approved May 31, 1990

IEEE Standards Board

Abstract: IEEE Std 1109-1990, *IEEE Guide for the Interconnection of User-Owned Substations to Electric Utilities*, provides a checklist and selected guidance, for persons not normally practicing in this specialized field, of major technical design areas that should be considered when interconnecting user-owned and utility-owned facilities at substations. Only medium- and high-voltage purchased-power interconnections are addressed. This guide does not discuss the considerable implications of interactive power systems design and operation, nor does it present criteria or directions for the design of substations.

Keywords: high-voltage purchased-power interconnections, interconnections, medium-voltage purchased-power interconnections, non-utility generation, substations, user-owned and utility-owned facilities at substations

ISBN 1-55937-041-6

The Institute of Electrical and Electronics Engineers, Inc.
345 East 47th Street, New York, NY 10017-2394, USA

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Foreword

(This Foreword is not a part of IEEE Std 1109-1990, IEEE Guide for the Interconnection of User-Owned Substations to Electric Utilities.)

This guide provides a "checklist" and selected guidance, for persons not normally practicing in this specialized field, on topics that should be considered when developing the interconnection of user-owned and electric-utility-owned electric power facilities, particularly substations. This guide is concerned with large substations for purchased-power-only service and also with substations of all sizes associated with the interconnection of user-owned generating (interactive power, dispersed power, cogeneration, or small-power-producer) facilities.

This guide is concerned with generation (interactive electrical system) interconnections of all magnitudes to the degree that the substation facilities are affected. However, it is not within the scope of this guide to discuss in detail the considerable implications of interactive power systems design and operations, since these are covered in other documents.

A listing of code and standard agencies relevant to substation design is included in the Appendix.

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IEEE Guide for the Interconnection of User-Owned Substations to Electric Utilities

1. Introduction and Scope

This guide presents a "checklist" of major technical design areas that should be considered when interconnecting user-owned and utility-owned facilities at substations. Guidance is presented in selected areas of particular importance.

This guide principally provides guidance for the interconnection of user-owned substations. In this regard only medium- and high-voltage purchased-power interconnections are addressed, since low-voltage (and some medium-voltage) interconnections for typical residential, commercial, and small industrial energy purchase are adequately covered by existing electric utility practices and standards.

Historically, most utilities with a significant industrial base load have established technical guidelines for large purchasers of electric energy when the user's demand mandates the construction of a medium- or high-voltage substation having a capacity greater than 500 kVA and connected to a three-phase power interconnection with a voltage greater than 15 kV. These substation and interconnection facilities were usually for the user purchase of electric power only. The presence of a user's own in-house generation facility was uncommon enough to be handled on a case-by-case basis.

The advent of the Public Utilities Regulatory Policies Act (PURPA) of 1978, as well as other public laws, has precipitated the development of numerous new electric power generating facilities that are necessarily interconnected to established electric utilities. It is common for these "dispersed" facilities to be fostered by entrepreneurial organizations that may or may not be cognizant of the complexities associated with connecting to and interacting with a large electric system by means of a dedicated substation facility, such as is addressed by this document. Therefore, this guide does address in general the interconnection of interactive (dispersed generation, cogeneration, and small-power producer) facilities of all sizes with electric utilities, to the degree that the interconnection substation design is affected. However, the subject of interactive power systems is addressed in greater detail in the publications of other agencies or committees.

It is not the intent of this guide to present detailed design criteria or directions. And it is beyond the scope of this document to discuss commercial or contractual issues, which are covered by other existing industry codes, standards, and practices. Also, detailed discussions of the design and operation of interactive power systems (cogeneration, dispersed power, small power producers; and user-owned generation) are not included, since it would be beyond the scope of this document and since these topics are covered by other existing or forthcoming documents.

A listing of related code and standard agencies is included as an appendix to aid the users of this guide in finding other codes and standards applicable to the design, operation, and equipment selection of proposed interconnection substations.

2. Definitions and References

2.1 Definitions

cogeneration. The generation of electric energy and commercial or industrial quality heat or steam from a single facility.

dispersed power. An electric power generation source (or sources) not directly under established electric utility ownership and control.

electrical system. The existing utility network consisting of interconnected and synchronized generation, transmission, and distribution facilities.

generation. The production or storage, or both, of electric energy with the intent of enabling practical use of commercial sale of the available energy. This includes photovoltaic, windfarm, hydro, etc., as well as normal commercial and industrial thermal sources.

interactive electrical systems. Two or more interconnected and compatible electrical systems with appropriate protection and measuring provisions at their interconnection point(s).

interconnection. The physical plant and equipment required to facilitate the transfer of electric energy between two or more entities. It can consist of a substation and an associated transmission line and communications facilities or only a simple electric power feeder.

small-power producer. A non-utility generation source that is a qualifying small-power production facility under PURPA and the Federal Energy Regulatory Commission (FERC).

user (or customer). The independent party that may be a purchaser of utility electric power or a producer of electric energy for sale to an electric utility or both.

2.2 References. This guide shall be used in conjunction with the following publications. When the following standards are superseded by an approved revision, the revision shall apply.

[1] ANSI C2-1990, National Electrical Safety Code.[1]

[2] ANSI C84.1-1989, Voltage Ratings for Electric Power Systems and Equipment (60 Hz).

[3] IEEE Std C37.1-1987, IEEE Standard Definition, Specification, and Analysis of Systems Systems Used for Supervisory Control, Data Acquisition, and Automatic Control (ANSI).[2]

[4] IEEE Std C37.2-1987, IEEE Standard Electrical Power System Device Function Numbers (ANSI).

[5] IEEE Std C37.122-1983, IEEE Standard Gas-Insulated Substations (ANSI).

[6] IEEE Std 80-1986, IEEE Guide for Safety in AC Substation Grounding (ANSI).

[7] IEEE Std 81-1983, IEEE Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Ground System (ANSI).

[8] IEEE Std 525-1987, IEEE Guide for the Design and Installation of Cable Systems in Substations (ANSI).

[9] IEEE Std 605-1987, IEEE Guide for Design of Substation Rigid-Bus Structures (ANSI).

[10] IEEE Std 979-1984, IEEE Guide for Substation Fire Protection (ANSI).

[11] IEEE Std 980-1987, IEEE Guide for Containment and Control of Oil Spills in Substations (ANSI).

[12] IEEE P998 (Draft), Guide for Direct Lighting Stroke Shielding of Substations.[3]

[13] IEEE Std 1001-1988, IEEE Guide for Interfacing Dispersed Storage and Generation Facilities With Electric Utility Systems (ANSI).

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[1] ANSI publications are available from the Sales Department, American National Standards Institute, 1430 Broadway, New York, NY 10018, USA.

[2] IEEE publications are available from the Institute of Electrical and Electronics Engineers, Service Center, 445 Hoes Lane, Piscataway, NJ 08855-1331, USA.

[3] This draft document is currently in production; when it is completed, approved, and published, it will become a part of the references of this guide.

[14] IEEE Std 1119-1988, IEEE Guide for Fence Safety Clearances in Electric-Supply Stations (ANSI).

[15] IEEE P1127 (Draft), Guide for the Design, Construction, and Operation of Safe and Reliable Substations for Environmental Acceptance.[4]

[16] NFPA 70-1990, National Electrical Code (ANSI).[5]

3. System Interconnection Considerations

Whether a proposed interconnection is for an interactive (i.e., including user-owned generation) or purchased-energy-only facility, the following significant design factors should be considered for the high-voltage electric power interface. Care should be taken to ensure that each party of the interconnection uses a comparable basis for ratings (i.e., temperature rise) and the same formulas for calculations (e.g., transformer loss-of-life or no-loss-of-life for overloading) to avoid wasteful overbuilding on the one hand or potentially destructive overloading on the other.

3.1 Voltage, Voltage Range, Frequency, and Frequency Range. Interconnection facility ratings should be selected to operate satisfactorily with the utility's nominal and normal operating voltage and frequency. Further, the design of the interconnection facility should consider the anticipated minimum and maximum voltage ranges below and above nominal, respectively. Typical permissible voltage ranges are up to ±5% of nominal voltage and can be higher. It is particularly important to determine the impact of starting large motors and other major equipment under low-voltage conditions. Standard nominal system voltages and voltage ranges can be found in ANSI C84.1-1987 [2][6]. The nominal operating frequency in the United States is 60 Hz. Under normal conditions, the instantaneous operating frequency may range from 59.970 to 60.030 Hz. For interconnected utility operation, frequency is usually discussed, measured, and displayed with a resolution of 0.001 Hz. In other parts of the world, other nominal operating frequencies (for example, 50 Hz) and other ranges of instantaneous operating frequency may be used.

3.2 Phase Rotation and Phase Position. The phase designation (A, B, C; 1, 2, 3; etc.) should be consistent and the phase sequence should be coordinated, particularly for user-owned generating facilities, as discussed elsewhere. The phase position must be known if the user facility has interconnections to different utility voltage levels or different utility locations that may have a relative phase shift by virtue of geography or differing system transformer configurations. Accommodating different phase positions is usually accomplished with appropriate transformer connections or by maintaining isolation of out-of-phase user facilities, either administratively or by permanent lack of interconnection.

3.3 Fault Interrupting and Momentary Ratings. Power generation and distribution equipment directly connected to an electric utility can be subjected to fault levels that are largely a product of the utility system's characteristics and the interconnection impedance. Therefore, the user-owned facilities must possess sufficient fault interrupting and momentary withstand ratings to meet the maximum expected utility system requirements, with appropriate margin for future system growth. Large user-owned generators and synchronous motors can also be another source of fault current contributions to a utility system. Conversely, for planned user-owned generation systems, it is necessary to confirm the utility system's ability to accommodate the additional fault interrupting and momentary withstand requirements.

3.4 Continuous Ratings. The continuous ratings of electrical power apparatus associated with the interconnection should be sufficient to accommodate the user's maximum load (or generation) as well as contributions resulting from system exchanges, such as power from the utility system being transferred ("wheeled") through the user's facilities, as

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[4] See footnote 3.

[5] NFPA publications are available from Publications Sales, National Fire Protection Association, Batterymarch Park, Quincy, MA 02269, USA.

[6] The numbers in brackets correspond to those of the references in 2.2.

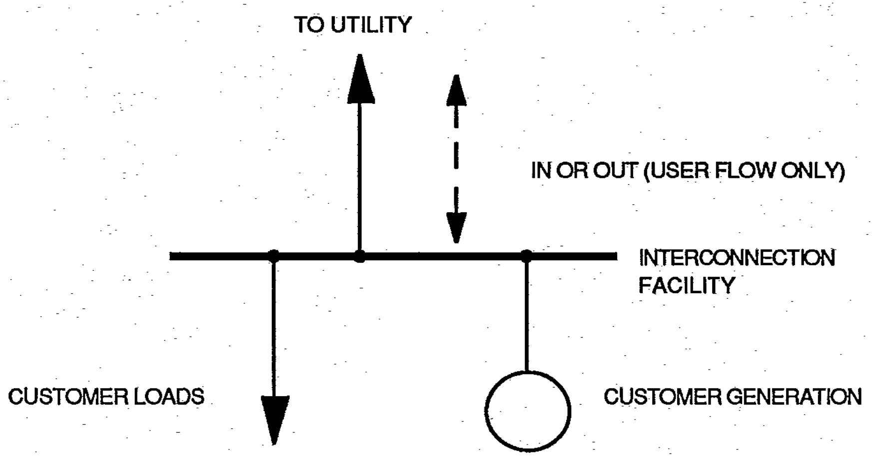

Fig 1
Radial Service (or Dedicated Service)

NOTE: The user-utility interface points indicated on the figures are shown only to compare alternate substations configurations and do not necessarily indicate the specific interface point(s) that may be negotiated between a user and the local utility.

can be the case if there is more than one point of interconnection with the utility. The determination of whether or not there will be system electric-energy exchanges depends on the type of service and the configuration of the interconnection facility (i.e., substation), as is discussed in other sections. If a system energy exchange can be expected to be superimposed on the specific user facility loads (or generation), the utility is the source of information regarding the magnitude and conditions of this occurrence.

3.5 Types of Service. The overall interconnection of a user-owned facility can be generally classified as either *radial* (or *dedicated*) or *loop* service.

Radial service consists of one or more lines configured in a manner such that only the user's load (or generation) constitutes the total loading of the interconnection line or lines. In effect, it is a branch of the utility system, with no power flow other than the user's load or generation passing through the interconnection facility (see Fig 1).

Loop service, however, consists of two (or more) lines configured in a manner that permits utility system exchange power to flow through the interconnection facility in addition to the user's load (or generation) contributions (see Fig 2).

Both radial and loop service substations can be arranged in numerous (and similar) configurations, as is discussed elsewhere in this guide.

3.6 Load and Power-Factor Considerations. The magnitude, integrity, duration (load factor), and time-of-day availability of the user's load (or generation) will normally be of great commercial interest to both parties. In addition to the impact that the magnitude of real power that is to be accommodated can have on ratings and configuration of facilities, the demand for (or generation of) reactive power may also warrant equivalent attention. Any large, purchased-power user may be expected to maintain the overall facility power factor at or above a level agreed between the local utility and the user.

A penalty charge may be incurred by the user for even a momentary deviation from the specified power factor. It is not uncommon for large industrial power users to include shunt capacitors or synchronous motors or both in their plants to offset the reactive power demands resulting from the induction motor load of the facility. Where capacitors are present, however, consideration should be given to the potential problems of electrical system self-excitation of induction machines, reso-

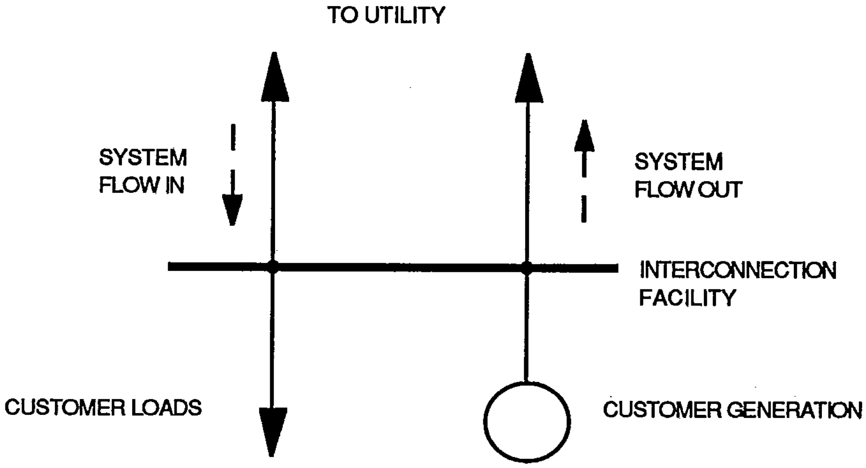

Fig 2
Loop Service

nance, and waveform distortions in rectifying equipment.

Conversely, user-owned generating facilities may well be expected to produce reactive power inherent within equipment capabilities and make it available to the system, as is discussed further in 5.5. This is a capability that cannot be achieved with induction generators.

4. Substation Configuration

Normally, some type of substation facility will be necessary to provide for the termination of the utility interconnection line(s). This substation usually contains the necessary switching and protective devices as needed to isolate and mitigate the effects of faults, to synchronize system elements, and to permit routine maintenance and switching. The substation can also be the location for any required power transformers to match voltages. Aesthetics should be considered where local conditions require special attention (see IEEE P1127 [15]).

4.1 Breaker Arrangement. Power circuit breakers and their associated bypass and disconnecting switches, where present, usually constitute the most significant active components of a substation. Breakers are used for load switching, synchronizing, disconnecting generation, and interrupting fault current. The use of bypass switches, particularly on main service breakers, is normally discouraged because of the loss of fault-protection coordination during the period the bypass switch is in service. (Using a transfer breaker and transfer bus can avoid this concern).

The simplest breaker arrangement is a single-series breaker in a simple radial arrangement (see Fig 3). However, any scheme requiring more than one connection element each (i.e., line or load) for the utility or customer, or requiring loop service, will necessitate a more complex breaker arrangement. Several of the most common alternatives are: loop service (Fig 4), "H"-tie (Fig 5), ring bus (Fig 6), main and transfer bus (Fig 7), breaker and one half (Fig 8), and double breaker, double bus (Fig 9).

The final selection of one particular breaker arrangement (or a hybrid arrangement) depends on an engineering analysis of reliability and cost, both of which are functions of the number of breakers per line and the number of load or generation source(s). The arrangement should be acceptable to both the user and the utility.

Utilities may recommend a scheme that has been demonstrated by past performance to be appropriate for their service area. Figs 4, 5, 6, and 7 would include most typical user-owned installations. Fuses and circuit interrupters

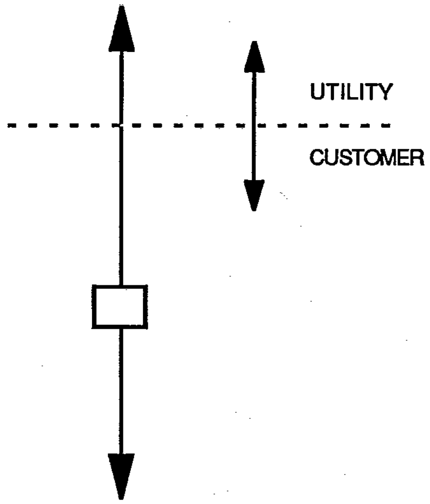

Fig 3
Radial Arrangement

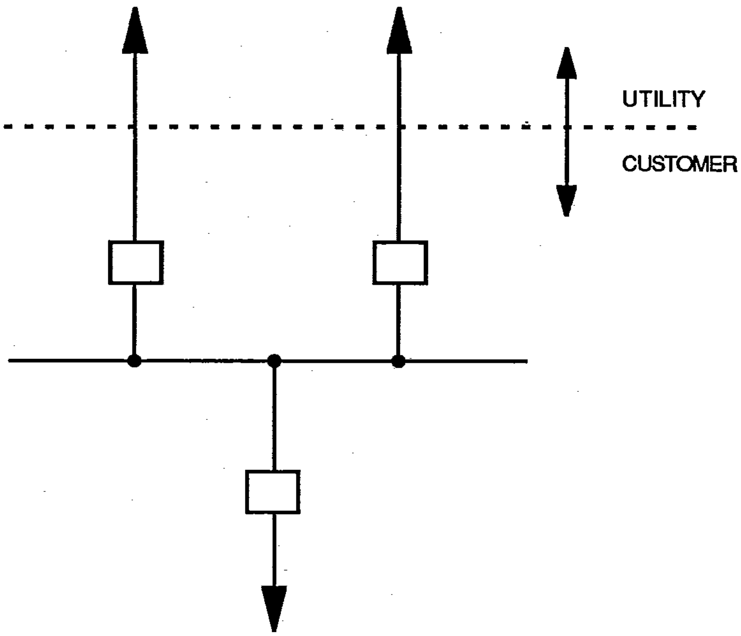

Fig 4
Loop Service Arrangement

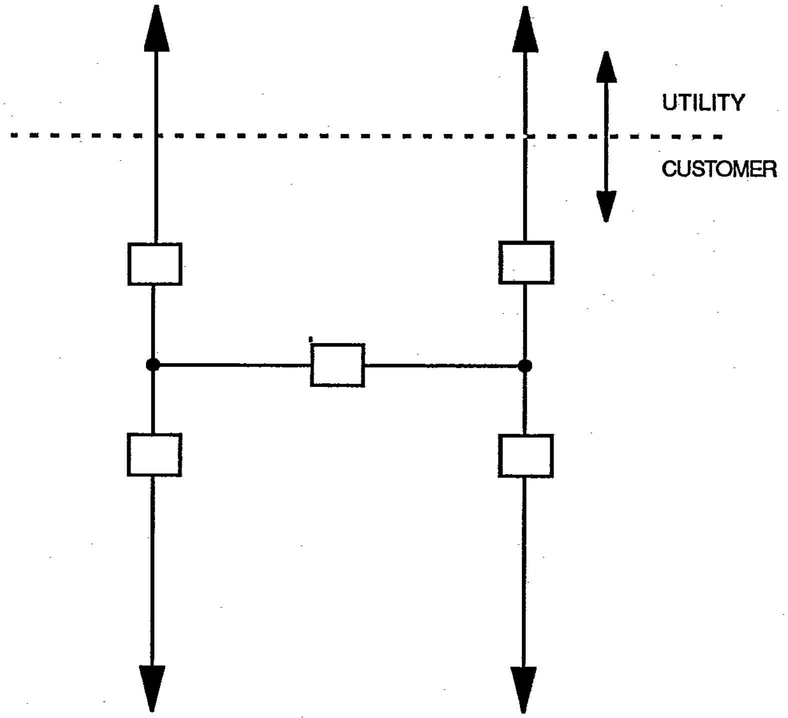

Fig 5
"H"-Tie Arrangement

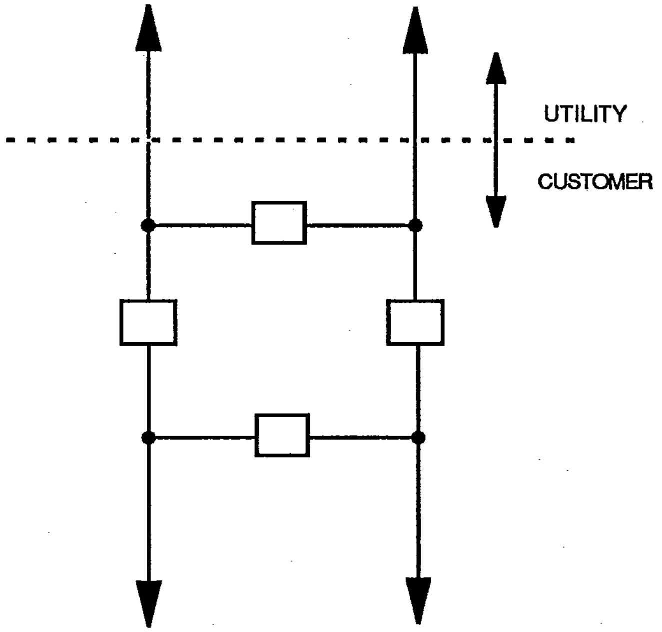

Fig 6
Ring Bus Arrangement

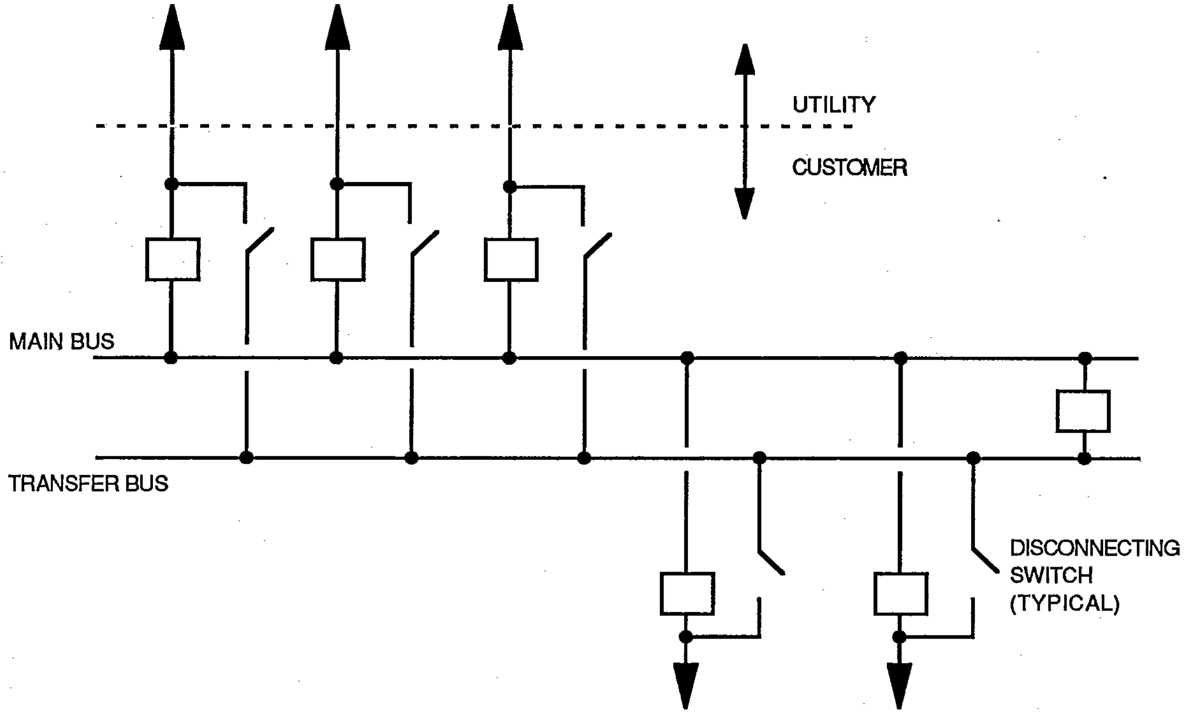

Fig 7
Main and Transfer Bus Arrangement

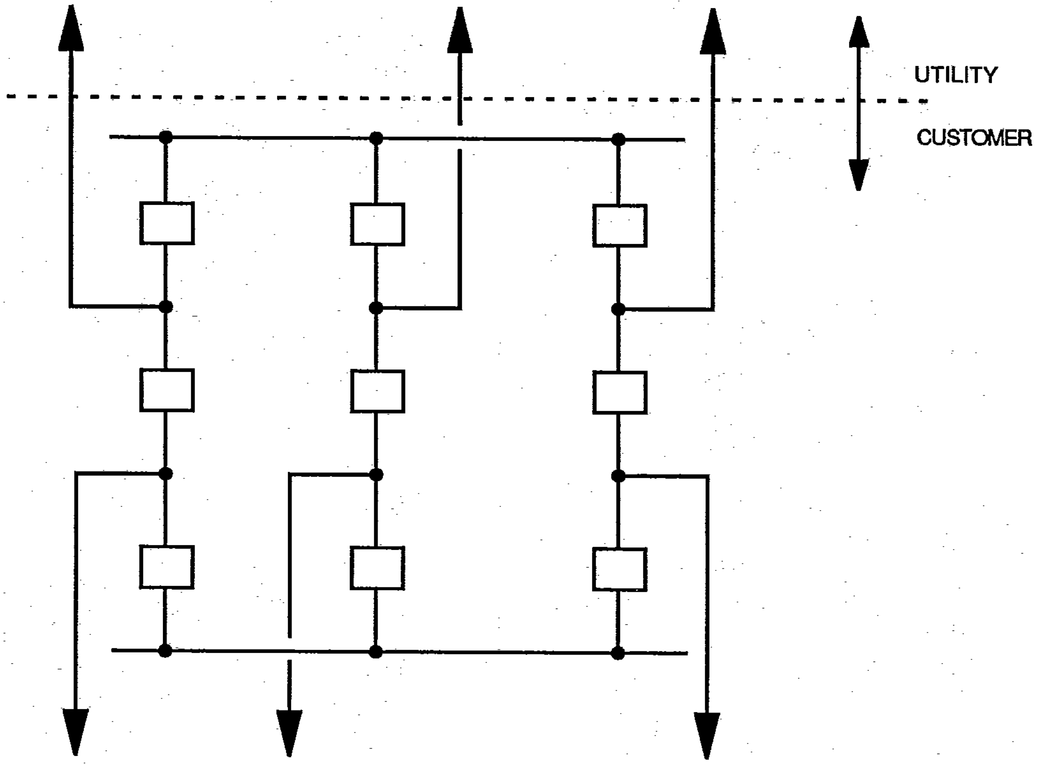

Fig 8
Breaker and One-Half Arrangement

can sometimes be used in lieu of circuit breakers for protection and switching of circuits. These devices are usually used only for low-voltage or lower-medium-voltage (i.e., 15 kV voltage class or less) applications. Further, user-owned generation may include its own dedicated generator breaker. Relaying of the generator breaker should be coordinated with the substation protective relaying.

4.2 Power Transformer Connections. Both user and utility should agree on the connection scheme for power and metering (instrument) transformers (wye-delta, delta-wye, wye-wye, zig-zig, autotransformer, etc.), as well as transformer capacity and voltage ratings. The selection (or absence) of wye-connected system grounding sources can have significant implications on reliability, protective relay selection, metering, fault levels, overvoltage conditions, and equipment cost.

In typical present-day practice, high-voltage utility connections are solidly wye-grounded; plant medium-voltage systems are resistance wye-grounded; and low-voltage systems are also solidly wye-grounded. There are exceptions to all of these.

When choosing transformer connections, the phase shifts should be considered to ensure proper synchronization of any interactive power systems. Transformer design selection will require analysis of the utility system and local generator characteristics (see Section 5).

4.3 Switch and Bus Construction. Substation switch and bus facilities can be open-air insulated, or metal-enclosed SF_6 (sulfur hexafluoride) gas-insulated, or another type of construction. The conventional outdoor air-insulated substation normally uses aluminum cable or tubing for bus conductors because of economic advantages. (See IEEE Std 605-1987 [9].) Copper is sometimes encountered in older stations or where corrosive environmental conditions preclude the use of aluminum. Energized parts are supported by porcelain, glass, polymer, or epoxy insulators and are maintained at safe vertical and hori-

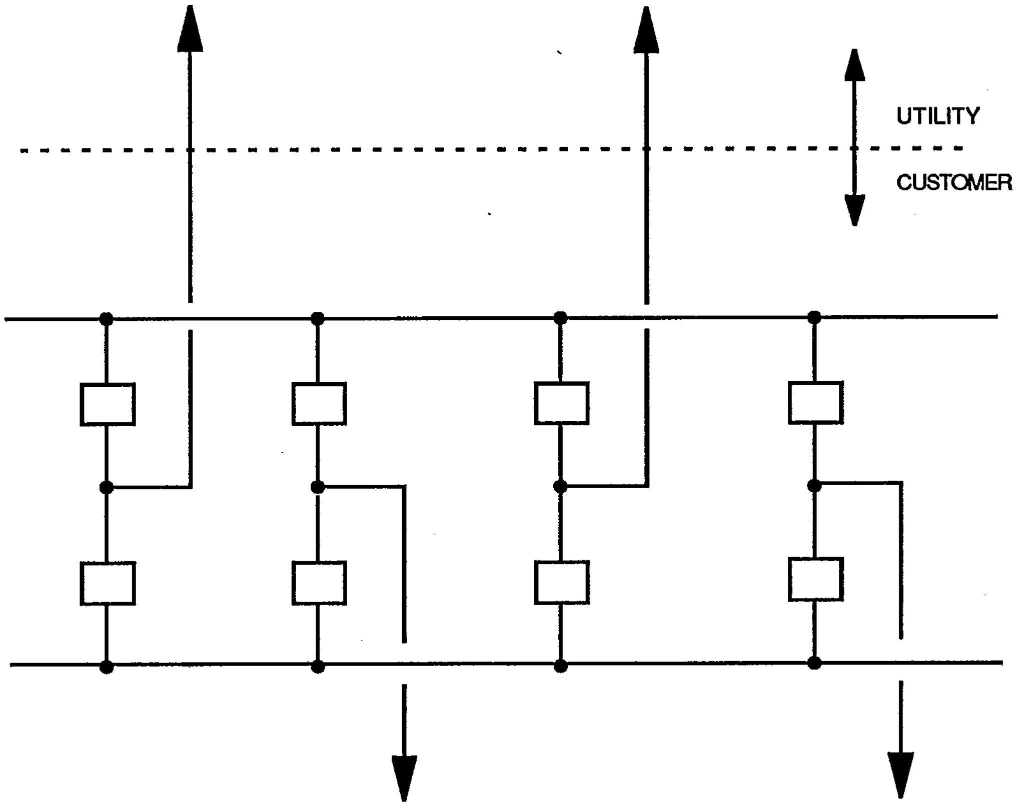

Fig 9
Double-Breaker, Double-Bus Arrangement

zontal clearances, which are dictated by industry or utility standards and code requirements, such as ANSI C2-1990 [1] and IEEE Std 1119-1988 [14]. Compact SF_6 gas-insulated substations (GIS) are generally installed where space is at a premium or contamination is a factor. All energized parts are concentrically placed in metallic enclosures that are at ground potential. The spaces between the live parts and the enclosures are filled with SF_6 gas at an appropriate pressure to achieve the desired dielectric strength. See IEEE Std C37.122-1983 [5] for further information on GIS.

Supporting structures for electrical equipment are most commonly constructed of galvanized steel. Other materials that can be used are aluminum, concrete pedestals, weathered steel, metalized steel, painted steel, and wood.

Metalclad switchgear is typically used for medium-voltage outdoor distribution substation facilities operating at 15 kV or less and occasionally for voltages greater than 15 kV, up to 38 kV.

Particular attention should be paid to access and removal of equipment, particularly transformers. Also, transformers may require consideration of sound attenuation, oil-fire prevention, and oil-spill mitigation measures, particularly in residential or wetland areas. IEEE Std 979-1984 [10] and IEEE Std 980-1987 [11] provide further guidance on fire prevention and oil-spill containment, respectively.

4.4 Interconnecting Lines Location and Orientation. The location and orientation of the substation facility should consider the direction and ultimate destination of the overhead or underground transmission lines connecting to either the utility or the user's facilities.

Provision should be made for appropriate right-of-way widths, avoidance of structures and other existing facilities, turning-tower positioning, and conductor-phase transpositions. The use of underground power cables is a technically feasible but usually more expensive alternative to overhead lines, particularly for voltages above 38 kV.

4.5 Control Building. A substation usually includes a building or enclosed area to provide a clean, dry indoor environment for needed relaying, metering, control, and communication equipment.

4.6 Future Expansion Consideration. Provision should be included in any substation for future expansion as needed to accommodate additional utility interconnections, additional user interconnections or loads, and additional breaker or switching complexity.

5. Interactive Power (User-Owned Generation) Considerations

The presence of user-owned generating facilities operating in parallel with a large electric utility entails operational complexities that would not exist in the case of a purchase-power-only user, as follows and as is further discussed in IEEE Std 1001-1988 [13].

5.1 Synchronizing. A proper synchronizing scheme consisting of necessary relays, indicators, control facilities, and a properly rated power circuit breaker should be provided for each generator to be connected to an interactive power system.

The synchronizing breaker(s) can be located in a user substation facility or in the power generating facility, depending on specific site conditions, load current magnitude, electrical system configuration, and equipment cost. The synchronizing breaker should be relatively close to the generator it serves, since there is a voltage drop limit for direct (hard-wired) equipment control circuits. (See Section 9 for a discussion of control and communications options).

5.2 Startup/Auxiliary Power. Any generating facility should provide for its normal plant (or station) auxiliary power requirements. These loads can be supplied from the user's own load buses or from the substation facility. If the generator is a unit-connected arrangement (i.e., normal auxiliary loads provided from the generator bus), an additional power source is needed to supply the auxiliary loads when the generator is off-line or not synchronized. Further, an appropriate transfer scheme should be provided to permit the transfer of auxiliary load from startup to normal source and vice versa.

The phase relationship of these two sources must be coordinated, especially if they originate at different voltage levels or if they include different voltage transformation sequences. Voltage regulation will be a consideration, since the generator(s) could be supporting the system voltage during operation or the generator auxiliary loads could be acting as a major load during the startup mode.

5.3 Generator Grounding. The grounding of a generator should be fully evaluated with regard to its impact on the following:

(1) The maximum fault-current level to which the generator will be subjected
(2) The presence of sufficient ground fault current to permit detection and selective isolation of the faulted generator without subjecting other generators to unnecessary additional ground fault current
(3) The grounding of the balance of the auxiliary power distribution system or utility system when the generator is disconnected

(2) is of particular importance when multiple generators are connected to a common bus. The ideal grounding scheme for a larger generator provides for the generator neutral to be grounded through a distribution transformer with a secondary winding resistor. However, this assumes that a wye-delta (or delta-wye) step-up transformer is provided for each generator power interconnection, which may not always be the case. For multiple generators connected to a single bus, resistance grounding is typically used. Effective ground protection of the faulted generator can be provided with low resistance grounding. However, resistance grounding usually subjects equipment to higher fault levels than distribution transformer grounding.

5.4 Generator Characteristics. While it is understood that the gross output capability of the generator(s) is probably the most important rating of interest to the owner, as well as to the utility, the specific generator electrical and dynamic characteristics will also be of equal importance to both parties and should not be overlooked.

The generator owner will need to obtain specific generator electrical characteristics in order to design the plant electrical distribution system. Furthermore, the utility will usually require significant dynamic data as well, in order to ascertain the generator's overall impact on system fault levels and stability. The latter is particularly true for a large synchronous generator.

Harmonic voltage generation between reactive components within an operating system can cause severe damage to equipment. The design effort should address the matter as a potential problem.

Any generator connected to an operating electrical system becomes, during its synchronous operation, functionally a part of that system.

5.5 Reactive Capability. As a corollary to the usual understanding that a large power user is expected to maintain the facility reactive power demands (power factor) within certain agreed limits, a utility may require each generator to be capable of providing reactive power to the utility system in proportion to the unit size and capability and within specified voltage limits for both generator(s) and system. This is a point that should be established early, since the reactive power contribution from a facility, whether expressed as a gross power factor at the generator, a net power factor at the utility, or a desired voltage to be maintained at the utility bus, may ultimately be reflected in changes in the capability of the generator (rotor, stator, or excitation system) or in the increased heating of these components.

Additional reactive capability does not entail any additional turbine (power) capability, but is reflected in generator and excitation system thermal capacity.

If a generator (or generators) is not capable of meeting some reactive power (var) requirement, shunt capacitors or static var compensators or both may be required to supplement the generator contribution. The location of shunt capacitors on the utility or user system should be reviewed to avoid self-excitation of the generator-capacitor network in the event of sectionalization and isolation ("islanding") of the interactive systems. If capacitors are present, switching devices that are transfer-tripped by the utility may be necessary. This particularly applies to induction generators. Any application of capacitors should be done with a full understanding of capacitor effects.

A fundamental premise is that the utility is responsible for providing reliable service in accordance with applicable regulatory requirements that should not be compromised by user-owned operations. Conversely, user-owned generation should not be subject to extraordinary requirements.

5.6 Isolating Switch. The user and utility should agree on the necessity of providing a manually operated isolation switch(es) with a visible break to isolate the generator(s) from the interconnection. Switch location, accessibility, and capability of being locked or tagged open should also be established.

6. Substation Facilities Design

The prudent design of a user-owned substation should include the following significant areas for consideration in the design criteria.

6.1 Grounding. A buried grounding grid of bare cable, possibly including electrodes (ground rods), is necessary for personnel safety and to provide ground connecting points for equipment. Normally, the substation grounding grid design should conform to the requirements of IEEE Std 80-1986 [6]. A ground-resistance test should be required and conducted in accordance with IEEE Std 81-1983 [7]. The grounding design criteria should be coordinated with adjacent utilities, plants, or other facilities to ensure that transfer potentials will not present personnel hazards in areas remote from an electrical event or will not damage communications circuits between the user-owned facilities and any remote facilities.

The effect of a generation facility or substation grounding system on adjacent existing or future cathodic protection systems (e.g., pipelines) needs careful study and, probably, field testing.

6.2 Insulation Levels (BIL). For any given electric power interconnection, the basic impulse insulation level (BIL) (or switching insulation level [SIL] for EHV voltage levels) should be coordinated for power distribution and transmission lines and equipment. Industry references or the local utility are the appropriate sources for existing insulation levels, which are frequently different for overhead line, insulated cable, and transformer insulation systems at the same voltage level in the same region.

6.3 Clearances and Access. Appropriate normal and minimal electrical clearances from energized parts above walkways, roads, and railroads and in other special circumstances are specified in ANSI C2-1990 [1] and IEEE Std 1119-1988 [14], local utility requirements, and state and local codes and ordinances. Overhead high-voltage lines can require significant right-of-way area. The presence of energized overhead conductors can affect some potential uses of property located under or adjacent to the conductors. The local utility should be consulted to provide access requirements for maintenance, operation, and metering facilities.

6.4 Lighting. Appropriate minimum lighting levels for various circumstances of indoor, outdoor, and roadway areas are given in NFPA 70-1990 [16] and ANSI C2-1990 [1], in ANSI and IES standards, and in other industry sources. Emergency lighting should be provided in attended areas, in accordance with local codes and regulations.

6.5 Lightning (Surge) Protection. Lightning (surge) protection for substation facilities should be designed for the isokeraunic level (thunderstorm days per year) for the particular site location. The local utility may be the best source of information on local lightning frequency, outage records, and application of particular lightning protection methods (shield wires, masts, arrays, arresters, higher BIL levels, reclosing, etc.) to the local system. See IEEE P998 [12] for further background on direct stroke lightning protection. For high-voltage facilities, switching surges are an additional design consideration. The need for surge protection at generator, transformer, and cable terminals should be considered.

6.6 Transmission (or Distribution) Line Termination. High-voltage transmission lines or medium-voltage distribution lines, whether overhead or underground cable, will usually constitute the most significant physical interface between a user-owned substation and the electric utility. Because of this, particular attention is needed to coordinate the interfacing span between the last utility tower and the substation terminal structure for overhead lines. For underground lines, the presence of existing underground utilities in the substation vicinity should be identified, which may impact a new underground cable location or rating. For both overhead and underground lines, orientation of the substation in relation to the utility and the user's lines should be arranged to minimize line angles, turning towers, crossings, etc., all of which will impact on the complexity and cost of the interconnection transmission facilities.

6.7 Switching Equipment. The final selection and arrangement of particular substation switching devices is closely related to the substation arrangement, discussed in Section 4.

For interactive interconnections, either power circuit breakers or circuit interrupters are required for power circuit switching and fault interruption. The choice between these switching devices will depend on required fault interruption capability, clearing and reclosing requirements, etc. For purchase-power-only interconnections, the switching equipment may be power circuit breakers, circuit interrupters, or fuses. The choice between these switching devices will depend on required fault interruption capability and on clearing and reclosing requirements. In addition, the application of fuses should address reduced reliability, increased outage time, single-phasing, ferroresonance, etc.

Disconnect switches are capable of interrupting line charging currents for short lines and switching low-level transformer magnetizing currents, particularly when arcing horns or quick-break (high-speed) interrupting devices are added to the switch. However, they are normally used only to isolate power switching apparatus, lines, and buses and are not suitable for application as a principal switching device.

Any further discussion of the numerous varieties and applications of switching devices mentioned above is beyond the scope of this guide.

6.8 Instrument Transformers. Instrument transformers are devices that are needed to produce a low-voltage reference potential or current source as required for protective relaying, synchronizing, metering, control, and indication functions.

Potential sources can be oil-filled or dry-type (epoxy or rubber insulated) wound voltage transformers, capacitor voltage transformers (CVTs), coupling capacitor potential devices, (CCPDs) or bushing potential devices. Voltage transformers are the most accurate sources of potential and are usually needed for revenue metering. Bushing potential devices, transformer or breaker mounted, are usually suitable only for indicating the presence of voltage and are inadequate for critical relaying or metering functions.

Current sources can be separately mounted oil-filled or dry-type (epoxy or rubber insulated) current transformers or bushing current transformers (BCTs). Again, separately mounted current transformers are the most accurate and are usually needed for revenue metering. Bushing current transformers, both transformer- and breaker-mounted, are suitable for the majority of relaying, control, indication, and nonrevenue metering functions.

6.9 Cable Systems. Cable systems required to interconnect protective relaying, metering, instrumentation, control, communications, and low-voltage power equipment systems should be in conformance with IEEE Std 525-1987 [8] or local utility practice.

7. Protective Relaying

Protective relaying is necessary to detect system disturbances and to initiate proper response from power switching equipment. Protective relaying also is necessary to monitor synchronizing, load transfers, and out-of-step operating conditions.

Protective relay application is probably the most complex aspect of power systems design. Successful design and operation needs intimate coordination of utility and owner protective relaying facilities and philosophies. Relay and other devices usually are designated as outlined in IEEE Std C37.2-1987 [4] or as specified by the local utility.

The following categories of protective relaying application are typical.

7.1 Line Protection. Line protection relays monitor the condition of a transmission line and initiate isolation of the line if a fault is detected. Lightning is frequently the principal source of transmission and distribution line faults. Trees, animals, and accidents are other sources of faults.

7.2 Transformer Protection. Transformer protection relays monitor the condition of a power transformer and initiate its isolation in the event abnormal conditions are detected that can indicate overloading or an internal fault.

7.3 Bus Protection. Bus protection relays monitor the integrity of a power bus to which several lines, generators, etc. are connected. Detection of a bus fault will initiate isolation of the bus from all connected elements.

7.4 Synchronizing/Synchronism Check. Synchronizing and synchronism check relays are necessary to verify the phase relationship of interactive power systems or generators before permitting the interconnection of two energized (interactive) systems. An automatic synchronizing device may be used to control the speed and voltage of a generator and initiate connection to the system.

7.5 Reclosing and Transfer Tripping. Reclosing relays are employed with power circuit breakers to permit the rapid restoration of service to a transmission line that has been isolated due to the detection of a transient fault condition. Automatic reclosing is appropriate to support continuity of service and to maintain stability of the interconnected system. The concept of rapid reclosing is based on the transient nature of most line faults, particularly those caused by lightning. Particular care should be used in applying reclosing to generator interconnections. An automatic reclosing scheme should be approved by and coordinated with the electric utility. Automatic reclosing is generally not applied to underground (cable) lines. Transfer-trip relaying is frequently employed to isolate a generator from a faulted line so as to prevent damage due to reclosing out of synchronism.

7.6 Load Shedding and "Islanding". Load shedding is necessary when available generation in a defined system, such as a large industrial or cogeneration plant, should suddenly become insufficient to meet the connected load with the system. Such action would serve to preserve essential loads in operation. Such a condition could be brought about by loss of in-plant generation or loss of a user-utility interconnection tie line that is importing power at the time of failure. The decay of online generator(s) frequency can be measured to initiate the sequential removal of selected, low-priority plant loads with the ultimate purpose of maintaining service to essential loads that in-plant generation is capable of supplying. The complete isolation of independent generating systems results in "islands" of load and generation, which are individually less reliable and more sensitive to disturbance than the interconnected interactive system. This islanding condition also raises safety concerns and may necessitate transfer-tripping of additional switching devices to completely isolate the systems. Reconnection of the isolated systems to a larger, stable system can also be difficult.

7.7 Generator Protection. Specifically designed relaying is required to monitor the condition of the numerous mechanical and electrical functions of a turbine generator or any other type of generating machine. Because of the significant capital investment inherent in any generating unit, sensitivity and speed of response are necessary to detect abnormal conditions. This permits isolating and repair before a catastrophic failure can occur, with its consequent financial and safety implications.

7.8 Relaying Interfaces and Interlocks. Protective relaying systems can be interconnected with other electrical control and metering systems and may be interconnected with mechanical process systems. Interlocks establish permissive or restrained systems of operation that are necessary to ensure the safety of operation and the protection of the investment.

8. Metering and Instrumentation

The following types of metering could be expected to be provided as part of any user-owned facility interconnected to an electric utility.

8.1 Revenue Metering. This is a very significant interconnection parameter for user-purchased power and for sale of user-generated electric energy. The revenue parameter(s) to be metered will depend on the specific interconnection agreement and could include kWh, kvarh, kW, kvar, kVA, and power factor, in almost any combination. Since bidirectional real and reactive power flow may be possible, detented (in and out) metering is frequently necessary. Also, time-of-day pricing may be included in the specific rate structure, tariff, or contract.

Revenue metering requires the most accurate metering equipment available. This includes calibrated and certified metering accuracy current and voltage transformers, transducers, recording devices, and instruments. Most utilities usually have well-defined requirements for the configuration, type, and location of revenue metering equipment. Revenue metering is normally located in areas that are accessible to the utility representatives, although it is not unreasonable to request a cumulative reading to be duplicated at a user-maintained area in order to be monitored by the customer or owner. A communications line is needed if remote access of the metering data is necessary (i.e., for dispatching or load research).

8.2 Indicating Instruments and Status. Indicating instruments are provided to display the presence and magnitude of parameters on specific lines, buses, and equipment. Parameters that could be expected to be measured are voltage, current, kW, kvar, kWh, power factor, kVA, and kvarh. The normal location for such an indication would be at a substation control house, generator control room, or other accessible area.

The choice of indicating instruments is very site-, user-, and utility-specific in that instruments are used to support operations and maintenance functions. Indicating instruments as implied here would be located in the geographic vicinity of the user-owned facility. Indicating instruments also include the discrete (open-closed-trip) status display of equipment such as power circuit breakers, electrically-operated load interrupters, and disconnecting switches.

8.3 Telemetering. Telemetering is the transmission of analog or digital parameters to a remote location. Telemetering is closely associated with supervisory control, which is discussed further in 9.2. The parameters that can be telemetered to a remote location are the same as those for local metering, status, and indication.

The remote location that would likely be the destination for telemetered data would be a utility dispatch center or a user's remote control/monitoring facility. Telemetering of data can be accomplished over wire circuits for short distances. For long-distance telemetering, dedicated communications lines, carrier equipment, radio transmission, microwave facilities, or fiber optics circuitry is needed.

9. Control and Communications

Control facilities are needed to provide the human interface for the operation of installed equipment. Communications media of various types are used to permit the transmission and reception of control initiation signals, as well as for data transmission (see 8.3). Utility companies may need remote metering, monitoring, and control capabilities of large, dispersed user-owned generating facilities in order to satisfy overall system safety and operation needs.

9.1 Local Control. Local control is usually accomplished by a direct electrical, mechanical, pneumatic, or hydraulic device and is initiated immediately at the equipment or at some control facility within sight or walking distance of the equipment. It is the least sophisticated (and most reliable) control mode.

"Remote Control" is an extension of local control, which implies a greater distance between the controlled device and the initiating signal, but this control can utilize the same communication medium as for local control and, in fact, can differ only by degree of proximity to the controlled device. Remote control is particularly applicable to unattended locations, which is the usual case for substations, switchyards, or switching stations.

9.2 Supervisory Control. Supervisory control, also generically referred to as SCADA (Supervisory Control and Data Acquisition) systems, represents the long-distance control and data transmission methodology for distances much greater than that capable with direct local or remote control. As opposed to hard-wired direct local or remote control, which utilizes a dedicated wire pair or similar dedicated communication medium for each control or data signal, supervisory control usually utilizes multiplex technology to superimpose multiple signals on a single communication channel. This system uses an RTU (Remote Terminal Unit) at each terminal to collect, process, and transmit the appropriate multiple input and output signals. Supervisory control is generally needed for a utility interconnection that includes remote utility control of selected customer-owned equipment, such as high-voltage power circuit breakers. Additional information is given in IEEE Std C37.1-1987 [3].

9.3 Remote Dispatch. Remote dispatch is merely local control of equipment in accordance with the verbal instructions received from a remote central control location, such as a utility central power dispatch center. Remote dispatch can reasonably be expected to be considered as part of the operations functions of any generator connected to an operating utility system. A voice communication channel, either dial-up or dedicated, is the normal dispatch coordination medium.

9.4 Communications. Various communications media may be considered for the different control functions, as follows.

(1) *Metallic Hardwire*—Suitable only for relatively short distances (up to several hundred feet) for control/relaying/metering functions.
(2) *Telephone*—For voice, SCADA and selected relaying functions (not guaranteed for continuous integrity if a normal line).
(3) *Power Line Carrier*—For voice or SCADA functions (also suitable for relaying functions). Maintaining con-

tinuous integrity during line faults can be a problem.

(4) *Leased Telephone Channel*—For voice or SCADA functions (also for relaying functions). May be more reliable than a normal telephone line).

(5) *Microwave*—For voice, SCADA, and relaying functions (expensive except for handling many signals at great distances; political and environmental considerations may also be necessary).

(6) *Fiber Optics*—For voice, SCADA, and relaying functions (option to a leased telephone line).

(7) *Radio*—For voice communications (backup to other systems and for limited switching operations).

Redundant communications links should be considered for any essential function or for installations with significant customer-owned generation. Reliable voice communication is essential between generator operators and the utility, particularly during system emergencies.

9.5 Communication Circuit Protection. The reliability of the communication circuit should be considered to ensure the integrity of the circuit under adverse conditions or to minimize the likelihood of circuit interruption. Communication circuits should be supervised continuously and checked periodically to ensure their continued integrity.

Events that could cause circuit interruption can be: digging of buried cables, lightning, insulation failure of conductors or devices due to transient potential rise, circulating currents, vandalism, and equipment maintenance.

10. Maintenance and Operation

In addition to the design coordination necessary to realize the physical and electrical interfaces between the user's facilities and the utility, it is necessary to coordinate normal life-of-plant maintenance and operation functions. The details of such coordination are usually outlined in an operational agreement to which all parties are obligated. Particular items that are likely to be covered by an operational agreement are as follows.

10.1 Coordination of Switching. For personnel safety and in order to avoid disruption of user and utility service or equipment damage or both.

10.2 Tagging, Lockout, and Grounding. Clearly defined procedures for isolating and grounding of equipment and circuits as needed for utility, user, and contractor maintenance functions.

10.3 Personnel Safety and Training. Minimum level of training needed for operations, maintenance, and construction personnel.

10.4 Access. Provision for both user and utility ingress and egress in all weather conditions at any time of day.

10.5 Testing. From time to time, customer or utility equipment may have to be removed from service. Such equipment may have failed, may have to be maintained, or may have to be tested. Circuit breakers require periodic preventive maintenance. Oil-filled devices are often Doble™ tested for their power factor or dissipation factor. Instrument transformers used for metering may have to be tested for accuracy. Therefore, current transformers may have to have bypasses and disconnects installed.

The station owner should be aware of these temporary and scheduled equipment outages and should factor them into the planned operation of the station and the generator(s).

10.6 Emergency Conditions. The user and utility should agree on any special control requirements for the generating facility during periods of defined utility system emergency condition operation. Administrative instructions should be made available to the user's operating personnel.

11. Administrative Items

The following administrative items, among others, should be considered for equipment and facilities that interface with both the user and utility facilities.

(1) *Drawings and Data*—A schedule should be prepared for submission and review of appropriate drawings and data by all parties during the user-facility interconnection design phase and utility or user system modification activities.
(2) *Color Codes*—For cable, wiring, raceway, signs, etc.
(3) *Nameplates*—For major equipment.
(4) *Equipment Numbers*—For operations and maintenance coordination.
(5) *Signs*—To indicate ownership limits and for safety.
(6) *Local Building Codes Compliance*
(7) *Access of Utility Employees to the User's Substation*
(8) *Insurance and Liability*

12. Contractual Documents

This guide is only a basis for specific discussions and agreements. It is understood that specific user-utility financial, operating, design, and other issues would be outlined in formal contracts, operating agreements, and other documents.

Appendix

(This Appendix is not a part of IEEE Std 1109-1990, IEEE Guide for the Interconnection of User-Owned Substations to Electric Utilities, but is included for information only.)

Related Code and Standard Agencies
(and area of applicability)

American Concrete Institute (ACI)
P.O. Box 19150, Redford Station
Detroit, MI 48219
Concrete Design

Association of Edison Illuminating Companies (AEIC)
51 East 42nd Street
New York, NY 10017
HV Cable Systems

American Institute of Steel Construction (AISC)
Three Gateway Center Suite 2350
Pittsburgh, PA 15222
Steel Application

American National Standards Institute (ANSI)
1430 Broadway
New York, NY 10018
Application and Design Standards

American Society of Mechanical Engineers (ASME)
345 East 47th Street
New York, NY 10017
Mechanical Equipment

American Society of Testing and Materials (ASTM)
1916 Race Street
Philadelphia, PA 19103
Components

Building Officials and Code Administrators International (BOCA)
4051 W. Flossmoor Road
Country Club Hills, IL 60477
Building Codes

Electrical Apparatus Service Association (EASA)
1331 Baur Boulevard
St. Louis, MO 63132
Electrical Testing and Maintenance

Edison Electric Institute (EEI)
1111 19th Street, N.W.
Washington, D.C. 20036
Handbook for Electricity Metering

Factory Mutual System Engineering and Research Association(FMERO)
1151 Boston-Providence Turnpike
Norwood, MA 02062
Insurance Requirements

Insulated Cable Engineers Association (ICEA)
P.O. Box P
South Yarmouth, MA 02664
Cable Application

Institute of Electrical and Electronics Engineers (IEEE)
445 Hoes Lane
Piscataway, NJ 08855
Electrical Systems and Equipment Application, National Electrical Safety Code

Illuminating Engineering Society of North American (IESNA)
345 East 47th Street
New York, NY 10017
Lighting

Instrument Society of America (ISA)
67 Alexander Drive
P.O. Box 12277
Research Triangle Park, NC 27709
Instruments

National Electrical Manufacturers Association (NEMA)
2102 L Street, N.W.
Washington, D.C. 20037
Electrical Equipment Design

National Fire Protection Association (NFPA)
Batterymarch Park
Quincy, MA 02269
Fire Protection Requirements, National Electrical Code

Prestressed Concrete Institute (PCI)
201 North Wells Street
Chicago, IL 60606
Concrete Structures

Southern Building Code Congress, International (SBCCI)
900 Montclair Road
Birmingham, AL 35213
Building Codes

Steel Structures Painting Council (SSPC)
4400 Fifth Avenue
Pittsburgh, PA 15213
Surface Protection and Coatings

ISBN 1-55937-041-6