IEEE Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

1547.2™

IEEE Standards Coordinating Committee 21

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Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage

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Abstract: Technical background and application details to support understanding of IEEE Std 1547-2003 are provided. The guide facilitates the use of IEEE Std 1547-2003 by characterizing various forms of distributed resource (DR) technologies and their associated interconnection issues. It provides background and rationale of the technical requirements of IEEE Std 1547-2003. It also provides tips, techniques, and rules of thumb, and it addresses topics related to DR project implementation to enhance the user's understanding of how IEEE Std 1547-2003 may relate to those topics. This guide is intended for use by engineers, engineering consultants, and knowledgeable individuals in the field of DR. The IEEE 1547 series of standards is cited in the Federal Energy Policy Act of 2005, and this guide is one document in the IEEE 1547 series.
Keywords: diesel generators, dispersed generation, distributed energy, distributed energy resources, distributed generation, distributed power, distributed resources, electric distribution systems, electric power systems, energy storage, Federal, fuel cells, grid, interconnection, inverter, islanding, microturbines, national, networks, paralleling, photovoltaic power systems, rulemaking, regional, state, utility, wind energy systems

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Introduction

This introduction is not part of IEEE Std 1547.2-2008, IEEE Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

IEEE Std 1547.2-2008 is one of a series of standards published by the IEEE or being developed by IEEE Standards Coordinating Committee 21 on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage (SCC21) concerning distributed resources (DR) interconnected with area electric power systems (EPS). IEEE Std 1547-2003[a] provides interconnection technical specifications and requirements as well as test specifications and requirements; IEEE Std 1547.1™-2005 provides the test procedures for verifying conformance to IEEE Std 1547-2003. IEEE Std 1547.3™-2007 is intended to facilitate interoperability of DR interconnected with an area EPS. The documents in the 1547 series are as follows:

- IEEE Std 1547™-2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.
- IEEE Std 1547.1™-2005, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.
- IEEE Std 1547.2™-2008, IEEE Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.
- IEEE Std 1547.3™-2007, IEEE Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems.
- IEEE P1547.4™, Draft Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems.[b]
- IEEE P1547.5™, Draft Technical Guidelines for Interconnection of Electric Power Sources Greater Than 10 MVA to the Power Transmission Grid.
- IEEE P1547.6™, Draft Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks.

The IEEE 1547 series of standards is an outgrowth of the changes in the environment for the production and delivery of electricity and builds on prior IEEE standards, recommended practices, and guides developed by SCC21. In 2005, the Federal Energy Policy Act cited and required the 1547 series of standards for interconnection.

IEEE Std 1547.2-2008 provides application details to support the understanding of IEEE Std 1547-2003 and is intended to serve DR owners and operators as well as area EPS staff. IEEE Std 1547.2-2008 provides technical background, application details and guidance, requirements rationale, schematics, and examples to facilitate the use of IEEE Std 1547-2003.

This guide addresses some topics that are related to DR project implementation to enhance user understanding of how IEEE Std 1547-2003 may relate. This guide does not interpret IEEE Std 1547-2003 or other standards in the IEEE 1547 series and does not provide additional requirements or recommended practices related to those other IEEE 1547 standards. The interconnection examples cited in this guide are illustrative approaches, but alternative approaches could be equally applicable.

[a] Information on references can be found in Clause 2.
[b] Numbers preceded by P are IEEE authorized standards projects that were not approved by the IEEE-SA Standards Board at the time this publication went to press. For information about obtaining drafts, contact the IEEE.

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Special recognition is given to former Chair N. Richard Friedman, who contributed tirelessly to the IEEE 1547 Working Group and this working group before his death in February 2006.

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Contents

IEEE Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

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1. Overview

1.1 Scope

This guide provides technical background and application details to support understanding of IEEE Std 1547-2003. [1]

1.2 Purpose

This document facilitates the use of IEEE Std 1547-2003 by characterizing the various forms of distributed resource (DR) technologies and the associated interconnection issues. Additionally, the background and rationale of the technical requirements are discussed in terms of the operation of the DR interconnection

[1] Information on references can be found in Clause 2.

with the electric power system (EPS). Presented in the document are technical descriptions and schematics, applications guidance, and interconnection examples to enhance the use of IEEE Std 1547-2003.

1.3 Intended audience

IEEE Std 1547.2™-2008 is intended for use by practicing engineers, engineering consultants, and knowledgeable individuals in the field of DR. It is presumed that the user is familiar with the general electrical engineering principles related to distributed electric power technologies and electricity distribution systems.

1.4 Document structure

This guide was developed to provide technical background and application details to support IEEE Std 1547-2003. This guide addresses some topics that are related to DR project implementation to enhance the user's understanding of how IEEE Std 1547-2003 may relate to those topics. Clause 1 through Clause 7 provide background information about DR, interconnection systems, EPSs, and system impacts. Topics in Clause 8 closely parallel those of IEEE Std 1547-2003. Each topic in IEEE Std 1547-2003 is quoted, and then application guidance is provided. Clause 9 discusses IEEE 1547.1™ test specifications and requirements, and Clause 10 provides an overview of interconnection process information. The annexes provide additional information and include a bibliography, glossary, and more detailed information about interconnection systems, DR, and EPSs.

1.5 Limitations

This guide applies to all DR technologies of aggregate capacity of 10 MVA or less at the point of common coupling (PCC) that are interconnected with an area EPS at typical primary or secondary distribution voltage. This guide does not define the maximum DR capacity for a particular installation that may be interconnected with a single PCC or connected to a given feeder.

- This guide is not a design handbook. It is not intended to provide comprehensive information about specific topics of power engineering or DR or EPS engineering necessary for successful interconnection of DR with an area EPS. The examples provided are not exhaustive or prescriptive.
- This guide does not provide guidance on how to meet business or tariff issues. However, it does recognize that these are important to the interconnection of DR.
- This guide assumes that the DR is a 60 Hz source (to be consistent with IEEE Std 1547-2003), although the principles could apply to other frequencies.
- This guide does not apply to automatic transfer schemes in which load is transferred between a DR and an area EPS in a momentary make-before-break operation if the duration of paralleling is less than 100 ms. However, it does address installation and application considerations that may be useful when designing specific installations that use this type of product.
- This guide does not interpret IEEE Std 1547-2003 or other standards in the IEEE 1547 series and does not provide additional requirements or recommended practices related to those other IEEE 1547 standards.
- This guide does not provide a guarantee that IEEE 1547 requirements will be met.
- The interconnection examples cited in this guide are illustrative approaches, but there are other alternative approaches that could be equally applicable as those stated in this document.

1.6 Functional descriptions

IEEE Std 1547-2003 Clause 4 states the technical specifications and requirements for interconnection of DR, and Clause 5 states the interconnection test specifications and requirements to meet the requirements of Clause 4. This guide provides background on the functions that an interconnection system provides to meet those specifications and requirements. In some cases, a functional description may read like a piece of equipment (e.g., a paralleling device). However, this guide describes function, not a piece of equipment in the interconnection system or the interconnection system itself. Sometimes, interconnection system functions are satisfied by a discrete piece of equipment within the interconnection system (e.g., a reverse power relay). In other cases, the function that satisfies the requirements is provided by software or firmware (e.g., an inverter-based system that uses software-based functionality to satisfy a technical specification). In yet other cases, it is the proper design and operation of the interconnection system as whole that satisfies a technical specification or requirement.

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.

IEEE Std 1547™-2003 (Reaff 2008), IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.[2, 3]

IEEE Std 1547.1™-2005, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.

IEEE Std 1547.3™-2007, IEEE Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems.

3. Definitions, acronyms, and abbreviations

For the purposes of this document, the following terms and definitions apply. *The Authoritative Dictionary of IEEE Standards Terms* [B19][4] should be referenced for terms not defined in this clause. Additional terms and definitions are included in Annex I.

3.1 Definitions, acronyms, and abbreviations

3.1.1 anti-islanding protection: *See:* **non-islanding protection**.

3.1.2 crowbar circuit: A protection circuit that rapidly short-circuits (or "crowbars") the supply line if the voltage or current exceeds defined limits. In practice, the resulting short blows a fuse or triggers other protection, which effectively shuts down the supply. This is usually achieved by a silicon-controlled rectifier (SCR) or other silicon device in power supplies or by a mechanical shorting device.

[2] IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, NJ 08854, USA (http://standards.ieee.org/).
[3] The IEEE standards or products referred to in Clause 2 are trademarks owned by the Institute of Electrical and Electronics Engineers, Incorporated.
[4] The numbers in brackets correspond to those of the bibliography in Annex J.

3.1.3 direct-transfer trip (DTT): A method of sending a trip signal from one location to another. Various communication systems—including, but not limited to, phone lines, spread-spectrum radio, licensed radio, microwave, and fiber optics—can provide the signal path. *Syn:* **transfer trip.**

3.1.4 directional power relay: A relay that operates in conformance with the direction and magnitude of power.

3.1.5 distributed resource (DR) controller: A system or device that manages the DR unit and can provide an operator interface, a communications interface, power management, monitoring, or metering.

3.1.6 non-islanding protection: The use of relays or controls to prevent the continued existence of an unintentional island.

3.1.7 stiffness: The ability of an area EPS to resist voltage deviations caused by DR or loading. *See:* **stiffness ratio**.

3.1.8 stiffness ratio: The relative strength of the area EPS at the PCC compared with the DR, expressed in terms of the short-circuit kilovoltamperes of the two systems. The stiffness ratio is calculated at the PCC, except when there is a transformer dedicated to one customer. In this case, the stiffness ratio is calculated on the high-voltage side of the dedicated transformer.

$$\text{stiffness ratio} = \frac{\text{SC kVA (area EPS)} + \text{SC kVA (DR)}}{\text{SC kVA (DR)}} = \frac{\text{SC kVA (area EPS)}}{\text{SC kVA (DR)}} + 1$$

where

SC kVA (area EPS) = The short-circuit contribution in kilovoltamperes of the area EPS (including all other sources)
SC kVA (DR) = The short-circuit contribution in kilovoltamperes of the DR being evaluated

3.2 Acronyms and abbreviations

ac	alternating current
AHJ	authority having jurisdiction
ANSI	American National Standards Institute
CBEMA	Computer and Business Equipment Manufacturers Association
dc	direct current
DFAG	double-fed asynchronous generator
DFIG	double-fed induction generator
DR	distributed resource(s)
DTT	direct transfer trip
EMI	electromagnetic interference
EMTP	Electromagnetic Transients Program
EPS	electric power system
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IGBT	insulated gate bipolar transistor

ISO	independent system operator
ITI	Information Technology Industry Council
mmf	magnetomotive forces
NEC	National Electrical Code
NFPA	National Fire Protection Association
PCC	point of common coupling
Pst	short-term flicker
p.u.	per unit
PV	photovoltaic
PWM	pulse-width modulation
SCADA	supervisory control and data acquisition
SCR	silicon-controlled rectifier
SSC	short-circuit capacity
UL	Underwriters Laboratories
VAR	voltampere-reactive
WTG	wind turbine generator

4. Interconnection systems

4.1 Interconnection system description

IEEE Std 1547-2003 states requirements and specifications for the interconnection of DR with the area EPS, and it is the resultant interconnection that needs to comply with IEEE Std 1547-2003 and not solely the pieces of equipment. Therefore, it is useful to review specific extracts of IEEE Std 1547-2003 to establish the context for interconnection systems. Also, it is useful to understand that interconnection systems are often designed and implemented to provide functionality and features beyond those required for compliance with IEEE Std 1547-2003.

Whereas IEEE Std 1547-2003 provides universally needed technical requirements and specifications for interconnection, in IEEE Std 1547.2-2008 guidance is provided toward DR technologies and applications. However, for any interconnection system examples described in this document, alternative approaches may be equally applicable.

IEEE 1547 definitions related to “interconnection” are repeated here, as follows:

— **Interconnection:** The result of the process of adding a DR unit to an area EPS.
— **Interconnection equipment:** Individual or multiple devices used in an interconnection system.
— **Interconnection system:** The collection of all interconnection equipment and functions, taken as a group, used to interconnect a DR unit(s) to an area EPS. See Figure 1.

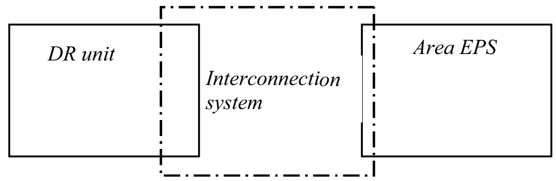


Figure 1—Schematic of interconnection

As further interconnection system background, the IEEE Std 1547-2003 Introduction provides additional information related to interconnection:

"This standard [1547] focuses on the technical specifications for, and testing of, the interconnection itself.

"It is beyond the scope of this standard [1547] to address the methods used for performing EPS impact studies, mitigating limitations of the Area EPS, or for addressing the business or tariff issues associated with interconnection."

There is a range of types of interconnection system equipment. Some interconnection systems are factory-packaged using embedded components and are included as part of a DR unit (e.g., a microturbine that is factory-packaged with an inverter-based interconnection system), or some may be mostly integral within an inverter (e.g., small inverters, perhaps < 10 kW, intended for use with photovoltaic (PV) energy conversion systems) that is separate from the distributed generator. Other interconnection systems use a field-assembled system of discrete components. In all cases, it is the resulting interconnection that is required to meet IEEE Std 1547-2003.

4.2 Interconnection system functions

IEEE Std 1547-2003 Clause 4 states:

"The functions of the interconnection system hardware and software that affect the Area EPS are required to meet this [1547] standard regardless of their location on the EPS.

"The requirements in this clause are functional and do not specify any particular equipment or equipment type."

Functional technical requirements are statements of what needs to be accomplished; they do not prescribe how to do that or what equipment to use. The functions of the interconnection system hardware and software as well as the location of the PCC may interplay in complying with IEEE Std 1547-2003. Sometimes, interconnection functions are satisfied by a discrete piece of equipment within the interconnection systems (e.g., a reverse power relay); in other cases, the functions are provided by software or firmware (e.g., an inverter-based system that uses software-based functionality to satisfy many of the IEEE Std 1547-2003 technical specifications). In still other cases, the proper design and operation of the interconnection system as a whole satisfies the technical specifications and requirements. And sometimes, it is the site-specific PCC location itself, such as for IEEE Std 1547-2003 4.4.1, where the requirement may be satisfied, i.e., where the DR aggregate capacity is less than one-third of the minimum load of the local EPS.

To better understand the interconnection system functions and their relationship to interconnection equipment, it is also helpful to review additional certain aspects of IEEE Std 1547-2003.

IEEE Std 1547-2003 Clause 4 categorizes interconnection system technical specifications and requirements as follows:

- General requirements
- Response to area EPS abnormal conditions
- Power quality
- Islanding

A one-to-one division of interconnection system functions into equipment categories is somewhat arbitrary because functions are often interrelated and equipment components often operate toward satisfying individual functional requirements or multiple functional requirements. Therefore, informative examples of equipment categorizations and their descriptions are provided in Annex A for illustrative purposes as opposed to here. Annex A provides informative examples of interconnection systems, DR applications and example equipment in relation to IEEE 1547 technical specifications and requirements. Annex A also describes certain functions and features beyond those required by IEEE Std 1547-2003.

5. Distributed resources

DR—also known as *distributed energy resources*—offer a variety of possibilities for energy conversion and electric power generation. Various energy sources, fuels, and converters are used to provide electricity through PV arrays, wind turbines, fuel cells, microturbines, conventional diesel and natural gas reciprocating engines, gas-fired turbines, and energy storage technologies.

Despite the range of DR technologies, the behavior of a DR as it interacts with an area EPS is largely influenced by the type of electrical converter it uses. Three types of electrical converter are considered here: synchronous generators, asynchronous (or induction) generators, and static (or electronic) inverters. The rotating generators can be driven by internal combustion engines, combustion turbines, steam turbines, water turbines, wind turbines, or electric motors. The static inverters can be supplied by dc storage sources (such as batteries), by dc generating sources (such as fuel cells), or by an ac generating source and a converter (such as a high- or variable-speed combustion or wind turbine). These machines respond differently to changes because of their different mechanical and electrical inertias and the time constants of the regulators by which they are controlled.

Capacity or energy supplied by a DR may be coupled directly with an EPS through a rotational system of polyphase ac generated waveforms or indirectly through a static power converter that synthesizes the rotating ac waveforms. Directly coupled synchronous generators run at a synchronous shaft speed so the power output is electrically synchronous with the EPS. Directly coupled induction generators operate asynchronously (i.e., not in synchronism). They operate at a rotational speed that varies with the prime mover, but to transfer energy into the EPS, they must be rotating at slightly higher than synchronous speed. Indirect coupling through a static power converter allows the basic energy converter to operate independently of the area EPS voltage and frequency. The static power converter provides the matching parameters to couple the DR with the area EPS. The interconnection method for any DR energy source is dependent on the type of energy conversion and electric generation, its characteristics, its capacity, and the type of EPS service available at the site.

5.1 Prime movers

More information about prime mover technologies is available in Annex B.

5.1.1 Rotating

Rotating prime movers drive rotating generators directly through a shaft or indirectly through a reduction gearbox. Rotating prime movers may also drive power through static electronic converters. Rotating prime mover technologies include the following:

- Reciprocating engines
- Combustion turbines
- Steam turbines
- Wind turbines
- Water turbines
- Microturbines
- Storage technologies such as flywheels

5.1.2 Non-rotating

Non-rotating prime movers produce dc power. Non-rotating prime mover technologies include the following:

- PV
- Fuel cells
- Storage technologies such as batteries, supercapacitors, and superconducting magnetic energy storage

5.2 Power conversion technologies

More information about these technologies is available in Annex C.

5.2.1 Synchronous machines

A synchronous machine has to be driven at a speed that corresponds to the number of poles of the machine and the frequency of the EPS with which it is connected. The real power that it produces is controlled by the governor of its prime mover. The reactive power that it produces is controlled by the level of excitation of its field.

A synchronous machine requires more complex control than does an induction machine, both to synchronize it with the EPS and control its field excitation. It also requires special protective equipment to isolate it from the EPS under fault conditions. Significant advantages are its ability to provide power during EPS outages and allow the DR owner to control the power factor at the facility by adjusting the dc field current.

5.2.2 Asynchronous (induction) machines

A conventional induction machine has to be driven at a speed slightly higher than the corresponding synchronous speed. If its speed drops below the synchronous speed, it will absorb power from the EPS. The real power it produces is controlled by the governor of the prime mover. The conventional induction machine always absorbs reactive power. It cannot control voltage or power factor.

Double-fed asynchronous generators (DFAGs), also known as double-fed induction generators (DFIGs), are a distinct class of asynchronous generators. They employ wound rotor induction machines with static power converters to drive the rotor field currents. The physical rotational speed of the machine can be varied over a wide range, both faster and slower than the synchronous speed. Unlike an ordinary induction machine, a DFAG can supply or absorb reactive power, which allows power factor or net reactive flow to be easily and quickly controlled. In some DFAGs, a crowbar circuit is added to the rotor side of the frequency converter to provide overcurrent protection and overvoltage control to the rotor winding. The crowbar circuit limits the transient current in the stator and the rotor to less than 1 p.u. for close-in and multiple-phase faults. In general, DFAG technology is widely used in wind generation.

5.2.3 Inverters and static power converters

Static power converters (inverters) convert dc electricity into ac electricity and offer additional electronic power conversion. They are sometimes referred to as *power conditioning systems.* Their fundamental role in a DR application is to convert dc or non-synchronous ac electricity from a prime mover energy source into a synchronous ac system of voltages that can be smoothly and easily interconnected with an EPS.

6. EPSs (area and local)

An EPS generally consists of generation, transmission, subtransmission, and distribution. Most electric power is generated by central-station generating units. Generator step-up transformers at the generation plant substation raise the voltage to high levels to move the power through transmission lines to bulk power transmission substations. The purpose of high-voltage transmission lines is to lower the current, reduce voltage drop, and reduce the real power loss (I^2R). Real power is the product of voltage, current, and power factor (the cosine of the angle between the voltage and the current phasors). As the voltage of a fixed amount of power is increased, the current decreases proportionately. The power transmitted remains constant, but the decrease in current results in reduced losses.

The North American Electric Reliability Corporation definition of bulk power system includes “all facilities and control systems necessary for operating an interconnected transmission grid (or any portion thereof), including high-voltage transmission lines; substations; control centers; communications, data, and operations planning facilities; and the output of generating units necessary to maintain transmission system security.” Its interpretation includes entities operating transmission facilities at 100 kV or above, with further definition on a regional basis. The U.S. Occupational Safety and Health Administration (OSHA) defines transmission voltages as varying from 69 kV up to 765 kV and subtransmission from 34.5 kV to 69 kV. Electric utility operators and owners have traditionally considered transmission lines at 138 kV and more. These are not hard limits. Many utilities consider 115 kV to be transmission, and others consider up to 138 kV as subtransmission. *The Authoritative Dictionary* [B19] does not provide definitive voltage levels for transmission and subtransmission.

Transmission substations reduce the voltage to subtransmission levels, usually between 44 kV and 138 kV. Distribution transformers step the voltage directly to the customer-used voltage. Subtransmission and transmission lines can service distribution substations. Interconnection with other area EPS operators' transmission and subtransmission systems form the power grid.

The system voltage is stepped down beyond the transmission system to lower the cost of equipment that serves the loads from the subtransmission and distribution segments of the power system.

The transmission and subtransmission systems are usually networked. In contrast, the distribution system usually consists of radial distribution circuits that are fed from single substation sources. Some distribution systems—particularly those in dense urban areas—are networked, but these distribution networks are typically fed from a single substation. The distribution system includes distribution substations; the primary voltage circuits supplied by these substations; distribution transformers; secondary circuits, including services to customer premises; and circuit protection, voltage-regulating, and control devices.

In North America, distribution system configurations typically consist of three-phase, four-wire, "Y" multigrounded and single-phase, two-wire, multigrounded circuits. Distribution circuit voltages range from 34.5Y/19.9 kV to 12.47Y/7.2 kV (phase-to-phase voltage/phase-to-ground voltage), although there are some lower-voltage, three-wire delta ungrounded systems still in existence. These lines are typically referred to as *primary circuits,* and their nominal voltage is referred to as the *primary voltage.*

Distribution or service transformers on the distribution system step the distribution line voltage to the customer use voltage, commonly referred to as the *secondary voltage.* The secondary system serves most customer loads at 120/240 V, single-phase, three-wire; 208Y/120 V, three-phase, four-wire; or 480Y/277 V, three-phase, four-wire. Three-phase, 240 V, three-wire and four-wire services are also common (four-wire delta services provide 240/120 V service on one phase). A complete list of preferred voltage levels is tabulated in ANSI C84.1-2006 [B3].

Residential, small commercial, and rural loads are served by overhead distribution feeders and lateral circuits or by underground distribution circuits. Most residential loads are served by three-phase, four-wire primary feeders with single-phase lateral circuits, although some three-phase laterals serve small industrial and large commercial loads. Most rural loads are served with single-phase primary, and they typically have one customer per distribution transformer.

The local EPS is all of the electrical systems on the customer's side of the PCC. The local EPS can range from a simple 120 V system for a traffic signal to a complex 230 kV system for an industrial facility.

The emphasis of IEEE Std 1547-2003 is on installation of DR on radial primary and secondary distribution systems, although installation of DR on primary and secondary network distribution systems is also considered. Recommended practices for DR installations interconnected with secondary networks are being developed by the IEEE P1547.6 Working Group. The *IEEE Color Books*® (see Annex J) provide recommended practices for electrical design of local EPSs for commercial buildings, health care facilities, and industrial plants.

Annex D discusses the design, construction, and configuration of area and local EPSs; the operation of area and local EPSs during normal and abnormal configurations and conditions; and area and local EPS concerns.

7. Potential effects on area and local EPS

One of the major technical challenges of DR interconnection (and the one categorized by many area EPS operators as the single most significant) is the effect of DR on the area EPS, commonly referred to as *impact.* Therefore, EPS effects are considered when applying DR. This clause suggests areas in which the EPS may be affected by the addition of DR. Because the location of interconnection on the EPS and the characteristics of EPSs vary widely, potential system impacts can also vary. Most of the impacts discussed apply to both the area and local EPS. By complying with the requirements of IEEE Std 1547-2003, operators can minimize many undesirable system impacts that could otherwise be associated with interconnection of DR.

The area EPS is affected in many ways by the addition of DR. To properly apply IEEE Std 1547-2003, operators need to have an understanding of these effects and mitigation methods. Effects may range from inconsequential to severe, depending on the size and technology of the DR and various characteristics of the area EPS with which it is connected.

Although not wholly inclusive, Clause 7 and Annex E describe facets of the area EPS that are commonly affected by DR and suggest evaluation methods and approaches for mitigation. Annex F describes the process and types of planning studies to detect possible impacts to the area EPS caused by the addition of DR.

Table 1 categorizes the system effects. There are additional coordination concerns that do not reflect effects of the DR on the area EPS but are concerns of the area EPS; these are presented in Table 2 as information exchange issues.

Table 1—System effects cross-references

EPS effects	References
Transformer connections — Effect on EPS fault duties — Effect on possible overvoltage conditions — Interaction with generator connections — System modifications	D.1.1.3 8.1.2 (see 8.1.2.2) 8.2.1 (see 8.2.1.2, 8.2.1.3) 8.2.3 (see 8.2.3.3.1 8.4.1 (see 8.4.1.3.9)
Grounding of the DR system — Grounding for safety — Effect on EPS ground protection	D.1.1.4 8.1.2 (see 8.1.2.2) 8.2.1 (see 8.2.1.2) 8.2.3 (see 8.2.3.3.1)
Abnormal system configurations — Alternate source — Abnormal sectionalizing — Alternate breaker or transfer bus	D.1.2 (see D.1.2.6) D.2.2 (see D.2.2.2) 8.1.1 (see 8.1.1.2)
Radial versus bidirectional power flow — Effect on protective equipment — Effect on voltage regulators — System modifications — System costs	D.1.2 (see D.1.2.2) D.1.3 (see D.1.3.5) 8.1.1 (see 8.1.1.2) 8.2.1 (see 8.2.1.2)
Voltage deviations — Three-phase — Single-phase — Induction versus synchronous — Voltage rise phenomenon — Surges, sags, and swell	D.2.2 (see D.2.2.3) 8.1.1 (see 8.1.1.2) 8.2.2 (see 8.2.2.2) 8.2.3 (see 8.2.3.2) 8.1.3 Annex C
Synchronization	8.1.3 9.2.3 See also IEEE Std 1547.1-2005.
Networks — Impact on network protectors — Spot networks	D.1.2.3 D.1.2 (see D.1.2.5, D.1.2.5.2; D.1.2.6, D.1.2.6.2; D.1.2.7, D.1.2.7.2) 8.1.4 See also IEEE P1547.6™.
Inadvertent energization and unintentional islanding	D.1.3 (see D.1.3.2) 8.1.5 (see 8.1.5.2) 8.1.7 (see 8.1.7.3) 8.2.3 (see 8.2.3.2)
Paralleling device	8.1.8 (see 8.1.8.3, 8.1.8.3.2)
Reclosing — Main or source circuit breaker — Reclosers or sectionalizers — DR equipment	8.2.2
Loss of synchronism	8.2.5 (see 8.2.5.3.2) 8.1.8 (see 8.1.8.3, 8.1.8.3.2) Annex C (see C.1)

Table 1—System effects cross-references *(continued)*

EPS effects	References
Harmonics	D.1.3 (see D.1.3.4.2) 8.3.1 (see 8.3.1.2) 8.3.3 (see 8.3.3.2) Annex C (see C.4, C.4.4)
Flicker	8.3.2 (see 8.3.2.2) Annex B (see B.2)
Operational safety practices	D.1.2 (see D.1.2.1) D.1.3 (see D.1.3.2) 8.1.7 (see 8.1.7.2)
System capability — Short-circuit capability of EPS equipment — Loading capability of area EPS	D.1.2 D.1.3 (see D.1.3.4, D.1.3.6) 8.2.1 (see 8.2.1.2)

Table 2—Information exchange issues

Issue	References
Monitoring	A.1 (see A.1.3, A.1.7) 8.1.6 (see 8.1.6.2) See also IEEE Std 1547.3-2007.
Compliance with regulatory requirements	D.1.3 (see D.1.3.3, D.1.3.4)
Operational coordination	Annex H

8. Application guidance for IEEE 1547 technical specifications and requirements

Topics in Clause 8 of this guide closely parallel those of IEEE Std 1547-2003. Each topic in IEEE Std 1547-2003 is quoted, and then application guidance is provided. The guidance provides background; alternate approaches; and tips, techniques, and rules of thumb for consideration with respect to the requirements of IEEE Std 1547-2003 and, in some cases, with respect to IEEE Std 1547.1-2005. However, when there is a question of which information applies, IEEE Std 1547-2003 and IEEE Std 1547.1-2005 take precedence.

Generally, IEEE 1547 requirements are met at the PCC, unless otherwise stated. IEEE 1547 requirements are functional and do not specify any particular equipment or equipment type. The stated technical specifications and requirements are universally needed for interconnection of DR—including synchronous machines, induction machines, and static power inverters/converters—and will be sufficient for most installations.

Additional guidance for DR interconnection with the area EPS is provided in IEEE Std 1547.3-2007. IEEE Std 1547.3-2007 provides insight into monitoring, information exchange, and control—such as for transfer trip. It is intended to facilitate the interoperability of DR and help DR project stakeholders implement monitoring, information exchange, and control to support the technical and business operations of DR and transactions among stakeholders. It is primarily concerned with monitoring, information exchange, and control between the DR unit controller and the outside world. However, the concepts and methods should also prove helpful to manufacturers and implementers of communications systems for loads, energy management systems, supervisory control and data acquisition (SCADA), EPS and equipment protection, and revenue metering. The guide does not address the economic or technical viability of specific types of DR. It provides examples called *use cases* (e.g., examples of DR unit dispatch, scheduling, maintenance, ancillary services, and reactive supply).

8.1 General requirements (IEEE Std 1547-2003 4.1)

8.1.1 Voltage regulation (IEEE Std 1547-2003 4.1.1)

"The DR shall not actively regulate the voltage at the PCC. The DR shall not cause the Area EPS service voltage at other Local EPSs to go outside the requirements of ANSI C84.1-1995, Range A."

NOTE—ANSI C84.1 was revised in 2006. However, no changes to ANSI C84.1-2006 [B3] were made applicable to IEEE Std 1547-2003.[5]

There is a subtle difference between actively regulating and fulfilling an area EPS request to supply or absorb reactive power. Often, local authorities having jurisdiction (AHJ) (e.g., state public utility commissions) have rules or tariffs that govern power factor operating values at customer interfaces with the area EPS.

When the DR actively regulates voltage, it may support the area EPS or work in opposition to regulation equipment installed by the area EPS operator. If the DR is requested to absorb or supply reactive power, the request is beyond the IEEE 1547 voltage requirement. Often, the area EPS operator will request that the DR operate at a constant power factor, which will vary the reactive power with respect to the power generated. This type of operation allows the DR voltage to follow the area EPS voltage but limits the impact of the DR facility on the area EPS. An example is the connection of a large DR facility near the end of an area EPS radial line. In this case, the DR may offset sufficient load to interfere with the normal voltage profile of the line and cause the voltage at the end of the line to be too high. By absorbing reactive power, this voltage rise can be offset. The EPS operator requests previously described are beyond the IEEE 1547 voltage requirement.

8.1.1.1 Background

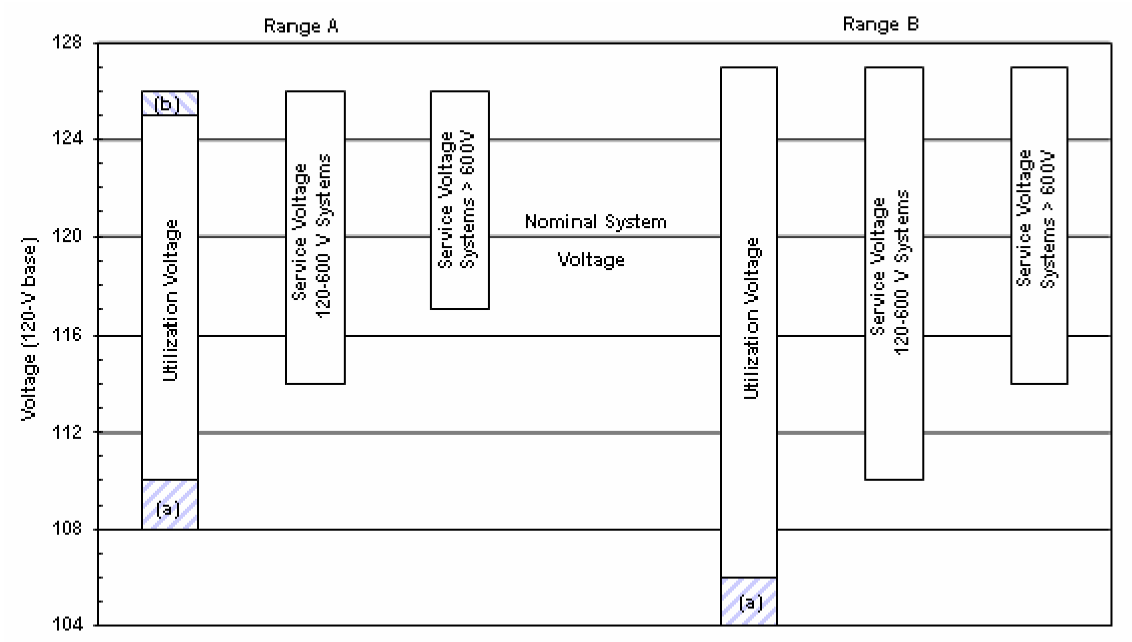
Voltage regulation describes the process and equipment to maintain voltage within acceptable limits. The primary objective of area EPS voltage regulation is to provide each customer connected to the area EPS with voltage that conforms to the design limitations of the customer's utilization equipment. There are applications in which the area EPS operator requests that the DR supply or absorb reactive power based on the impact to the area EPS. A request by the area EPS operator to govern power factor requirements or for reactive power support, under the requirements set by the AHJ, is beyond the scope of IEEE Std 1547-2003.

Almost all utilization equipment is designed for use at a definite terminal voltage: the nameplate voltage rating. The voltage drops in each part of the EPS from the source to the utilization devices make it economically impractical to provide all customers with a constant voltage that corresponds to the nameplate voltage of their utilization devices. Thus, a compromise is necessary between the allowable deviation from utilization equipment nameplate voltage supplied by the power system and the deviation above and below the nameplate voltage at which satisfactory equipment performance can be obtained.

The voltage limits at the PCC, where the area EPS is connected with a local EPS, are specified in ANSI C84.1 Range A. This is a stringent requirement that narrowly defines normal operating conditions at the PCC. The area EPS is to be designed and operated so that the service voltage at each PCC is within the limits of Range A. However, this standard does allow infrequent voltage excursions outside of these limits. This standard also defines the Range A utilization voltage. Utilization equipment is to be designed and rated to give fully satisfactory performance when the voltage at its terminals is within Range A utilization voltage limits.

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

Figure 2[6] shows the Range A service and utilization voltage limits on a 120 V base.[7]



NOTE 1—These shaded portions of the ranges do not apply to circuits supplying lighting loads.

NOTE 2—This shaded portion of the range does not apply to 120 V to 600 V systems

NOTE 3—The difference between minimum service and minimum utilization voltages is intended to allow for voltage drop in the customer's wiring system. This difference is greater for service at more than 600 V to allow for additional voltage drop in transformers between service voltage and utilization equipment.

NOTE 4—The Range B utilization voltage limits…for 6900 V and 13800 V systems are 90% and 110% of the voltage ratings of the standard motors used in these systems and deviate slightly from this figure.

Figure 2—ANSI C84.1 Range A voltage limits (120 V base)

The voltage supplied to each customer at the PCC is an important measure of service quality. A satisfactory voltage level is required to operate lights, equipment, and appliances properly. In many states within the U.S., the voltage regulation to be maintained at the PCC by the area EPS operator under normal system conditions is specified by the state regulatory AHJ. These requirements vary from state to state and may be different from those specified in ANSI C84.1-2006 [B3]. The maximum permissible deviation from nominal system voltage at the PCC is typically 5%; this agrees with the service voltage limits of ANSI C84.1-2006.

Because of the dynamic nature of most customer loads, the load current and power factor at any given point on the area EPS are constantly changing. Accordingly, the voltage at any given point away from a generator bus is subject to constant change because of the voltage drops in the impedances between that point and the generators. Voltage regulation is required to maintain voltage within acceptable limits.

[6] To make it easier to compare the voltage ranges on an electrical power system, a 120 V base is frequently used. The use of a 120 V base cancels the transformation ratios between the voltage levels in the power system so that the actual voltages vary solely on the basis of the voltage drops in the system. Any voltage may be converted to a 120 V base by dividing the actual voltage by the ratio of transformation to the 120 V base. For example, the ratio of transformation for a 480 V level of the power system is 480/120 or 4, so 460 V measured on the 480 V level of the system would be 460/4 or 115 V on a 120 V base.

[7] Reprinted from ANSI C84.1-2006 for Electric Power Systems and Equipment—Voltage Ratings (60 Hertz) [B3] Figure B.1 by permission of the National Electrical Manufacturers Association. Copyright © American National Standards Institute.

The distribution substation provides the connection between the transmission system, where most generation is currently interconnected, and the distribution system. The distribution system consists of distribution circuits used to distribute power from the distribution substations to numerous transformers that serve individual or small groups of customers. Most area EPSs are radial and have only one source of power (i.e., the distribution substation). The typical area EPS is regulated at its source substation with voltage regulators,[8] automatic load tap changing transformers,[9] and switched and fixed shunt capacitor banks.[10] Often, line regulators and shunt capacitor banks are used on the area EPS as a component of the feeder voltage-regulation scheme. Series capacitor banks, static reactive power compensators, and other devices installed on the area EPS contribute to improved voltage regulation, but these types of devices are usually installed to address transient voltage disturbances.

Another important aspect of voltage regulation is the maintenance of balanced three-phase voltage on the area EPSs. Eighty percent or more of the customers on an area EPS may be served from single-phase tap lines or single-phase transformers connected to the main feeder of the area EPS. These single-phase loads may create unbalanced voltage drops on the area EPS, which results in unbalanced voltage at customer locations where there are three-phase utilization devices. The operation of three-phase motors and other three-phase utilization devices is adversely affected by unbalanced phase voltage. If the voltage unbalance is significant (i.e., 2.5% to 3% or more), the motor or device may overheat or become inoperative. Some utilization equipment, such as large chiller compressors, is even more sensitive to voltage unbalance.

Factors involved in determining voltage drop on an area EPS include the primary voltage at which the area EPS is operating; the number, size, and type of conductors; the length of the lines; the size and power factor of the various loads; and the location of loads on the area EPS. Multiple voltage-regulating devices are commonly used on area EPSs, and it is necessary to coordinate the timing of the automatic voltage-regulating devices to prevent hunting (i.e., the regulating devices constantly adjusting the voltage in an attempt to reach the desired target voltage). The voltage-regulating devices commonly used on area EPSs cannot respond instantaneously to maintain a constant regulated voltage output. When multiple voltage-regulating devices are used, the voltage-regulating devices closest to the source substation operate with the least time delay, and the voltage-regulating devices farther from the source substation have increased time delays. In the design of the power system, the number, size, type, and control settings of these regulating devices are chosen based on known operating ranges of power flow and short-circuit duty.

8.1.1.2 Impact of distributed resources

Voltage regulation of the area EPS is based almost entirely on radial power flow from the substation to the loads connected to the area EPS. The introduction of DR may introduce a two-way power flow at certain times that may interfere with the effectiveness of standard voltage-regulating practices. DR can affect the area EPS voltage two ways:

- If power from a DR device is injected into the power system, it will offset load current and thus reduce the voltage drop on the area EPS. Just the existence of a DR can completely offset the local EPS load, and the offset of this load may result in a voltage rise because of the elimination of the “voltage drop.”
- If the DR device supplies reactive power (capacitive) into the power system or absorbs reactive power (inductive) from the power system, it will affect the voltage drop on the area EPS. For a given load level, if a DR device supplies reactive power (capacitive), the voltage drop on the area EPS will be

[8]Voltage regulators can be single-phase or three-phase construction. Today’s voltage regulators are step-voltage type. A step-voltage regulator is an autotransformer with numerous taps in series with the windings. These taps are changed automatically under load by a voltage sensing, switching mechanism to maintain a voltage as close to predetermined level as possible.

[9]Automatic load tap changing transformers operate in a manner similar to that of step-voltage regulators, except they are three-phase devices. They have voltage sensing on one phase and step all three phases in unison.

[10]Shunt capacitor banks are often used as part of the overall voltage regulation scheme on the area EPS. Fixed shunt capacitor banks are typically applied to bring the light load power factor on the area EPS to about 100%. Then, automatically switched shunt capacitor banks are added to achieve the economic full load power factor, which is typically 95% to 100%.

reduced; if a DR device absorbs reactive power (inductive), the voltage drop on the area EPS will be increased. These effects will be in addition to the first effect of reducing the load.

In accordance with IEEE Std 1547-2003 4.1.1, DR devices cannot actively regulate voltage at the PCC, and DR devices cannot cause the area EPS service voltage at the local EPSs to go outside the requirements of ANSI C84.1 Range A. These restrictions will prevent many operating problems. However, in some situations, the operation of DR can still result in area EPS voltage regulation problems if precautions are not taken.

Examples of potential operating problems and their possible solutions are as follows:

— Low voltage

  Many feeder voltage regulators use line drop compensation to raise the regulator output voltage in proportion to the load and maintain constant voltage downstream from the regulator. The line drop compensator raises the regulator output voltage to compensate for line voltage drop between the regulator and the load center. A DR device located downstream of an area EPS voltage regulator may cause the voltage regulator to lower its output voltage if the DR output is a significant fraction of the normal regulator load. As a result, low-voltage levels may be created downstream from the regulator if the DR fails to inject sufficient reactive power into the EPS.

  If line drop compensation is used and a DR device of sufficient size to affect primary voltage regulation is to be located downstream, the area EPS operator may need to modify the line drop compensator or other regulator control settings or relocate or add other voltage-regulating devices to the area EPS. Alternatively, it may be possible to coordinate the operation of the DR device and the voltage-regulating devices on the area EPS.

  Low-voltage levels may also be created when DR devices draw lagging reactive power. DR devices shall cease to energize the area EPS when the voltage goes out of range, as specified in IEEE Std 1547-2003 4.2.3. This specifies out-of-range voltage set points and clearing times. By default, it also specifies the operating voltage range for DR devices as 88% to 110% of nominal voltage. When a DR device is drawing lagging reactive power from the area EPS and the primary voltage on the area EPS is near the lower limit of ANSI C84.1-2006 [B3], the reactive power draw from the DR device can drag the voltage below the ANSI lower limit but above the DR device's low-voltage out-of-range trip point. Under these conditions, unacceptably low voltage conditions will exist until the DR device increases its real power output to raise the voltage, the area EPS voltage increases, or the voltage decreases out of range and the DR device trips to disconnect from the area EPS. This problem is mainly limited to induction generator-type DR devices. If the lagging reactive power drawn by a DR device will create low voltage, appropriately sized and located capacitors may be installed by the DR operator or the area EPS operator to eliminate the problem.

— High voltage

  When a DR unit is installed on the area EPS and the primary voltage on the area EPS is near the upper limit of ANSI C84.1-2006 [B3], the introduction of real power and leading reactive (capacitive) flow from the DR can push the voltage higher than the ANSI upper limit but lower than the DR device's high-voltage out-of-range trip point. Under these conditions, unacceptably high voltage will exist until the DR device reduces its output to lower the voltage, the area EPS voltage decreases, or the voltage increases out of range and the DR device trips to disconnect from the area EPS. If the DR is large enough to influence the service voltage of other customers on the area EPS and it is located where the primary voltage on the area EPS is expected to be near the upper limit of ANSI C84.1-2006, the area EPS operator may need to change regulating device control settings and add a voltage-regulating device. The intent of IEEE Std 1547-2003 was to limit the impact the DR might have on the area EPS if the DR was to actively regulate the voltage when this was not desired by the area EPS. In many situations, the area EPS operator may want regulation to control voltage, reactive power flow, or power factor at the DR PCC. Alternatively, the DR operator may reduce the high-voltage out-of-range trip point on the DR device to prevent the DR device from driving the area EPS voltage beyond its high limit.

In another solution, the DR absorbs reactive power (i.e., operates at a leading power factor and acts like an inductor) to offset the voltage rise because of the real power delivered to the system.

NOTE—In general, *lagging VARs* (voltampere-reactive) refers to capacitive or to a DR that supplies reactive power to the area EPS. In general, *leading VARs* refers to inductive or to a DR that absorbs reactive power from the area EPS.

— Voltage unbalance

Single-phase DR devices generate power on only one phase. By injecting power on only one phase of the area EPS, the voltage balance between the three-phase voltages can be changed. The voltage change created by the DR device may combine with existing unbalanced voltage on the area EPS to create unacceptably high unbalance. This high unbalance can exist even if the phase voltages are within the limits of ANSI C84.1-2006 [B3] and the power flow from the DR does not push the voltage out of range to trip the DR unit. To prevent problems from unbalanced voltage, it may be desirable to transfer single-phase load connected to the highest loaded phase to one of the other two phases and to interconnect the DR device to the highest loaded phase.

— Excessive operations

The introduction of a DR device—especially one such as wind or solar with a fluctuating source—can disrupt normal operation and interact with voltage-regulating devices. Multiple voltage-regulating devices are commonly used on area EPSs, and it is necessary to coordinate their timing. DR device output changes may disrupt the timing of voltage-regulating devices and contribute to excessive tap changes or capacitor switch operations. To minimize problems, it may be desirable to change the time-delay settings on voltage-regulating devices to provide better coordination with the DR device. In extreme cases, the installation of static VAR compensation or a similar device may be necessary. Coupling the DR device with a fluctuating source with another DR device that has the ability to "flatten" out the fluctuations may also be possible.

— Improper regulation during reverse power flow conditions

A DR device or multiple DR devices that export power to an area EPS may create reverse power flow conditions on voltage-regulating devices. Many voltage regulators have reverse flow sensing, which reverses the control algorithm. This action is based on the assumption that the direction from which power flows is the strong source location (from a short-circuit strength standpoint). Reverse flow sensing is used on feeders that have alternate sources on the other side of the regulator as the normal source. Sensing reverses the control algorithm so that correct regulation can be provided when the alternate source is used. A DR can reverse power flow, but it does not typically provide a source strength stronger than the substation. Reversal of the controlled bus will cause the regulator control to move the tap to the limit in one direction or the other because the tap change produces a voltage change opposite from what the control algorithm expects. As a result, customers on the DR side of the regulator can experience very high or very low voltage.

— Improper regulation during alternate feed configurations

A DR device or multiple DR devices that export power to the area EPS may cause voltage-regulating devices to operate improperly under alternate feed conditions. Some area EPSs are radial and have only one source of power (i.e., the distribution substation). However, most area EPSs in urban and suburban areas have tie points with one or more other area EPSs. These tie points create the possibility of switching all or a portion of an area EPS to an alternate source of power. When all or a portion of an area EPS is properly designed to be switched to an alternate source, the voltage-regulating devices will operate to maintain adequate voltage. However, the operation of a DR device or devices while the area EPS is in an alternate feed configuration could result in one or more of the voltage regulation problems previously described. To avoid this problem, the area EPS operator may need to replace the controls on the affected voltage-regulating devices to provide proper regulation during reverse power flow conditions, or the area EPS operator or DR operator may need to take other measures.

8.1.1.3 Tips, techniques, and rules of thumb

IEEE Std 1547.3-2007 provides sample cases of DR integrated with the EPS and corresponding information exchange interactions. Included are the following:

— *DR unit scheduling:* The DR operator creates, edits, and deletes schedules to dispatch commands to a DR unit. The DR operator's system communicates the scheduled operation to the DR controller, which invokes commands to the DR unit at appropriate times and notifies the DR operator of status.

— *DR ancillary services:* The DR may be used to provide any or all of the following ancillary services: load regulation, energy losses, spinning and non-spinning reserve, voltage regulation, and reactive supply.

— *DR providing reactive supply:* The DR unit may provide reactive supply by absorbing VARs or producing VARs by changing the field current to match a preestablished schedule. Alternatively, a stated power factor on the high side of the interconnection transformer or PCC can be established.

In most cases, the impact of an individual residential-scale (<10 kW) DR unit on the primary voltage level of the area EPS will be negligible. This may not be the case if a number of small units or a single larger unit is installed on the same area EPS. In this case, the voltage regulation scheme may need to be reviewed so that the area EPS voltage will be maintained within appropriate limits.

At secondary voltage levels on the area EPS, even a small, individual residential-scale DR device may adversely affect voltage to other customers. When DR devices are added to a transformer that serves multiple customers, the voltage regulation may need to be reviewed so that the area EPS voltage will be maintained within appropriate limits.

The voltage regulation may also need to be reviewed when many individual residential-scale DR devices, a larger DR device, or multiple DR devices are to be located as follows:

— On the load side of area EPS voltage regulators or load tap changing transformers that use line drop compensation under either system normal or alternate feed configurations

— Where the voltage approaches the upper ANSI C84.1 Range A limit or approaches the lower ANSI C84.1 Range A limit under either system normal or alternate feed configurations

— On the area EPS and the DR device(s) has a fluctuating power source such as wind or solar

— On the area EPS and the DR device(s) may create reverse power flow conditions through voltage regulators or load tap changing transformers under either system normal or alternate feed configurations

— On the area EPS, and there are a significant number of single-phase DR devices

— On a line section of the area EPS in which the aggregate generation from DR devices will exceed 10% of the line section's peak load

8.1.2 Integration with area EPS grounding (IEEE Std 1547-2003 4.1.2)

"The grounding scheme of the DR interconnection shall not cause overvoltages that exceed the rating of the equipment connected to the Area EPS and shall not disrupt the coordination of the ground-fault protection on the Area EPS."

8.1.2.1 Background

This requirement is intended to:

— Prevent damaging phase-to-ground voltages that may exist in unintentional islands after the island forms but before it is detected and de-energized by the DR.

— Prevent excessive desensitization of the area EPS ground-fault detection device.

— Facilitate detection of area EPS faults by the DR.

Integration with an area EPS requires recognition and accommodation of the characteristics of the installation on each side of the PCC. Possible issues include the desensitization of the area EPS distribution system ground-fault protection and the detection of area EPS ground faults by the DR. Other factors that should be considered include the insulation ratings of the DR equipment (e.g., transformers) connected at the PCC, the maximum continuous operating voltage ratings of lightning arresters on the area EPS, the insulation ratings of area EPS equipment, and dynamic conditions such as ferroresonance.

A grounding system consists of all interconnected grounding connections in a specific power system. It is defined by its isolation or lack of isolation from adjacent grounding systems. The isolation is provided by transformer primary and secondary windings coupled only by magnetic means.

System grounding (the intentional connection of a phase or neutral conductor to earth) controls the voltage to earth, or ground, within predictable limits. It also provides for a flow of current that will allow detection of an unwanted connection between system conductors and ground. When such a connection is detected, the grounding system may initiate the operation of automatic devices to remove the source of voltage from the conductors with undesired connections to ground.

The National Electrical Code® (NEC®) (NFPA 70, 2007 Edition) [B57] prescribes certain system grounding connections. The control of voltage to ground limits the voltage stress on the insulation of conductors so that insulation performance can more readily be predicted. The control of voltage also reduces the shock hazard to persons who might come in contact with live conductors.

The grounding of distribution feeders is usually derived from a distribution substation transformer with wye-connected secondary windings. The neutral point of the windings is solidly grounded or connected to ground through a non-interrupting, current-limiting device such as a reactor. A grounding transformer may also establish a grounded system. The circuits associated with four-wire grounded distribution systems have a neutral conductor connected to the supply grounding point. The neutral conductor of the distribution circuits may be:

— *Multigrounded*—Connected to earth at frequent intervals

— *Unigrounded*—Fully insulated and no other earth connection except at the source

— *Ungrounded*—Fully insulated and no intentional connection to earth.

U.S. distribution feeders are (1) four-wire multigrounded or unigrounded, (2) three-wire unigrounded, or (3) three-wire ungrounded systems.

8.1.2.1.1 Four-wire multigrounded and unigrounded systems

Most U.S. distribution feeders are four-wire multigrounded-neutral systems, which are effectively grounded with respect to the substation source. The neutral conductor associated with the primary feeders of multigrounded neutral distribution systems is connected to earth at intervals specified by national or local codes and practices. It is common practice to bond this neutral conductor to surge-arrester ground leads and all noncurrent-carrying parts, such as equipment tanks and guy wires, and to interconnect it with the secondary neutral conductor or grounded conductor.[11] For a single line-to-ground fault, this arrangement limits the voltage rise on unfaulted phases to about 125% to 135% of the pre-fault condition.

In four-wire unigrounded systems, a neutral conductor is run with each circuit but is fully insulated except where it is grounded at the substation transformer or grounding transformer. For a single line-to-ground fault, the voltage rise on unfaulted phases is higher than for multigrounded systems.

8.1.2.1.2 Three-wire unigrounded systems

In three-wire unigrounded systems, a neutral conductor is not run with each circuit, but the system is grounded through the connections of the substation transformer or grounding transformer. On three-phase, three-wire primary distribution circuits, single-phase distribution transformers are connected phase-to-phase. The connection of three single-phase distribution transformers or of three-phase distribution transformers is usually delta-grounded wye or delta-delta. (The floating wye-delta or T-T connections also can be used.) The grounded wye-delta connection is generally not used because it acts as a grounding transformer. Surge arresters are generally connected phase to ground. However, the surge arrester rating is higher than those used on multigrounded neutral systems because the temporary 60 Hz overvoltages expected under fault conditions are also higher. See IEEE Std C62.92.4™-1991 [B52].

8.1.2.1.3 Three-wire ungrounded systems

Three-wire ungrounded systems are clearly in the minority of U.S. distribution feeders. Although this type of system has no intentional grounding to earth, current can flow between the phase conductors and earth because of transducers, measuring devices, and the inherent capacitance between the lines and the earth.

8.1.2.2 Impact of distributed resources

The majority of distribution systems were designed under the assumption of radial power flow from the substation to the loads connected to the area EPS. The introduction of a DR raises the possibility that the distribution circuit can be energized from the load side. The effect depends on the distribution circuit type and the winding configuration and grounding of the distribution transformer that serves the local EPS containing the DR.

The common selections for the distribution transformer winding configuration and grounding are delta-grounded wye and grounded wye-grounded wye. Other winding arrangements could be selected, but they are normally restricted to special uses.

If the DR distribution transformer winding configuration and grounding do not form a compatible energization source for the distribution circuit, then the following issues can arise:

— Phase-to-ground overvoltages

  Following the operation of an area EPS isolation or sectionalizing device, the DR will be isolated with a section of the area EPS and, potentially, other customer loads. This is an unintentional islanding situation that will continue until the DR senses the abnormal condition and ceases to energize the area EPS. The temporary unintentional island includes the section of the area EPS feeder up to the open isolation or sectionalizing device. This section of the area EPS feeder is now isolated from any

[11] In some situations, the same neutral conductor is used for the primary and secondary systems. There is some variation in this practice, however, and some utilities do not interconnect the primary and secondary neutral conductors or bond the neutral to the guy wire. If no direct interconnection is made, the secondary neutral conductor may be connected to the primary neutral conductor through a spark gap or arrester. Surge arresters on multigrounded neutral systems are connected directly to earth, and their grounding conductor may be interconnected directly to the primary neutral conductor and equipment tanks. They may also be interconnected with the secondary neutral at transformer installations.

grounding source provided by the substation transformer. The phase-to-ground voltages that exist in the temporary unintentional island depend on the winding configuration and grounding of the distribution transformer that is now energizing the distribution circuit section.

— Desensitization of area EPS ground-fault detection devices

If the DR and the associated distribution transformer act as an effectively grounded source, they can supply fault current to a ground fault on the distribution circuit. This can affect the ability of the area EPS protective devices to detect and isolate high-impedance ground faults.

These potential DR issues affect the distribution circuit as follows:

— Four-wire multigrounded systems

A case of particular concern is a four-wire multigrounded distribution circuit that supplies a local EPS through a source, such as a delta-grounded wye distribution transformer, that is not effectively grounded. It should also be noted that a grounded wye-wye transformer connection does not create a ground source but can pass through a ground source created on the local EPS side if such a ground source is created there by a grounded DR or a grounding transformer. An unintentional island can form in the event of a single phase-to-ground fault that is detected and isolated by the area EPS before it is detected by the DR. If the DR is of sufficient size to support the loads in the island, even for a short time, the phase-to-ground voltages on the unfaulted phases could, in the worst case, increase to 173% or more of the pre-fault voltage level. This will be sustained until the DR detects the abnormal condition and ceases to energize the area EPS. At this high voltage level, area EPS and customer equipment would almost certainly be damaged.

This problem may be avoided if the DR and the associated distribution transformer form an effectively grounded source to the distribution circuit. However, if the ground-fault current contribution of the DR and distribution transformer is significant, it may cause desensitization of the area EPS ground-fault detection devices.

— Four-wire and three-wire unigrounded systems

A similar concern exists for phase-to-ground overvoltage in four-wire or three-wire unigrounded systems in which the distribution transformer is not effectively grounded. However, these types of distribution circuits are typically designed to tolerate higher phase-to-ground voltages than are four-wire multigrounded distribution circuits.

— Three-wire ungrounded systems

To maintain compatibility with an ungrounded system, the DR and associated distribution transformer will typically be an ungrounded source, such as a delta-grounded wye or delta-delta transformer. This prevents any issues with desensitization of area EPS ground-fault detection devices.

Three-wire ungrounded systems are not likely to be affected by phase-to-ground overvoltage because they are compatible with supply from an ungrounded three-phase source and can tolerate the level of phase-to-ground voltage that occurs during a single phase-to-ground fault.

8.1.2.3 Tips, techniques, and rules of thumb

Distributed generation needs to be applied with a transformer configuration and grounding arrangement that is compatible with the area EPS to which it is to be connected. Otherwise, voltage swells and overvoltages that can damage area EPS or customer equipment may be imposed on the system, and short-circuit currents may impair fault protection on the area EPS.

8.1.2.3.1 Assuring DR integration with the EPS ground

Integration with the area EPS grounding depends on the distribution circuit type and whether the DR and its associated distribution transformer form an effectively grounded source. An effectively grounded source is typically defined as one that has a ratio of zero sequence reactance to positive sequence reactance of less than 3 and a ratio of zero sequence resistance to positive sequence reactance of less than 1.

— Four-wire multigrounded systems

  To minimize phase-to-ground overvoltage problems, all DR sources on multigrounded neutral systems that are large enough to sustain an island should either present themselves to the area EPS as an effectively grounded source or use appropriate protective relaying to detect primary-side phase-to-ground overvoltages and quickly trip off-line (instantaneous trip). The former approach provides an adequate ground current source to limit the phase-to-ground voltage on the distribution circuit that will occur during temporary unintentional islanding conditions. However, if the DR does appear as an effectively grounded source to the area EPS, the DR ground current source should not be so large that it significantly diminishes the fault-current contribution from the area EPS's source substation and thereby degrades the ground-fault detection sensitivity of the area EPS.

  The use of primary-side phase-to-ground overvoltage protective relaying, although used successfully in many installations, could subject the area EPS to many cycles of phase-to-ground overvoltage prior to the DR unit ceasing to energize the area EPS. If the DR is not cleared quickly enough, equipment could be damaged. A particular concern is damage to surge arresters that are connected phase to ground in the distribution circuit. The timing of the phase-to-ground overvoltage protection and DR isolation needs to be coordinated with the overvoltage withstand characteristics of the surge arresters used in the distribution circuit. An additional concern is ferroresonance issues with potential transformers that are connected phase to ground, particularly on cable-fed distribution transformers.

— Unigrounded and three-wire ungrounded systems

  DR interconnections with area EPS primary feeders of three-wire unigrounded or ungrounded systems, or to tap lines of such systems, should not provide any metallic path to ground from the primary feeder except through suitably rated surge arresters or high-impedance devices used only for fault detection purposes.[12]

  In the case of four-wire or three-wire unigrounded systems, if the DR source is large enough to sustain an island, primary-side phase-to-ground overvoltage protective relaying may be applied to prevent sustained phase-to-ground overvoltage.

8.1.2.3.2 Local EPS grounding issues

A local EPS may consist of a single DR unit, or it may include local loads and multiple DR units. In every case, the grounding of the circuit on each side of every transformer within the local EPS is established for all potential operating conditions. The considerations applied for grounding compatibility of transformers within the local EPS are similar to those within the area EPS.

The opening of a transformer secondary circuit breaker would remove the ground reference by the transformer for the local EPS. If the DR source can carry the remaining load, an alternate ground reference needs to be established. In any case when a second source is used as a parallel ground connection, it will affect the monitoring of ground current. As the number of connections increases, multiple grounds make ground current measurement and interpretation increasingly difficult.

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[12]Grounded metallic enclosures or support structures, such as steel poles or metallic conduit, should not be considered metallic paths to ground from the primary feeder.

Where the transformer secondary provides an intermediate voltage at which another source is operating, the second source is another potential ground reference.

8.1.2.3.3 Grounded versus ungrounded neutrals on the local EPS

The NEC [B57] differentiates between system and equipment grounding as follows:

— *System ground:* A system ground is a connection to ground from one of the current-carrying conductors of a distribution circuit or an interior wiring scheme.

— *Equipment ground:* An equipment ground is a connection to ground from one or more of the non-current-carrying metal parts of the wiring system or apparatus connected to the system. As used in this sense, the term *equipment* includes all such metal parts as metal conduits, metal raceway, metal armor of cables, outlet boxes, cabinets, switch boxes, motor frames, and metal enclosures of motor controllers.

— *System neutral ground:* A system neutral ground is a connection to ground from the neutral point or points of a circuit, transformer, rotating machine, or system. The neutral point of a system is the point that has the same potential as the point of junction of a group of equal non-reactive resistances if connected at their free ends to the appropriate main terminals or lines of the system.

An ungrounded system features no intentional connection between the system conductors and ground. What is easily forgotten, though, is the capacitive coupling that always exists between system conductors and ground. Because of the danger to personnel and possible damage to equipment and property, should there be leakage to ground because of shorts or high-impedance paths, the NEC requires that certain grounding practices and detection be designed into systems.

Power is generally provided to large users via three-phase grounded-wye distribution. The power transformer that feeds the user will have its neutral grounded.

For a system with a neutral conductor that is not grounded, the possibility of destructive transient voltages appearing from line to ground during switching of a circuit with a line-to-ground fault is very likely. In addition, an ungrounded neutral system that develops a fault to ground may go unnoticed until a second ground fault causes a line-to-line fault, which can be of major proportions. These ungrounded systems are designed into critical industrial processes that cannot afford tripping of protective devices should a ground fault develop. Such a condition could shut down operations or parts of a process that could result in explosion or loss of product.

A system that features neutral grounding has many advantages over an ungrounded system. It offers the following:

— Greater safety for personnel and equipment

— Increased service reliability

— Lower operating and maintenance expenses

— Reduced magnitude transients

— Simplified ground-fault location

The NEC (section 230.95) requires ground-fault protection for all solidly grounded-wye services of more than 150 V to ground and up to 600 V phase-to-phase with a disconnect rated 1000 A or more. Sustained arcing on grounded 480Y/277 V systems can be very damaging. Overcurrent devices with trip times for less than 1000 A will probably clear an arcing ground fault in sufficient time to limit damage. However, under this NEC rule, a designer could choose as many as six 800 A mains in a 480Y/277 V switchboard (4800 A of service) without having to install ground-fault protection.

Ground-fault protection equipment is designed to detect phase-to-ground faults and ignore overloads and phase-to-phase faults. Four methods of detection may be employed, as follows:

- *Window current transformer:* Detects vector unbalance of current sum in each phase and the neutral. Outputs if not zero.
- *Residual connected:* Uses three or four current transformers and four time overcurrent relays. Any leakage to ground will output a signal.
- *Source ground:* Detects current flow through a system grounding conductor, which is connected between neutral and ground.
- *Phase voltage:* Voltage relays detect an undervoltage on a single phase or with a residually connected voltage relay.

None of these methods is without problems. Proper operation requires that detection monitor all fault currents to ground. Should there be multiple grounding of the neutral, it is possible that the ground-fault protection device will not monitor the total fault. Therefore, it is important that grounding of the neutral not occur at multiple locations because this could create unintended paths and defeat the ground-fault protection sensor. The NEC further limits neutral grounding via the "non-separately derived system" rule. That is, a system source such as a transformer or generator can have its neutral grounded at only one place. The correct place to ground the service neutral is at the main panel board or switchboard. It is not permitted to be grounded at other points.

Some DR installations can operate either parallel with the area EPS or as an isolated intentional island (within the local EPS). It is typical for these installations to operate in parallel with the area EPS during normal conditions and reconfigure for isolated operation during abnormal conditions. The grounding system should be designed so that it is effective during parallel and isolated operation. Further information can be found in IEEE Std 446™-1995 (*IEEE Orange Book*™) [B26].

8.1.3 Synchronization (IEEE Std 1547-2003 4.1.3)

"The DR unit shall parallel with the Area EPS without causing a voltage fluctuation at the PCC greater than ±5% of the prevailing voltage level of the Area EPS at the PCC, and meet the flicker requirements of [IEEE Std 1547-2003] 4.3.2."

IEEE Std 1547-2003 4.1.3 is a voltage fluctuation requirement. IEEE Std 1547-2003 5.1.2 states the test results that are accepted as indicating compliance with IEEE Std 1547-2003 4.1.3 requirements. Further, IEEE Std 1547.1-2005 provides corresponding test procedure requirements.

8.1.3.1 Background

Synchronization is the act of matching, within allowable limits, the voltage magnitude, phase angle, and frequency of a DR with an area EPS prior to closing the DR paralleling device. To minimize the transients to both the DR and the area EPS, it is important that all three quantities be closely matched across the paralleling device before closing the paralleling device. For three-phase DR applications, DR phase rotation is typically checked at the time of DR installation, with the phases being connected to the switches such that the phase rotation will always be correct. Phase rotation is not usually checked again unless wiring changes are made on the generator, inverter, or EPS.

Synchronization is, for the most part, only a major concern for synchronous generators or an operating local EPS, which will be generating a voltage prior to closing a device to synchronize with the EPS. Induction generators may be driven to near synchronous speed by the prime mover before closing the paralleling device, but they will connect in a manner very similar to that of an induction motor before actually generating a voltage of concern. Most inverters will simply start generating voltage when the area EPS is present.

Evaluation to the requirements of IEEE Std 1547-2003 4.1.3 is based on test results for interconnection system-specific technologies (i.e., synchronous interconnection with an EPS or an energized local EPS with an energized area EPS, induction interconnection, or inverter-based interconnection). For the evaluation of DR equipment for general use, IEEE Std 1547-2003 5.1.2 provides test specifications and requirements that are accepted as indication that the requirements, except for the flicker portion, of IEEE Std 1547-2003 4.1.3 will be met. These test specifications and requirements, with suitable test conditions for double-fed asynchronous interconnections, are repeated as follows. Further, IEEE Std 1547.1-2005 provides corresponding test procedure requirements.

— Synchronous interconnection to an EPS, or an energized local EPS to an energized area EPS (IEEE Std 1547-2003 5.1.2 A)

  "This test shall demonstrate that at the moment of the paralleling-device closure, all three parameters in Table 5 [Table 3] are within the stated ranges. This test shall also demonstrate that if any of the parameters are outside of the ranges stated in the table [Table 3], the paralleling-device shall not close."

Table 3—IEEE 1547 Table 5 synchronization parameter limits for synchronous interconnection to an EPS or an energized local EPS to an energized area EPS

Aggregate rating of DR units (kVA)	Frequency difference (Δf, Hz)	Voltage difference (ΔV, %)	Phase angle difference ($\Delta\Phi$, °)
0–500	0.3	10	20
>500–1500	0.2	5	15
>1500–10 000	0.1	3	10

— Induction interconnection (IEEE Std 1547-2003 5.1.2 B)

  "Self-excited induction generators shall be tested as per [IEEE Std 1547-2003 5.1.2 A].

  "This test shall determine the maximum start-up (in-rush) current drawn by the unit.[13] The results shall be used, along with utility impedance information for the proposed location, to estimate the starting voltage drop and verify that the unit shall not exceed the synchronization requirements in [IEEE Std 1547-2003] 4.1.3 and the flicker requirements in [IEEE Std 1547-2003] 4.3.2."

— Inverter interconnection[14] (IEEE Std 1547-2003 5.1.2 C)

  "An inverter-based interconnection system that produces fundamental voltage before the paralleling device is closed shall be tested according to the procedure for synchronous interconnection as stated in [IEEE Std 1547-2003 5.1.2 A].

  "All other inverter-based interconnection systems shall be tested to determine the maximum startup current. The results shall be used, along with Area EPS impedance for the proposed location, to estimate the starting voltage magnitude change and verify that the unit shall meet the synchronization requirements in [IEEE Std 1547-2003 4.1.3] and the flicker requirements in [IEEE Std 1547-2003 4.3.2]."

[13]NEMA MG-1 [B56] contains an acceptable method for determining inrush current.
[14]Some inverter-based interconnection systems may need to be tested to both requirements of [IEEE Std 1547-2003] C in 5.1.2.

— Double-fed asynchronous interconnection

The phase and magnitude of the output of a double-fed generator is directly controlled by the ac excitation provided to the generator rotor. This excitation is precisely controlled by power electronics to produce a voltage with magnitude, phase angle, and frequency that match those of the area EPS. There should be no significant inrush when this type of generator is interconnected with the area EPS, as long as the control is correctly functioning. This type of generator should be tested in the same manner as an inverter interconnection.

8.1.3.2 Impact of distributed resources

Synchronization with phase angles out of phase between the distributed generator and the EPS may result in overheating of the synchronous generator armature core ends and damage to the distributed generator equipment because of the very high torques that can occur when systems are paralleled out of phase.

When operating with a low DR voltage, the DR will experience potentially large reactive power flow into the generation immediately after synchronization. The area EPS may experience low voltage because of the large reactive flow from the area EPS into the generation.

When operating with a high DR voltage, the DR will experience potentially large reactive power flow out of the generation immediately after synchronization. The area EPS may experience high voltage because of the large reactive flow into the area EPS from the generation.

8.1.3.3 Tips, techniques, and rules of thumb

Manual or automatic synchronization devices may be used for synchronization of the distributed generator with the EPS. Automatic synchronization devices are much preferred for the application because successful manual synchronization requires a highly skilled operator and unsuccessful synchronization can easily damage equipment on the area EPS and the DR itself. Generally, manual synchronization is not recommended.

Considerations in the design and operation of both types are discussed as follows.

— Automatic synchronization

Many types of automatic synchronizers are available to replace part or all of the manual synchronizing functions. Sync-check relays, which are designed to check the EPS voltage and the distributed generator voltage, close a contact when the two voltages are within certain limits for a certain length of time. The sync-check relays are the least costly and simplest to operate. The sync-check relays may also serve as signal devices for automatically closing the breaker at the PCC.

Highly accurate and reliable automatic synchronizing relays and electronic transducer combination packages are available with adjustable ranges to monitor and control the synchronism, frequency, phase, or power factor and the voltage levels of the distributed generator. Dead bus relays can also be included in the combination packages to allow connection to a dead bus (used to restore a totally de-energized local EPS) when the synchronizing relay itself will not provide a signal to close the circuit breaker at the PCC.

— Manual synchronization

Manual synchronization equipment is rare and used only on smaller (i.e., less than 100 kW) distributed generator equipment or as a backup to an automatic system on larger units. Manual synchronization equipment varies with distributed generator size but should include sync-check supervision to prevent closing outside of the accepted range. Guidance on equipment that may be used for manual synchronization is given in Table 4.

Table 4—Synchronizing guidance for manually paralleled DR units

DR size (kVA)	Voltage meters	Frequency meters	Phase angle		Sync scopes	Sync-check supervision
			Meter	Sync-lights		
0–10	2	0	0	2	0	Yes
>10–500	2	2	0	2	0	Yes
>500–1500	2	2	1	2	1	Yes
>1500–10 000	2	2	1	2	1	Yes

Small single-phase systems (i.e., 10 kW or less) may be manually synchronized with the EPS with two voltmeters, two synchronization lights, and sync-check supervision. One voltmeter monitors the EPS voltage. The other monitors the distributed generator voltage. [15]

Systems that are 10 kW or larger may be manually synchronized with the EPS with two voltmeters, two frequency meters, a synchroscope, and sync-check supervision. One voltmeter and one frequency meter monitor the EPS voltage and frequency. The other voltmeter and frequency meter monitor the distributed generator voltage and frequency. A synchroscope pointer indicates the phase angle between the EPS voltage and the distributed generator voltage. The straight-up, or 12:00, position indicates that the two voltages are in phase.

When a synchroscope is used, the connection between the EPS and the distributed generator is made with the synchroscope rotating slowly in the clockwise direction and the pointer in about the 11:30 position. The rotation of the pointer shows that the frequencies of the EPS and the distributed generator are not exactly the same. Synchronization with the pointer rotating slowly clockwise ensures the connection between the two units is made and there is a small outflow of power from the distributed generator. This prevents the generator anti-motoring protection from tripping erroneously.

NOTE—The reference to a *clockwise* rotation of the synchroscope refers to the standard connection, in which the generator (DR) rotates slightly faster than the area EPS. The result, as stated, is a slight power flow from the DR to the area EPS.

Synchronism check relays are generally suitable for providing a permissive signal for manual synchronizing. Occasionally, these relays can exhibit a "ratcheting" action that can result in incorrect operation. This can occur when the two systems (DR and area EPS) are rotating with respect to each other. In this case, there is a frequency difference between the two systems, and the synchroscope slowly rotates clockwise or counterclockwise. If the synchrocheck relay is left on and there is not time for it to reset between successive in-phase conditions, the contacts can ratchet closed at some point other than at the in-phase condition.

This condition is most likely to occur with older electromechanical relays in which the reset time of the induction disk takes longer than the time between the in-phase condition. The newer static and microprocessor-based relays should not suffer from this condition.

8.1.4 DR on distribution secondary grid and spot networks (IEEE Std 1547-2003 4.1.4)

The PCC applications discussed in other areas of this document are intended for DR units interconnected with radial primary or secondary distribution circuits, which is the most common distribution configuration. However, in large cities, a number of area EPS operators use a low-voltage network distribution. These

[15] Synchronizing lights serve as a backup to the synchroscope or can substitute for the synchroscope. They are connected across the PCC contacts and go dark at synchronism. Synchronizing lights can also be applied in three-phase sets such that one light is connected on a single phase across the synchronizing device and the other two cross phases on the synchronizing device (e.g., one light connected Phase A–Phase B, one light connected Phase B–Phase A, and the third light connected across Phase C) such that two lights are at maximum brilliance and the third light is dark at synchronism.

low-voltage networks are of two subtypes: the secondary grid network (also referred to as an area network, grid network, or street network) and the spot network. Secondary grid networks serve numerous sites, usually several city blocks, from a grid of low-voltage mains at 208Y/120, three-phase. Secondary spot networks usually serve only a single building or a part of a building.

The IEEE standard development project IEEE P1547.6[16] will cover both secondary grid networks and spot networks.

8.1.4.1 Distribution secondary grid networks (IEEE Std 1547-2003 4.1.4.1)

"This topic is under consideration for future revisions of this standard."

As noted previously, this issue will be addressed in IEEE P1547.6.

8.1.4.2 Distribution secondary spot networks[17] (IEEE Std 1547-2003 4.1.4.2)

"Network protectors shall not be used to separate, switch, serve as breaker failure backup or in any manner isolate a network or network primary feeder to which DR is connected from the remainder of the Area EPS, unless the protectors are rated and tested per applicable standards for such an application.[18]

"Any DR installation connected to a spot network shall not cause operation or prevent reclosing of any network protectors installed on the spot network. This coordination shall be accomplished without requiring any changes to prevailing network protector clearing time practices of the Area EPS.

"Connection of the DR to the Area EPS is only permitted if the Area EPS network bus is already energized by more than 50% of the installed network protectors.

"The DR output shall not cause any cycling of network protectors.

"The network equipment loading and fault interrupting capacity shall not be exceeded with the addition of DR.

"DR installations on a spot network, using an automatic transfer scheme in which load is transferred between the DR and the EPS in a momentary make-before-break operation shall meet all the requirements of this clause regardless of the duration of paralleling."

8.1.4.2.1 Background

A secondary spot network consists of two or more transformers with network protectors connected in parallel on the secondary side. Spot networks usually serve a single site, such as a large building or a portion of a large building. The secondary voltage may be 480Y/277 or 208Y/120. These network units are often located in transformer vaults within the building or in underground vaults in the street. Figure 3 shows an example of a secondary spot network.

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[16] Numbers preceded by P are IEEE authorized standards projects that were not approved by the IEEE-SA Standards Board at the time this publication went to press. For information about obtaining drafts, contact the IEEE.

[17] When required by the authority who has jurisdiction over the DR interconnection, a study may be conducted to determine that all of the requirements of this subclause can be met when the aggregate DR installed on a spot network exceeds 5% of the spot network's maximum load.

[18] IEEE Std C37.108™-2002 [B44] and IEEE Std C57.12.44™-2000 [B46] provide guidance on the capabilities of network systems to accept distributed resources.

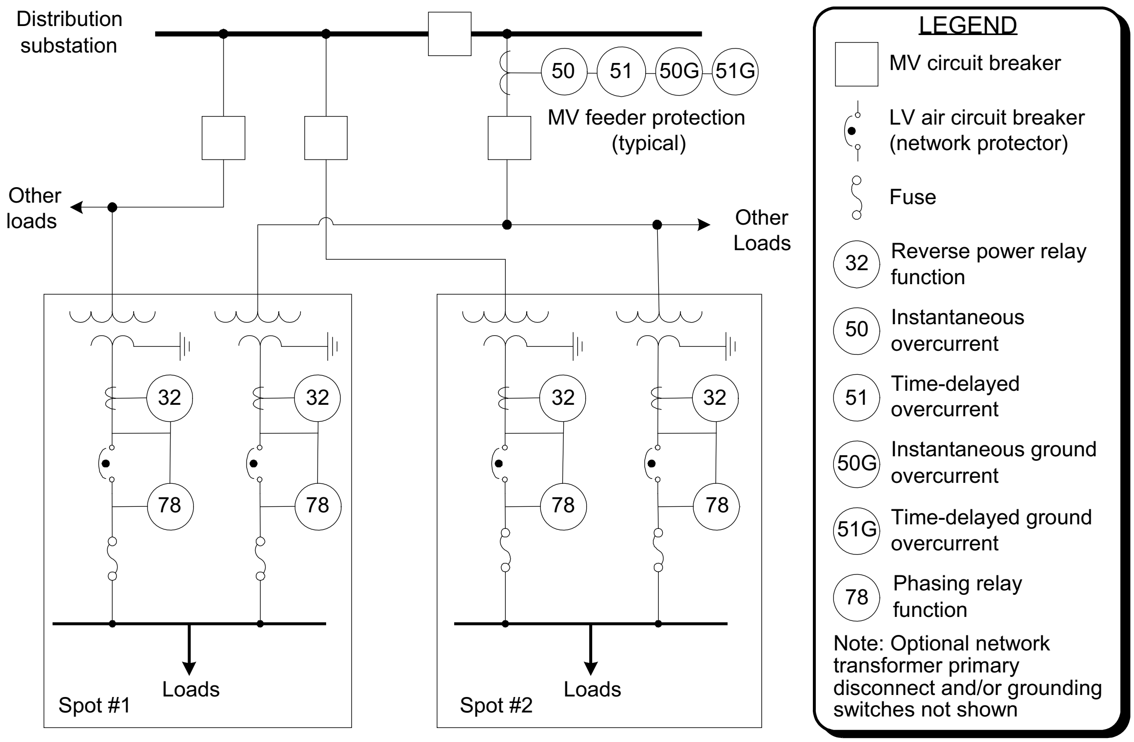

Figure 3—Example secondary spot network

Primary feeders for the spot network originate at a distribution substation with a circuit breaker and overcurrent protection. Typically, the overcurrent protection will not see faults on the secondary side of the network transformer. IEEE Std C37.108™-1989 [B44] provides additional information about protection of network transformers.

A network protector contains a low-voltage circuit breaker and a protective package. The protective package includes a network relay or master relay that is sensitive to directional real and reactive power flow. It senses the reverse flow through the transformer for primary feeder faults or flow because of the feeder charging current or transformer magnetizing current. The network relay is a very sensitive reverse-power relay, with a pickup level on the order of 1 kW to 2 kW. The master relay also supervises the closing of the network protector. The relay looks at the voltage on both sides of the protector, and if the transformer-side voltage is higher than the bus-side (by perhaps 1 V), the first close criterion is met. The phasing relay looks at the angle across the open contacts of the protector. If the phasing voltage is leading the network line-to-ground voltage or is not lagging by a large angle as determined by the setting of the phasing relay, the phasing relay will make its close contact. Basically, the phasing relay permits closing if the transformer-side line-to-ground voltage is leading the network-side line-to-ground voltage at the open protector. Network protectors also contain fuses for overcurrent protection. These fuses are sized well above the capability of the transformer and have limited capability to operate for arcing-type faults that are the most common in the network vault.

Multiple sets of secondary cables are typically installed between network protectors and the load. These cables may be protected with inline fuses, called *cable limiters,* on each end such that cable faults are isolated by the limiters. Limiters may also be installed on the service cables going to the customer switchgear. The primary purpose of a limiter is to protect the insulation of the conductors from excessive thermal damage.

In normal operation, the spot network is supplied simultaneously from all the primary feeders. When a primary feeder is faulted, the network relay senses reverse power flow (from the network toward the primary feeder) and opens the network protector, thereby isolating the network bus from the faulty feeder and allowing service on the network to continue without interruption. Figure 4[19] shows the operation of a network protector to isolate a faulted primary feeder. Later, when the faulted primary feeder is repaired and returned to service, the network relay senses voltage at the transformer side of the open network protector. If this voltage is such that power will flow from the network unit to the bus when the protector is closed, the network relay commands the protector switch to close.

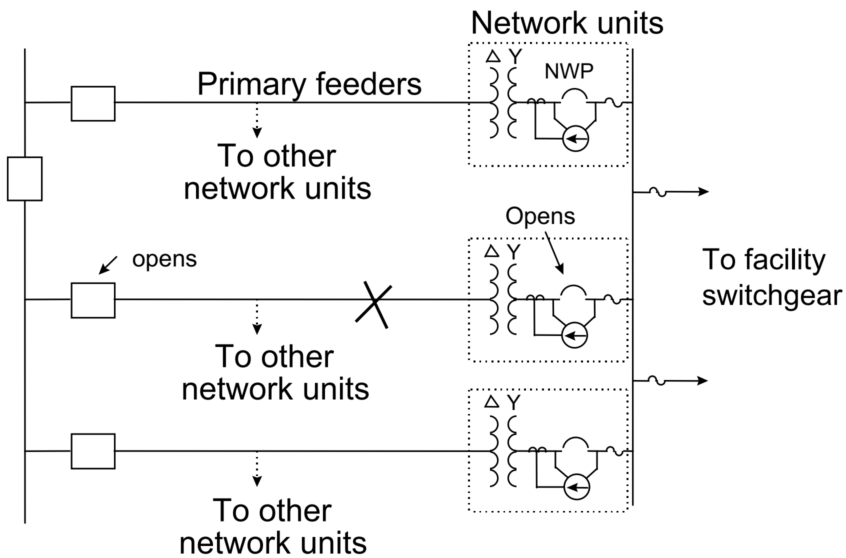

Figure 4—Network primary feeder fault

8.1.4.2.2 Impact of distributed resources

If a DR is installed on a spot network, a number of special problems arise.

- Exporting power from a spot network, or even serving an entire facility load from a DR, is not practical because of the reverse-power method of protection on the network units. If DR generation exceeds the onsite load, even momentarily, power flows from the network toward the primary feeders, and the network relays will open their network protectors and isolate the network from its area EPS supply. Minimum site loads (e.g., late at night or on weekends) may severely limit the size or operating hours of a DR. Even if a DR is sized to the site's minimum load, consideration has to be given to the possibility of a sudden loss of a large load, which might reverse power flow through the network units.
- Network protectors, built in accordance with IEEE Std C57.12.44™-2000 [B46], are not required to withstand the 180º out-of-phase voltages that could exist across an open switch with DR on a network. They are also not required to interrupt fault currents with higher X/R ratios than those usually encountered in low-voltage network systems.
- The fault current delivered from a DR to external faults can cause network protectors to open, which may potentially isolate the network.

[19] Behnke et al. [B5].

— If the network protectors open and isolate the network and the DR from the utility source, the network relay may repeatedly attempt to reclose the network protector, which may lead to the destruction of the protector and catastrophic failure of the network unit.

— The network relays are part of an integrated assembly often in a submersible enclosure mounted in vaults in the street and are not as easily modified as those in a typical relay control scheme.

— There is a possibility that protector cycling could occur under light load conditions if the minimum net load supplied by the protectors is fewer than a few percent of the protector rating.

8.1.4.2.3 Tips, techniques, and rules of thumb

DR may be accommodated on spot networks if the timing of the reverse power relay and the tripping of the DR can be coordinated. Figure 5 shows the adjustability of the reverse power relay. If the prevailing practice of the utility does not allow time delay of network protector tripping for reverse power conditions, only insignificant amounts (less than 25% of the minimum load) of inverter-interfaced, and load-coincident, generation can be installed. Inverter-based DR have the advantage that fault current is very limited (to about 100% to 200% of normal load current). In addition, an inverter can respond rapidly to signals that control its power output level.

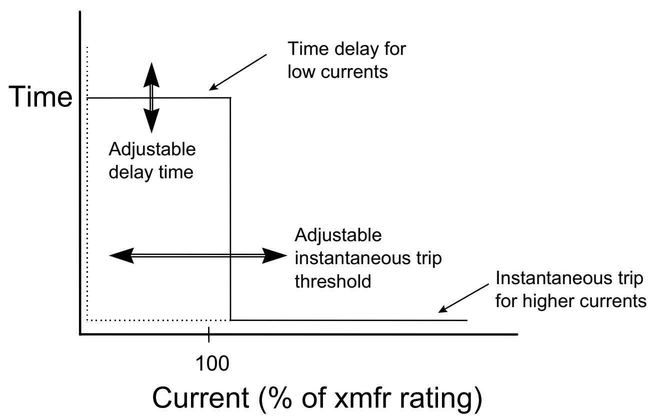

Figure 5—Adjustable reverse-power characteristic

There are also interconnection schemes that monitor the load on the network protectors and DR and control the output of the DR or trip the DR off-line when the minimum net loading of the network is detected. To avoid protector cycling, the exact load point at which control is initiated has to be determined based on the minimum loading of the lightest-loaded protector serving the spot network (i.e., the facility minimum divided by the ratio of the minimum protector to average protector load).

Another possible interconnection problem involves DR installed on a primary feeder that serves a secondary spot network. If the primary feeder breaker trips and the DR is not isolated, the DR may provide power to the secondary network. Site-specific control schemes will be required for this application.

8.1.5 Inadvertent energization of the area EPS (IEEE Std 1547-2003 4.1.5)

"The DR shall not energize the Area EPS when the Area EPS is de-energized."

8.1.5.1 Background

For personnel safety reasons, it is critical that inadvertent energization of area EPS circuits be prevented during line maintenance or service restoration activities when the area EPS is de-energized.

8.1.5.2 Impact of DR

The DR will not transfer power to the area EPS side of the PCC when the area EPS has been de-energized for any reason. In addition, when the voltage or frequency of the area EPS is outside acceptable limits, unless islanding is permitted, power transfer from the DR to the area EPS needs to cease beyond the PCC. In the case of a system fault, this will allow the area EPS to step through its relaying and reclosing schemes to clear the fault without interference from the DR beyond initial fault-clearing.

8.1.5.3 Tips, techniques, and rules of thumb

After an area EPS disturbance, no DR reconnection will take place until the area EPS voltage is maintained within Range B of ANSI C84.1 Table 1 and frequency is in the range of 59.3 Hz to 60.5 Hz for a stabilization period of up to 5 min. See 8.2.6 for further details.

8.1.6 Monitoring provisions (IEEE Std 1547-2003 4.1.6)

"Each DR unit of 250 kVA or more or DR aggregate of 250 kVA or more at a single PCC shall have provisions for monitoring its connection status, real power output, reactive power output, and voltage at the point of DR connection."

8.1.6.1 Background

IEEE Std 1547.3-2007 provides guidelines for monitoring, information exchange, and control of DR interconnected with EPSs.

The monitoring provisions described in IEEE Std 1547-2003 are local at the point of DR connection. The data monitored may be interfaced with either local or remote monitoring equipment. The monitored information may be available in real time or stored with periodic read-out as appropriate for the application.

The need to monitor DR unit status, real power, reactive power, and voltage is typically driven by area EPS planning and operating concerns. For units above an area EPS-specified size limit, real-time monitoring (e.g., SCADA) of DR status may be used as part of the area EPS personnel safe working practices.

8.1.6.2 Impact of distributed resources

Larger-capacity DR installations may be located at sites with relatively high electrical load. If the size of a DR is less than the size of a load (i.e., non-exporting) but is significant compared with the capability of the area EPS serving the site, an operational basis may exist for remote monitoring (SCADA) by the area EPS.

If DR of significant size relative to the area EPS load in the near vicinity are installed, the operation of the DR can affect the area EPS's activities to serve customers. In such cases, the status of the DR installation can be critical to area EPS operations. Recorded performance of the DR may also be important to the area EPS as it considers future system development plans. This is an example of monitoring that can be local and non real time.

This discussion of monitoring (local or remote) does not take into account the application of revenue metering. IEEE Std 1547-2003 only addresses the technical requirements of interconnection; revenue metering is a business and contractual issue that is not covered here.

8.1.6.3 Tips, techniques, and rules of thumb

IEEE Std 1547-2003 requires "provisions for monitoring." This may be local or SCADA. This can mean appropriate dry contacts wired to terminal blocks and currents and voltages accessible for connecting to transducers or other monitoring equipment. Monitoring may not be required for some applications.

In this subclause, *local* means the point of DR connection and is used to cover the IEEE 1547-required monitoring provisions. *Remote* covers the possible requirement for area or local EPS monitoring, such as SCADA.

When SCADA is required, the area EPS operator is typically provided with local indication and discrete signals for remote monitoring of the local EPS. This includes the following:

— Connection status (connected or not connected)
— Real power, reactive power, and voltage at the point of DR connection
— Current flow and power factor (and, occasionally, frequency)
— In some instances, critical alarms

The physical arrangements for monitoring may take many forms. They may include the following:

— Transducers, such as potential and current transformers (which can be shared with relaying)
— Software ports on the DR equipment for retrieval of required information
— Local data-logging devices or meters
— Remote terminal units for performing SCADA functions

An area EPS SCADA remote terminal unit can take on many forms.

— It can take potential transformer (0 Vac to 120 Vac), current transformer (0 A to 5 A), and contact inputs directly and provide all of the analog to digital conversion and protocol conversion to communicate with the area EPS master SCADA equipment.
— It can provide a communication port to another device that provides the required information in a suitable digital format.
— It can handle only low-level signals and "dry" contacts.
— It can be a combination of any or all of the above.

Because the area EPS can take many forms and any two area EPS SCADAs can be set up differently, it is difficult to provide detailed guidance for interfacing with this equipment. The area EPS operator can provide advice on inputs, outputs, and interface signals.

NOTE—Monitoring is technically complex. Although this information is not prescriptive, it is intended to be useful for the EPS operator or DR developer. It should be noted that kilowatt and kilovoltampere-reactive metering is not included. This is likely to require revenue-grade metering, which is not within the scope of IEEE Std 1547-2003 and that will need to be addressed by the contractual arrangement with the DR owner.

Potential free or dry contacts and analog values represent specific technologies that may be applicable for some systems but inappropriate for others. For example, a common PV application uses multiple smaller inverters (often 1 kW to 2 kW) to make an aggregate system rated at more than 50 kW. Typically, these inverters communicate via a communication link to a central computer that can display all of the required data (and more). However, they would not have the dry contacts or analog values.

In any case, if the DR is large enough that the area EPS desires or needs to monitor via SCADA, detailed discussions with the area EPS operator are required to determine the best approach.

As a caution, if remote communications are being developed with the DR using commercial telephone circuits, the developer, in concert with the local telephone provider, should carefully review IEEE Std 487™-2000 [B27] to determine the specific protection requirements. A particular concern is damaging and dangerous voltages induced on telephone equipment should ground faults occur in or near the DR facility. IEEE Std 487-2000 addresses three levels of communication circuit performance related to circuit criticality, as follows:

— *Class A:* Non-interruptible service performance (i.e., should function before, during, and after the power fault condition)

— *Class B:* Self-restoring interruptible service performance (i.e., should function before and after the power fault condition)

— *Class C:* Interruptible service performance (i.e., can tolerate a station visit to restore service)

This telephone line protection issue should be considered not only for data and control circuits but also for voice-type communications circuits. A variety of phone circuits are now available, including analog, digital, fiber optic, and copper. Care should be exercised that the correct type of phone line is provided for the equipment used. In many cases, the local telephone company may have requirements in addition to IEEE requirements. The typical area EPS dedicated SCADA phone line is a Class A analog telephone circuit.

IEEE Std 1547.3-2007 provides the following monitoring, information exchange, and control examples for DR integrated with the EPS and their corresponding information exchange interactions:

— *DR unit dispatch.* The DR operator dispatches a single DR unit for parallel operation with the area EPS and coordinates with the area EPS operator for economic energy (but no ancillary services) for shaving peak. This is a diesel generating unit that requires environmental monitoring.

— *DR unit dispatch for energy export.* The DR operator of a single-unit 1.1 MW wind turbine intends to operate as an independent power producer. The DR operator will dispatch this DR unit with the intention of selling energy back to the owner of the area EPS.

— *DR unit scheduling.* The DR operator creates, edits, and deletes schedules to dispatch commands to a DR unit. The DR operator's system communicates the scheduled operation to the DR controller, which invokes commands to the DR unit at appropriate times and notifies the DR operator of status.

— *DR aggregation.* The DR operator dispatches multiple DR units during peak periods of energy use per information (e.g., real-time pricing, dispatch request, or interruptible rate) provided by the DR aggregator and coordinated with the area EPS operator. The DR aggregator monitors net metering information from the site.

— *DR maintenance.* The DR owner contracts with a DR maintainer to periodically service a DR unit and perform emergency repairs. The DR maintainer monitors key performance indicators and coordinates with the DR operator when service is required.

— *DR ancillary services.* The DR may be used to provide any or all of the following ancillary services: load regulation, energy losses, spinning and non-spinning reserve, voltage regulation, and reactive supply.

— *DR providing reactive supply.* The DR unit may provide reactive supply by absorbing VARs or producing VARs by changing the field current to match a preestablished schedule. Alternatively, a stated power factor on the high side of the interconnection transformer or PCC can be established.

8.1.7 Isolation device (IEEE Std 1547-2003 4.1.7)

"Where required by the Area EPS operating practices, a readily accessible, lockable, visible-break isolation device shall be located between the Area EPS and the DR unit."

As noted previously, IEEE Std 1547-2003 4.1.7 does not universally require an isolation device. Also, it states that, where required by area EPS operating practices, its location need not be at the PCC but between the area EPS and the DR unit. IEEE Std 1547-2003 does not preclude installing any required isolation device at a location that is otherwise allowable.

Additionally, IEEE Std 1547-2003 5.3.2 provides the requirement for the isolation device interconnection installation evaluation. IEEE Std 1547-2003 5.3.2 states:

"A system design verification shall be made to ensure that the requirements of [IEEE Std 1547] 4.1.7 have been met."

IEEE Std 1547-2003 5.3.2 "system design verification" is not an operational test, i.e., not a commissioning test in the manner that the IEEE 1547 cease to energize functionality is evaluated.

An isolation device electrically separates the DR from the local or area EPS. If the isolation device is required by the area EPS, then its location should be carefully considered as required by the area EPS and for consequences and compliance with local codes and regulations {e.g., NEC [B57] or National Electric Safety Code® (NESC®) (Accredited Standards Committee C2-2007) [B1] and state rules and tariffs}.

The isolation device is not required to be a paralleling or interrupting device, but it shall comply with IEEE Std 1547-2003 4.1.7 and 5.3.2 requirements. It needs to be able to provide sufficient isolation such that if the area EPS or the DR unit is powered after the isolation device is activated, the isolation device does not constitute an unsafe condition (e.g., does not arc or conduct electricity between the DR unit and the remainder of the local or area EPS).

The readily accessible, lockable, visible-break aspects of IEEE Std 1547-2003 4.1.7 are based on NEC requirements related to similar devices (e.g., breakers or switches) and on area EPS operating practices.

There has been an evolution from the term *visible-break* to the NEC term *clearly indicating.* When referring to "isolating means" in the NEC (2005), "clearly indicating" has basically replaced "visible break." For higher-voltage applications (e.g., more than 600 V) "visible break" is still often used to indicate an isolating means with adequate visible inspection of all contacts in the open position. However, draw-out circuit breakers are generally acceptable as complying with the visible-break criteria.

8.1.7.1 Background

The isolation device requirement of IEEE Std 1547-2003 differs from IEEE Std 1547-2003 4.1.5 and 4.1.8.3 requirements. IEEE Std 1547-2003 4.1.7 is not universally mandated unless area EPS practices require it. The intent of the isolation device requirement is driven by preexisting area EPS operating practices (e.g., mandated by OSHA or electric worker labor practices).

IEEE Std 1547-2003 may not be the only standard applicable to a DR interconnection project. For example, compliance with the NEC [B57] or NESC [B1] may be required. The NEC, which is applicable to public and private buildings and structures, includes requirements for disconnecting means. The NEC, OSHA, and all other standards and practices required by a DR interconnection project need to be reviewed for additional disconnecting or isolation device requirements for power sources, loads, and circuits.

All area EPS operators have established practices and procedures concerning operational safety of the area EPS under normal and abnormal conditions. Several of these identify methods to ensure that the electrical system is properly reconfigured from its normal service mode for the safety of area EPS line and service personnel. Although these procedures vary somewhat among operators, their intent is to establish "safe work area clearances" for the safety of personnel operating in proximity to the EPS. To achieve this, area EPS operators have established procedures that require protective grounding, jurisdictional tagging of the portion of the EPS where clearance is to be gained, and visible isolation; others have established work practices that presume any line is "live" or "hot," regardless of whether that is the case when a worker arrives.

Qualified area EPS personnel generally use one of two practices to work on primary conductors: dead line clearance or live line work (also called *hot work*). Dead line clearance work practices typically mandate that the previously energized conductors be visibly isolated from all sources, tagged out, checked for voltage, and grounded before any work is done. When dead line clearance work involves a DR installation, a DR isolation device may be necessary to provide a visible break. Some state-level interconnection rules do not require visible-break isolation devices for small DR (e.g., of 10 kW or less) that use certified non-islanding inverters.

In live line work, conductors remain energized during the work, or the worker must treat the line as though it were energized. Specialized work practices, techniques, tools, and training are required to perform live line work. Safety rules, developed to minimize the potential for electrical shock or arc flash, require that any automatic reclosing scheme, such as a line recloser or substation breaker, be disabled on the source protective device. In addition, protective device trip values may be temporarily reduced during hot work to further reduce the personnel exposure time should a contact or fault occur.

OSHA 29 CFR 1910.269 [B61] has a requirement for de-energizing lines and equipment for employee protection. It states that:

> "All switches, disconnectors, jumpers, taps, and other means through which known sources of electric energy may be supplied to the particular lines and equipment to be de-energized shall be opened. Such means shall be rendered inoperable, *unless its design does not so permit*, and tagged to indicate that employees are at work."

This practice relates to dead line clearance work. Other OSHA and NESC regulations apply to hot work and dead line work and may have additional requirements pertaining to DR unit isolation.

8.1.7.2 Impact of distributed resources

After the area EPS is de-energized, the DR could reenergize it if the interconnection system were to somehow experience a multiplicity of non-compliance with IEEE 1547 requirements. For example, IEEE Std 1547-2003 4.1.5 and 4.2.6 would have to be violated simultaneously. Thus, the IEEE Std 1547-2003 4.1.7 isolation device requirement is redundant for preventing energization of a dead line. Further, non-islanding inverter-based DR that do not produce fundamental voltage before the interconnection system paralleling device is closed cannot generate electrical energy in the absence of an external electric source such as the area EPS. In this case, too, IEEE Std 1547-2003 4.1.7 is redundant for preventing energization of a dead line.

8.1.7.3 Tips, techniques, and rules of thumb

It is imperative to check with the AHJ (e.g., state and local codes as well as the area EPS operator) to establish the isolation device requirements. Some state interconnection rules require utility-accessible, lockable, visible-break disconnect switches. Some states in the U.S. (e.g., Arizona, Colorado, and New Jersey) do not require the DR owner to install them for certified, small, inverter-based DR. Still other states defer to area EPS requirements. Isolation devices—typically electrical disconnect switches or draw-out circuit breakers—provide visible isolation of the DR from the area EPS. Some area EPS operators allow for a draw-out-type circuit breaker with a provision for pad locking at the draw-out position to meet the requirement for an isolation device. Check all applicable standards and codes for requirements on isolation devices and related equipment, practices, and functions.

If the DR were to remain in parallel with the area EPS during hot work, area EPS personnel performing hot work would be exposed to increased electric shock time and extended arc flash time in the event of a contact or fault because of the added contribution from the DR. Therefore, it is imperative that area EPS practices for isolation be considered, where required. For hot work, some area EPS operating practices require the isolation of DR sources from the affected area to protect personnel.

In a DR installation, some equipment and fuses or breakers may be energized from two or more directions. If a disconnect means is required by the area EPS, it needs to electrically separate the DR from the area EPS. There may be other disconnection means within the local EPS in which the load-side contacts are still energized when the switch is in the open position, so a safety label with a warning should be placed by these switches. Also, a means should be provided for fuse replacement (in fused switches) without exposing the worker to energized parts.

In addition, much work has been, and continues to be, performed to develop inverters that can ensure that the DR will not be able to generate electrical energy in the absence of the utility electrical source (the non-islanding inverter). Some area EPS operators have modified their work practices by waiving their requirement for an isolation device when such an inverter has been installed and tested to appropriate standards for the “non-islanding” function.[20]

Another option for DR projects less than 10 kW (e.g., small residential PV installations) is a plug or twist-lock plug, if it can be removed in a manner that prevents it from being plugged back into the system. A pad-lockable cap that can be placed over the plug for which only utility personnel have the key is one example.

Where a readily accessible isolation device is required by the area EPS, the typical location will be at the PCC, but other locations (such as the DR point of connection) could be considered for operational flexibility and cost effectiveness. The location of the isolation device should be determined with consideration to the operation of the local EPS both with the generator isolated or operating. Regardless of isolation device location, this device needs to be accessible and in series with the DR unit. There is not a universal requirement for mandating an isolation device, nor is there a single optimal location for the isolation device because location involves application-specific, local EPS and area EPS operating procedure considerations. IEEE 1547 requirements do not address specific details such as equipment location, ownership, who pays, etc. Area EPS operating practices, local rules, or regulations sometimes have guidance, and prior discussion with the area EPS operator is good practice.

[20] UL 1741 [B68] is one example of a standard for inverters interconnected with the Area EPS.

8.1.8 Interconnect integrity (IEEE Std 1547-2003 4.1.8)

8.1.8.1 Protection from electromagnetic interference (IEEE Std 1547-2003 4.1.8.1)

"The interconnection system shall have the capability to withstand electromagnetic interference (EMI) environments in accordance with (IEEE Std C37.90.2™-2004 [B43]). The influence of EMI shall not result in a change in state or misoperation of the interconnection system."

8.1.8.1.1 Background

The use of hand-held transceivers[21] (i.e., walkie-talkies) and cell phones is common in industrial and commercial settings. When operated, these transceivers produce high field-strength electromagnetic radiation in their immediate vicinity, which has a tendency to produce undesired performance in nearby solid-state and digital relay and control equipment. This interaction necessitated the development in 1987 of IEEE Std C37.90.2-2004 [B43].

The test field-strength level in IEEE Std C37.90.2-2004 is intended to roughly approximate the effect of a walkie-talkie operated at 15 cm (6 in) from the exposed surface of the relay. This value is the result of extensive testing by members of the working group formed to update IEEE Std C37.90.2-2004.

It is expected that all of the interconnection system components will be subjected to these tests. For new installations, this will probably be completed by the equipment manufacturer. However, if existing equipment is put to use in the interconnection system, the DR operator may have to arrange for the tests. Older equipment may not have been tested for electromagnetic interference (EMI) because the use of radio-based equipment was not as widespread 20 to 25 years ago. The use of older equipment for the interconnection system could leave the DR subject to misoperation in the presence of radio signals.

The use of radio-based equipment has increased dramatically in the past 10 years. Cell phones, personal digital assistants, cameras, walkie-talkies, and other devices may be present as part of the DR installation or in daily use during DR operation. Further, many DR installations are installed at existing facilities, which may present additional opportunities for interference.

The test needs to be applied to all interconnection system equipment. For the purpose of this subclause, interconnection system equipment consists of components that provide protective or control functions, including the following:

— Relays

— Programmable logic controllers

— Computers

For the purposes of this subclause, the test would not be applied to the following:

— Circuit breakers

— Air switches

— Disconnect switches

— Current transformers

— Potential transformers

[21] A transceiver is a device or circuit that generates high-frequency electric energy, controlled or modulated, that can be radiated by an antenna.

8.1.8.1.2 Impact of distributed resources

This IEEE 1547 requirement focuses exclusively on the continued operation of the interconnection system during and after EMI exposure. The DR interconnection system is essentially being held to the same standard of performance as generators, protective relaying, and other electrical equipment.

8.1.8.1.3 Tips, techniques, and rules of thumb

In the design of equipment for protection against the effects of radiated EMI, the use of discrete frequency steps throughout the test frequency range has been made an alternative to a continuous sweep of the pertinent frequencies. These changes are in recognition of the variety of modern equipment used to conduct these types of tests.

Portable radio transmitters, when used in close proximity, provide the most common source of single-frequency interference to static-protective and control relays. The portable transceivers normally used in power system communications have output power less than 10 W, measured at the base of the antenna. However, besides power level, other factors (such as the frequency and modulation level) may affect the susceptibility of relay equipment to these devices. When deciding on a meaningful test level, it is important to know what field strengths are produced by commercial portable transceivers because these are the dominant interfering sources.

8.1.8.2 Surge withstand performance (IEEE Std 1547-2003 4.1.8.2)

"The interconnection system shall have the capability to withstand voltage and current surges in accordance with the environments defined in (IEEE Std C62.41.2™-2002 [B48] or IEEE Std C37.90.1™-2002 [B42]) as applicable."

8.1.8.2.1 Background

Transient surge voltages that occur in ac power circuits can be the cause of operational upset or product failure in industrial and residential systems and equipment. These problems have received increased attention in recent years because of the widespread application of complex semiconductor devices that are more sensitive to voltage surges than vacuum tubes, relays, and earlier generations of semiconductor devices. Logical and economical design of circuits to protect vulnerable electronic systems from upset or failure requires knowledge or estimates of the following:

— Transient voltage and current waveforms

— Frequency of occurrence of transients with various energy levels

— Particular environmental variations (such as amplitudes)

— Upset or failure thresholds of the particular equipment to be protected

Occasionally, attempts will be made to describe surges in terms of "energy" to help in the selection of the rating of a candidate surge-protective device. However, this concept can be a misleading oversimplification because the energy distribution among the circuit elements involved in a surge event depends on the impedance of the power system source (including the ac mains) and the surge-protective device called on to divert the surge. There are no independent, meaningful, and self-contained descriptions of surges in terms of energy alone. The energy delivered to the end equipment is the significant factor, but it depends on the distribution between the source and the load (equipment or surge-diverting protective device or both).

8.1.8.2.2 Impact of distributed resources

This requirement focuses exclusively on the survivability and continued operation of the interconnection system during and after exposure to surge voltages in low-voltage ac power circuits (in this case, the area EPS distribution system). In particular, IEEE Std C37.90.1™-2002 [B42] emphasizes the performance of the protective functions of the DR interconnection system in the presence of surges as defined within that standard.

The DR interconnection system is essentially being held to the same standard of performance as generators, protective relaying, and other electrical equipment.

8.1.8.2.3 Tips, techniques, and rules of thumb

These surge voltages originate from two major sources: lightning effects (direct or indirect) on the power system and system switching transients.

In the case of reflected wave harmonics, the system needs to be altered to eliminate the addition of the reflected harmonics. Possible methods include changing the operating frequency of the inverter and applying filters, capacitors, or inductors to change the tuning of the system.

Lightning

Models of lightning effects consistent with available measurements have been made to yield predictions of surge levels, even if the exact mechanism underlying the production of any particular surge is unknown. The major mechanisms by which lightning produces surge voltages are:

— A nearby lightning strike to objects on the ground or within the cloud layer produces electromagnetic fields that can induce voltages on the conductors of the primary and secondary circuits.

— Lightning ground-current flow from nearby cloud-to-ground discharge couples onto the common ground impedance paths of the grounding network and causes voltage differences across its length and breadth.

— If a primary gap-type arrester is used to limit the primary voltage, the rapid drop of voltage that may occur when the arrester is coupled through the capacitance of a transformer can produce surge voltages in addition to those coupled into the secondary circuit by normal transformer action.

— A direct lightning strike to high-voltage primary circuits injects high currents into the primary circuits, which produces voltages by either flowing through ground resistance and causing a ground potential change or flowing through the surge impedance of the primary conductors. Some of this voltage couples from the primary to the secondary of the service transformers, by capacitance or transformer action or both, and thus appears in low-voltage ac power circuits.

— Lightning strikes the secondary circuits directly. Very high currents and resulting voltages can exceed the withstand capability of equipment and conventional surge protective devices rated for secondary circuit use.

Switching transients

System switching transients can be divided into transients associated with normal or abnormal conditions. These include the following:

— Minor switching near the point of interest (such as an appliance turnoff in a household or the turnoff of other loads in the individual system).

— Periodic transients (i.e., voltage notching, caused by a momentary phase-to-phase short circuit with a rapid change in voltage and lasting in the 100 µs range) that occur each cycle during the commutation in electronic power converters.

— Multiple reignitions or restrikes during a switching operation (Air contactors and mercury switches can produce, through escalation, surge voltages of complex waveforms and of amplitudes several times greater than the normal system voltage).

— Major power system switching disturbances (such as capacitor bank switching, fault clearing, or grid switching).

— Various system faults (such as short circuits and arcing faults).[22]

— Power factor correction capacitor switching.[23]

— Switching of long runs of underground cable.

The most visible effect of a switching surge is generally found on the load side of the switch and involves the equipment that is being switched as well as the switching device. In the case of the equipment being switched, the prime responsibility for protection rests with either the manufacturer or the user of the equipment. However, the presence and source of transients may be unknown to the user. This potentially harmful situation occurs often enough to command attention.

8.1.8.3 Paralleling device (IEEE Std 1547-2003 4.1.8.3)

"The interconnection system paralleling-device shall be capable of withstanding 220% of the interconnection system rated voltage."

8.1.8.3.1 Background

The paralleling device needs to be capable of withstanding 220% of the rated voltage across the open contacts. This is not a phase-to-ground voltage withstand requirement.

This requirement is based on aspects of two other parts of IEEE Std 1547-2003, together with normal area EPS operating criteria. ANSI C84.1-2006 [B3] suggests a maximum area EPS operating voltage of 110% of the "nominal voltage" and is usually mandated by regulatory agencies. IEEE Std 1547-2003 4.1.1 specifies that "The DR shall not cause the area EPS service voltage at other local EPSs to go outside the requirements of ANSI C84.1, Range A." And IEEE Std 1547-2003 4.2.3 defines the maximum allowable operating voltage to be 110% of the nominal system voltage, as defined in ANSI C84.1 Table 1. The 220% withstand requirement in this clause is based on these factors.

If the local EPS with the DR connected operates isolated from the area EPS, with the point of isolation being the paralleling device, the voltage on the area EPS side of the paralleling device could be 180º out of phase with the voltage on the local EPS side. Both voltages could be at 110% of nominal system voltage, and both could be operating precisely at 60 Hz, which would result in a long-term, steady-state voltage of 220% of nominal across the open paralleling device contacts.

[22]One type of switching transient, for example, results from fast-acting overcurrent protective devices such as current-limiting fuses and circuit breakers capable of arcing times of less than 2 ms. These devices can leave inductive energy trapped in the circuit upstream; if no low-impedance path is offered to lessen the stored energy, high voltages are generated. The resultant voltage surge appears in parallel with the loads where the fault is being cleared.

[23]Transient overvoltages associated with switching of power-factor correction capacitors have levels, at least in the case of restrike-free switching operations, of generally less than twice the normal voltage, though the levels of the transients often can be 1.5 times normal (i.e., the absolute value may be 2.5 times the normal peak). These transients can occur daily, and their waveforms generally show longer time durations, such as several hundred microseconds, compared with typical durations on the order of microseconds to tens of microseconds for other switching events and lightning-induced transients. If multiple reignitions or restrikes occur in the capacitor-switching device during opening, then the transient overvoltage can exceed three times the normal system voltage and involve high energy levels.

8.1.8.3.2 Impact of distributed resources

In practicality, this requirement would seem to apply only to synchronous generators or installations that are designed such that the DR (or several DR units) of any type can support the local EPS in an isolated fashion. In the case of synchronous generators, this requirement would be germane whenever the generator is synchronizing with the system. In the latter case, the requirement is meaningful during steady-state operation of the local EPS while disconnected from the area EPS.

When DR that use other technologies (e.g. inverter-based interconnections or induction generator interconnections) are intended to operate only in the presence of the area EPS, they usually produce a voltage only when the area EPS is present. The requirement diminishes to a short-time capability, which may be less demanding.

There are several new technologies for variable-speed asynchronous generators. Many of these use ac-dc-ac-type equipment in which the generator operates at a variable frequency. This is converted to dc and then to 60 Hz ac. Depending on the specific technology, these installations may look like an induction or synchronous machine just prior to synchronism. The choice of the rating for the paralleling device needs to match the operation of the connected equipment.

8.1.8.3.3 Tips, techniques, and rules of thumb

The specifications for equipment being considered for use as a paralleling device should be carefully reviewed to ensure that it meets this requirement. Failure to adhere to this requirement could result in violent failure of the paralleling device, collateral damage to equipment in the vicinity of the paralleling device, and a hazard to personnel.

8.2 Response to area EPS abnormal conditions (IEEE Std 1547-2003 4.2)

"Abnormal conditions can arise on the Area EPS that require a response from the connected DR. This response contributes to the safety of utility maintenance personnel and the general public, as well as the avoidance of damage to connected equipment, including the DR. All voltage and frequency parameters specified in these subclauses shall be met at the PCC, unless otherwise stated."

8.2.1 Area EPS faults (IEEE Std 1547-2003 4.2.1)

"The DR unit shall cease to energize the Area EPS for faults on the Area EPS circuit to which it is connected."

8.2.1.1 Background

This requirement is based on the premise that if an area EPS has detected a fault and de-energizes a circuit, any other source on that circuit needs to also stop energizing it.

This started with a requirement that a DR separate for any fault on an area EPS. It was acknowledged that a typical area EPS cannot recognize some faults (such as very high-impedance ground faults). The requirement, as stated, is intended to relieve the DR from having to respond to faults that are not seen by the area EPS and to allow it to disregard any faults seen on another circuit.

In the U.S., short-circuit currents on distribution circuits can be more than 200 000 A to less than 1 A for high-impedance, single-phase-to-ground faults. The maximum fault can be controlled by system design.

Area EPSs are designed not to exceed the rating of distribution line equipment. Maximum faults are limited by restricting substation transformer size, impedance, or both; installing bus or circuit reactors; or inserting reactance or resistance in the transformer neutral. Minimum fault magnitude is largely dependent on fault resistance, which cannot be controlled. These low-magnitude faults are the most dangerous and difficult to detect. To clear faults, all electrical sources need to be isolated from the fault. It is important that all detectable faults be cleared to minimize equipment damage, provide for public safety, and maintain overall reliability and power quality for all customers.

Clearing times for short circuits on distribution circuits vary widely and depend on the magnitude and type of protective equipment installed. In general, on most circuits, large current faults will be cleared in 0.1 s or less. Low-current faults frequently require clearing times of 5 s to 10 s or longer. Some very low level but potentially dangerous ground faults may not be cleared except by manual disconnection of the circuit.

The majority of distribution faults are temporary in nature, so it is common practice to isolate long enough for a temporary fault to clear and then reclose. Every DR that can sustain a fault needs to isolate so that the fault can clear.

A distribution circuit is typically supplied through a single circuit breaker or recloser located at the supply substation. It is divided into zones by fuses, other line reclosers, or automatic sectionalizing devices that operate after counting current interruptions within a predefined time period. Other load taps off the main distribution line, called *laterals,* are usually protected with line reclosers or fuses at the point where they tap off. All these devices are carefully coordinated so that a fault in any section can be isolated quickly and with minimum or no interruption to other portions of the circuit. Of course, a fault in the main trunk section near the source substation will interrupt the entire circuit.

Most faults on the distribution system are temporary in nature. That is, most faults are due to tree encroachment in an overhead distribution line, lightning, or other causes such that the source of the fault is gone after the initial operation of the protective devices. Therefore, automatic reclosing is usually employed on substation breakers or reclosers and on line reclosers, so the duration of an outage for most faults is limited to only a few seconds. Distribution circuits are also often configured so that portions of the circuit can be automatically connected to another distribution substation in the case of a major fault on part of the main feeder.

Instantaneous reclosing typically has no or very little intentional time delay in the reclosing of a circuit breaker after a fault. Circuit dead time is typically 12 cycles to 30 cycles. One-shot and three-shot reclosing refer to the number of automatic reclosing attempts following a fault.

In order of occurrence, faults are categorized as single-phase-to-ground, phase-to-phase, double-phase-to-ground, bolted-three-phase, and open-circuit.

The major causes of faults are summarized in Table 5.

In many jurisdictions, a tariff, statute, or both define minimum quality-of-service standards. These standards define acceptable voltage and frequency ranges for service to all customers. Deviation from these standards, in many cases, can cause equipment damage. These quality-of-service standards also often prescribe reliability requirements, such as customer outage minutes, which motivate the widespread use of automatic reclosing on the area EPS.

Safety and system restoration require detection of all faults. This also limits damage to faulted equipment and nearby equipment.

Table 5—Major causes of faults

Type of fault	Cause
Insulation	Design defects Improper manufacturing Improper installation Aged or polluted insulation
Electrical	Lightning surges Switching surges Dynamic overvoltages
Mechanical	Animal contact Tree contact Vehicle collisions Wind Snow or ice Contamination Vandalism Major natural disasters
Thermal	Overcurrent Overvoltage

Detection and isolation of area EPS faults is also associated with other IEEE Std 1547-2003 clauses, notably:

- 4.1.2 Integration with area EPS grounding
- 4.2.2 Area EPS reclosing coordination
- 4.2.3 Voltage
- 4.2.4 Frequency
- 4.2.6 Reconnection to Area EPS
- 4.4.1 Unintentional islanding

The signature of the fault itself is dependent on the implementation of IEEE Std 1547-2003 4.1.2. The effectiveness of the isolation of the fault directly affects IEEE Std 1547-2003 4.2.2 and 4.2.6. Dependent on the interconnection technology, the actual isolation and detection of the fault may be accomplished by the same methods that are used to satisfy IEEE Std 1547-2003 4.2.3, 4.2.4, and 4.4.1.

As noted, the nature of faults involving ground, as well as the means of detecting them, will be heavily dependent on how the integration with area EPS grounding is implemented. This is also dependent on the nature of the interconnection technology itself (i.e., whether the DR appears to the interconnection as a synchronous generator, an induction generator, or an inverter). For that reason, different approaches to fault detection and isolation are suggested for each generator technology and, where appropriate, each variation of area EPS grounding integration.

To minimize the amount of the system isolated for faults, on the local EPS and the area EPS, it is usually necessary to review the "coordination" among fault protective devices. In general, the protective devices closest to the fault location should be the most sensitive of all protective devices that may detect the fault and also quickest to operate. In general, coordination can be best achieved if all the affected protective devices have similar operating characteristics. The details of reviewing coordination between protective devices are extensive and addressed in numerous texts and reference materials. Thus, they are not addressed comprehensively here.

8.2.1.2 Impact of distributed resources

Fault-current and fault-clearing issues related to the addition of DR to an area EPS may result in considerable impacts on the area EPS, depending on the DR size and type. If the DR contributes fault current to the area EPS, the coordination of protective devices on the area EPS may be adversely affected, and the fault current from the DR may thermally overduty area EPS equipment and cause fault-interrupting equipment to experience fault current that exceeds equipment ratings. These are actually area EPS impact issues not strictly involved in the interconnection, but they should be carefully considered when adding the DR to the area EPS and setting fault protective devices at the DR.

The DR system should be designed with adequate protection and control equipment, including an interrupting device that will disconnect the generator if the EPS that connects to the DR system or the DR system itself experiences a fault. The DR system should have, as a minimum, an interrupting device that:

— Has sufficient capacity to interrupt maximum available fault current at its location.

— Is sized to meet all applicable ANSI and IEEE standards.

— Is installed to meet all local, state, and federal codes.

A failure of the DR system's protection and control equipment, including loss of control power, should automatically open the disconnecting device[24] and, thus, disconnect the DR system from the EPS. The design of the DR system's protection and control should consider the impact of the loss of control power, and consideration should be given to automatically opening the disconnecting device. This will limit the possibility of misoperation of the DR facility or damage to the DR facility.

The specific details of the protection and control equipment depend, to a large degree, on the nature of the DR and the method of integration with the area EPS grounding system.

8.2.1.2.1 Synchronous interconnections

Interconnections that appear as synchronous generators will produce fault currents for extended periods of time if the fault involves multiple phases. The fault current may initially be as high as six (or more) times the generator full-load current and may decay over several seconds to less than the generator full-load current as the generator field collapses. However, the terminal voltage on the generator is severely depressed during the duration of the fault. The time relationship of the fault current supplied is thoroughly quantified by standard production tests for synchronous generators and described by defined reactances and time constants, which are provided in the generator test report.

8.2.1.2.2 Induction generators

Induction generators usually will not support a fault but will instead cease to produce current because of the loss of reactive power, which is necessary to support a rotating magnetic field within the generator. In these cases, the "non-islanding protection" that supports IEEE Std 1547-2003 4.4.1 will also provide for detection of faults. If sufficient capacitive reactance is available to supply the reactive power requirements of the induction generator field, either through the installation of power factor correction capacitors or the presence of considerable cable-type power conductors, it may be necessary to provide for direct detection of faults in a manner similar to that of synchronous generators.

[24] A physical device such as a relay or switch or a computer-controllable capability in electronic power equipment designed to isolate a portion of the area EPS and/or DR systems.

8.2.1.2.3 Inverters

If an inverter is designed such that other sources of generation provide the clocking signal to produce ac electricity (referred to as *line-commutated*), the inverter will not support a fault on the local or area EPS and will shut down, via self-protective features or the non-islanding detection system. If an inverter is designed to provide its own clocking signal (referred to as *self-commutated*), it can usually supply fault current for an extended time. Unlike the case for synchronous generators, the fault current supplied by a self-commutated inverter is a fairly constant value determined by the design of the inverter. It usually ranges from 1.2 to 1.5 times the rated load current of the inverter. In this case, undervoltage relaying may be effective at detecting the fault. The types of relays discussed for synchronous generators may also be effective.

8.2.1.2.4 Double-fed asynchronous generators

The response of DFAGs depends on the fault severity and generator design. Depending on the design of the DFAG, the rotor may be short-circuited by a crowbar circuit, or crowbar action using the rotor-side converter, in response to a severe fault. With the rotor shorted, the generator reverts to an induction generator. The duration of this crowbar action depends on the fault and the DFAG design. The rotor may remain short-circuited for the duration of the fault, and perhaps beyond, or the crowbar may be removed and return control of the rotor current to the converter while the fault is present. If the rotor is not short-circuited, the initial fault current can be several times rated load current, but the control quickly controls current output to magnitudes near or below the load current value.

8.2.1.2.5 Grounding methods

The method of grounding (which is usually an interface transformer, generator step-up transformer, or transformer that connects the local EPS to the area EPS) implemented at the PCC to satisfy the requirements of IEEE Std 1547-2003 4.1.2 will have a major effect on the ability of the DR, and particularly on synchronous DR, to detect faults involving ground. In some cases, direct detection of ground faults via the relays discussed for detection of phase faults may be possible (significantly, at the same voltage level as the generator), but this tends to be unreliable in most cases (and particularly for faults on the far side of a transformer). It is far more common to apply protection directly for the purpose of detecting ground faults.

8.2.1.3 Tips, techniques, and rules of thumb

A DR (or a local EPS) has a number of means to detect a fault. These are generally based on the expectation that a fault will reduce or unbalance the apparent system impedance. This subclause addresses all of these scenarios to some degree, as follows:

— Local (at DR) detection of the initial area EPS fault condition and subsequent isolation of the DR

— Remote detection of the initial area EPS fault condition and subsequent isolation of the DR via (remote) direct transfer tripping

— Local (at DR) detection of the loss of the area EPS source because of the area EPS response to the initial area EPS fault condition and subsequent isolation of the DR

For "local detection" of faults involving ground, the winding configuration of the transformer connecting the DR to the area EPS dictates the means by which a fault can be detected. The most common receiving transformer connections[25] are delta-grounded wye, floating wye-delta, or grounded wye-grounded wye. The first two connection alternatives do not contribute directly to primary ground current and will require

[25] The first winding described is on the area EPS side.

primary potential transformers or another source of ground current to detect an area EPS ground fault. Also, the third connection alternative (grounded wye-grounded wye) does not provide a ground by itself and only contributes ground current to the area EPS if there is a ground source connected to the local EPS side of the transformer. Many DR generation sources do not provide a ground source. Grounded wye-delta is generally used only with larger DR when there is potential for an unintentional island to form. It should be noted that, when used, the normal area EPS voltage unbalance may cause serious overloading of the delta winding as it tries to reduce the unbalance. When a DR can sustain the isolated section of an area EPS, it becomes very important that the area EPS voltages be monitored to prevent serious overvoltage on other area EPS customers and system lightning (surge) arresters.

The reduction in impedance can be indicated by an elevated level of current or a reduction in voltage. These effects can be combined with a voltage-restrained overcurrent relay or a voltage-controlled overcurrent relay. They are similarly combined in a distance relay. Each type of relay has its proponents and may be best for a particular case. They all have problems being coordinated with some other system relays.

A DR may respond to isolation by the area EPS in more than one way. Separation of the feeder from the substation source may be seen by the local EPS as a drop in area EPS apparent source impedance, which will cause separation. The area EPS trip initiation can be passed to the DR as a transfer trip. Either of these can take effect at the PCC or the point of interconnection.

The selection of protective devices and functions depends on the type of DR unit. However, regardless of the type of DR, the following four characteristics should be considered:

- *Dependability:* A high probability of clearing faults that occur on the area EPS
- *Security:* A low probability of interrupting the circuit unnecessarily
- *Selectivity:* The ability to discriminate and not isolate any area beyond the PCC
- *Speed:* The ability to operate as rapidly as possible, consistent with coordination requirements, to minimize damage

8.2.1.3.1 Synchronous interconnections

Three methods are commonly used to detect the time-variant magnitude of multi-phase faults involving synchronous generators: voltage-controlled overcurrent relays, voltage-restrained overcurrent relays, and distance relays. All three capitalize on the depressed generator terminal voltage during fault conditions to aid in fault detection.

The behavior of synchronous generators during fault conditions is traditionally quantified by three reactance values: subtransient reactance (typically referred to as X″ or X double-prime), which addresses generator behavior during the early time domain of a fault; transient reactance (X′ or X prime), which addresses generator behavior during the medium time domain of a fault; and synchronous reactance (Xs), which addresses generator behavior during the long time domain of a fault. The duration of the time domains is addressed by two time constants: Td″ (subtransient time constant) and Td′ (transient time constant). The effective generator reactance as a function of time is calculated by an exponential equation that uses all three generator reactances and both time constants.

$$I(t) = (I'' - I')e(-t/T'') + (I'-I)e(-t/T') + I$$

For a generator that radially feeds a three-phase fault with X_{system} as the impedance between the generator and the fault, the following conditions apply:

$$I'' = 1/(X'' + X_{system}),\ I' = 1/(X' + X_{system}),\ \text{and } I = 1/(Xs + X_{system})$$

Protective relaying for detection of multi-phase faults is generally located on the generator or, if provided, on the generator breaker. To provide fault detection, these relays usually also have to detect faults on the opposite sides of various transformers and, possibly, also have to account for some amount of system impedance to the fault.

Voltage-controlled overcurrent relays will be adjusted for a sensitivity that will adequately detect the minimum appropriate current magnitude during fault conditions. In this relay type, a voltage element controls the overcurrent function such that the function is enabled only when the voltage is depressed. The sensitivity of this relay type does not vary. The fixed sensitivity of this type of relay forces the relay to be set at a sensitivity that will detect the low magnitude of faults that persist for a long time, which can cause difficulty "coordinating" these relays with other relays, both on the area EPS and within the local EPS, such that only the relays that operate to isolate any particular fault actually trip.

Voltage-restrained overcurrent relays are also adjusted for a sensitivity that will adequately detect the minimum appropriate current magnitude during fault conditions. At 25% voltage, this type of relay is typically four times as sensitive as it is at rated voltage. This allows the relay to respond more quickly for the lower-magnitude faults with depressed generator terminal voltage.

Distance relays employ measuring principles that "calculate" apparent impedance from the relay location to the fault location. Because the impedance from the relay location to the fault remains constant throughout the duration of the fault, distance relays can present very consistent and predicable behavior during faults. Distance relays, however, can often be significantly more difficult to "coordinate" with other fault protection on both the local EPS and area EPS and are therefore often not a preferred alternative.

To illustrate the application of the three general types of relay characteristic, example calculations are shown in Table 6, representing a 1 MVA, 4.16 kV synchronous generator with X″ = 20%, X' = 30%, and X = 150%. Td″ will be 0.05 s, and Td will be 1.5 s. Furthermore, a 1 MVA transformer will be considered within the area for fault detection, with 4.5% transformer impedance, together with additional distribution system impedance of 25%, representing a portion of the area EPS. These impedances are not based on data from any particular manufacturer but are somewhat representative of values that may be found in a specific application. In all cases, the protective relays will be located in the secondary of the 150/5 A current transformers located on the generator terminals. There will also be a set of potential transformers having a 4.2 kV to 120 V ratio located at the generator terminals to provide voltage to the various relays. Table 6 describes the voltage and current that will be observed by the relays throughout the duration of a fault, together with an adjustment to indicate the effective operating current to a voltage-restrained type overcurrent relay (noted as a 51 V relay in Table 6).

Table 6—Generator short-circuit current and reactance versus time

Constants:

T''	0.035 s
T'	1.50 s

X''	0.2 p.u.
X'	0.3 p.u.
X	1.5 p.u.

For system faults (radial system)

Voltage	1 p.u.
I''	5
I'	3.333333333
I	0.666666667

System X from generator terminals: 0.295 (p.u., same base)

Equation:	I(t) = (I'' – I')e^(–t/T'') + (I' – I)e^(–t/T') + I															
Results:	All in p.u. on same base as generator reactances															
Time (cycles)	1.000	2.000	3.000	5.000	7.000	10.000	20.000	30.000	50.000	70.000	100.000	200.000	300.000	500.000	700.000	1000.000
I(t)	4.339	3.918	3.645	3.343	3.193	3.067	2.802	2.577	2.197	1.892	1.545	0.956	0.762	0.677	0.668	0.667
Equiv X	0.230	0.255	0.274	0.299	0.313	0.326	0.357	0.388	0.455	0.529	0.647	1.046	1.313	1.477	1.497	1.500
Seconds	0.017	0.033	0.050	0.083	0.117	0.167	0.333	0.500	0.833	1.167	1.667	3.333	5.000	8.333	11.667	16.667
Total X (system faults)	0.525	0.550	0.569	0.594	0.608	0.621	0.652	0.683	0.750	0.824	0.942	1.341	1.608	1.772	1.792	1.795
Total I (system faults)	1.903	1.817	1.756	1.683	1.644	1.610	1.534	1.464	1.333	1.214	1.061	0.745	0.622	0.564	0.558	0.557
Gen term volts (p.u.)	0.561	0.536	0.518	0.497	0.485	0.475	0.453	0.432	0.393	0.358	0.313	0.220	0.183	0.166	0.165	0.164
Gen term apparent Z	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295	0.295

Generator kV base:	4.16	**Generator base I**	138.78612
Generator kVA base	1000	**Generator CT ratio**	50.0
		Generator PT ratio	35.0
		51V relay tap	1.00

System faults:

51 V operating I (amperes)	5.282	5.044	4.875	4.672	4.564	4.470	4.258	4.064	3.700	3.370	2.945	2.069	1.727	1.566	1.549	1.546
51 V pickup I multiplier	1.798	1.883	1.948	2.033	2.081	2.125	2.231	2.337	2.568	2.819	3.225	4.000	4.000	4.000	4.000	4.000
51 V effective multipliers of p.u.	9.500	9.500	9.500	9.500	9.500	9.500	9.500	9.500	9.500	9.500	9.500	8.277	6.906	6.265	6.194	6.186

It may be noted that the impedance to the fault is constant at the value of the total system impedance including the transformer. This represents the constant operating characteristic of a distance relay. It may also be noted that the sensitivity of the voltage-restrained overcurrent relay, corrected for the operating voltage, is also relatively constant, representing the relative ease of setting a voltage-restrained overcurrent relay. However, a voltage-controlled overcurrent relay should be set for the lowest actual generator operating current, which decreases greatly with time. Further investigation shows that the benefits of using a voltage-restrained overcurrent relay versus a voltage-controlled overcurrent relay are minimal with little or no system impedance considered and become appreciable as the system impedance to be considered becomes larger than the X″ of the generator.

8.2.1.3.2 Induction interconnections

If an interconnection composed of induction generators is designed such that the reactive power necessary to excite the generators are drawn from the area EPS, the induction generators will be unable to supply persistent phase fault current. Short-term fault currents will still be supplied and may be calculated based on the reactance of the induction generators, and ground-fault currents may be supplied, depending on the methods used to integrate the DR grounding with the area EPS grounding.

The ability of protective relays to detect faults in the area EPS on the basis of fault-current contribution from the induction generators depends on the persistence of the fault-current contribution and the time required for relay operation. The persistence of fault current depends on the type of fault (single- or multi-phase), the severity of fault, and the means by which the reactive power requirements of the induction generator are supplied.

8.2.1.3.3 Inverter interconnections

A characteristic of most inverters is their inability to supply excessive currents under area EPS fault conditions. Fault detection schemes using overcurrent principles that are universally applied to equipment other than inverters are not usually effective. DR units that use this technology rely on other methods, such as abnormal voltage or frequency sensing, to detect electrical faults on the area EPS.

When an area EPS fault occurs, abnormal voltage conditions are typically experienced. Under- and overvoltage and frequency sensing is typically used to detect these conditions. Detection of these abnormal voltage conditions by voltage-sensing circuitry within the inverter can be effective to isolate the DR from the fault. Faster disconnection times for the DR should be expected for extreme voltage excursions to reduce the possibility of equipment damage.

8.2.1.3.4 Double-fed asynchronous generators

The response of DFAGs to faults depends on their protection and control schemes. The design of the fault detection scheme for a DFAG unit needs to consider the characteristics of the particular type of DFAG—especially in applications of multiple DFAG units behind one PCC.

The ability of protective relays to detect faults in the area EPS on the basis of fault-current contribution depends on the persistence of the fault-current contribution, which, in turn, depends on the details of the DFAG design and the characteristics of the fault.

8.2.1.3.5 Detection of faults in the area EPS

A range of protective relay devices to detect fault conditions exists. In most cases, a fault-detection device is installed between the source of energy and the circuit in which the fault is to be detected. In the case of phase-to-phase or phase-to-ground faults, the effectiveness of the fault-detection device typically increases with the level of fault current supplied from the energy source to fault. If the fault-current level is low enough, the fault-detection device may not detect the fault.

Fault-detection devices can be deployed in the area EPS or in the local EPS. (The use of fault-detection devices in a local EPS usually is limited to the detection of faults within the local EPS and is regulated by national and local codes.) The area EPS contains sufficient fault-detection devices to detect the vast majority of faults in area EPS circuits and persistent faults in local EPS circuits. The fault-detection devices in the area EPS are used to trip fault-interrupting devices that isolate the faulted circuit from the sources of energy in the area EPS.

Once a DR unit is connected to an area EPS circuit, it is an energy source that can also supply current to a fault in the circuit. The fault-current contribution of the DR unit is the amount of current that the DR will supply to a fault in the area EPS circuit. If the DR fault-current contribution is substantial, it will contribute significantly to the total current supplied to the fault. The area EPS contribution to the fault will be reduced by the presence of the DR. This may affect the time taken by the area EPS to detect the fault or, in the extreme case, prevent the area EPS from detecting the fault.

If the proper operation of the area EPS fault-detection devices is affected by the presence of DR units, then the affected fault-detection devices are adjusted or supplemented with additional fault-detection devices. For example, it is typical to include devices to detect area EPS faults in the interconnection system of a DR unit with significant fault-current contribution.

If the aggregate fault-current contribution of DR units on an area EPS circuit does not affect the operation of the area EPS fault-detection devices, then area EPS faults can be detected without using additional fault-detection devices.[28] However, the information that a fault has been detected needs to be conveyed from the area EPS fault-detection device to the DR interconnection system so the DR can cease to energize the area EPS.[29]

NOTE—For technical or commercial reasons, it may still be preferable to include devices in the DR interconnection system to detect area EPS faults rather than communicate the status of each area EPS fault-detection device to the DR interconnection system.

For DR units with low fault-current contribution, the direct detection of some phase-to-phase and phase-to-ground faults by devices contained in the DR interconnection system may not be feasible. Many of these DR units are contained in local EPSs that are supplied by the area EPS at low voltage. In this case, the local EPS does not have access to the medium-voltage feeder for phase-to-ground voltage measurements. Also, the fault-current contribution of the DR may be too small for current-based fault-detection devices to be effective. For example, inverter-based systems have typical short-circuit currents of between only 100% and 200% of the rated current.

In particular, it may not be feasible for DR units and interconnection systems with low fault-current contribution to detect high-impedance phase-to-phase or phase-to-ground faults. Instead, they rely on fault-detection devices in the area EPS. Other types of faults—such as open-phase faults, island conditions, and faults that result in considerable voltage or frequency deviation—can be detected directly by these DR units and their interconnection systems.

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[28] Additional fault-detection devices may be required to prevent the total fault-energy rating of any equipment in the area EPS from being exceeded or to maintain proper coordination during fault conditions. For example, area EPS fault-detection devices may be required in the DR interconnection system to prevent nuisance tripping of fuses or sectionalizers in the area EPS.

[29] The time lag associated with the communication of the fault-detection device status must be considered during fault coordination analysis.

8.2.1.3.6 Process for the DR unit to cease to energize the area EPS after fault detection

Once a fault has been detected in the area EPS circuit, the DR unit needs to cease to energize the circuit. This process is simple if the fault-detection device is located in the DR interconnection system. For example, the fault-detection device output can be used to trip a circuit breaker in the interconnection system.

If the DR interconnection system relies on fault-detection devices in the area EPS, the status of these devices is communicated to the DR interconnection system. One method is to use a dedicated communication channel. For example, this is used in a direct-transfer trip (DTT) scheme. These methods are well known and provide a reliable and rapid means of communicating the status of an area EPS fault-detection or fault-interrupting device to the DR interconnection system.

For small DR installations with low fault-current contribution, the installation and operating costs of a dedicated communication channel from each area EPS fault-detection device to the DR interconnection system are typically prohibitive. Instead, an indirect detection method is applied for faults that the DR interconnection system cannot detect directly. The principle of this method is outlined as follows:

a) A fault occurs.

b) A fault-detection device in the area EPS detects the fault.

c) The fault-detection device operates a fault-isolating device in the area EPS.

d) The fault-isolating device opens, and the area EPS circuit becomes islanded or open-phase.

e) The DR interconnection system detects the island, open-phase, or undervoltage condition.

f) The DR ceases to energize the area EPS.

8.2.1.3.6.1 Considerations for the use of indirect fault detection

The main difference between the indirect fault-detection approach and the DTT is the time lag between when the fault is detected by the area EPS device and when the DR ceases to energize the area EPS. As permitted in IEEE Std 1547-2003, the island or open-phase detection may take up to 2 s. The implications of this time lag needs to be considered when evaluating the suitability of the indirect detection method.[30] The supply of fault current by the DR to the fault during this period should not cause the total fault energy rating of any equipment in the area EPS to be exceeded. Therefore, a limit exists on the aggregate fault-current contributions that can be allowed on any area EPS circuit from DR that use the indirect method to detect certain faults. The assessment should take into account that some DR units use direct detection for low-impedance faults and indirect detection for high-impedance faults.

Other considerations, such as possible phase-to-ground overvoltages and recloser coordination, are associated with the existence of temporary unintentional island conditions between the opening of the area EPS fault-isolation device and the DR ceasing to energize the area EPS. It should be noted that unintentional island conditions can occur for reasons other than faults, so these considerations are not unique to the use of indirect fault detection. However, the rate of occurrence of temporary unintentional island conditions will be higher for DR units that employ indirect fault detection.

8.2.1.3.7 Ground-fault detection

The vast majority of faults (often more than 90%) on overhead distribution circuits involve ground. Therefore, it is paramount that the grounding of the DR be integrated with the area EPS grounding

[30]When the actual maximum detection time for islands and single-phase open conditions is known for a DR unit and interconnection system, these values should be used for analysis in place of the IEEE 1547 2 s limit.

(IEEE Std 1547-2003 4.1.2 and IEEE Std 1547.2-2008 8.1.2) and that the detection of ground faults by the DR be carefully addressed. The issues related to detection of ground faults depend heavily on the methods used to integrate the DR with area EPS grounding practices and will not vary considerably with different types of DR.

If the DR is connected through a transformer-connected grounded-wye on both sides, and the DR provides a ground source (e.g., a generator with a grounded-wye winding configuration), or through a transformer-connected delta on the generator side and grounded-wye on the area EPS side, it will usually be possible to apply overcurrent relays for ground-fault detection. The grounded-wye windings may be solidly grounded or grounded through an impedance. A current transformer appropriately rated will be connected into the area EPS-side neutral connection of the transformer, and following fault calculations, a time-overcurrent relay will be connected into these current transformers and set to detect the appropriate fault. This method of detecting ground faults is also effective if the DR is connected grounded-wye or impedance-grounded-wye and directly without an interposing transformer. In the latter case, the current transformer will be located on the DR neutral connection itself.

For any other combination of transformer windings, or if a grounded wye-wye transformer winding is used but the DR does not provide a ground source, it will be necessary to detect "zero sequence" voltage on the area EPS. A set of potential transformers will be needed on the area EPS side of the transformer, with the potential transformer primary winding connected grounded-wye and the secondary connected delta, with one corner of the delta left open. A voltage relay can be connected into the open corner of the delta potential transformer winding. A ground fault occurring on the area EPS will produce a zero-sequence voltage of up to 1.5 times the normal phase-to-ground voltage, and this voltage will be present on the potential transformer secondary after applying the appropriate transformation factors. The time characteristic for the voltage relay will depend, to some extent, on area EPS fault detection practices. This method is also useful if a delta-connected DR is connected directly without an interposing transformer.

8.2.2 Area EPS reclosing coordination (IEEE Std 1547-2003 4.2.2)

"The DR shall cease to energize the Area EPS circuit to which it is connected prior to reclosure by the Area EPS."

8.2.2.1 Background

The area EPS commonly uses automatic reclosing to limit the duration of interruptions to customers. This is done by using devices (e.g., reclosers and circuit breakers) that can be automatically reclosed after a fault condition. Most (70% to 95% of) faults on overhead distribution systems on the area EPS are transient in nature and result from factors such as lightning or tree contact. By de-energizing the EPS facility for a short time, the arc will extinguish and the facility can be restored to service if the initial fault does not result in equipment damage. See 8.4.1.2 for additional information about reclosing.

A salient issue should be highlighted. The reclose attempts previously described are performed without any undervoltage-permissive supervision (testing to ensure that the circuit is de-energized prior to the reclose attempt) or sync-check supervision (testing to ensure that the standing angle between the area EPS voltage and a possible voltage on the feeder side of the open area EPS feeder breaker is within acceptable limits) because the feeders are radial in design and the area EPS source is the only source of power. The installation of DR changes these basic design principles.

Automatic reclosing allows immediate testing of a previously faulted portion of the feeder and makes it possible to restore service if the fault is no longer present.

Automatic reclosing practices vary widely among area EPS operators. Lines that have cable installed as part of the line typically have no automatic reclosing. Some area EPS operators use one-shot reclosing, and some use up to three-shot reclosing. In this context, *shot* refers to an attempt to close the associated device. Automatic reclosing schemes have widely varying timing, depending on the operation of the area EPS. Many area EPSs use instantaneous reclosing. This is an attempt to reclose the circuit breaker or recloser as quickly as possible after opening for a fault. Typically, the first reclosure occurs in 15 cycles to 20 cycles (or 0.24 s to 0.33 s) after the fault. Other area EPSs delay the first reclosure up to several seconds. The faster the reclose occurs, the higher the impact to the DR. If unsuccessful, the initial attempt is usually followed by subsequent (typically two or three) time-delayed attempts of varying time intervals. If none of the reclose attempts is successful, the feeder circuit breaker will no longer reclose. In common terminology, the circuit breaker is *locked out.*

It is common practice for area EPS operators with overhead distribution system circuits to attempt to automatically reclose circuit breakers for operations following a relay-initiated trip. This trip-reclose sequence may be initiated by reclosing relays that control the corresponding feeder breaker at the substation or by pole-mounted reclosers located on the feeder away from the substation. Pole-mounted reclosers or sectionalizers are strategically placed to limit the number of customers affected per given feeder fault. Although sectionalizers do not interrupt fault current and do not automatically reclose, they open to isolate faulted feeder sections after the feeder has been de-energized by a breaker or recloser.

The DR is required to cease to energize the area EPS prior to the first reclosure of the area EPS to ensure that the fault completely clears. This also prevents out-of-synchronism conditions during reclosure to limit nuisance fuse trips or damage to transformers, motors, and the DR. This will require careful coordination of the DR protective functions with the area EPS.

8.2.2.2 Impact of distributed resources

The presence of DR on the feeder invalidates the conventional assumption that the area EPS substation is the sole source of energization for the feeder. DR can potentially maintain energization of the feeder after the area EPS circuit breaker or circuit recloser opens.

The primary concern for DR reclosing coordination remains reliability. If a fault is temporary in nature and the DR does not trip off and extinguish the fault arc prior to the area EPS reclosing attempt, the reclosing attempt will be unsuccessful and the automatic restoration of that circuit may be jeopardized. This can result in an extended outage to hundreds or thousands of customers rather than a less-than-a-second interruption. Second, even if the fault was interrupted, the islanded feeder is likely to drift out of synchronism with the area EPS. If the area EPS breaker should reclose when the area EPS and the island, energized by the DR, are out of phase, very severe and potentially damaging transients can result.

Possible ramifications of an out-of-phase reclose include the following:

- If the DR energizing the island is a rotating generator, it can be subjected to severe electromechanical torques. These torques pose a substantial risk of equipment damage.
- A severe transient overvoltage surge is likely to be created on the feeder, which can reach three times the normal crest voltage (3 p.u.). With practical values of system damping, the voltage surge will be less severe but can easily exceed 2 p.u. Figure 6 shows simulation results for a typical system in which the peak surge reaches 2.2 p.u. The voltage surges created on the feeder will appear with roughly equivalent per-unit magnitude at the secondary services of other customers connected to the feeder. Overvoltage surges of this magnitude can result in failure of area EPS surge arresters, customer load device damage, and failure of customer surge protectors.
- Transformers and motors connected to the feeder reclosed out of phase can experience magnetic inrush currents far more severe than normal energization inrush. Because the inrush will appear simultaneously in all connected magnetic devices, the currents can cause undesired operation of fuses and circuit breakers, both on the area EPS and within customer systems.

- The abrupt change in voltage phase angle created by an out-of-phase reclosing, illustrated in Figure 6, will cause abnormal electromechanical torques on motors and their mechanical loads. This can result in mechanical damage of customer equipment, including equipment not on the local EPS where the DR is connected.

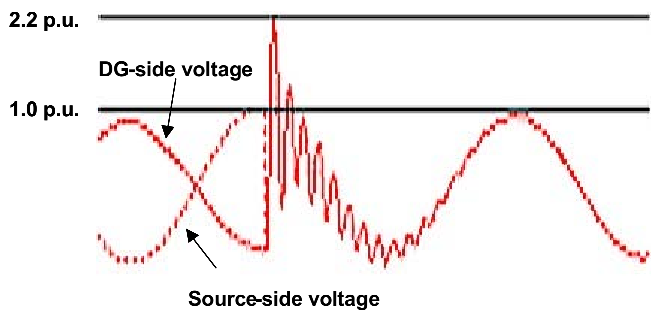


Figure 6—Overvoltage surge from out-of-phase reclosing

For these reasons, it is important to coordinate DR tripping (the elimination of DR as a feeder source) with feeder reclosing practices so that out-of-phase reclosing does not occur. Because of the potential for reduced reliability to area EPS customers and equipment damage (particularly damage to equipment owned by parties other than the area EPS operator and DR owner), liability considerations tend to force area EPS operators to closely and conservatively address the issue of reclosing coordination.

The response of the DR unit is coordinated with the reclosing strategy of the isolation devices within the area EPS. Coordination is required to prevent damage to area EPS equipment, the DR, and equipment connected to the area EPS other than the DR. The DR and area EPS reclosing strategy will be coordinated if one or more of the following conditions are met for all reclosing events:

- The DR is designed to cease to energize the EPS before the reclosing event. This condition can sometimes be met simply by considering the rating of the DR relative to the minimum load on the EPS circuit to which it is connected (i.e., if the DR capacity is sufficiently small that the minimum load on the feeder causes the island to reach an underfrequency or undervoltage trip point in sufficient time for the DR to cease to energize the feeder prior to feeder reclosing) to allow for relay time and interruption time of any switchgear needed to cause the DR to cease to energize the feeder.
- The reclosing device is designed to delay the reclosing event until after the DR has ceased to energize the area EPS.

Area EPS practice also can include the use of multi-shot reclosers (i.e., feeder breakers or reclosers that can reclose two and three times for a permanent fault). Typically, the multi-shot reclosing process takes place in a period of roughly 1 min to 3 min. Although additional reclosings have no effect on a DR that has promptly separated, the overall reclosing coordination issue is taken into account if the DR facility is to re-parallel automatically.

A long-standing problem with feeder protection is the clearing of high-impedance faults. A common example of a high-impedance fault is a conductor of a grounded-wye feeder lying on dry asphalt. Because of the high resistance to ground, the fault current will be very small. The relaying for the feeder will either respond very slowly (because of the low fault current) or not at all. If the feeder reclosing relay resets in a short time (typically 10 s), then breaker cycling could occur. This occurs when the feeder trips and then recloses and the reclosing relay resets before the relaying trips the breaker again. Because a high-impedance fault has very low fault current, the relaying takes an extended time (on the order of seconds to minutes) to operate again. In the mean time, the reclosing relay has reset. This can go on indefinitely until remote intervention occurs, equipment malfunctions, or the fault characteristic changes.

When being fed by fault current from one or more DR units, the ability of the area EPS feeder relaying to detect a high-impedance fault is diminished. To avoid desensitizing the relaying during a high-impedance ground fault, if the DR is a substantial source of ground-fault current, it should remain isolated from the area EPS until the automatic reclosing on the feeder breaker has reset.[31] The reset time is typically 180 s (3 min). This is one basis for the requirements of IEEE Std 1547-2003 4.2.6. See 8.2.6 for further details.

8.2.2.3 Tips, techniques, and rules of thumb

- The area EPS commonly uses automatic reclosing to limit the duration of interruptions to customers.
- Typical reclose settings are from instantaneous (no intentional delay) to minutes.
- This requirement may be more restrictive than the non-islanding requirement in terms of detection times. (Results from the non-islanding test may be used to help assess reclose coordination.)
- Area EPS may delay or block reclose operations to assist with coordination.

8.2.2.3.1 Use of transfer trips

Control devices at the DR need to recognize that a feeder has tripped and be able to initiate a command to separate the DR from the feeder prior to feeder reclosing. If separation cannot be obtained prior to the area EPS's initial reclose attempt using local sensing approaches, additional protection may be required. This may include the addition of DTT from the feeder breaker or automatic line sectionalizing devices to the DR or the addition of sync-check relaying[32] or undervoltage-permissive relaying at the feeder breaker or automatic line sectionalizing devices. Even for large facilities, it may be necessary to use a DTT scheme to avoid accidental paralleling. However, DTT may require communications not only from the substation breaker but also from any automatic line sectionalizing devices upstream from the DR. Reclosing after a trip can be initiated from any one of these devices. (Consideration can be given to using DTT from devices other than the substation source circuit breaker. If the island can form when the substation breaker operates, then when another device operates, there will be a substantially different load-to-generation ratio, and the DR should trip on overfrequency.)

8.2.2.3.2 Feeder reconfiguration

Many distribution systems can be reconfigured manually or automatically. If feeder reconfiguration is employed, the feeder section to which the DR is connected can be connected to the area EPS through a number of paths. It is becoming more common for area EPS operators to use a loop design for feeders in which two feeders are joined together with a normally open recloser (automatic sectionalizing). Even more complex automatic reconfiguration schemes, involving additional backup sources for the feeder, are sometimes used. In addition to automatic reconfiguration, many circuit sections can be manually switched to alternate feeds from other feeders to equalize loading, allow continuity of service during maintenance, and allow for restoration following outage.

When a DR is placed on a feeder with automatic reconfiguration, or where manual reconfiguration is performed, it may be possible for the unit to be connected to the area EPS through different feeders. This affects coordination of the DR with feeder reclosing because coordination is maintained for every possible

[31] Sectionalizers have a lockout time similar to the recloser relay reset time. To ensure proper sectionalizer operation, the DR unit should also remain isolated during the sectionalizer lockout time.
[32] Sync-check relaying may increase the reclosing time—a potential problem in some situations.

energization source. Any protection that is required on the original feeder may also be required on the alternate feeders or the DR may need to be prohibited from generating on the alternate feeder.

A DTT scheme in reconfigurable systems can become quite complex because DTT channels from breakers and possibly reclosers in every possible energization path may need to be provided, along with logic to determine the current system configuration and identify which DTT signals are to be enabled.

8.2.2.3.3 Reclosing scheme modification

Many area EPS operators are not willing or able to change their reclosing practices. Therefore, system modifications may be necessary to integrate the operation of the DR with the area EPS. One way that this is done is by controlling the circuit breakers and reclosers. Equipment is installed to monitor the voltage (27x) on the load side of these devices. If voltage is present, this is an indication that the DR has not yet been isolated. Reclosing is blocked until the voltage goes to zero (or some very low value), at which point the device is allowed to reclose.

Voltage monitors are necessary when it is not certain whether the DR will cease to energize an unintentional island prior to the first area EPS reclosing attempt.

In Figure 7, it cannot be ensured that the DR will cease to energize an intentional island. Therefore, devices C and B need to be modified to include the voltage check relays (device C because the estimated minimum load is almost the same as the generation and device B because the total estimated minimum load would be 1100 kW, which is less than the three-to-one safety ratio generally needed to assure that the DR will cease to energize an island). Device A would not need to be modified.

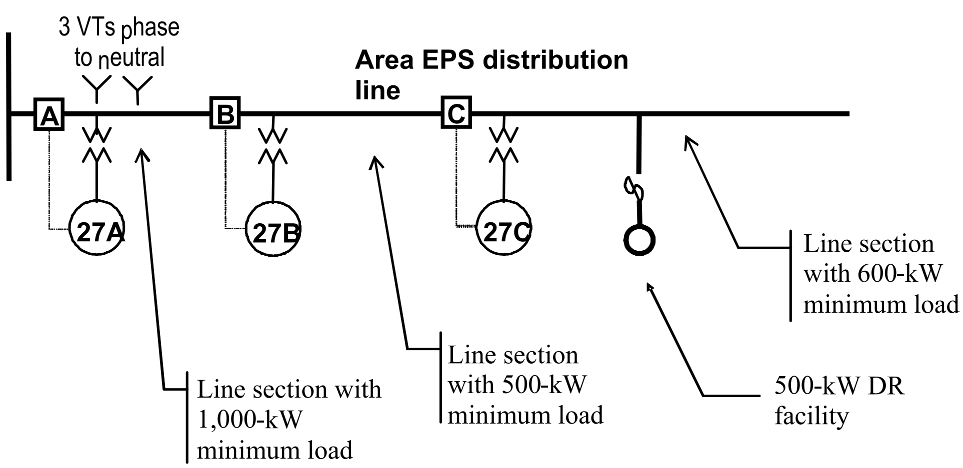


Figure 7—An example 12 kV line

8.2.3 Voltage (IEEE Std 1547-2003 4.2.3)

"The protection functions of the interconnection system shall detect the effective (rms) or fundamental frequency value of each phase-to-phase voltage, except where the transformer connecting the Local EPS to the Area EPS is a grounded wye-wye configuration, or single-phase installation, the phase-to-neutral voltage shall be detected. When any voltage is in a range given in [Table 7], the DR shall cease to energize the Area EPS within the clearing time as indicated. Clearing time is the time between the start of the abnormal condition and the DR ceasing to energize the Area EPS. For DR less than or equal to 30 kW in peak capacity, the voltage set points and clearing times

shall be either fixed or field adjustable. For DR greater than 30 kW, the voltage set points shall be field adjustable.

"The voltages shall be detected at either the PCC or the point of DR connection when any of the following conditions exist:

a) **The aggregate capacity of DR systems connected to a single PCC is less than or equal to 30 kW**

b) **The interconnection equipment is certified to pass a non-islanding test for the system to which it is to be connected**

c) **The aggregate DR capacity is less than 50% of the total Local EPS minimum annual integrated electrical demand for a 15-minute time period, and export of real or reactive power by the DR to the Area EPS is not permitted."**

Table 7—Interconnection system response to abnormal voltages

Voltage range (% of the base voltage [a])	Clearing time [b] (s)
V<50	0.16
50≤V<88	2.00
110<V<120	1.00
V≥120	0.16

[a] Base voltages are the nominal system voltages stated in ANSI C84.1 Table 1.

[b] DR ≤30 kW, maximum clearing times; DR >30 kW, default clearing times.

8.2.3.1 Background

This requirement is intended to detail a method to detect faults on the area EPS and a means to prevent overvoltage or undervoltage damage to area EPS and customer equipment in case a DR is the source of an abnormal condition (e.g., during unintentional islanding).

Voltage magnitude and frequency are fundamental characteristics of electrical power and thus represent fundamental criteria for determining if an EPS or DR equipment is experiencing difficulty or failure. The greater the deviation of the magnitude of voltage, whether measured at the PCC or the point of DR interconnection, the greater (or more proximate) is the likely problem. Table 7 defines two steps of response for overvoltage and two steps of response for undervoltage. These rapid and delayed voltage protection functions enable the interconnection system to respond more quickly to voltage excursions.

The primary purpose of rapid undervoltage protection is to detect faults on the area EPS. The purpose of rapid overvoltage protection is to detect potentially damaging overvoltages that can occur in an unintentional island. The primary purpose of the delayed undervoltage and overvoltage protection is to detect more sustained voltage abnormalities in the area EPS. All of the abnormal-voltage protection functions can assist with the detection of unintentional islands.

Requiring field-adjustable voltage set points and clearing times allows the area EPS operator some discretion to accommodate specific area EPS characteristics. Incidentally, although the wording in the requirements specifies only the voltage set points be adjustable for DR larger than 30 kW, the intention is that clearing times be adjustable as well (as noted in footnote).

Voltage and frequency deviations may damage equipment on the area EPS or the equipment of customers served from the area EPS. However, if instantaneous tripping for voltage and frequency deviation is implemented in the DR interconnection system, DR nuisance tripping may occur for a variety of external system disturbances—thus, the requirement of a time delay for minor variations. Field-adjustable set points and clearing times are to be protected against unauthorized adjustment. Adjustment by a qualified individual (or automatic adjustment for prevailing conditions) is desirable to allow compensation for voltage difference between the DR and the PCC. For DR units larger than 30 kW (peak capacity) fed from medium-voltage switchgear, consideration should be given to measuring the voltage for the requirements of the section at the PCC to avoid problems with voltage drop in various transformers, wiring, or feeder circuits within the local EPS. Any compensation applied at the DR to mimic the values at the PCC should be agreed to by all parties.

8.2.3.2 Impact of distributed resources

8.2.3.2.1 General

The sensing of voltage deviations outside a normal range is critical to detecting faults and, possibly, unintentional islands. Many DR will have difficulty maintaining a voltage within narrowband if they are supplying either a faulted area EPS circuit or a mildly fluctuating load without the stabilizing influence of the area EPS. DR equipment sized well less than facility demand and precluded from export will also not sustain an unintentional island as well as DR equipment certified to pass a non-islanding test. These conditions are specifically identified as criteria to allow voltage to be measured at the point of interconnection rather than at the PCC (the default in the standard).

If an induction generator is operating self-excited, very high resonant overvoltages can result on an islanded system. Because equipment failures related to these overvoltages happen quickly as equipment insulation strength is exceeded, an overvoltage trip level less than the equipment insulation level should be established, with an instantaneous trip. This is an example of a case in which the area EPS operator may wish that all time delay be removed from the 120% voltage overvoltage trip, which is specified in IEEE Std 1547-2003 as a 0.16 s total clearing time.

8.2.3.2.2 Voltage-based fault detection to indicate EPS problems

Voltage-based fault detection is intended to replace current-based fault detection for DR units unable to produce or sustain significant fault-current contribution during area EPS fault conditions. Inverter-based DR are normally current-limited by inverter controls, and induction generator-based DR fault-current contribution decays very quickly as the air gap flux collapses under short-circuit conditions. Even a synchronous generator may fail to see significant increases in current during EPS faults for certain combinations of generator impedance, source impedance, fault impedance, and fault duration.

8.2.3.2.3 Phase-to-phase or phase-to-ground voltage measurements

Short circuits on the EPS are primarily unbalanced faults, with single-phase-to-ground, phase-to-phase, and phase-to-phase-to-ground faults being far more common than three-phase (balanced) faults. For this reason, it is critical for three-phase DR that overvoltage and undervoltage detection be provided for all three phases because not all unbalanced fault conditions will affect the voltage on the unfaulted phases in sufficient magnitude to be distinguished from normal operating conditions. In addition, for any grounded or unigrounded system (including a four-wire, grounded-wye system and three- and four-wire unigrounded systems), it takes only one phase-to-ground fault or phase-to-phase fault to result in short-circuit current flow. Therefore, all the phase-to-ground voltages are required to be measured.

One of the consequences of this is that, in a three-phase DR installation that consists of three single-phase inverters connected to a four-wire grounded-wye connection, the inverters need to measure the phase-to-ground voltages, not the phase-to-phase voltage. Even if the inverters are connected between phases, they need to at least measure the phase-to-ground voltages.

If the DR is connected to an ungrounded area EPS, the phase-to-ground voltages are *not* required to be measured. On these systems, it will take two phase-to-ground faults on different phases to cause fault current to flow. Consequently, measuring the phase-to-phase voltage is sufficient to measure a fault resulting in short-circuit current flow.

8.2.3.3 Tips, techniques, and rules of thumb

When there are other effective methods to detect faults, it may be appropriate to set the abnormal voltage protection trip times longer than the default values to prevent nuisance trips.

8.2.3.3.1 Impact of transformers between the PCC and point of DR interconnection

Transformers between the PCC and the point of DR interconnection can have a significant effect on the phase-to-phase or phase-to-neutral voltages present at the point of DR interconnection for unbalanced voltages on the area EPS. With the exception of the grounded-wye/grounded-wye transformer connection, voltage imbalances at the PCC that may occur as the result of phase-to-ground or phase-to-phase-to-ground faults on the area EPS can be significantly different when detected at the point of DR interconnection, depending on how the zero-sequence component of the voltage is reflected across the transformers and how the positive- and negative-sequence voltages are affected by any phase shift across the transformers.

For some transformer interconnections, it may be appropriate to adjust the voltage set points to reduce the impact of the transformer on the effectiveness of the voltage-based fault detection. Typically, this involves increasing the rapid undervoltage trip level because this is the primary means for voltage-based detection of faults. For example, with a four-wire, grounded-wye service at the PCC and a delta/grounded-wye transformer between the PCC and point of DR interconnection, a rapid undervoltage trip level of 76% may provide voltage-based fault detection similar to that obtained with a grounded-wye/grounded-wye transformer and default rapid undervoltage trip level of 50%.

8.2.3.3.2 Single-phase and split single-phase measurements

Single-phase DR interconnection systems are required to sense phase-to-ground voltage. A single voltage measurement is sufficient for a two-wire DR system connected to one phase and the neutral. Two phase-to-ground voltage measurements are required for two-wire DR systems connected phase-to-phase on split single-phase circuits or on four-wire grounded circuits. Two phase-to-ground voltage measurements are required for three-wire DR systems connected to two phases and the neutral.

It is necessary to measure two phase-to-ground voltages on a two-wire, single-phase DR system that is connected phase-to-phase. This is to detect potentially damaging overvoltages that can occur between one phase and neutral during unintentional islanding. In this case, phase-to-neutral voltage balance is determined by the impedance balance of the loads connected between each phase and the neutral. When the loads are not balanced, damaging overvoltages can occur between one phase and neutral, even though the phase-to-phase voltage is within the nominal range.

More information about electric distribution system disturbances can be found in Annex G.

8.2.4 Frequency (IEEE Std 1547-2003 4.2.4)

"When the system frequency is in a range given in [Table 8], the DR shall cease to energize the Area EPS within the clearing time as indicated. Clearing time is the time between the start of the abnormal condition and the DR ceasing to energize the Area EPS. For DR less than or equal to

30 kW in peak capacity, the frequency set points and clearing times shall be either fixed or field adjustable. For DR greater than 30 kW the frequency set points shall be field adjustable.

"Adjustable underfrequency trip settings shall be coordinated with Area EPS operations."

Table 8—Interconnection system response to abnormal frequencies

DR size	Frequency range (Hz)	Clearing time [a] (s)
≤30 kW	>60.5	0.16
	<59.3	0.16
>30 kW	>60.5	0.16.
	<{59.8 to 57.0} (adjustable set point)	Adjustable 0.16 to 300
	<57.0	0.16

[a] **DR ≤30 kW, maximum clearing times; DR >30 kW, default clearing times.**

8.2.4.1 Background

This requirement is intended to establish the following:

— The operation of an area EPS protective device following its detection of an area EPS fault

— A method to detect islands

— Coordination with some load-shed schemes

— Prevention of overfrequency or underfrequency damage to area EPS and customer equipment (in case the DR is the source of the abnormal condition, e.g., during unintentional islanding)

The following documents are sources of additional information. However, not all have been maintained to date.

— The National Rural Electric Cooperative Association Application Guide for Distributed Generation Interconnection [B62]

— IEEE Std 929™-2000 [B34]

— IEEE Std 1001™-1998 [B35]

— Edison Electric Institute 29 Issues Report [B9]

— ANSI C84.1-2006 [B3], and the North American Electric Reliability Corporation (and regional reliability councils) underfrequency load-shedding standards

Under- and overfrequency protective functions are among the most important means of detecting a DR island. These protections should operate promptly, but nuisance trips also need to be avoided. The frequency in a typical area EPS is very stable. However, voltage phase-angle swings can occur in transmission and distribution lines because of sudden changes in feeder loading and load current. If extremely short time measurements are employed, these voltage swings can cause nuisance trips of under- or overfrequency protective functions.

The purpose of the allowed time delay in this requirement is to ride through short-term disturbances to avoid excessive nuisance tripping of the DR.

8.2.4.2 Impact of distributed resources

Following the operation of an area EPS protective device, the DR will be isolated with a section of the area EPS and, potentially, other customer loads. This is an unintentional islanding situation that will continue until the DR senses the abnormal condition and ceases to energize the area EPS. The frequency of the unintentional island will depend on the characteristics and balance of the DR and loads in the island. The IEEE 1547 requirement for under- and overfrequency protection ensures that the DR will cease to energize an unintentional island when the frequency is outside the agreed-upon operating ranges. This serves to detect unintentional islands and limit the range of frequency that will be experienced by the area EPS equipment and customer loads during the temporary unintentional island.

DR units of less than 30 kW potentially have less impact on system operations and typically can disconnect from the area EPS well within 10 cycles of clearing time. DR units larger than 30 kW can have a positive effect on distribution system reliability. The IEEE 1547 requirement takes this into account by allowing the area EPS operator to specify the frequency setting and time delay for underfrequency trips down to 57 Hz.

Area EPS stability depends, to a large part, on the system's ability to withstand the outage of certain lines or equipment without being forced into a system emergency. Stability also depends on the proper matching of system load and generation. When generation is inadequately matched with system load, the EPS frequency will decline or accelerate. When this happens, the area EPS and/or generator operator or automatic large generator control systems seek to quickly match load with available generation. Underfrequency and undervoltage relays may also be installed on the area EPS to automatically shed load to stabilize operations. Coordination with these stabilizing techniques is the reason for allowing the area EPS operators to modify the setting of the DR underfrequency trip relay.

Some of these underfrequency relays are sensitive to the rate of EPS frequency decay and provide information to the system operator to assist in the timing of load-shedding. Similar problems on the EPS can occur when generation exceeds available load, as is the case when a large block load is suddenly lost, or when tie lines exporting power quickly relay open. Significant overfrequency conditions occur less often than significant underfrequency conditions.

8.2.4.3 Tips, techniques, and rules of thumb

When there are other effective methods to detect islands, it may be beneficial to use longer trip times than the IEEE 1547 default values to prevent nuisance trips and retain generation on the area EPS for recoverable system swing conditions.

Another matter of concern is overall area EPS reliability. The regional reliability councils that are part of the North American Electric Reliability Corporation specify criteria for the regionally interconnected area EPSs that mandate shedding large blocks of system load for various levels of underfrequency operation in an effort to restore the area EPS to an acceptable frequency. If a block of generation is lost when overall system reserve margins are low, the regional reliability councils also generally require that the operator serving load in the area of the lost generation trip a similar amount of system load. As a result, the area EPS operator needs to consider the affect of DR on the overall underfrequency load-shedding programs to which they adhere. For smaller, individual DR, this is not generally a problem, but, as the penetration of DR increases, this will gradually become a concern.

In contrast to voltage disturbances, frequency disturbances are the result of imbalances between load and generation and, therefore, manifest themselves equally on all three phases of the area EPS. Detection of over- and underfrequency on a single-phase basis, therefore, meets the requirements of IEEE Std 1547-2003 4.2.4.

8.2.5 Loss of synchronism (IEEE Std 1547-2003 4.2.5)

"Loss of synchronism protection is not required except as necessary to meet [IEEE Std 1547-2003] 4.3.2."

8.2.5.1 Background

This subclause applies only to synchronous generators. Loss of synchronism is primarily a risk to the generator and therefore out of the scope of IEEE Std 1547-2003, except to the extent that it may impact power quality.

Because a loss-of-synchronism condition presents a phenomenon at the PCC that appears very similar to flicker (see IEEE Std 1547-2003 4.3.2 and IEEE Std 1547.2-2008 8.3.2), IEEE Std 1547-2003 addresses this condition as being a concern only if the voltage fluctuations relating from loss-of-synchronism conditions otherwise violate the requirements of that clause.

8.2.5.2 Impact of distributed resources

The impacts of the DR for a loss-of-synchronism condition are focused in two areas: response of the generator to an external system fault and transients within the generator for a remote area EPS reclosing operation. For loss of synchronism to be a concern, an area EPS fault needs to be electrically near the generator but also be in a location where it is not necessary for the generator to otherwise cease to energize the area EPS. This fault location is referred to as being in the *electrical vicinity* of the generator.

An electrical fault decreases the electrical power that can be delivered from a synchronous generator, while the mechanical power input to the generator remains approximately constant. As a result of the imbalance between power input and output, the rotational speed of the generator will increase and cause the phase angle of the generated voltage to advance. The advancing phase angle will cause the electrical power output to increase. However, because of the fault, the increase of power may not equal the mechanical input, and the acceleration may continue. When the fault clears, the electrical power will usually exceed the mechanical power unless the generator has already advanced to the point at which the generated voltage phase angle leads the area EPS voltage phase angle by more than 90 electrical degrees. This reversal in the power imbalance will cause the rotor to decelerate, but the electrical angle difference between the generator and the area EPS will continue to increase until the rotor slows to the synchronous speed. If the electrical angle difference should pass through 90 electrical degrees, further angle increase actually decreases the electrical power delivery, and the rotor will again accelerate, breaking out of synchronism or *slipping poles.*

If the rotor reaches synchronous speed before it reaches 90 relative electrical degrees of advance, the rotor will continue to decelerate below synchronous speed, and the phase angle will decrease and eventually drop below the point necessary to deliver electrical power equal to the mechanical power input. The generator rotor will again accelerate. This process continues as oscillations in the speed of the rotor, relative phase angle, current, voltage, and power flow. Normally, these oscillations damp out, and the generator returns to a steady-state condition at synchronous speed. However, it is possible for interaction with the generator exciter, or other system interactions, to negatively damp these oscillations such that they grow in magnitude to the point that the rotor angle passes 90 degrees and the generator breaks out of synchronism. This loss of synchronism because of growing rotor angle oscillations is called *dynamic instability* (in contrast with the instability that occurs in the first excursion of rotor angle, which is called *transient instability*).

Whether a fault condition leads to instability depends on the severity and location of the fault, the operating power of the generator, the location of load served by the generator, the duration of the fault, and the impedance of the EPS after the fault is cleared.

8.2.5.3 Tips, techniques, and rules of thumb

8.2.5.3.1 Impact of loss-of-synchronism conditions on generators

A loss-of-synchronism condition on an operating generator, while rare, is a very serious concern for the electrical and mechanical integrity of the generator and prime mover. Serious damage can result from this condition.

A loss-of-synchronism condition produces heavy surge currents in the armature windings of a magnitude that may exceed those associated with the generator short-circuit capabilities and may cause serious thermal damage to the windings.

Out-of-synchronism conditions also cause torque reversals that create, in many parts of the generator-prime mover system, high mechanical stresses of magnitudes that may be several times the system rated torque. These excessive torques may cause damage to the shaft of the generator or prime mover or actually cause the generator and/or prime mover to wrench free of the mountings to the foundations.

High induced voltages and currents in the field circuit may also cause flashover of the collector rings and the commutator of an associated exciter and may cause damage to solid-state exciter components and systems.

For these reasons, out-of-synchronism operation needs to be promptly identified and the condition remedied. Possible corrective action includes the tripping of the unit from the EPS.

8.2.5.3.2 Impact of loss-of-synchronism conditions on the area EPS

Loss of synchronism causes oscillations in voltage as well as current and power flow throughout the local and area EPS. The magnitude and frequency of the voltage transients are related to the size of the generator relative to the strength of the area EPS. One way of characterizing the potential for related problems is by analysis of the stiffness ratio.

To accurately predict a loss-of-synchronism phenomenon, it is necessary to perform complex (and costly) stability studies, which address the EPS inertia, generator-prime mover system inertia, generator governor behavior, prime mover fuel supply, generator excitation design, and any features of the generator control system that may be intended to limit loss-of-synchronism conditions.

If loss of synchronism presents a problem as presented in IEEE Std 1547-2003, it will probably be necessary to add relaying or other equipment with loss-of-synchronism protective functions to immediately isolate the DR from the area EPS. It will usually be necessary to perform the stability studies previously noted to adequately apply these protective functions.

8.2.6 Reconnection to area EPS (IEEE Std 1547-2003 4.2.6)

"After an Area EPS disturbance, no DR reconnection shall take place until the Area EPS voltage is within Range B of ANSI C84.1-1995, Table 1, and frequency range of 59.3 Hz to 60.5 Hz.

"The DR interconnection system shall include an adjustable delay (or a fixed delay of five minutes) that may delay reconnection for up to five minutes after the Area EPS steady-state voltage and frequency are restored to the ranges identified above."

8.2.6.1 Background

This requirement is closely related to the requirements of IEEE Std 1547-2003 4.2.1 and 4.2.2. As the requirements of IEEE Std 1547-2003 were being developed, those two subclauses and this subclause on reconnection were discussed as a group. The sequence of events begins with the DR detection of a fault on the area EPS. This is followed by coordination with the feeder restoration activities of the distribution circuit and then, ultimately, reconnection of the DR with the area EPS. As noted in the other subclauses, the response of the DR unit needs to be coordinated with the reclosing strategy of the isolation devices within the area EPS. Coordination is required to prevent possible damage to area EPS equipment and other connected equipment.

A distribution circuit is typically supplied through a single circuit breaker located at the supply substation and is divided into various zones by automatic sectionalizing devices. The intent of this design is to quickly isolate a faulted section of a feeder with limited or no interruption of service to adjacent customers on unfaulted portions of the same feeder.

8.2.6.2 Impact of distributed resources

In the case of a relay-initiated trip reacting to a fault on a distribution feeder, the DR facility must be capable of isolating its generation prior to the utility's reclose attempts to avoid equipment damage. If separation cannot be obtained prior to the utility's initial reclose attempt, additional protection may be required. This includes the addition of DTTs from the utility feeder breaker to the DR or synchronism-check relaying at the utility feeder breaker. The latter may increase the reclosing time, especially where instantaneous overcurrent settings are used.

It is common practice for utilities to attempt to automatically reclose their circuit breakers following a relay-initiated trip. The time delay between tripping and the initial reclose attempt can range from 0.2 s (12 cycles) to 15 s (or more).[33] For radial feeders, the initial attempt is usually followed by two time-delayed attempts, normally with 30 s to 90 s intervals. If none of the reclose attempts is successful, the feeder will lock out. The reclose attempts are normally performed without any synchronism-check supervision because the feeders are radial in design, with the utility being the only source of power.

It is also imperative that the DR generation remain isolated from the utility until the automatic reclosing on the feeder breaker has reset. This time is typically 180 s (3 min). This is to avoid desensitizing the utility relaying during a high-impedance fault. Similar to the recloser relay reset time, sectionalizers have a lockout time. For the same reason, the DR generation must remain isolated for the sectionalizer lockout time.

Reclosing coordination consideration of different feeder designs must also be examined. These include the addition of reclosers and sectionalizers on the feeder. It is becoming more common for utilities to use a loop design for feeders where two feeders are joined together with a normally open recloser (automatic sectionalizing). When DR generation is placed on a feeder with automatic sectionalizing, it may be possible for the unit to be tied back to the utility through a different feeder. In this case, any protection that is required on the original feeder (e.g., DTTs or synchronism check) would also be required on the alternate feeder, or the DR should be prohibited from generating on the alternate feeder. Similarly, this same consideration should be placed on any customers with automatic throw-over gear on site.

The DR should never energize a de-energized utility feeder. This is a major safety concern to the utility.

[33] The local utility practice should be checked because the specific timing may be less than the common practice.

8.2.6.3 Tips, techniques, and rules of thumb

IEEE Std 1547-2003 4.2.6 allows DR reconnection once the area EPS voltage is within Range B of ANSI C84.1 Table 1. Ranges A and B in the referenced standard cover normal (steady-state) and infrequent operating levels of most area EPS circuits. Range B is a wider range of voltage than Range A, with the caveat being that Range B operation is infrequent. For example, for a nominal system voltage of 120 V, Range B allows customer utilization voltage (at the terminals of the customer equipment) to vary between 106 V and 127 V. Range A requires the voltage to be held between 110 V and 126 V. Consequently, by allowing reconnection under area EPS Range B voltage conditions, this requirement is more lenient than it could be (if Range A operation were required). Range B voltages for low- and medium-voltage services from ANSI C84.1-2006 [B3] are shown in Figure 2.

8.3 Power quality (IEEE Std 1547-2003 4.3)

8.3.1 Limitation of dc injection (IEEE Std 1547-2003 4.3.1)

"The DR and its interconnection system shall not inject dc current greater than 0.5% of the full rated output current at the point of DR connection."[34]

8.3.1.1 Background

DC injection by a DR into the local or area EPS produces a dc offset in the voltage waveform. Very small amounts of dc can result in significant saturation of magnetic components, such as cores of distribution transformers. This saturation, in turn, causes the injection of harmonic currents into the power system. These can reach unacceptable levels. There are also other, generally less critical, effects of saturation, including increased heating of magnetic components, audible noise, and reactive power demand.

Transformer core flux is equal to the time integral of the applied voltage. A dc voltage component, therefore, causes the sinusoidal flux wave to have a dc offset that continues to increase. As a result, exciting current of the transformer will develop a dc component. The resistive dc voltage drop in the transformer winding counters the applied dc voltage and reduces the rate at which the core flux offset increases. When the dc component of the exciting current and the injected dc are equal, an equilibrium is reached at which the flux offset stops increasing. Thus, the injection of dc results in transformer core flux offset to be sufficient for the average value (dc component) of the exciting current to be equal to the injected dc.

The economics of magnetic component design dictate using the smallest amount of magnetic core material possible to accomplish a task. This results in the magnetic circuit of the component operating near that part of the B-H curve where the curve begins to become very nonlinear, or saturated. For a typical distribution transformer core, a flux offset of 10% to 20% will result in profound saturation at the peak of one polarity of the flux wave. When the flux peaks exceed the saturation level, the instantaneous exciting current increases dramatically. As a result, the exciting current is highly distorted, as illustrated in Figure 8. Because the current spikes are in one polarity, they inherently have a large even-order harmonic component. Even-order harmonics are particularly objectionable in a power system.

The distorted current is effectively a harmonic current injection into the system. IEEE Std 1547-2003 imposes limits on harmonic injection into the area EPS by the DR. It is similarly necessary to prevent the DR from causing consequential injection of excess harmonics by the transformer with which it is interconnected.

[34] This value or a lower value may be required to meet a limit of 0.5% of the rated capacity at the PCC.

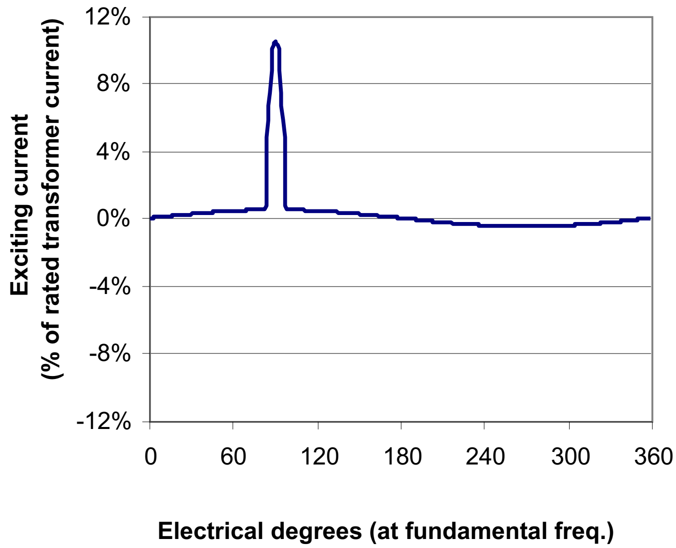


Figure 8—Exciting current waveform for typical distribution transformer with 0.5% dc injected

8.3.1.2 Impact of DR

There is a concern that transformerless inverters may inject sufficient current into distribution circuits to cause distribution transformer saturation sufficient to create an objectionable harmonic source or pose risks to power system equipment.

A transformer operates at a peak flux that is defined normally by the applied voltage. An exciting current flows in the primary that is equal to the applied voltage divided by the magnetizing inductive reactance. Ignoring leakage, the peak flux does not change as the transformer is loaded (the primary ampere-turns increase to compensate for additional secondary ampere-turns).

Until the saturation flux level is reached, the flux offset that results from dc is equal to the dc times the magnetizing inductance. For a typical distribution transformer, this inductance can be as great as 100 to 200 p.u. With a flux "headroom" of 10% to 20%, the saturation level can be reached for dc injection of 0.05% to 0.2% of transformer rated current. Thus, the most miniscule amount of dc can result in some degree of saturation. Once the saturation level is reached, the dc component of the exciting current is dominated by the once-per-cycle current spike. With more dc injected into the transformer, a higher-magnitude and longer-duration excitation current spike is the result.

The exciting current spike caused by flux-offset saturation is rich in even and odd harmonic components. Figure 9 shows an exciting current spectrum, through the ninth harmonic, for a typical transformer with 1% dc applied. Higher-frequency components are also injected, with magnitudes that generally tend to decrease with harmonic order. Harmonic current injections from a transformer saturated by dc from a DR add vectorially to the harmonics produced directly by the DR. Thus, it is necessary to limit the DR dc output to the degree that the harmonics consequentially produced by the distribution transformer are well below the limits imposed on DR harmonic output in IEEE Std 1547-2003 4.3.3.

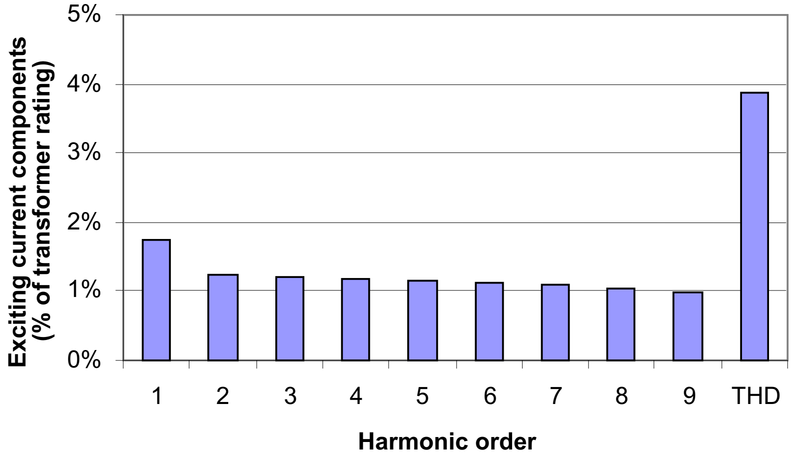


Figure 9—Exciting current harmonic spectrum for typical distribution transformer with 1% dc injected

Figure 10 shows a roughly linear relationship between dc injection and transformer harmonic production for a typical distribution transformer. These results are relatively insensitive to transformer parameters within a practical range. In this low-order harmonic range, IEEE Std 1547-2003 limits DR harmonic currents to 4% at individual odd harmonics, 1% at individual even harmonics, and 5% total demand distortion. Both the largest even harmonic (second), and the total harmonic distortion are at approximately 40% of the limit for DR injection, with the dc at 0.5% on the transformer rated current base. Because the harmonics injected by the transformer tend to be in random phase relationship with any harmonics injected by the DR, the two sources have a combined effect defined by the root-sum-square of their individual contributions. With the DR injecting the maximum allowable 5% total harmonic distortion, addition of the injections from an equally rated distribution transformer subjected to DR dc injection of 0.5% results in a total effective demand distortion of 5.4%. This constitutes a relatively minor increase in distortion above the maximum DR contribution. Thus, a 0.5% DR dc injection limit was deemed reasonable.

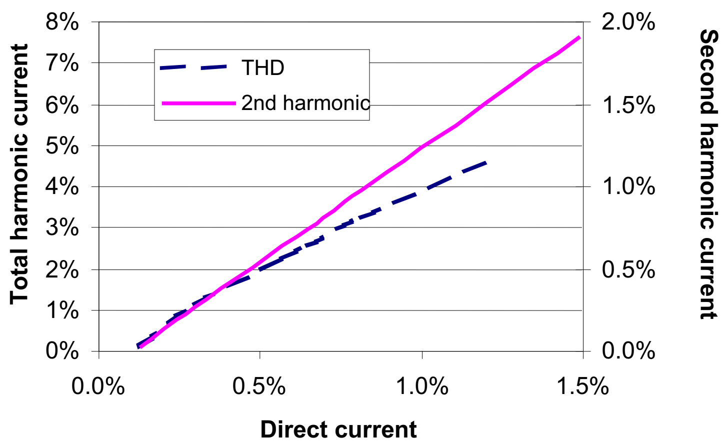


Figure 10—Exciting current total harmonic distortion and second harmonic component for typical distribution transformer with 1% dc injected

This conclusion is supported by language in another relevant IEEE standard (IEEE Std C57.110™-1998 [B47]):

> **DC components of load current**
>
> A dc component of load current will increase the transformer core loss slightly but will increase the magnetizing current and audible sound level more substantially. Relatively small dc components (up to the rms magnitude of the transformer excitation current at rated voltage) are expected to have no effect on the load-carrying capability of a transformer determined by this recommended practice. Higher dc load current components may adversely affect transformer capability and should be avoided.

Excitation currents for typical distribution transformers run as low as 0.5%. Given the above peak-to-rms ratio, the IEEE 1547 dc injection limit of 0.5% is reasonable.

The preceding analysis highlights the worst-case condition for a single distribution transformer. In it, the aggregate DR rating is equal to the distribution transformer rating. It further assumes that the dc component of output current from multiple DR units adds constructively on each phase. For many DR installations, the aggregate DR rating will be significantly less than the distribution transformer rating. Also, many installations with multiple DR units will benefit from some cancellation between units of dc component of output current. In these cases, the distribution transformer will be subjected to a dc current significantly less than 0.5% of the rated value, and the harmonic effect will be less than the worst case considered previously. Therefore, the per-unit harmonic effect on the distribution system because of dc current from DR is expected to be much less than the worst-case condition for a single distribution transformer.

8.3.1.3 Tips, techniques, and rules of thumb

In general, the dc component of output current is only a concern for inverter-based DR.

Several techniques can be applied to limit the dc component of output current produced by inverter-based DR. These include the following:

— Control of component tolerances and timing asymmetry to limit the dc component of output current by design

— Measurement and feedback control to reduce the dc component of output current

— Insertion of an isolation transformer between the inverter ac output circuit and the PCC. In this case, the saturation characteristic of the transformer should be chosen to tolerate the expected level of dc produced by the inverter.

8.3.2 Limitation of flicker induced by the DR (IEEE Std 1547-2003 4.3.2)

“The DR shall not create objectionable flicker for other customers on the Area EPS.”[35]

8.3.2.1 Background

Flicker is a power-quality issue predominately associated with noticeable changes in light output from incandescent lighting caused by minor changes in voltage levels. Flicker can exist in fluorescent lighting, but this requires somewhat larger voltage deviations.

[35]Flicker is considered objectionable when it either causes a modulation of the light level of lamps sufficient to be irritating to humans, or causes equipment misoperation. For guidance, refer to IEEE Std 519-1992 [B29], IEEE Std 1453-2004 [B40], IEC 61000-3-7:2008 [B18], IEC 61000-4-15:2003 [B16], and IEC 61400-21:2008 [B17].

Studies have shown that sensitivity depends on how much the illumination changes (magnitude), how often it occurs (frequency), and the type of work activity undertaken. The problem is further compounded by the fact that fluorescent and other lighting systems have different response characteristics to voltage changes. For example, incandescent illumination changes more than fluorescent, but fluorescent illumination changes faster than incandescent. Sudden voltage changes from one cycle to the next are more noticeable than gradual changes over several cycles. Illumination flicker can be especially objectionable if it occurs often and is cyclical.

IEEE Std 519™-1992 [B29] and IEEE Std 141™-1993 *(IEEE Red Book™)* present curves that show acceptable voltage flicker limits for incandescent lights used by a large number of utilities. The frequency content is extremely important to determine whether flicker levels are observable (or objectionable). The typical frequency range of observable flicker is from 0.5 Hz to 30.0 Hz, with observable magnitudes starting at less than 1%. The most sensitive frequency range for voltage flicker is approximately 5 Hz to 10 Hz. In essence, this means that the human eye is more susceptible to voltage fluctuations in the 5 Hz to 10 Hz range. As the frequency of flicker increases or decreases, the human eye generally becomes more tolerant to luminance fluctuations.

IEEE Std 1453™-2004 [B40] supersedes the traditional curves by adopting IEC 61000-4-15:2003 [B16] (which is included as an annex to IEEE 1453-2004). The recommended practice builds on the previous methods. The advent of solid-state compensators and loads may produce modulation of the voltage magnitude that is more complex than what was envisioned by the original flicker curves. The recommended practice introduces an instrument—referred to as the *flickermeter* and based on IEC 61000-4-15—that more accurately accounts for these complexities.

The flickermeter blocks, when converted to an analog curve, are very similar to the traditional borderline for irritation curve. Output of the flickermeter is a per-unit value (Pst for short-term flicker) of deviation from the minimum irritation level table. A Pst of less than 1 is acceptable, while a Pst of more than 1 is unacceptable. Because this is a new concept in North America, flickermeter methodology is not yet universally accepted.

8.3.2.2 Impact of distributed resources

Flicker caused by DR could occur on any radial distribution system. The risk of flicker should be evaluated for any type of distribution system. Flicker may be a simple or complex issue for analysis and mitigation. From the simple perspective, it can be the result of starting a machine (e.g., an induction generator) or step changes in DR output that produce significant voltage change on the feeder. If a generator starts or its output fluctuates frequently enough, flicker of lighting loads may be noticeable to customers.

Determining the risk of flicker because of basic generator starting conditions or output fluctuations is fairly straightforward using the flicker curve approach, particularly if the rate of fluctuation is well defined, the fluctuations are "step" changes, and there are no complex dynamic interactions of equipment. The dynamic behavior of machines and their interactions with upstream voltage regulators and generators can complicate matters considerably. For example, it is possible for output fluctuations of a DR (even smoother ones from PV or wind systems) to cause hunting of an upstream regulator. Although the DR fluctuations alone may not create visible flicker, the hunting regulator may create visible flicker. Thus, flicker can involve factors beyond simple starting and stopping of generation machines or their basic fluctuations. Dealing with these interactions requires an analysis far beyond the ordinary voltage-drop calculation performed for generator starting. Identifying and solving these types of flicker problems can be difficult, and the engineer needs to have a keen understanding of the interactions between the DR unit and the system.

8.3.2.3 Tips, techniques, and rules of thumb

Historically, voltage that caused flicker was measured with fast time-constant rms meters, load duty cycles, and a strip chart or similar recorder. Recently, a flickermeter that gives a much more quantitative measure of the likelihood of flicker problems has been developed. In the highly specialized field of power quality analysis, techniques have evolved to estimate the margin that might be available in any given system before flicker would be a problem. Of course, flicker measurements can always be taken after the DR has been installed, but if a problem is discovered, the DR unit has to be shut off or limited in operation until a distribution system reinforcement can be installed.

The IEC has comprehensive standards for assessing flicker levels on area EPSs. These standards take into account complex disturbances and multiple sources. For example, IEC/TR 61000-3-7:2008 [B18] provides detailed explanation and calculation methods for determining if any type of voltage change can cause objectionable flicker. All major wind turbine manufacturers publish data that can be used with this standard to predict flicker levels at any location on the area EPS. The flickermeter and these computational techniques can produce an acceptable measure of Pst severity, denoted as the Pst level.

Using this technique, flicker produced by a DR will be acceptable under the IEC standard if the Pst severity is less than or equal to 1 for a PCC at the secondary distribution voltage or less than or equal to 0.9 for a PCC at the primary distribution voltage—both with 99% compliance (on a one-week basis). Higher flicker levels may be allowed at the discretion of the area EPS operator.

DR units will meet the IEC requirement if the power variations from the unit (ΔS) compared with the available short-circuit capacity (SSC) of the area EPS at the PCC are within the limits described in Table 9.

Table 9—Acceptable voltage changes as a function of $(\Delta S/SSC)_{max}$

Voltage changes per minute (r)	$(\Delta S/SSC)_{max}$ (%)
r >200	0.15
10≤ r ≤200	0.23
r <10	0.46

See Annex B for a discussion of DR characteristics that may produce voltage deviations in the flicker frequency range.

8.3.3 Harmonics (IEEE Std 1547-2003 4.3.3)

"When the DR is serving balanced linear loads, harmonic current injection into the Area EPS at the PCC shall not exceed the limits stated below in [Table 10]. The harmonic current injections shall be exclusive of any harmonic currents due to harmonic voltage distortion present in the Area EPS without the DR connected.

Table 10 —Maximum harmonic current distortion in percent of current (I) [a]

Individual harmonic order (odd harmonics)[b]	h <11	11 ≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h	Total demand distortion
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

[a] I = The greater of the local EPS maximum load current integrated demand (15 min or 30 min) without the DR unit or the DR unit rated current capacity (transformed to the PCC when a transformer exists between the DR unit and the PCC).

[b] Even harmonics are limited to 25% of the odd harmonic limits shown.

8.3.3.1 Background

Harmonic distortion is a form of electrical noise; harmonics are electrical signals at multiple frequencies of the power line frequency. Many electronic devices—including personal computers, adjustable speed drives, and other types of equipment that use just part of the sine wave by drawing current in short pulses (as shown in Figure 11)—cause harmonics.

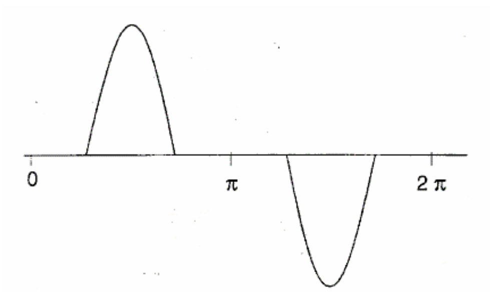


Figure 11 —Wave of switched-mode power supply

Linear loads, those that draw current in direct proportion to the voltage applied, do not generate large levels of harmonics. The nonlinear load of a switched power supply superimposes signals at multiples of the fundamental power frequency in the power sine wave and creates harmonics. The nonlinear loads connected to area EPSs include static power converters, arc discharge devices, saturated magnetic devices, and, to a lesser degree, rotating machines. Static power converters of electric power are the largest nonlinear loads. Harmonic currents cause transformers to overheat, which, in turn, overheat neutral conductors. This overheating may cause erroneous tripping of circuit breakers and other equipment malfunctions. The voltage distortion created by nonlinear loads may create voltage distortion beyond the premise's wiring system, through the area EPS, to another user.[36]

This IEEE 1547 requirement applies to voltages from 120 V to 69 kV and is drawn directly from IEEE Std 519-1992 [B29].[37] IEEE Std 519-1992 is based on the premises that the harmonic distortion

[36]When reactive power compensation, in the form of power factor improvement capacitors, is used with these nonlinear loads, resonant conditions can occur that may result in high levels of harmonic voltage and current distortion when the resonant condition occurs at a harmonic associated with nonlinear loads.

[37]The limits listed in Table 10 are the same as those presented in IEEE Std 519-1992 [B29]. These should be used as system design values for the worst case for normal operation (conditions that last longer than 1 h). For shorter periods, during startups or unusual conditions, the limits may be exceeded by 50%.

caused by a single consumer should be limited to an acceptable level at any point in the system and that the entire system should be operated without substantial harmonic distortion anywhere in the system.[38]

The IEEE 1547 requirement is based on the most restrictive harmonic current limits from IEEE Std 519-1992, but it also specifies how to interpret these limits when the local EPS contains a mixture of load and generation. The IEEE 1547 requirement applies only to the harmonic current at the PCC because of the DR serving linear loads. The harmonic current contribution at the PCC from nonlinear loads is excluded when evaluating the IEEE 1547 requirement.

NOTE—In IEEE Std 1547.1-2005, the type (design) test for harmonics is conducted at the point of DR connection. This simplifies the issue of separating the harmonics because of the DR and those because of nonlinear loads present in the local EPS.

8.3.3.2 Impact of distributed resources

As discussed, distributed generators can contribute to harmonic distortion of the area EPS voltage. Current injection limits are the responsibility of the DR operator, and area EPS voltage distortion is the responsibility of the area EPS operator. The two requirements are interrelated: Voltage on a feeder near the voltage distortion limit may be pushed over the threshold limit by the addition of a “distorted” DR unit.

For proper analysis, a number of factors are considered. First, the underlying background level of harmonic distortion of the area EPS voltage prior to the addition of any DR units is important. Also important are the contributions of harmonic current made by distributed generators and the effect these currents will have on voltage distortion.

DR installations should be reviewed to determine compliance with IEEE Std 1547-2003 and whether harmonics will be confined to DR sites or injected into the area EPS. If they are injected into the area EPS, the effect on voltage distortion should be determined, especially if there is a threat to adjacent customers or area EPS equipment. Measurements and modeling of system harmonics may be required to assess conditions.

The type and severity of harmonic contributions from a DR unit depend on the power converter technology, its filtering, and its interconnection configuration. There are concerns about the possible harmonic current contributions inverters may make to the area EPS. Fortunately, these concerns are, in part, because of older silicon-controlled rectifier (SCR) power inverters that are line-commutated and produce high levels of harmonic current. Most new inverter designs are based on solid-state technology that uses pulse-width modulation (PWM) to generate the injected ac. These newer inverters are capable of generating a clean output, and they should normally satisfy IEEE 1547 requirements.

In general, harmonic contributions from DR units are less of an issue than other problems associated with other equipment on the distribution system. In some cases, equipment at the DR site may need to be de-rated because of added heating caused by harmonics elsewhere on the system. Filters and other mitigation approaches are sometimes required.

8.3.3.3 Tips, techniques, and rules of thumb

If individual customers meet the current distortion limits and there is not sufficient diversity between individual customer harmonic injections, then it may be necessary to implement some form of filtering on the area EPS to limit voltage distortion levels. However, it is more likely that voltage distortion problems will be caused by system frequency response characteristics that result in magnification of harmonic current at a particular harmonic frequency. This changing of system impedances versus frequency

[38]The harmonic distortion limits of this requirement establish the maximum allowable current distortion for a DR unit and use the index of TDD. This is the harmonic current distortion in percent of maximum demand load current (15 min or 30 min demand).

characteristic is a result of the system's physical configuration. This situation has to be solved on the area EPS by changing capacitor locations or sizes or designing a harmonic filter.

If the limits are exceeded, the following steps may be taken:

a) Perform harmonic measurements at selected points within the area EPS, including the PCC, and look for consumers with converters operating with current distortion beyond the limits. When identified, ask such consumers to keep the harmonic distortion within the recommended limits by installing filters, reducing harmonic generation, or through other means.

b) Install filters to control the harmonics.

c) Install a new feeder. This is effective at stiffening the source and isolating the harmonic problems. However, cost is obviously a major consideration.

It is possible to add new converter loads to a circuit already polluted with harmonics to the recommended limits as long as properly designed filters are also provided. This is the responsibility of the DR owner.

The harmonic current distortion limits shown in Table 10 are only permissible provided that the transformer that connects the user to the area EPS will not be subjected to harmonic currents in excess of 5% of the transformer's rated current (see IEEE Std C57.12.00™-2000 [B45]). If the transformer that connects the user will be subjected to harmonic levels in excess of 5%, the installation of a larger unit, capable of withstanding the higher levels of harmonics, should be considered. When the harmonic current flowing through the transformer is more than the design level of 5% of the rated current, the heating effect in the transformer should be evaluated so that the transformer insulation is not stressed beyond design limits.[39]

8.4 Islanding (IEEE Std 1547-2003 4.4)

An island is defined as a condition in which a portion of an area EPS is energized solely by one or more local EPSs through the associated PCCs while that portion of the area EPS is electrically separated from the rest of the area EPS. IEEE Std 1547-2003 does not address intentional island operation; this will be addressed in a future guide, IEEE P1547.4.

8.4.1 Unintentional islanding (IEEE Std 1547-2003 4.4.1)

"For an unintentional island in which the DR energizes a portion of the Area EPS through the PCC, the DR interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island."[40]

[39]The methodology contained in IEEE Std C57.110-1998 should be applied. This evaluation includes consideration of the following:
—Transformer capability equivalent calculation using design eddy-current loss data
—Transformer capability equivalent calculation using data available from certified test report
—Neutral bus capability for nonsinusoidal load currents that include third harmonic components.
The user is cautioned that local and national electrical codes should be consulted before any installed unit is officially de-rated (i.e., changing the nameplate). Some units may not be de-rated without violating these codes.

[40]Some examples by which this requirement may be met are:
—The DR aggregate capacity is less than one-third of the minimum load of the Local EPS.
—The DR is certified to pass an applicable non-islanding test.
—The DR installation contains reverse or minimum power flow protection, sensed between the point of DR connection and the PCC, which will disconnect or isolate the DR if power flow from the Area EPS to the Local EPS reverses or falls below a set threshold.
—The DR contains other non-islanding means such as (a) forced frequency or voltage shifting, (b) transfer trip, or (c) governor and excitation controls that maintain constant power and constant power factor.

8.4.1.1 Background

When a protective device (e.g., a circuit breaker, recloser, or sectionalizer) between the area EPS source and a DR opens, there is the possibility that an island will form. The concern in this situation is the condition in which the amount of isolated load is close to the amount of generation in the island. Under these conditions, the island can have slowly changing voltage or frequency. If the load and generation are not matched (at least a 3-to-1 ratio), then the voltage or frequency will change rapidly, and an unintentional island should not occur.

See 8.2.2 for further discussion of the impact of the voltage or frequency change and the impact on reclosing.

8.4.1.2 Impact of DR

It takes finite time to detect and react to an island. It is not desirable for a DR to island beyond 2 s on an unplanned basis. This can lead to safety and power-quality problems that will affect the area EPS and local loads.

During area EPS repair operations, such as dealing with downed conductors, it is important that workers use their mandatory safe work practices that invariably require them to validate that lines are de-energized or to use “hot work” practices (see 8.1.7).

Unintentional islanding can pose a threat to the public, emergency response personnel, and utility workers because the DR represents an unknown source. For example, applying the safety ground to energized conductors (from the unintentional island) will cause a fault and possible injury to area EPS personnel. The local EPS feeding an unintentional island may not be able to support the fault arc and lead personnel to believe mistakenly that the conductors are de-energized.

Service restoration can be delayed as line crews seek to ensure that unintentional DR islanding is not a problem.

Reclosing operation of the upstream breaker or reclosing during unplanned islanding could cause major damage to the DR using the rotation machine because of out-of-phase closing. Area EPS devices (e.g., circuit breaker and reclosers) typically do not monitor load-side voltage and, therefore, assume the line is dead when a reclosing attempt is made. If the island is still energized by a DR, severe transients could result.

8.4.1.2.1 Voltage

Typically, the area EPS operator has performed studies and tests and installed equipment to maintain proper voltage only when the local EPS is energized from generation sources of the area EPS. An island condition can result in high- or low-voltage conditions, depending on the system configuration and DR size, type, transformer connection, and regulation method.

8.4.1.2.2 Undetected islands

Should an island condition result from the operation of an unmonitored sectionalizing device and customers experience no abnormal conditions, they are not likely to report a problem. This could result in the island condition existing for an extended period. The area EPS operator will not be aware of the operation of the sectionalizing device. IEEE Std 1547-2003 specifically states that the DR is not to allow this condition. The unintentional island should be detected and isolated within 2 s. The creation of a stable island is addressed in IEEE P1547.4.

8.4.1.2.3 Reclosing problems

If the island resulted from the operation of a breaker or sectionalizing device, it is unlikely that the DR is capable of synchronizing to the area EPS at that open device. Typically, the island is shut down before it can be reconnected to the area EPS. The area EPS will typically study the DR connection and determine if the installation of the DR will impact the reclosing by the decay of voltage or frequency after the operation of an area EPS device.

See 8.2.2 for further discussion about reclosing.

8.4.1.3 Tips, techniques, and rules of thumb

To satisfy IEEE Std 1547-2003 4.4.1, in particular, the DR has to cease to energize an unintentional island before any reclosing occurs on the area EPS. The area EPS operator may choose to install voltage detection equipment to determine if an island has formed.

To prevent continued unintentional islanding, a DR unit operating in parallel with the area EPS is required to cease to energize the area EPS within 2 s of the formation of the island. This is typically not fast enough to allow disconnection prior to the shortest reclosing times (i.e., instantaneous reclosing times from 20 cycles to 60 cycles) found in protective relays on the area EPS. If the area EPS study indicates this may be a problem, then voltage-blocking relays or DTTs are typically installed to block automatic reclosing until the unintentional island is de-energized. Another option is to delay the reclosing operation for more than 2 s if this is acceptable to the area EPS operator.

IEEE Std 1547-2003 suggests specific options—each of which involves several facets—for meeting this requirement. Each of these options is described in more detail as follows.

8.4.1.3.1 Limited DR capacity as share of customer load

If the aggregate DR capacity is less than one-third of the local EPS load, it is generally agreed that, should an unintentional island form, the DR will be unable to continue to energize the load connected within the local EPS and maintain acceptable voltage and frequency. The origin of this 3-to-1 load-to-generation factor is an IEEE paper (Gish, Greuel, Feero [B13]) based on simulations and field tests of induction and synchronous generation islanded with various amounts of power factor-correcting capacitive kilovoltamperes reactive. It was shown that as the pre-island loading approached three times the generation, no excitation condition could exist to support the continued power generation.

Because minimum loads are rarely well-documented and can vary, using a conservative load-to-generation criteria of 3-to-1 gives a margin against future changes in the customer's minimum load. However, a 2-to-1 ratio may be acceptable in some applications. For installations in which the DR is interfaced through inverters, the need for margin to guard against future drops in minimum load also exists, and the 3-to-1 rule still seems prudent. Where the actual minimum load is known, lower load-to-generation margins may be applied.

8.4.1.3.2 Non-islanding inverter

Many inverters are designed such that they are unable to supply a load without the presence of the electrical system. The inverter, in many cases, will lock to the area EPS frequency. The inverter controls may also be equipped with non-islanding means, which usually continually attempt to force the inverter off the power system frequency so that, if the power system is unavailable, the inverter voltage and frequency quickly deviate from nominal ranges to cause under/overvoltage or frequency trips.

8.4.1.3.3 Reverse power protection

If the DR is intended to supply power only to its own local EPS and not to the area EPS across the PCC, reverse power relays may be installed at the PCC to operate isolating devices. These isolating devices may be the generator isolation device itself or, if the DR wishes to continue to support the local EPS as an intentional island, an isolating device at the PCC.

Caution should be taken when using reverse power as a means for non-islanding protection. Its setting, along with time delay, should be carefully selected to allow load swing of the facility to prevent nuisance trips.

8.4.1.3.4 Acceptable non-islanding protection

This option may take many forms. It is intended to encompass many other methods of satisfying this requirement.

8.4.1.3.5 Protection

Protection may use voltage and frequency relays as a means of anti-island protection, as previously detailed. This reactive scheme measures electrical variables at the PCC and detects conditions that indicate an island has been formed. This protection scheme is based on the DR's inability to satisfy a sudden change in load without a corresponding change in voltage or frequency. In this instance, the voltage or frequency relays will take the unit off-line. Besides under/overvoltage and frequency relays, several means derived from voltage and frequency changes are commonly used for non-islanding detection. These include phase or vector jump and rate of change of frequency. Proactive protection attempts to detect an island directly. Non-islanding controls in an inverter fall into this category. In some cases, reactive scheme protection can be fooled if the generator is able to carry the load of the island without a substantial change in voltage or frequency. Some inverter manufacturers have added an additional "active" non-islanding compatibility.

One "active" approach is based on inverter design. When the area EPS voltage signal is available, the inverter is "forced" to operate at 60 Hz. In this case, it is the forcing area EPS voltage function that causes the inverter to operate within frequency specification. During an islanded situation in the case of an area EPS interruption, the inverter may seek its natural "tuned" frequencies at a value outside the normal frequency range. In the process of drifting to the natural inverter frequency, the unit will trip its internal frequency relays. These relays are typically set to trip when the frequency is outside the normal operating range of 59.3 Hz to 60.5 Hz.

One class of active scheme is to use external devices (i.e., to actively inject current signal with certain frequencies other than fundamental frequency and then measure voltage at those frequencies). Islanding will be detected by examining the impedance changes.

Active schemes measure electrical variables at the PCC, but the response of the variables is checked against a deliberate variation in some aspects of the DR output. Active non-islanding is more robust than reactive, but even it cannot guarantee that an island will not develop in some rare cases. Non-islanding relays are available to continually monitor minute, momentary changes in the vector relationships of the current and voltage to detect events on the area EPS that would form an unintentional island.

8.4.1.3.6 Synchronous generator excitation system controls

Synchronous generators may also be equipped with excitation system controls that maintain a constant power factor or constant power and rely on under/overvoltage or under/overfrequency relays to operate if the load on the generator does not match the generator output.

For example, power factor control can be used for non-islanding. The DR is set to regulate at a fixed power factor. This power factor should be selected to be significantly different from the load that would be isolated with the DR. If an island condition develops, the DR will supply too little or too much reactive power support, which will result in a low- or high-voltage condition. For example, if the load power factor is 0.9 (inductive) and the DR is regulating to a power factor of 1.0, the DR will not provide sufficient reactive power support should an island form. This will result in an undervoltage condition, which, in turn, will cause the generator to trip because of low voltage (assuming standard undervoltage protection per IEEE Std 1547-2003).

8.4.1.3.7 Direct transfer trip

DTT may also be used and is a very direct approach to ensure that the DR ceases to energize an unintentional island. DTT involves communication equipment both on the area EPS and at the DR. The specific events on the area EPS will be used to send a secure, reliable communications signal to the DR to cause the DR to open isolation devices as needed to satisfy this requirement.

8.4.1.3.8 Operating conditions with a sustained unintentional running island

The potential problems described in this subclause can occur only during a sustained unintentional running islanding condition. This may occur if non-islanding protection fails to detect an islanded condition and ceases to energize within 2 s. With a normal connection to the substation in place, the area EPS stabilizes the system voltage and the neutral. If islanding is a physical impossibility because the system characteristics are such that a stable island cannot be formed, then these possible problems can likely be ignored.

If a running island is possible, then possible conditions in the island need to be evaluated to determine the maximum level of system overvoltages and how fast the interconnection protective relaying will respond to them. These overvoltage magnitude and duration results should then be compared with arrester temporary overvoltage curves and published curves for consumer equipment temporary overvoltage capability. Arranging the system to avoid the possibility of isolating a large capacitor bank and a small load with a DR will reduce the risk of overvoltages.

8.4.1.3.9 Avoiding excessive phase-to-ground voltages

Excessive phase-to-ground voltages in an island can be avoided with suitable transformer connections or by adding an appropriately sized grounding transformer on the primary circuit. The grounding transformer has two advantages: (1) It may avert the need to replace an existing power transformer, which would otherwise be suitable, and (2) it can be sized to provide the minimum effect on ground-relaying sensitivity, which is consistent with a stable neutral under islanded conditions.

A relaying scheme to protect against excessive phase-to-ground voltages can be considered but generally requires voltage transformers connected to the primary distribution voltage to detect high phase-to-ground voltage or zero-sequence overvoltage. Also, the minimum operating time of overvoltage relays and circuit breakers is typically much longer than the few milliseconds of withstand capability that published curves give at 173% voltage. See 8.1.2 for additional information.

8.4.2 Intentional islanding (IEEE Std 1547-2003 4.4.2)

"This topic is under consideration for future revisions of this standard."

There is no requirement in IEEE Std 1547-2003 regarding intentional islanding, so no specific application guidance can be offered. However, the following information is provided.

Currently, most area EPSs are reluctant to create isolated subsystems (or islands) that contain area EPS customers. However, local EPS operators can set up isolated subsystems on their own local EPSs. If the local EPS operator decides to create an isolated subsystem, the area EPS operator should be aware of this method of operation. Normally, the area EPS operator will expect the generation to trip for faults or problems on the area EPS. In the case of an islanded subsystem, the "tie" breaker will typically trip. This will leave the generation operating with the local load. For maximum benefit, the local EPS operator will want to parallel to the area EPS *without* shutting down the generation. This will require the capability to parallel with a *different* breaker, such as a breaker between the area EPS and the islanded EPS, than is used to normally parallel the generation.

The area EPS and the local EPS will need to discuss the required interlocks and the method of operation for paralleling the intentional island or local EPS. Typically, the area EPS operator will require a sync- check relay, and the local EPS will require full synchronizing capability.

There may be times when a customer seeks the increased reliability associated with a planned DR island. This can be accomplished if the DR system and the interconnection are designed to provide "backup islands" during upstream area EPS outages. Reliable DR units and careful coordination of sectionalizing and protection equipment are necessary for this approach.

Any time such a scheme is implemented, it needs to be well-planned to avoid problems. Figure 12 shows one scheme in which an upstream automatic switch is used to island a section of a distribution feeder. For this approach to work, the switch needs to be open during upstream faults, and the generator needs to be able to carry the load on the islanded section and maintain suitable voltage and frequency levels at all islanded loads.

Unless a static switch is employed, this scheme will usually result in a momentary interruption to the island because the DR will necessarily trip during the voltage disturbance caused by the upstream fault. The DR assigned to carry the island should be able to restart and pick up the island load after the switch has opened.

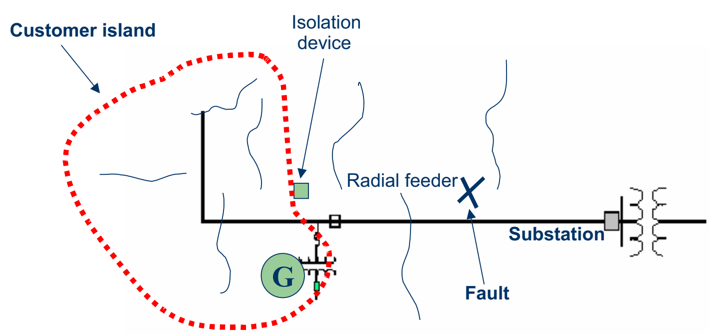


Figure 12—Intentional island

Power flow analysis of island scenarios needs to be performed to ensure that proper voltage regulation is maintained and establish that the DR can handle inrush during "starting" of the island. The DR unit needs to be able to load-follow during islanded operation, and the switch needs to sense a fault current downstream and send a signal to block islanding if a fault occurs within the island zone. When utility power is restored, the switch should not close unless the area EPS and "island" are tightly in synchronism. This requires measuring the voltage on both sides of the switch and transmitting that information to the DR unit supporting the island so that it can "synchronize" with the area EPS and allow reconnection. New, automated switch technology and advanced communications are making this approach practical today.

9. Application guidance for interconnection test specifications and requirements

Topics in Clause 9 of this guide closely parallel those of IEEE Std 1547-2003 Clause 5 and IEEE Std 1547.1-2005. However, when there is a question of which information applies, IEEE Std 1547-2003 and IEEE Std 1547.1-2005 take precedence.

IEEE Std 1547.1-2005 provides tests and procedures to verify interconnection system conformance with IEEE Std 1547-2003. The IEEE 1547.1 test procedures provide a means for manufacturers, area EPS operators, and independent testing agencies to confirm the suitability of any interconnection system or component intended for use in the interconnection of DR with an EPS. Such certification can lead to the ready acceptance of confirmed equipment as suitable for use. Although this standard defines test procedures, it does not specify measurement techniques. Suitable measurement techniques can be found in various technical publications, including but not limited to IEEE Std 120™-1989 [B20].

Equipment that interconnects DR with an EPS has to meet the requirements specified in IEEE Std 1547-2003. Standardized test procedures are necessary to establish and verify compliance with those requirements. These test procedures provide both repeatable results, independent of test location, and flexibility to accommodate the variety of DR technologies.

It is recognized that an interconnection system can comprise a single device that provides all required functions or an assembly of components, each of which has limited functions. Components that have limited functions shall be tested for those functions in accordance with IEEE Std 1547.1-2005. Conformance may be established as part of a combination of type (referred to as *design* in IEEE Std 1547-2003), production, and commissioning tests.

9.1 Type (design) tests (IEEE Std 1547-2003 5.1, IEEE Std 1547.1-2005 Clause 5)

Type tests are performed on a representative unit and may be conducted in the factory, at a testing laboratory, or on equipment in the field. Unless otherwise specified, equipment shall be installed per manufacturer specification and operated under nominal operating conditions.

Test regimens that accomplish the same measurements with the same accuracy and are agreed upon by the parties involved can be used. When the equipment under test cannot be evaluated using one or more of the test regimens specified in IEEE Std 1547.1-2005, alternative test regimens agreed to by the manufacturer and the testing agency may be used. When used, the details of such alternative tests regimens shall be recorded in the test report with an explanation of why the alternative test regimen was used.

9.2 Production tests (IEEE Std 1547-2003 5.2, IEEE Std 1547.1-2005 Clause 6)

Production tests verify the operability of every unit of interconnect equipment manufactured for customer use. These tests assume the equipment has met the requirements for type tests. Production tests may be conducted as a factory test or as part of a commissioning test. Tests are performed to verify manufacturer settings rather than specific IEEE 1547 requirements because IEEE Std 1547-2003 allows adjustability of set points, and it is of value to have the unit factory-set and tested at specific settings.

Interconnection systems with adjustable set points shall be tested at a single set of set points as specified by the manufacturer. As applicable, production tests shall include the following:

- Response to abnormal voltage
- Response to abnormal frequency
- Synchronization

9.2.1 Response to abnormal voltage (IEEE Std 1547.1-2005 6.1)

The purpose of this test is to verify that the DR interconnection component or system responds to abnormal voltage conditions as required. Trip setting shall be as specified by the manufacturer.

9.2.2 Response to abnormal frequency (IEEE Std 1547.1-2005 6.2)

The purpose of this test is to verify that the DR interconnection component or system responds to abnormal frequency conditions as required. Trip setting shall be as specified by the manufacturer.

9.2.3 Synchronization (IEEE Std 1547.1-2005 6.3)

The purpose of this test is to verify that the DR interconnection component or system will connect the DR only when the voltage, frequency, and phase angle differences are acceptable or will not induce flicker on the area EPS. Equipment that is using the startup (in-rush) current method is exempt from this production test. Two procedures are offered: one for equipment that does not include provisions for switching off the synchronizing function and another for equipment that can be manipulated to control the synchronization process.

Settings shall be as specified by the manufacturer and shall be within the requirements of IEEE Std 1547-2003.

9.3 Interconnection installation evaluation (IEEE Std 1547-2003 5.3)

This part of IEEE Std 1547-2003 is covered in IEEE Std 1547.1-2005 Clause 7.

9.4 Commissioning tests (IEEE Std 1547-2003 5.4, IEEE Std 1547.1-2005 Clause 7)

The commissioning test shall be conducted after the interconnection system is installed and is ready for operation. An individual qualified in testing protective equipment (e.g., professional engineer, factory-certified technician, or licensed electrician with experience in testing protective equipment) should perform or directly supervise commissioning tests. The area EPS operator has the right to witness commissioning tests as described below or to require written certification by the equipment owner describing which tests were performed and their results. All commissioning tests shall be performed based on written procedures. Commissioning procedures are typically provided by equipment manufacturers or system integrators and approved by the equipment owner and area EPS operator. Once complete and accepted, the commissioning tests do not have to be repeated unless set points are changed.

9.5 Periodic interconnection tests (IEEE Std 1547-2003 5.5, IEEE Std 1547.1-2005 Clause 8)

At the time of commissioning, a written "Periodic Interconnection Test" procedure should be agreed upon by the equipment owner and the area EPS operator. Periodic test procedures are typically provided by the equipment manufacturer. The procedure shall describe a test process that will verify all interconnection-related protective functions and associated batteries are functional, but it need not replicate the type, production, and commissioning test procedures. The interval between periodic tests shall be specified by the manufacturer, system integrator, or the AHJ over the DR interconnection. Written test reports or a log for inspection shall be maintained. If changes are made to functional software or firmware of the interconnection system or if a hardware component of the interconnection system has been modified in the field, replaced, or repaired with parts different from those in the tested configuration and if such hardware, software, or firmware has not been previously type-tested, then the applicable type, production, and commissioning tests shall be performed. If such hardware, software, or firmware has been previously type-tested or if settings have been changed, then the type, production, and commissioning tests should be conducted applicable to the changes made.

10. Interconnection process information

The interconnection process and rules, information required to complete the interconnection process, and business-related requirements vary by AHJ and EPS/DR operator and are often collectively referred to as *interconnection standards.* Contact the relevant parties (e.g., the public utility commission and area EPS operator) for specific information, requirements, and forms.

In general:

— The area EPS operator typically has a form that lists the required initial project information. If available, a one-line diagram should be provided with this form. This is usually the minimum information necessary to start the screening process.

— The DR owner will need access to current area EPS interconnection requirements, rate schedules, and any local operation constraints.

— The regulator or AHJ may require information about the size, location, fuel, type of operation, and other aspects of the proposed DR facility. Permits or other legal requirements may be involved.

— The proposed operation and, specifically, the sale of the power generated needs to be discussed with many if not all of the above-mentioned parties. The DR owner may be able to choose to offset existing power use, sell excess power, or sell all power generated. The considerations of these discussions are beyond the scope of this document; however, they may be very important to the economical operation of the DR.

— Most area EPS operators have a fee schedule based on the size or effect of the DR on the area EPS.

— Most area EPS operators have guidelines or requirements that indicate when additional studies are required. Typically, these are not required for expedited, small, and simplified projects unless there is a high concentration of DR in a given area. Large projects (i.e., projects that did not pass the initial screens) typically require impact or stability studies. See Annex F for more information about planning studies that may be required.

— For safety and reliability reasons, many area EPS operators or AHJ will require the DR to use a licensed professional engineer to design the interconnection system. This requirement may be waived for certified DR installations. Larger installations typically are composed of separate components that are designed and connected correctly.

- Many, if not all, local AHJ will have some form of inspection requirements or commissioning test requirements. In addition, in some areas, the AHJ may rely on the area EPS operator for inspection requirements and commissioning test requirements. All required inspections and commissioning tests will need to be completed prior to the normal operation of the DR facility.

Detailed observations about the interconnection process can be found in Annex H.

The timely, accurate, and complete exchange of interconnection information is essential for an efficient DR interconnection process. The DR interconnection process encompasses the full range of activities from the planning of a proposed DR interconnection to the start of parallel operation of the new DR. Many issues that need to be considered in the DR interconnection process are outside the scope of IEEE Std 1547-2003.

- Relay versus system testing

  Small and self-contained installations typically are tested as a complete system. These systems will typically meet the design test and production test requirements in IEEE Std 1547-2003. Existing protective relays can also be tested for compliance with the design and production tests of IEEE Std 1547-2003; however, the use of certified protective relays may still require field testing of the complete interconnection system. Full compliance with IEEE Std 1547-2003 requires that the entire system be tested, and this will usually be very difficult with component-based designs.

- Information requirements

  Information requirements tend to increase with the size of units. Except for extremely small DR, the information that will need to be exchanged between the DR developer and the area EPS operator may be significant. An extremely small unit, such as a certified 2 kW PV system, requires only minimal information for the area EPS operator to determine its impact and approve its installation.

- Queues

  Occasionally, the AHJ will require the area EPS operator to maintain a queue system for determining the appropriate level of generation to be installed on an area EPS facility or the appropriate charge for system modifications. It is beyond the scope of this document to discuss the queue system, except to inform the reader that it may exist.

- System modifications system impact

  Based on the information provided by the DR developer, the area EPS operator will evaluate the system impact of the proposed DR and its interconnection system.[41] If studies reveal a significant negative system impact, the area EPS operator will determine area EPS modifications, upgrades, or changes to the planned DR and interconnection system to accommodate the proposed DR interconnection. After the DR developer is informed of the area EPS modifications, upgrades, or changes to the planned DR and interconnection system and the DR developer decides to go forward with interconnection, arrangements are made to complete the required modifications, upgrades, or changes. Typical modifications include changes to the following:

  - The existing circuit breaker controls to include voltage check reclosing
  - One or more reclosers or sectionalizers to control reclosing
  - The DTT to limit the probability of forming an unintended island
  - The SCADA to provide real-time data and control of the DR facility
  - The relay settings to provide coordination
  - The point of interconnection

[41]Some area EPS operators may first conduct an abbreviated study using screening criteria for smaller DR. The use of screening criteria enables the area EPS operator to quickly determine if (a) the DR interconnection request will not have a significant system impact and can be approved without further study, or (b) further study is required to determine system impact. This approach allows small DR with no impact to be interconnected more quickly. See Annex F for more information about screening methods.

Annex A

(informative)

Interconnection system equipment

A.1 Interconnection system functions

This subclause includes descriptions of functions that may be included in an interconnection system. The functions described here are not necessarily discrete components. Suppliers often integrate functions into control subsystems.

The interconnection system is often designed to integrate additional functions beyond those required to comply with IEEE Std 1547-2003. For example, the interconnection system may be designed to interact with and serve as the communication and control interface among the DR, the area EPS, and the local EPS loads. Because of functional requirements both within and beyond the scope of IEEE Std 1547-2003, the system may need to respond (monitor and control) quickly (e.g., on the order of milliseconds or cycles in the case of voltage and frequency regulation, reactive power supply, and fault protection and coordination) or more slowly (e.g., on the order of seconds or minutes in the case of power export or peak-shaving).

However, any division of interconnection system components is somewhat arbitrary because the components may be engineered, assembled, and sold in many configurations. Nonetheless, it is useful to categorize the components into groups based on the following categories:

— Synchronizing and paralleling
— Power source transfer
— Metering and monitoring
— Electrical protection
— DR control
— Power conversion
— Power conditioning
— Dispatch, communication, and control

Examples of these functional categories and the specific equipment needed to accomplish these functions are described as follows. The examples are not exhaustive or prescriptive.

A.1.1 Synchronizing and paralleling

The interconnection of any two ac EPSs requires that the systems be synchronized before they are connected together (paralleled). Failure to synchronize the DR and area EPS prior to interconnection can result in voltage disturbances that are disruptive to other customers on the area EPS, tripping of protective devices in the local and area EPSs, and serious damage to the DR. The damage to the DR at the instant of interconnection is caused by the nearly instantaneous shift in frequency and voltage from the pre-closure value to the area EPS value. In other words, at the instant of interconnection, the DR frequency and voltage is forced to be the same as that of the area EPS. The disturbance on the area EPS is caused by the large electrical load surge caused by the mechanical or electrical output shift in the DR.

The magnitude of disturbance that the DR can cause is related to its physical size relative to the area EPS, so synchronizing requirements in IEEE Std 1547-2003 are more stringent for larger machines than they are for smaller ones. The frequency of the DR must be within a specific frequency range relative to the area EPS so that the machine does not move too far out of acceptable closing range between the time that connection is signaled and the when the equipment actually makes the connections. The voltage difference and phase angle difference requirements in IEEE Std 1547-2003 provide assurance that the disturbance at the instant of interconnection will not be disruptive to other customers on the area EPS and, generally, will not damage the DR.

It should be emphasized that IEEE Std 1547-2003 does not include any provisions for the protection of DR, so the DR owner or system designer must evaluate equipment needs and provide any required functions to protect the DR.

The synchronizing process is normally not fully manual because of the risks involved with improperly performing this action. In general, whether the process is manually initiated through a sync-check device or automatic, the voltage of the DR will be matched to that of the area EPS (within the range specified by IEEE Std 1547-2003) and then the frequency will be adjusted to be close to the frequency of the area EPS. When the frequency of the two sources is different but close, the voltage waveforms will slowly but constantly move in and out of phase. The smaller the frequency difference, the slower the phase angle difference between the sources will change, and the longer the two sources will remain in the *synchronizing window,* which is the time period when the phase angle is within plus or minus the phase angle difference required. If the frequency difference between the two sources is too large, they will not stay in the synchronizing window long enough to safely close within the required parameters, so interconnection should not be attempted.

In general, with synchronous machines, the frequency of the DR will be slightly higher than that of the area EPS. Therefore, at the point of interconnection, the DR will pick up load rather than be exposed to reverse power conditions, which are potentially damaging to the prime mover.

When a DR is operating with load while it is synchronizing, the dynamics of the load can affect synchronizing speed and accuracy. When multiple DR units are simultaneously synchronized to an area EPS, a separate synchronizer is often used to influence all the machines simultaneously and maintain load balance on the isolated machines during the synchronizing process.

When the two sources are physically connected together, they are *paralleled.* To maintain parallel operation, the DR must have controls that maintain its output kilowatts and kilovoltamperes reactive within acceptable operating ranges. The kilowatt and kilovoltampere reactive load on the DR can be controlled to a constant value, which is often called *base loading,* or to a fixed value in the power imported into the facility, which is called *peak-shaving.*

In general, the DR is intended to operate in parallel with the area EPS without significantly affecting the voltage or frequency of the area EPS. It may affect the voltage of the area EPS simply by changing the load level on the system at a specific point, but to be in compliance with IEEE Std 1547-2003, the DR must not attempt to regulate or control area EPS voltage.

The equipment required to synchronize and parallel DR equipment depends, to a large degree, on the nature of the energy source and the primary and secondary conversion device. For example, if a reciprocating engine is used to burn landfill gas and parallel to the area EPS with a synchronous alternator, the engine is the primary conversion device, and the alternator is the secondary conversion device. To synchronize the system, the excitation control system of the alternator must drive the alternator output voltage to the proper value by manipulation of the excitation system of the alternator. The fuel rate of the engine is controlled to cause the required frequency difference between the two sources, and the phase angle difference is achieved by minor adjustments in fuel rate.

For other primary and secondary conversion devices, the physical devices required to make voltage, frequency, and phase angle adjustments are provided by a variety of hardware and operation strategies.

For any specific type of conversion device, there are likely many types of control devices and strategies. Separate devices are often available for synchronization and load control while paralleled. In other cases, especially for smaller equipment, synchronization and load control are integrated functions of the DR.

For larger systems, the control equipment necessary for synchronizing and paralleling is often, for convenience, located in the switchgear that physically houses the breakers and bus structure used for power distribution. The switchgear assembly can be UL-listed for specific situations. Low-voltage systems can be listed to UL 891 [B66] or UL 1558 [B67].

The sequence of operation of these systems can be complex, and care should be taken to identify all necessary sequences of operation required for a specific application.

Given their purpose, paralleling switchgear subsystems are often packaged with other central control components, including DR controls; metering and monitoring equipment, including the DR SCADA system; power distribution equipment; and protective relaying equipment.

A.1.2 Power source transfer

Many DR systems are designed to parallel with the area EPS by providing part of the power needed by a local EPS. These systems incorporate the major functions described in A.3.1. In other cases, the DR equipment is not only designed to provide power during parallel operation but also includes the capability to serve all or part of the facility load with emergency or standby power. When a DR system serves these dual roles, it includes a power source transfer function.

Power source transfer can be automatic or manual. It may operate in open-transition or closed-transition modes. Open-transition transfer systems disconnect one source before connecting the new source. The operating time is typically in the range of 0.1 s to 1 s. This means that, in all situations in which a power transfer occurs, there is a short power interruption to the loads. In closed-transition transfer systems, when power is transferred between live sources, the sources are synchronized and paralleled to prevent the total interruption in power. Open-transition transfer systems and closed-transition transfer systems that operate from source to source in less than 100 ms are not required to meet the requirements of IEEE Std 1547-2003 but are sometimes used for DR applications.

Closed-transition transfer systems that require 100 ms or more to complete the transfer must conform to IEEE Std 1547-2003. Closed-transition transfer systems can include active synchronizing functions in conjunction with other features that parallel to the area EPS, transfer power from source to source without an interruption or perceptible disturbance, and operate in several modes, depending on the needs of the application.

Power source transfer typically includes a control system that senses availability of the normal area EPS source and the DR equipment, provides timing functions and other control logic, and physically switches power from source to source. These controls are often microprocessor-based, which improves their features and capabilities while maintaining relatively low costs. They often are field-programmable to provide different functions and include integral displays.

The power-switching means in the power-source transfer may be composed of contactors, circuit breakers, a static transfer switch, or a transfer switch mechanism.

Static transfer switches that use self-acting, solid-state equipment that rapidly (i.e., as fast as 2 ms to 4 ms) transfer one or more load conductor connections from one power source to another are available. Static transfer switches use high-speed digital sensing to detect voltage irregularities and instantly transfer critical loads from a primary power source to an alternate power source without any detectable interruption.

A transfer-switch mechanism is specifically built to transfer power from source to source and often includes a mechanical interlocking device for open transition transfer applications. Transfer switches are evaluated and listed to the requirements of standards that validate their switching capabilities and fault-withstand capabilities.

The power switching means for applications that must comply with IEEE Std 1547-2003 will often be composed of power circuit breakers in a switchgear lineup.

All the available switching mechanisms are available in a range of voltages, amperages, and pole configurations.

A.1.3 Metering and monitoring

IEEE Std 1547-2003 has few requirements for monitoring, and metering is beyond its scope. The IEEE 1547 monitoring clause includes provisions for systems 250 kVA and larger for monitoring connection status, real and reactive power output, and voltage at the DR connection point. This information is the minimum data necessary for an area EPS operator or DR owner to manage their systems. IEEE Std 1547-2003 does not specify the means used to monitor the required functions.

However, in most DR installations, some metering functions are installed. The following three groups commonly use data from DR sites:

— The DR owner, which has a financial interest in how and when the plant is operated
— The DR operator, which has an interest in operational data to track efficiency, schedule maintenance, determine cost of operation, etc.
— The area EPS operator, which has an interest in the real-time operation of the area EPS

One complication is that these entities are typically in different locations, use different systems to collect data, and use different protocols for communication. The result is that, in the worst case, multiple communication systems are required—one for each system. However, some data collection systems can provide a database-type operation in which modems or protocol converters can be "plugged into" host equipment and programmed to provide appropriate data to the end user.

Metering-quality data are quite different from monitoring-quality data. Metering data are used for business and financial considerations. Revenue-quality meters (as well as associated current transformers and potential transformers) are located at various points to provide data to determine load, gross generation, and net generation, as required by contractual or tariff requirements. The data are usually collected in 15 min or 1 h intervals. These data are generally not required in real time. Gross generation metering may also be used for distribution system capacity planning. Monitoring data, on the other hand, are often used for real-time operations. For example, the area EPS may monitor real power, reactive power, and voltage at the point of DR connection. The operator of the DR facility also may be interested in this data but may require other information as well.

When large DR units are interconnected with an area EPS, a range of variables is typically metered and monitored. Small DR facilities have fewer or no data monitoring requirements. Intermediate units fall between these. Energy users want to measure the energy generated at different times of the day. Using this information, they can determine how much revenue they should receive from power purchasers. Energy users can also use this information to verify payment from utilities or other power purchasers. Similarly, utilities need to meter the energy they receive from DR generators. Depending on the purchase agreement or tariff, the meter may need to monitor one or more of the following: net, gross, and load real and reactive power—and all at different times of the day. Collection may occur in 15 min integrated intervals to compute the energy delivered or generated (depending on the agreement). The frequency of data collection affects data memory capacity requirements, which, in turn, affect the cost of the metering device. These quantities are revenue data, and they are usually available from revenue meters. The newest revenue meters have the ability to monitor analog quantities. However, this revenue metering may be sited at a location other than the PCC because of contractual requirements.

In addition to hardware, the metering and monitoring system typically requires software and communications media. Software at the meter time-stamps the data and designates its quality. Based on the data-quality codes, the software processes the data and computes the appropriate parameters (e.g., maximum demand at peak, shoulder, off-peak periods) and corresponding designations for the results. Meters also may have communications interfaces with a central computer that allow metered data to be remotely retrieved and processed.

Using metered data, monitoring systems allow DR operators to control unit performance. Many vendor products monitor all major parameters for DR operations. These offerings often include the functionality of utility-grade metering and the ability to trend data for display. Typical software monitoring includes measure and control of DR operation parameters, measure and control of area EPS operation parameters, alarms that indicate when parameters exceed predetermined levels, event histories, reports that summarize incident data, pre-planned DR operation schedules, and real-time trends.

See IEEE Std 1547.3-2007 for a detailed description of equipment for metering and monitoring the interconnection system

A.1.4 Electrical protection

Protection requirements in IEEE Std 1547-2003 are directed toward protection of the area EPS so that power quality is maintained to all users, area EPS equipment is not damaged by DR, and line crews are protected from unnecessary hazard. The standard does not include protection of DR equipment or distribution systems, but protection may be necessary for compliance with other codes and standards and to protect financial investments in DR systems.

IEEE Std 1547-2003 requires several types of protection, as follows:

- The interconnection system must include protection that prevents energization of the area EPS when it is de-energized.
- The interconnection system must be able to detect faults in the area EPS and isolate the DR. Although the requirement in the standard is absolute in its wording, it is recognized that it is possible to have faults of various types that do not cause significant variation in the current flow, voltage, or frequency sensed at the PCC. As a practical matter, if a fault is too distant from the PCC or too minor to be sensed reliably at the PCC, there is no technical reason to isolate the DR.
- The interconnection system must be coordinated with any recloser in the area EPS that may isolate the feeder that connects the DR with the area EPS. Failure to coordinate can result in damage to equipment on the area EPS and hazards to work crews. There is also a high probability of damage to the DR if coordination with reclosers is not provided, but protection of the DR is not required by the standard. Coordination will generally require the DR system designer to coordinate the interconnection design with the area EPS operator. Because recloser operation may not be reliably sensed at the PCC in all cases, and if recloser operation times are relatively fast, transfer trip or other means may need to be added to the area EPS to achieve coordination. Coordination may also be achieved by extending the operating time of the recloser. However, this directly affects the reliability of service to other users on the feeder, so it may not be a good choice, even though it may be the lowest cost means to achieve coordination.
- The primary means for detecting faults and other disturbances on a line, including those caused by a DR, is through overvoltage and undervoltage protection and overfrequency and underfrequency

detection. The operation times intend to quickly isolate the DR under severe conditions but allow longer operation when conditions are less severe so that unnecessary disconnection is avoided when reasonable. The standard delineates settings for frequency trip that depend on the size of the DR. The rationale is that smaller systems will not be particularly useful in supporting the area EPS in the event of a temporary overload of the area EPS, but larger systems may have underfrequency settings adjusted to allow DR to support the area EPS for a short time to prevent a more general failure. Note that the default settings for this protection are the faster and higher frequency set points, so adjusting for support of the area EPS should be done only with consultation and agreement with the area EPS operator.

— DR are required to isolate from the area EPS to prevent a sustained island condition. Many means, depending on the nature of the DR equipment and controls, may be used to achieve this goal. Note that when the interconnection system and DR controls are designed to always import power at the PCC, reverse power alone (relative to the area EPS) can be used to provide protection.

— A readily accessible, visible-break isolation device is required by many area EPS and local codes. Readily accessible means that the isolation device is accessible to the area EPS operator at any time and can easily be located. It is often at the service entrance to a facility, but it can be elsewhere. The isolation device for a DR is often, but is not required to be, a visible-break disconnect switch. Other devices that can be used include drawout carriages for circuit breakers when that device meets all other requirements for an isolation means. If the isolation device is not located at the service entrance, many local codes, including the NEC [B57], require that a plaque be placed there to clearly identify the location of the DR isolation device. The visible-break requirement allows a lineman to be absolutely sure that all the live phases of the system are isolated. Overloads or short-circuits at a device can result in welded contacts that may be energized even when the mechanical switch or flags that indicate position show that a device is open. Finally, in emergency situations, it is not uncommon for poor communication between workers to result in closure of a device and energization of a circuit that is still under service. The lockout provision provides a means for multiple specific workers to prevent closure of a device until they remove their personal lockout protection.

When DR are integrated into the local EPS, it is important to provide sufficient protection for the area EPS and the DR. Area EPS operators are concerned about the dynamic security and integrity of the EPS and the safety of line crews that might work on lines with which the DR units are interconnected. The DR owner needs to protect the DR unit and ensure synchronization with the grid. Because of this, in any installation, protective devices are likely to be installed for purposes beyond the requirements of IEEE Std 1547-2003. Other protective functions for the area EPS may be provided because of the particular needs of a specific site.

Many area EPS operators require point-of-contact protection for high-voltage (primary) customers. This can be as simple as a set of high-voltage fuses or as complicated as a set of directional overcurrent relays that operate as circuit breakers. The purpose is to protect the area EPS from a fault on the customer facilities when the facilities are operating as a load.

A good reference for further information about protection is IEEE Std 242™-1991 (*IEEE Buff Book™*) [B24], which provides guidance on the selection of protective functions for many types of equipment and situations.

Relays normally provide protection at the area EPS and DR ends of the connection. Protective relaying devices interpret input conditions (which reflect the operation of another piece of equipment) in a prescribed manner and, after specified conditions are met, respond by controlling the DR to protect an electrical circuit. Relays ensure that DR equipment operates normally and ceases to energize the area EPS during faults or other abnormal conditions. Protective relays may be electromechanical, solid-state, or multifunction. In some cases, protective functions may be integrated with the DR control or system controls. In the case of inverters, these protective functions are often built into the controlling software of the inverter.

Protective relays typical in a DR interconnection system are shown in Table A.1. Depending on the size of the DR unit and the number of phases, some or all of these protective relays might be needed.

Table A.1—Relay functions

Function and IEEE standard device number	Description
Sync-check (25)	Synchronizing or synchronism-check relay. A synchronizing device that produces an output that causes closure at zero phase angle difference between two circuits. It may or may not include voltage and speed control. A sync-check relay permits the paralleling of two circuits that are within prescribed limits of voltage magnitude, phase angle, and frequency.
Under/overvoltage (27/59)	A device that operates when its input voltage is less than a predetermined value (27). A device that operates when its input voltage exceeds a predetermined value (59).
Directional power (32)	A device that operates on a predetermined value of power flow in a given direction.
Negative phase sequence current (46)	A device in a polyphase circuit that functions upon a predetermined value of polyphase current in the desired phase sequence, when the negative phase-sequence current exceeds a preset value.
Negative phase sequence voltage (47)	A device in a polyphase circuit that functions upon a predetermined value of polyphase voltage in the desired phase sequence, when the negative phase-sequence voltage exceeds a preset value.
Neutral under/overvoltage (27G/59G)	A device, installed to specifically detect the voltage on the neutral of a three-phase system relative to system ground, that operates when its input voltage is less than a predetermined value (27). A device that operates when its input voltage exceeds a predetermined value (59).
Directional overcurrent (67)	A device that functions at a desired value of ac overcurrent flowing in a pre-determined direction.
Instantaneous phase overcurrent (50)	A device that operates with no intentional or coordinated time delay when the current exceeds a preset value.
Neutral overcurrent (50/51 N)	A device that operates with coordinated time delay when the current exceeds a preset value.
Phase overcurrent (51)	A device that functions when the ac input current exceeds a predetermined value and in which the input current and operating time are inversely related through a substantial portion of the performance range.
Undercurrent or under power (37)	A device that functions when the current or power flow decreases below a predetermined value.
Voltage-restrained overcurrent (51V)	An overcurrent relay that changes its sensitivity based on varying voltage levels.
Under/overfrequency (81 U/O)	A device that responds to the frequency of an electrical quantity and operates when the frequency exceeds or is less than a predetermined value.
Transformer differential (87T)	A device that operates on a percentage, phase angle, or other quantitative difference of two or more currents or other electric quantities.

Source: IEEE Std C37.2™-1996 [B41].

A.1.5 Distributed resource control

DR control modules provide the person-machine interface, a communication interface, power management, synchronizing, and monitoring and metering. The DR control module performs functions that affect the on/off operations and the voltage, frequency, and power output of the generator. For example, if the prime mover is based on combustion, once the generator is paralleled, the control module regulates voltage and frequency by controlling excitation and fuel rate and maintains its power output while paralleled by regulating fuel flow and excitation. Other technologies (e.g., wind turbines and PV) may have variable output that has to be controlled.

Controls may be analog or digital. However, because a digital controller is electronic in nature, it allows the DR control module to exchange signals with other systems (e.g., power management software) for coordinated control.

It is important that the DR control module be able to coordinate operation with the power management functions so that the latter can regulate the operations of the DR to coordinate with other DR units and the grid. This is often accommodated via electronic control of the governor and voltage regulator.

In DR systems made by vertically integrated companies, various system controls may provide the core system technology for DR controls, automatic transfer switch controls, and remote monitoring software. Such microprocessor-based system controls are normally designed to meet national and international certification standards.

A.1.6 Power conversion and conditioning

A power conversion subsystem accepts power from the DR generator (or non-rotating prime mover) and converts it to clean ac power at the required voltage. If the electric generator (or non-rotating prime mover) supplies dc power or very high-frequency ac power, an inverter is required (to convert the supplied power into suitable ac power). If the electric generator supplies 60 Hz ac power, a transformer may be required (to convert ac power from one voltage to another or to provide isolation).

Inverters convert power from a variety of DR voltages. Inverters can produce one- or three-phase ac power. Some units provide automatic, built-in overload and short-circuit protection. Numerous manufacturers provide inverters that are suitable for interconnecting DR units with the grid at the proper ac voltage. Inverter-based interconnection systems can also provide hardware- and software-based functions such as protection, voltage regulation, and reactive power supply. More information about inverters is available in Clause 5 and Annex C.

Transformers are static electric devices that consist of a winding (or windings) that transfers power by electromagnetic induction between circuits, usually with changed voltage and current but at the same frequency.

An isolation transformer may contain an electrostatic shield between the primary and secondary windings to reduce unwanted electrical noise. For DR, isolation transformation is used to isolate the generation from the area EPS for grounding, load balance, or harmonic reasons.

A.1.7 Dispatch, communication, and control

This group includes devices and communication equipment that interface with the DR and manage it. Somewhat different equipment is needed for dispatch, communication, and control. Some of this equipment is located on or near the DR unit; the rest is located at the dispatch center. See IEEE Std 1547.3-2007 for more information about the issues related to monitoring, information exchange, and control.

System dispatchers are responsible for operating the area EPS such that sufficient resources are available to serve the connected load and all loads connected to the area EPS are served with acceptable voltages. To accomplish this, the dispatchers often require specific information from the DR units.

Integrating DR into the area EPS creates special challenges for system dispatchers because the DR units are usually geographically dispersed. A major challenge is the proper representation of the many DR units as resources in the application software of the energy management system/SCADA area EPS control system. The energy management/SCADA system for the area EPS can be closely integrated with the distribution management system to monitor and control DR units located at the distribution and subtransmission levels. The distribution management system can include equipment to perform myriad functions such as meter reading, regional load management, distribution automation, feeder switching, short-circuit analysis, voltage profile calculation, trouble call management, work order management, and billing services and can interface with the customer information system, billing system, and energy information network. If the area EPS is in a deregulated state, then the local dispatcher will likely be interested only in instantaneous analog quantities and bidirectional kilowatthours. Control, dispatch, and area regulation will generally be handled by others—possibly the regional transmission organization or independent system operator (ISO).

Under certain conditions, the interconnected DR system may need to have the ability to communicate with the control center and have remote control and monitoring capability so the area EPS dispatch center knows the status of the DR and what to control at various times.

The geographical dispersion of DR units also presents a challenge for the communication system. It is important that the communication system be able to link economically with DR units across the service territory. The closer a unit is located to the existing communications backbone, the lower the cost of the link will be. The most economical communications medium varies with the location of the DR. However, the telephone system may be the logical choice for most installations because telephony has fully penetrated all service territories. Point-to-point radio technologies (e.g., multiple-address radio in the 900 MHz range) may be another good option. Increasingly, interconnection systems use Web-based communication. In some cases, more than one medium may be used for communication with the DR.

Web-based communication opens the area EPS to additional requirements of critical infrastructure protection. Meeting these requirements may require a substantial investment in firewalls, security software, virtual private network software, and secure SCADA remote terminal unit equipment as well as in the support and maintenance of this equipment. The area EPS will ensure the existing SCADA system meets critical infrastructure protection requirements. However, as currently defined, critical infrastructure protection will virtually eliminate the use of modems—and the Internet—without all of the abovementioned security equipment.

Because of the myriad sensors and controllers involved in dispatch, communication, and control systems, a large number of vendors develop this equipment. Most DR manufacturers also build their own control systems for working with dispatch centers. This means a variety of communication protocols are in use, and the compatibility of communication protocols is an issue. Aggravating this situation, only a handful of protocols are normally implemented in manufacturers' equipment.

There are several approaches to the implementation of SCADA, as follows:

- The area EPS installs suitable equipment for the new protocol.

  This requires the area EPS to install sufficient equipment to implement the newer protocols and communication methods. This may include the Internet, which provides a low-cost communication medium but has security concerns. The equipment installed at the area EPS needs to provide all of the necessary security and isolation to keep hackers and other security threats out of the area EPS SCADA system. The equipment at the DR will also need suitable security against hackers while allowing access to the area EPS equipment.

- The DR owner installs equipment that will interface with the existing area EPS distribution management system SCADA system.

  The area EPS provides suitable information to allow the DR owner to purchase and install the equivalent of an area EPS SCADA. This equipment will interface with the area EPS SCADA system like a normal SCADA remote terminal unit and use the normal communication interface. It will provide all of the required functions to the area EPS, and the protocols will be the same as those of the area EPS.

- The ISO provides suitable SCADA equipment and the interface to the area EPS.

  At least one ISO has provided a means to collect the typically required data for DR facilities. In this approach, the ISO provides the required Internet-related security equipment, a virtual private network tunnel to the DR, and the encryption key for each DR facility. This implementation is based on commercially available PC104 equipment. The ISO arranged with the equipment vendor to provide the necessary software for communicating securely with the ISO. The ISO has existing data links with all of the area EPS. The result is a low-cost, Internet-based SCADA communications system.

However, the ISO may not be set up to actually control devices. For example, in the ISO arrangement, the area EPS may complete the actual control functions based on directions received from the ISO. In this case, the area EPS may have to install additional equipment to provide control of DR facilities. Once again, commercially available contact-over-Ethernet devices use the Internet to transfer the position of one or more contacts between the DR and the area EPS. The area EPS provides an Internet connection and, typically, a dry contact interface to an existing area EPS SCADA. This arrangement has several advantages: (1) It is low cost, (2) it is isolated from the area EPS by dry contacts and therefore not subject to critical infrastructure protection requirements, and (3) it is relatively fast (typically less than 1 s to 5 s). There is some exposure to the DR if a hacker were to access this equipment, but current implementations use 128-bit Advanced Encryption Standard (AES) encryption, which is very secure.

A.2 Distributed resource applications

DR applications are interconnected with the area EPS for a reason: The local EPS wants to use both the DR and the area EPS. The area EPS operator and the DR owner can receive benefits from the DR, but they must be satisfied the interconnection is safe and does not unduly affect local and area EPS reliability or power quality.

The complexity of the interconnection will depend on the level of interaction desired among the DR, the local EPS loads, the area EPS, and the related stakeholders. For example, IEEE Std 1547.3-2007 "provides methodologies for establishing monitoring, information exchange, and control for DR interconnected with the area EPS for DR applications, along with example applications such as remote dispatching." The IEEE Std 1547.3-2007 "use case" methodology presented therein provides an example of how to establish the functionalities beyond IEEE Std 1547-2003 that participating stakeholders may desire. As an example a DR application that is planned and designed to be remotely dispatchable adds an additional level of complexity. If a DR application is designed to be remotely dispatchable, then communication equipment and metering and monitoring beyond that required by IEEE Std 1547-2003 will likely be mandated to facilitate the dispatching of the DR, to control the DR output as scheduled by the dispatching entity, to meter the DR energy and capacity participation, and to monitor the DR output to provide the dispatching entity the necessary information to integrate the DR with other dispatchable sources.

A DR can be interconnected with an area or local EPS in many arrangements. For example, the DR may provide cogeneration (combined heat and power), or it may provide prime, peak-shaving, emergency, backup, premium, or remote power. Unfortunately, there are no standard definitions or applications for these types of power. The terms may have different meanings to different people. For example, a peak-shaving system can operate in parallel to reduce load, or it can be isolated and the load transferred to the generation to reduce load. The effect of reducing load is the same; however, only in the first case is the generation paralleled with the area EPS.

Today, many owners of emergency and backup generation are considering interconnecting their DR units with the area EPS. However, the use of generation designated as emergency (or possibly backup if it is used for safety) for other purposes (e.g., peak-shaving) must be reviewed according to the NEC [B57] or local AHJ. There may also be air quality permit issues. Many emergency and backup generation sources may be limited to 200 or fewer hours of operation each year. Operation as a peak-shaving installation may exceed this limit.

A.3 Example interconnection and EPSs

A.3.1 Example interconnection systems (including special configurations)

A functional block diagram of an interconnection system is shown in Figure A.1.

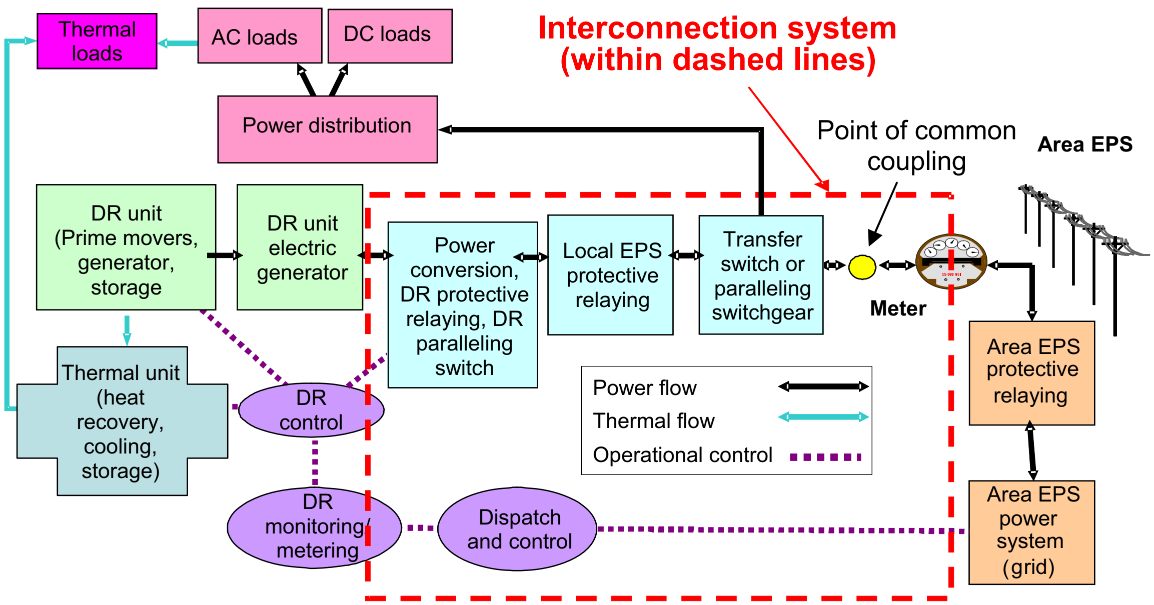


Figure A.1—Functional diagram of an interconnection system

The following questions can differentiate DR interconnection systems:

— Does the system use an inverter?

— Does the system have a parallel connection to the area EPS?

— Can the system export power to the area EPS?

— Is the system remotely dispatchable?

— What is the capacity of the system?

Some observations follow based on the answers to these questions.

— Inverter-based systems are used in fuel cell, PV, wind turbine, and microturbine applications. Fuel cells and PV systems generate dc power, and the inverter converts the dc power to ac power. Most microturbines generate very high-frequency ac power. This is converted to dc and then to 50 Hz or 60 Hz ac. Inverter-based systems designed for parallel operation with the area EPS have built-in protective relay functions and perform the basic requirements of the interconnection system.

— Systems that run in parallel with the area EPS have an interconnection system that connects the DR and the area EPS to the same common bus in synchronization. These systems are used for DR applications such as peak-shaving, prime power, cogeneration, and some emergency/standby power.

- Exporting power to the area EPS requires an interconnection system that parallels with the area EPS and has adequate protective relays to ensure both systems can run together safely.
- Interconnection systems can be configured to be remotely dispatchable so that area EPS operators can start and stop operation of the DR remotely on a real-time basis. This requires additional metering, monitoring, control equipment, and communications.

The DR application served or the type of DR technology used can also classify interconnection systems. An interconnection system for emergency power is designed and configured differently from a premium power installation even if, for example, both use reciprocating engines. For a peak-shaving application, the interconnection system for a reciprocating engine would be configured differently than for a microturbine.

The following diagrams show six common types of DR applications that require interconnection systems:

- A reciprocating engine/combustion turbine used for emergency/backup power
- A reciprocating engine/combustion turbine used for premium power
- A reciprocating engine/combustion turbine used for backup and as a dispatchable peaker
- A microturbine used for prime power, as a peaking unit, for backup, or for power export
- A small PV system with net metering
- A fuel cell used for prime power

NOTE—The diagram shown for each system type is a representative functional diagram. Other system arrangements are possible.

A.3.1.1 Reciprocating engine or combustion with generator

This first configuration, shown in Figure A.2, is the most common type of DR interconnection system. In cases of a failure (i.e., of the area EPS), an automatic transfer switch breaks the connection with the area EPS and then makes the connection with the DR. There is a momentary outage in the local EPS during the transfer.

NOTE—This guide does not apply to automatic transfer schemes in which the load is transferred between the DR and the area EPS in a momentary make-before-break operation provided the duration of paralleling the sources is less than 100 ms.

The second interconnection system, illustrated in Figure A.3, is used to provide premium power, which is free of power-quality problems such as frequency variations, voltage transients, dips, and surges. Power of this quality is not available directly from the area EPS. It requires auxiliary power-conditioning equipment (including uninterruptible power supplies) and emergency or standby power. A transfer switch or paralleling switchgear is required.

Some interconnection equipment manufacturers have designed systems in which backup systems can be converted to allow them to be dispatchable. These systems, as shown in Figure A.4, allow the DR owner or the area EPS operator to run the unit on demand. Currently, most dispatchable systems use a local area EPS remote terminal unit to communicate to the DR. Typically, a dry set of contacts is used to initiate system transfers to the DR. The DR could be operated to assume all facility load or to assume facility load and export excess power back to the utility.

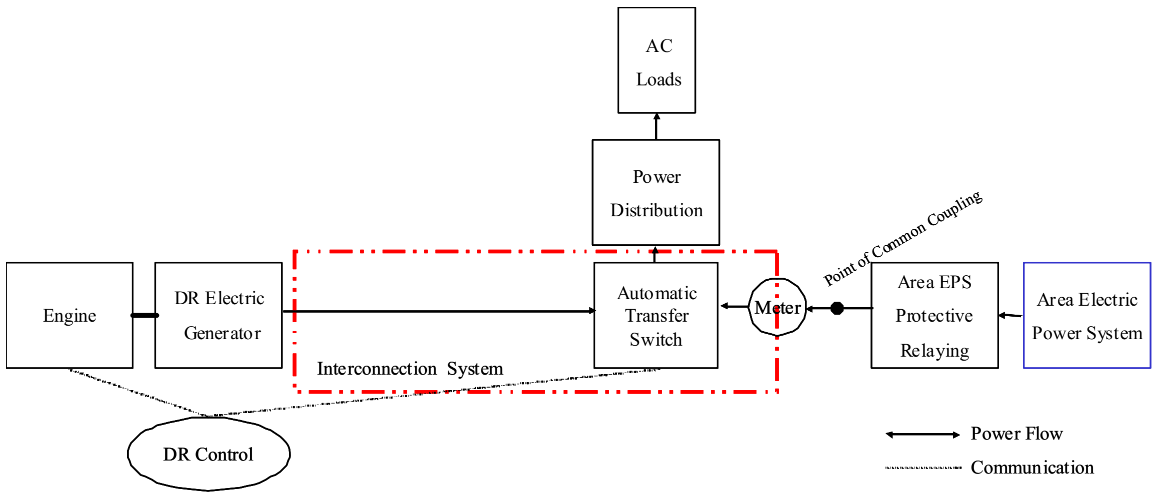


Figure A.2—Reciprocating engine/combustion turbine used for emergency/backup power

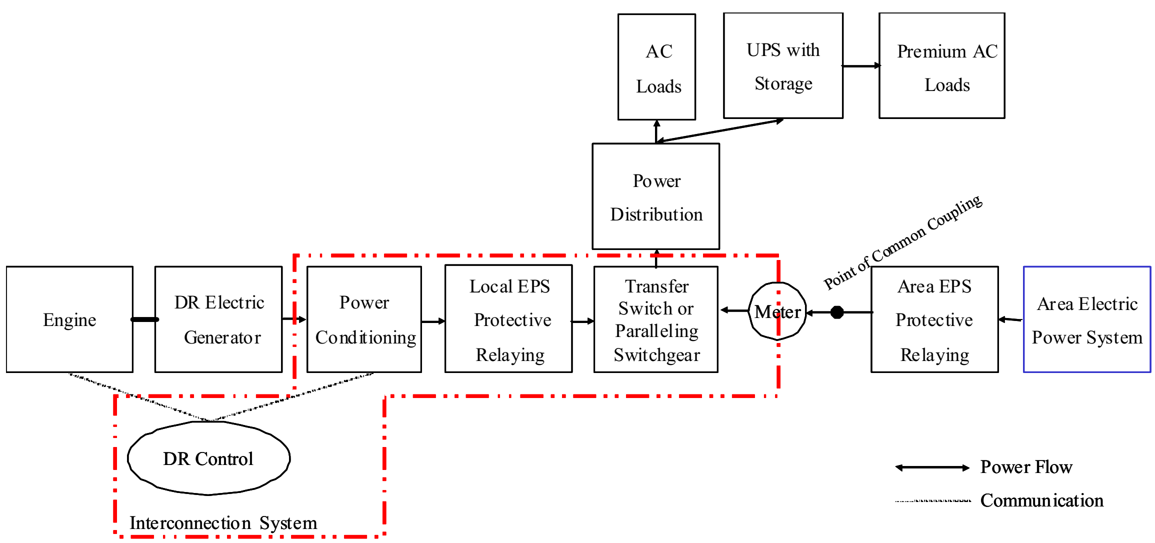


Figure A.3—Reciprocating engine/combustion turbine used for premium power

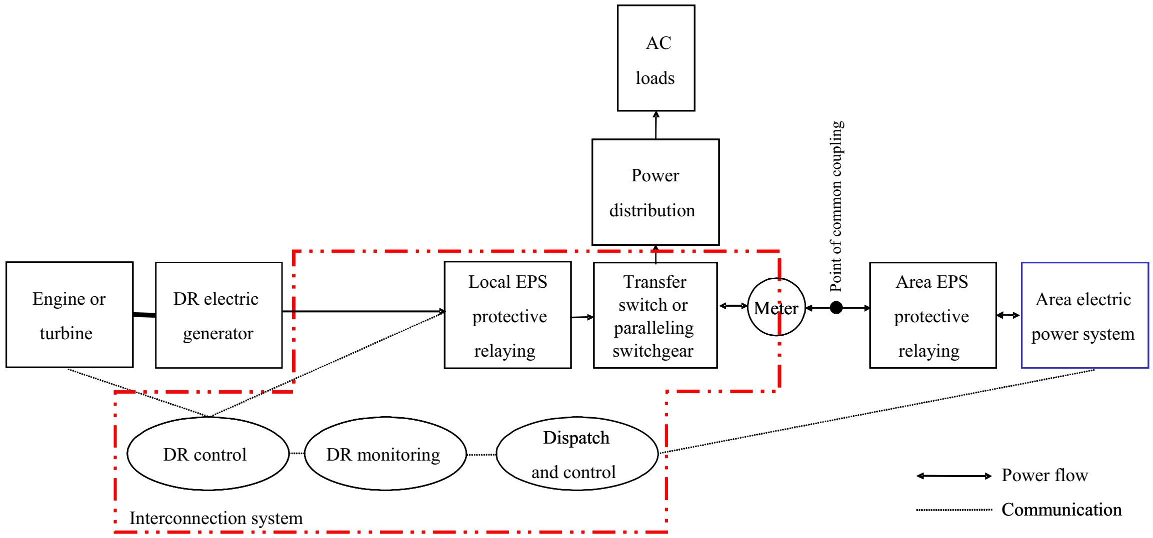


Figure A.4—Reciprocating engine/combustion turbine used as a dispatchable peaker

A.3.1.2 Microturbine with integrated generator and power conversion

Most microturbines use inverter-based interconnection systems (see Figure A.5). These units use software algorithms to provide functions such as protective relaying.

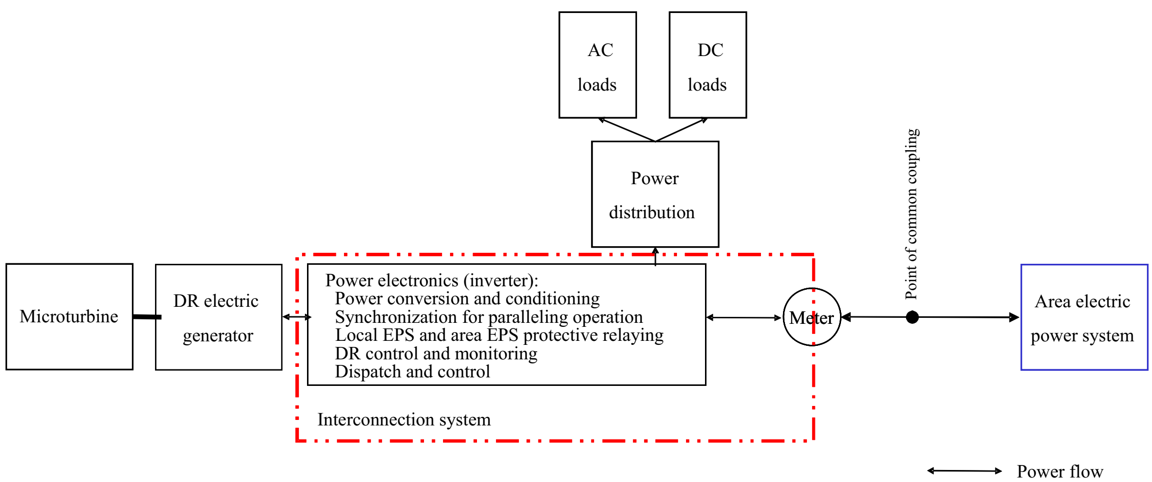


Figure A.5—Microturbine used for prime power, as a peaking unit, or for power export

A.3.1.3 Wind turbine with generator

Most larger wind turbines and multiple-wind turbine "wind farms" do not fit the definition of DR because they are directly connected to the transmission system via a dedicated substation or portion of a transmission substation. They are more like central-station power plants. Smaller wind turbines typically use inverters. Figure A.6 shows a wind turbine system with net metering.

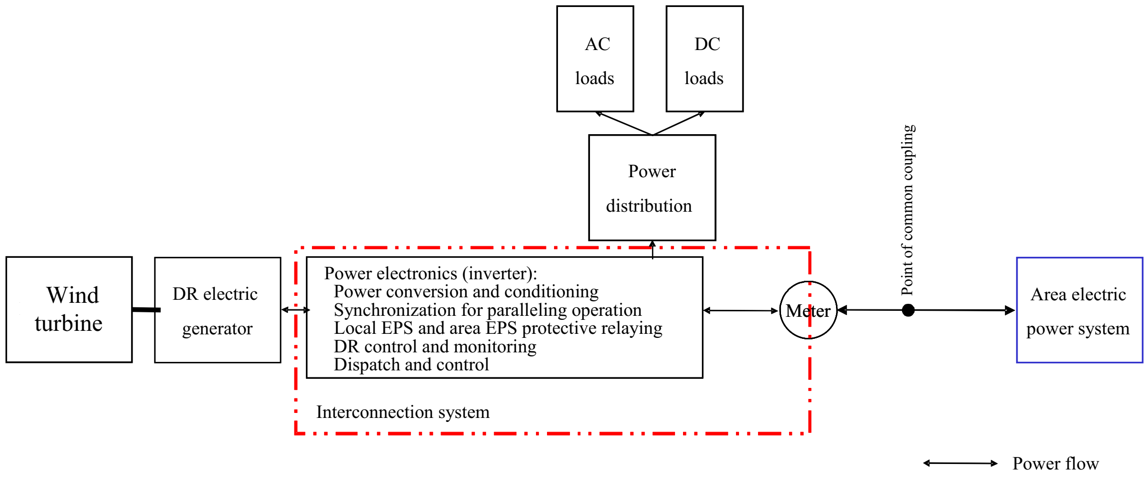


Figure A.6—Wind turbine system

A.3.1.4 PV system with inverter

Small PV systems use inverter-based interconnection systems, and some state public utility commissions require utilities to allow for net-metering systems (see Figure A.7).

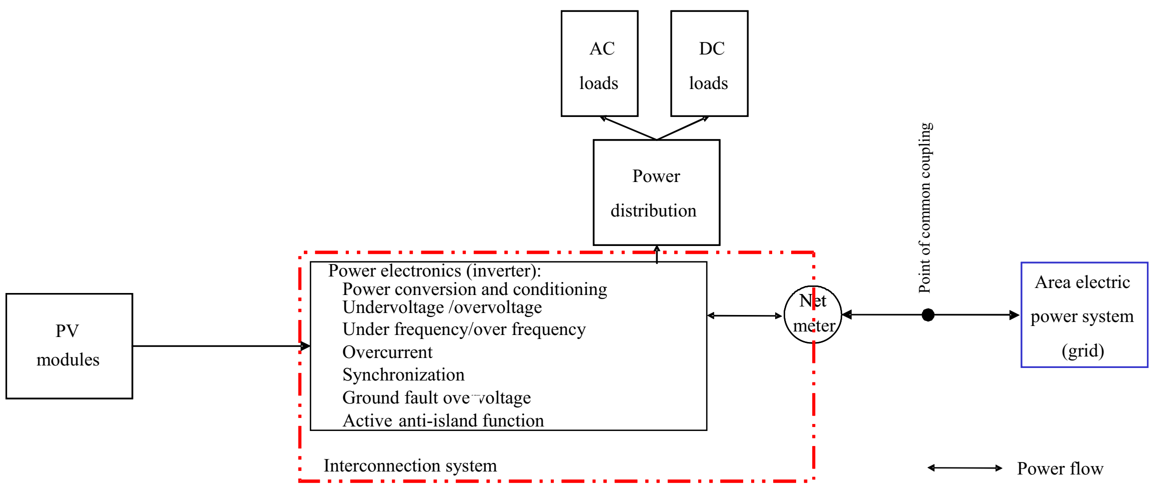


Figure A.7—Small PV system with net metering

A.3.1.5 Fuel cell with inverter

Most fuel cells are used to produce premium power and use inverter-based interconnection systems (see Figure A.8). These units use software algorithms to provide functions such as protective relaying.

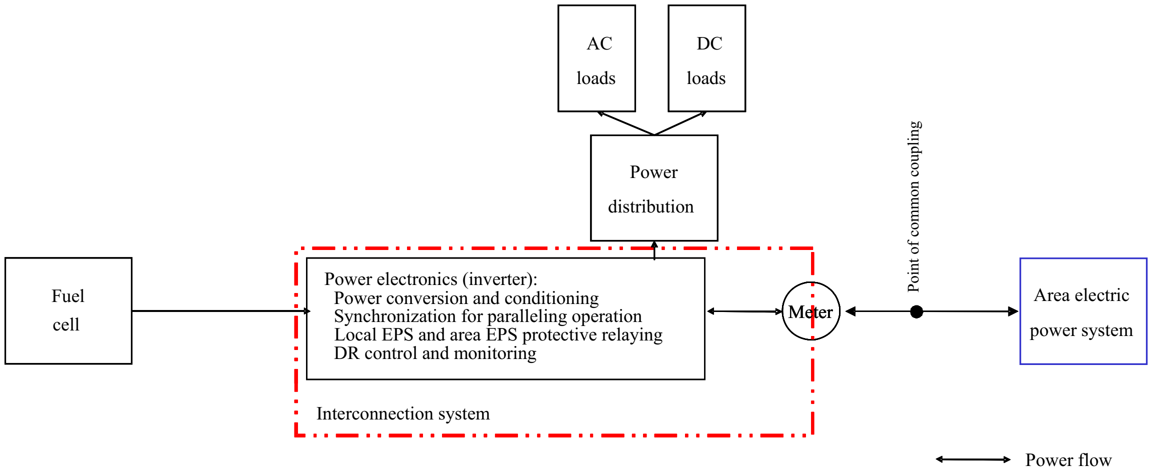


Figure A.8—Fuel cell used for prime power

A.3.2 Example one-line diagrams

The following are example one-line diagrams of interconnection systems.

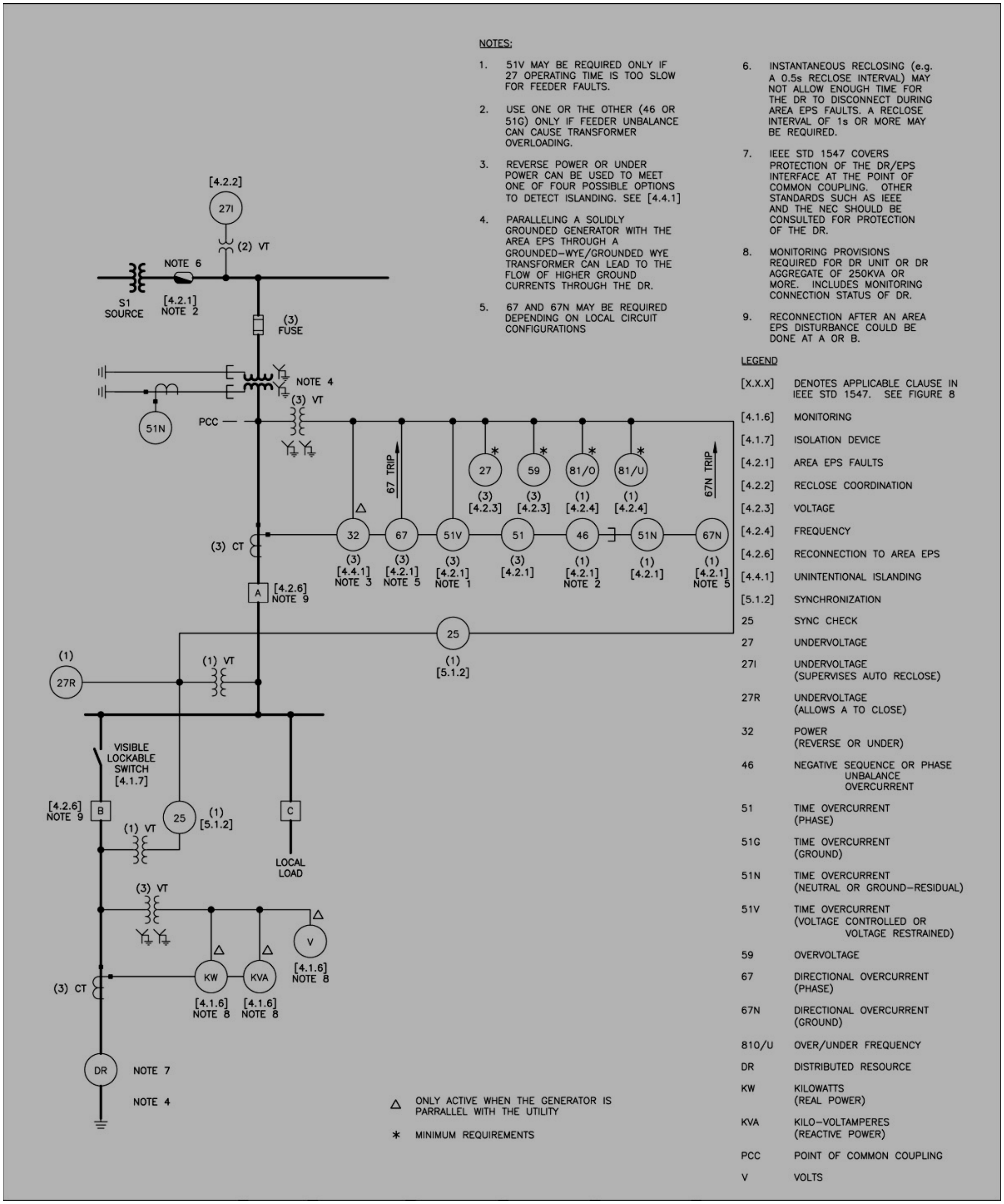


Figure A.9—Example protection for a synchronous generator interconnected through a wye-wye transformer

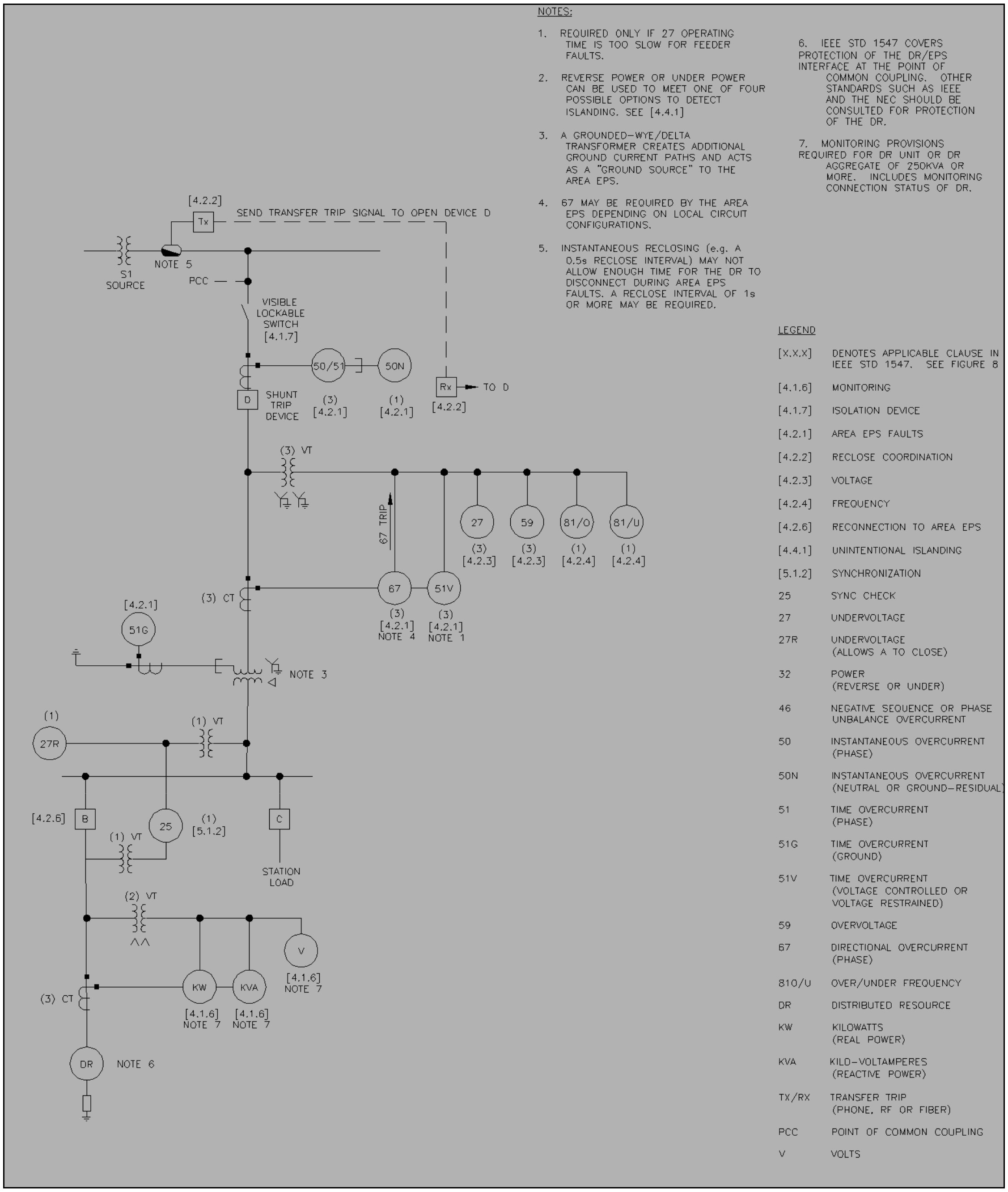


Figure A.10—Example protection for a synchronous generator interconnected through a wye-delta transformer typical export scheme

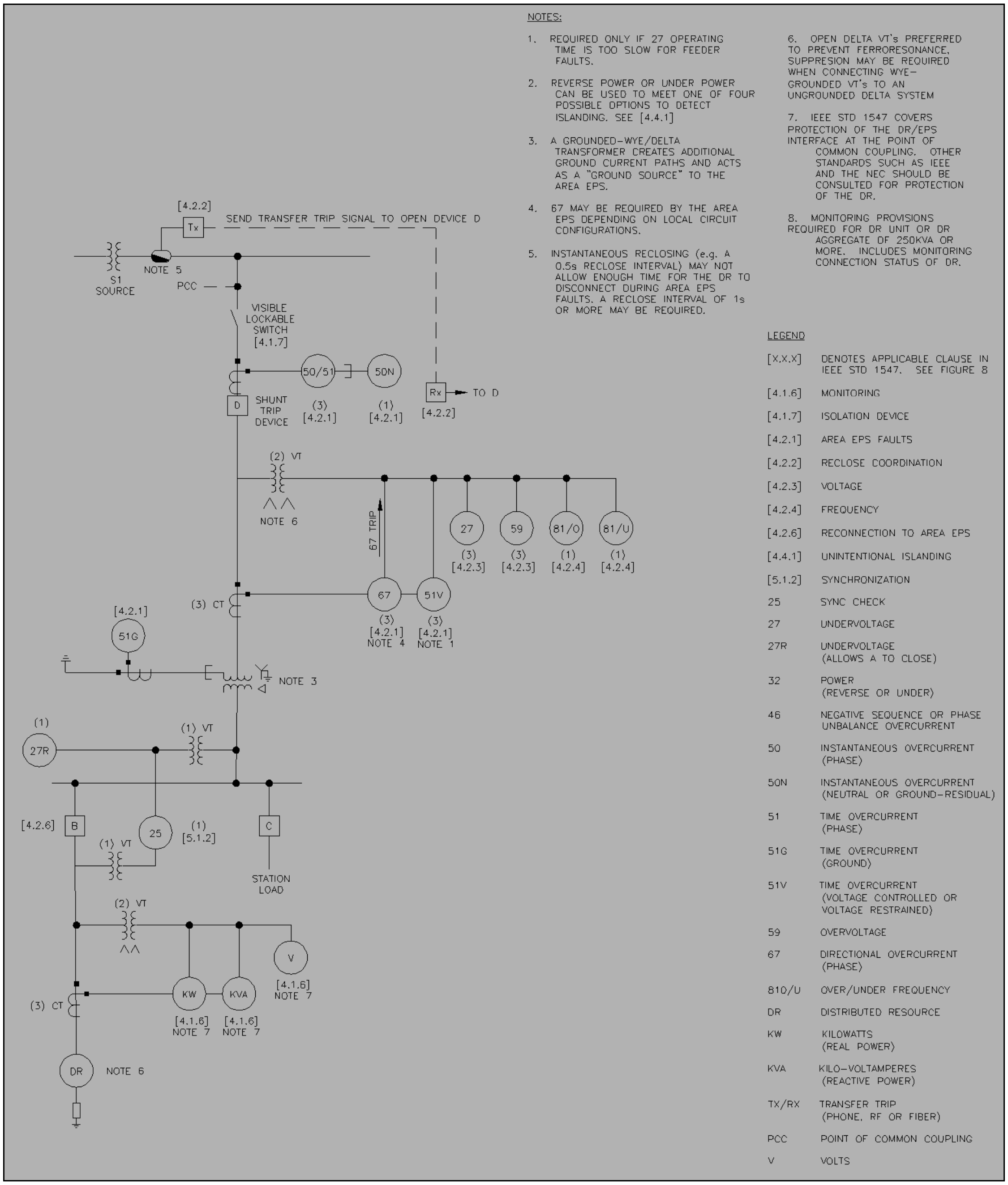


Figure A.11—Example protection for a synchronous generator interconnected through a wye-delta transformer alternate export scheme

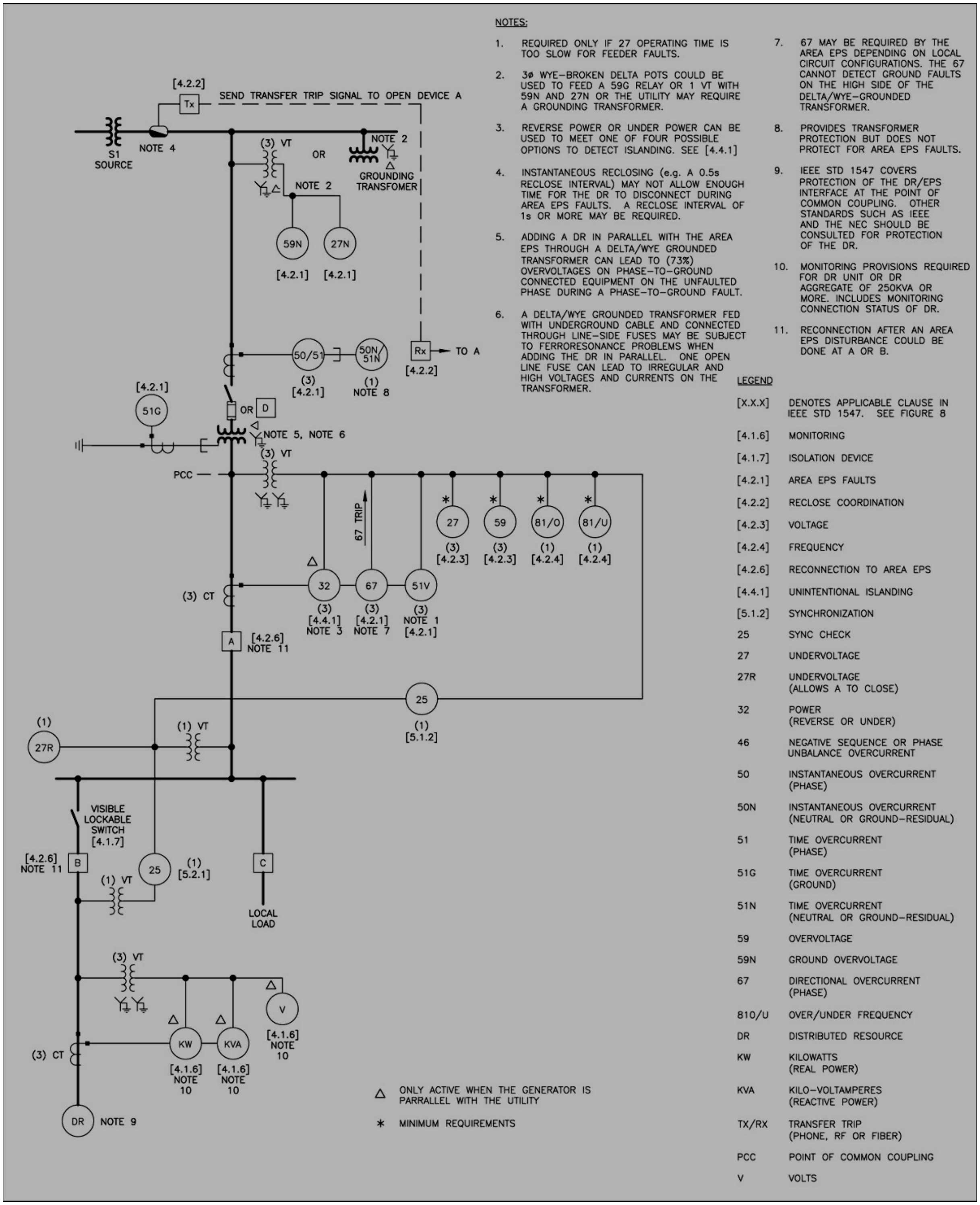


Figure A.12—Example protection for a synchronous generator interconnected through a delta-wye transformer

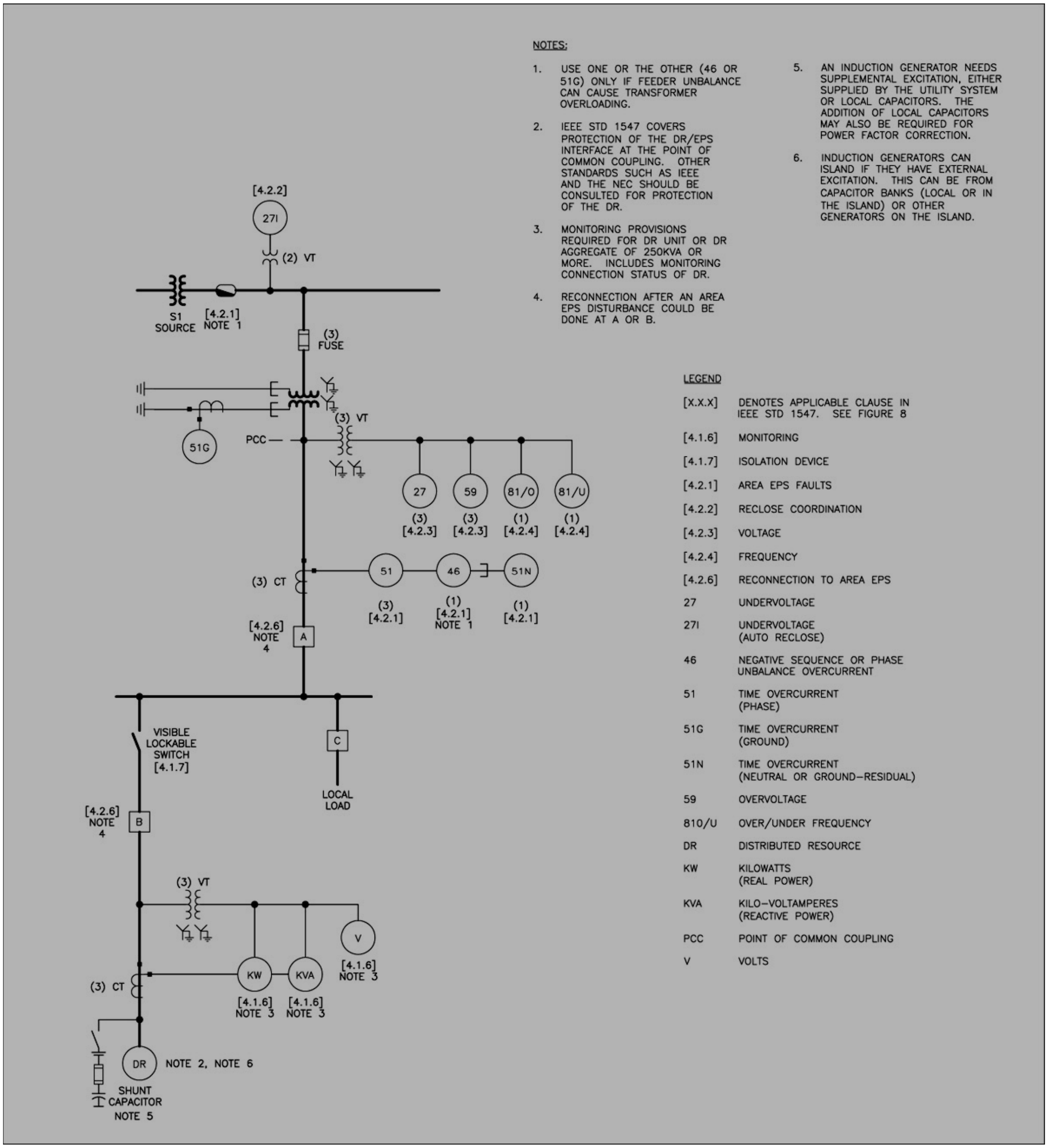


Figure A.13—Example protection for an induction generator interconnected through a wye-wye transformer exporting scheme

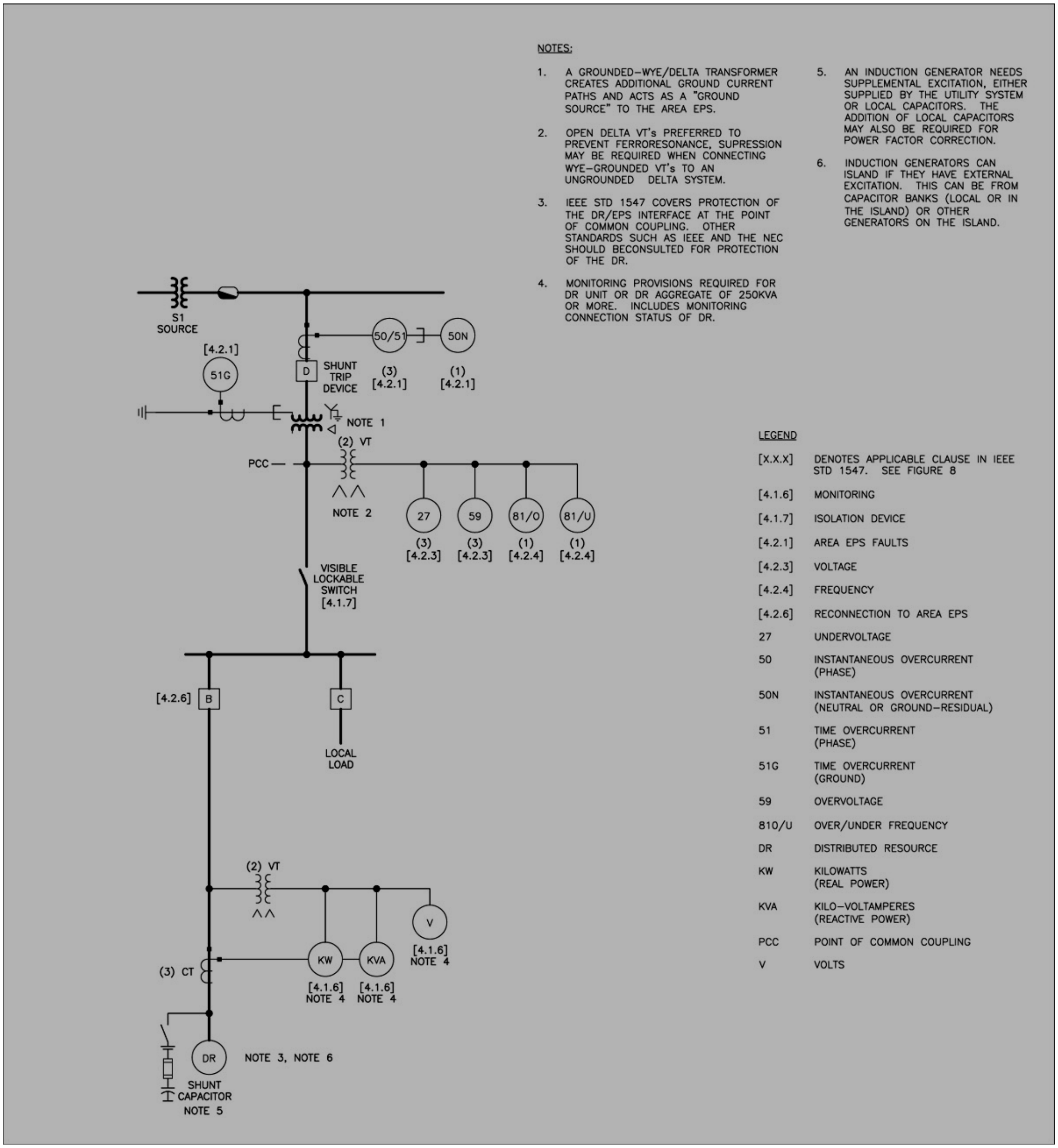


Figure A.14—Example protection for an induction generator interconnected through a wye-delta transformer

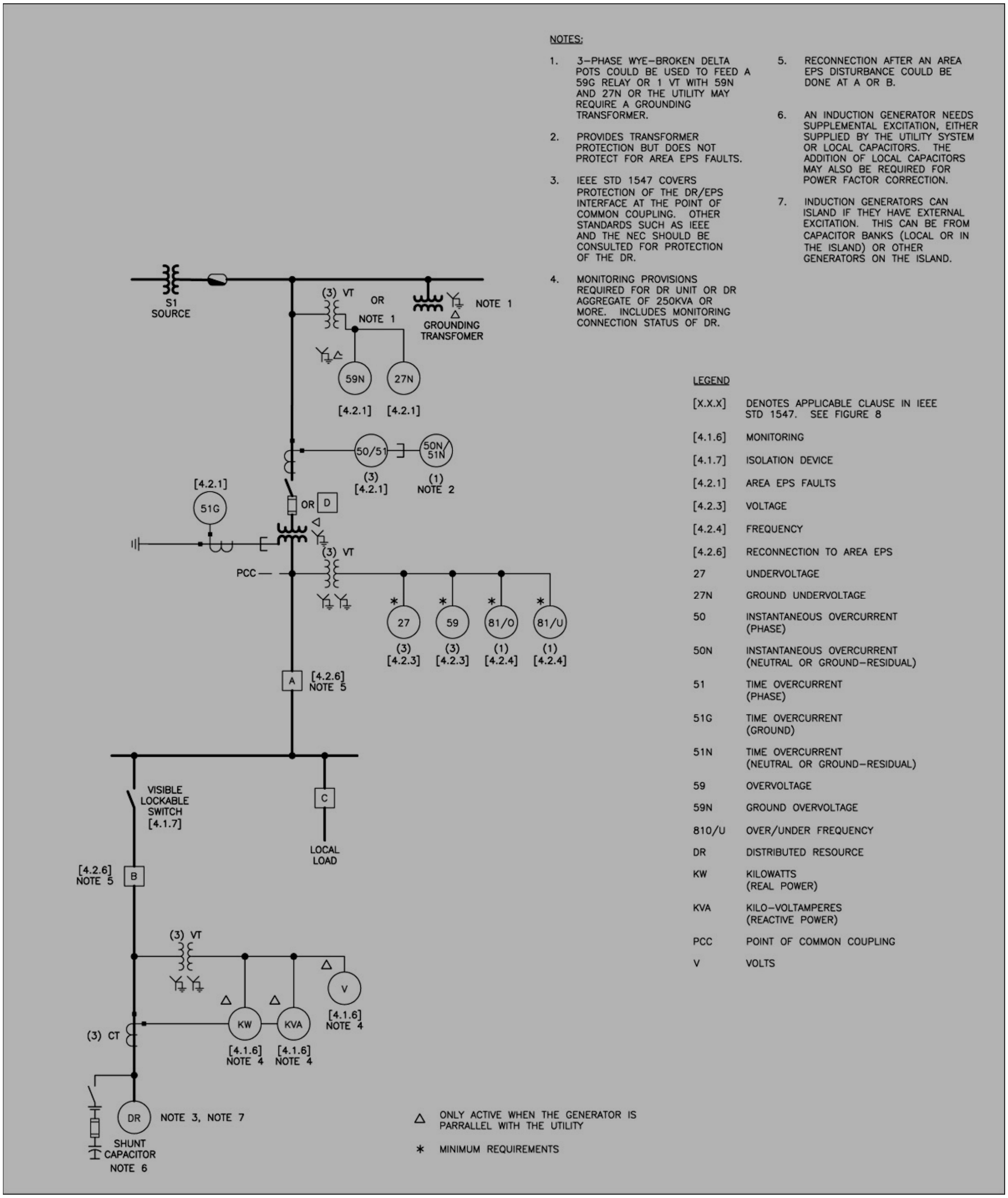


Figure A.15—Example protection for an induction generator interconnected through a delta-wye transformer

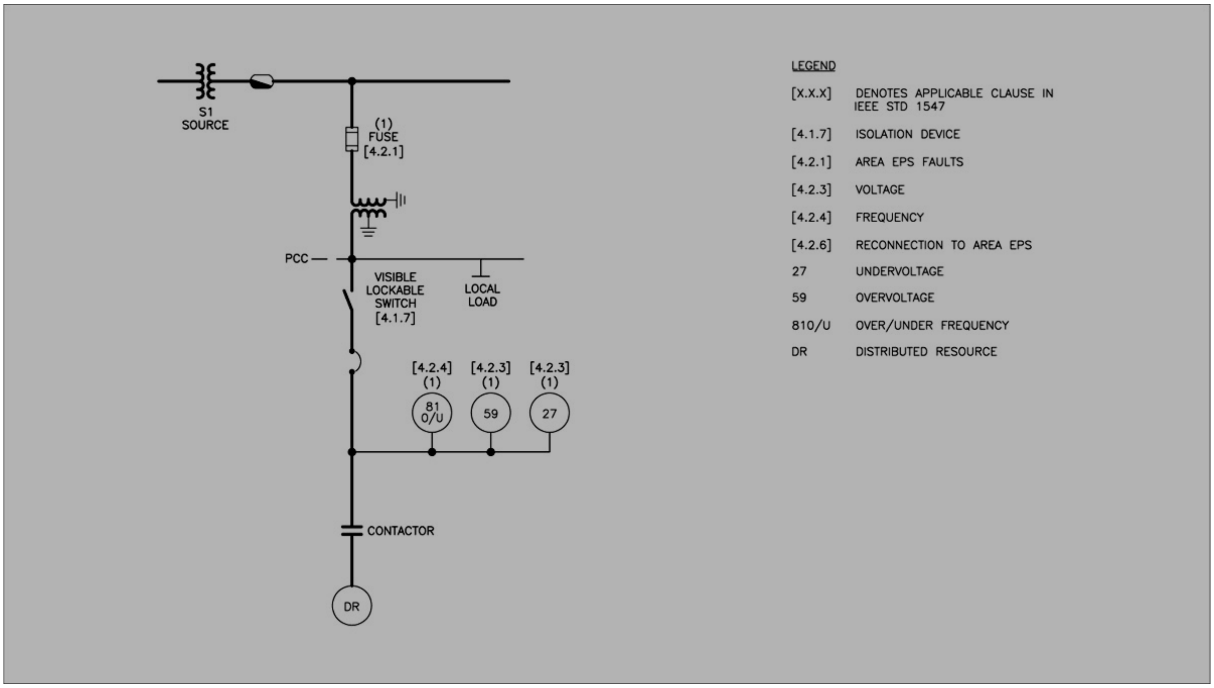


Figure A.16—Example protection for a single-phase generator

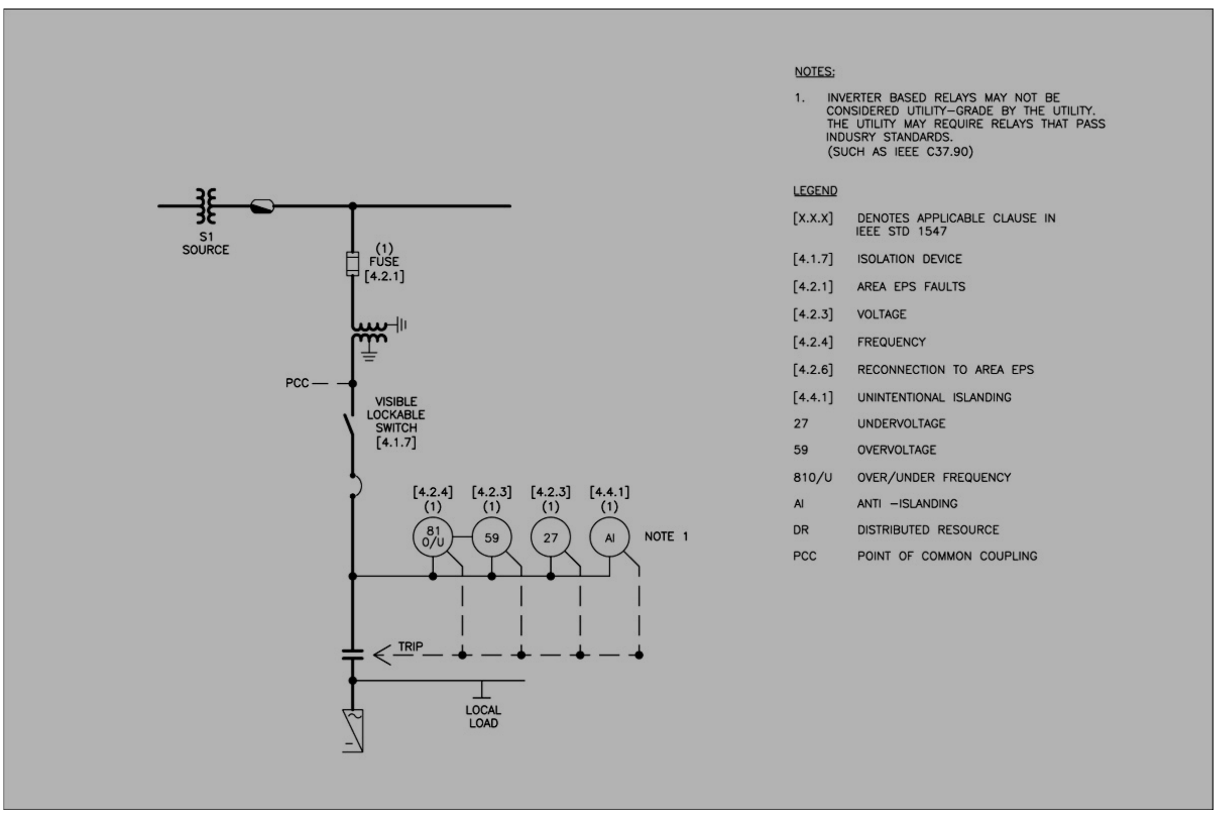


Figure A.17—Example protection for a single-phase inverter

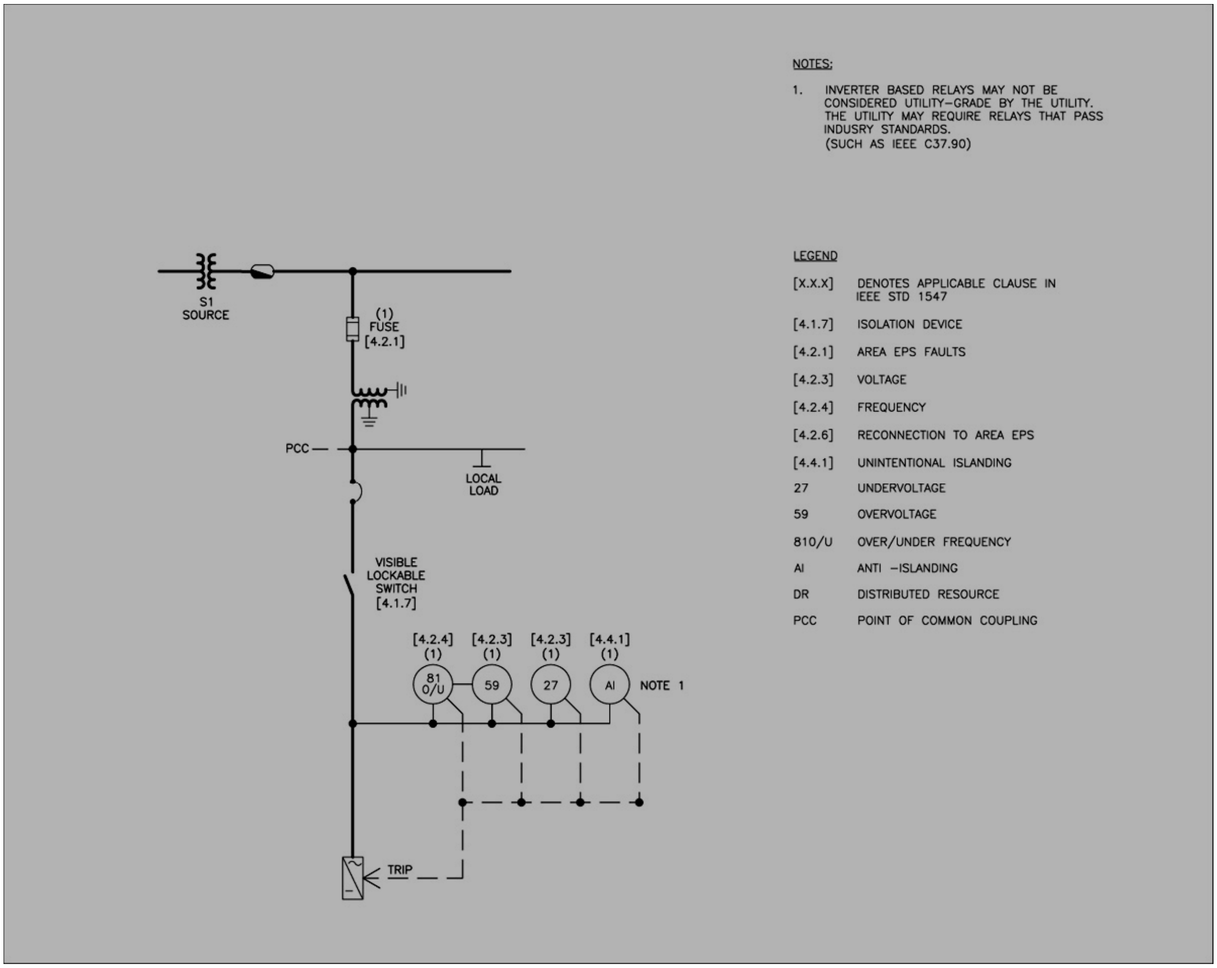


Figure A.18—Example protection for a single-phase inverter

CLAUSE BRIEF SUMMARY OF 1547 REQUIREMENT

[4.1.6] MONITORING –A DR UNIT (OR DR AGGREGATE) > 250KVA AT A SINGLE PCC SHALL HAVE PROVISIONS FOR MONITORING CONNECTION STATUS, KW, KVA & VOLTS.

[4.1.7] ISOLATION DEVICE – WHEN REQUIRED BY AREA EPS, A READILY ACCESSIBLE, LOCKABLE, VISIBLE–BREAK ISOLATION DEVICE SHALL BE LOCATED BETWEEN THE AREA EPS AND DR UNIT.

[4.2.1] AREA EPS FAULTS – THE DR SHALL CEASE TO ENERGIZE THE AREA EPS FOR FAULTS ON THE AREA EPS CIRCUIT TO WHICH IT IS CONNECTED.

[4.2.2] RECLOSE COORDINATION – THE DR SHALL CEASE TO ENERGIZE THE AREA EPS CIRCUIT PRIOR TO RECLOSURE BY THE AREA EPS.

[4.2.3] VOLTAGE –

27–1<50%	@ 0.16s	(9.6 CYC)
50%≤27–2<88%	@ 2s	(120 CYC)
110%<59–1<120%	@ 1s	(60 CYC)
59–2≥120%	@ 0.16s	(9.6 CYC)

(% OF BASE VOLTAGES ARE THE NOMINAL SYSTEM VOLTAGES STATED IN ANSI C84.1 TABLE 1)

[4.2.4] FREQUENCY – DR ≤ 30KW
810>60.5 Hz @ 0.16s (9.6 CYC)
81U>59.3 Hz @ 0.16s (9.6 CYC)

DR > 30KW
810>60.5 Hz @ 0.16s (9.6 CYC)
81U>59.8 Hz @ 0.16s TO 300s (9.6 TO 1800 CYC) ADJ.
81U>57.0 Hz @ 0.16s (9.6 CYC)

[4.2.6] RECONNECTION TO AREA EPS – AFTER AN AREA EPS DISTURBANCE, NO DR RECONNECTION SHALL TAKE PLACE UNTIL THE AREA EPS VOLTAGE IS WITHIN RANGE B OF ANSI C84.1 TABLE 1 AND FREQUENCY RANGE OF 59.3Hz TO 60.5Hz.

THE DR INTERCONNECTION SYSTEM SHALL INCLUDE AN ADJUSTABLE DELAY (OR FIXED DELAY OF 5 MINUTES) THAT MAY DELAY RECONNECTION UP TO 5 MINUTES AFTER THE AREA EPS STEADY STATE VOLTAGE AND FREQUENCY ARE RESTORED TO THE RANGES IDENTIFIED ABOVE.

[4.4.1] UNINTENTIONAL ISLANDING – CEASE TO ENERGIZE WITHIN 2 SECONDS, SOME EXAMPLES BY WHICH CLAUSE 4.4.1 MAY BE MET ARE:
1. DR AGGREGATE CAPACITY <1/3 OF MIN LOAD ON LOCAL EPS
2. DR CERTIFIED NON–ISLANDING
3. REVERSE POWER (32R) OR UNDER–POWER (32U OR 37)
4. a) FORCED FREQ OR VOLT SHIFTING OR
   b) TRANSFER TRIP, OR
   c) GOVERNOR AND EXCITATION CONTROLS THAT MAINTAIN CONSTANT KW AND CONSTANT PF

[5.1.2] SYNCHRONIZATION –
A. SYNCHRONOUS INTERCONNECTION

0< DR ≤ 500KVA	ΔF=0.3Hz, ΔV=10%, ΔΦ=20 DEG
500KVA< DR ≤ 1500KVA	ΔF=0.2Hz, ΔV=5%, ΔΦ=15 DEG
1500KVA< DR ≤ 10,000KVA	ΔF=0.1Hz, ΔV=3%, ΔΦ=10 DEG

B. INDUCTION INTERCONNECTION
SELF–EXCITED INDUCTION GENERATORS SHALL BE TESTED PER CLAUSE 5.1.2.A

C. INVERTER INTERCONNECTION
AN INVERTER BASED INTERCONNECTION SYSTEM THAT PRODUCES FUNDAMENTAL VOLTAGE BEFORE THE PARALLELING DEVICE IS CLOSED SHALL BE TESTED PER CLAUSE 5.1.2.A

Figure A.19—Example protection summary of IEEE 1547 interconnection requirements

Figure A.20, Figure A.21, and Figure A.22[42] are some typical interconnection diagrams developed by PJM Interconnection. These show the current implementation of IEEE Std 1547-2003 in the PJM tariff. While not exhaustive, these cover a large number of the typical installations.

[42] Figure A.20, Figure A.21, and Figure A.22 reprinted with permission from PJM Interconnection, PJM Manual 14B "PJM Regional Planning Process," Revision 11, dated October 5, 2007, © 2007. All other rights reserved.

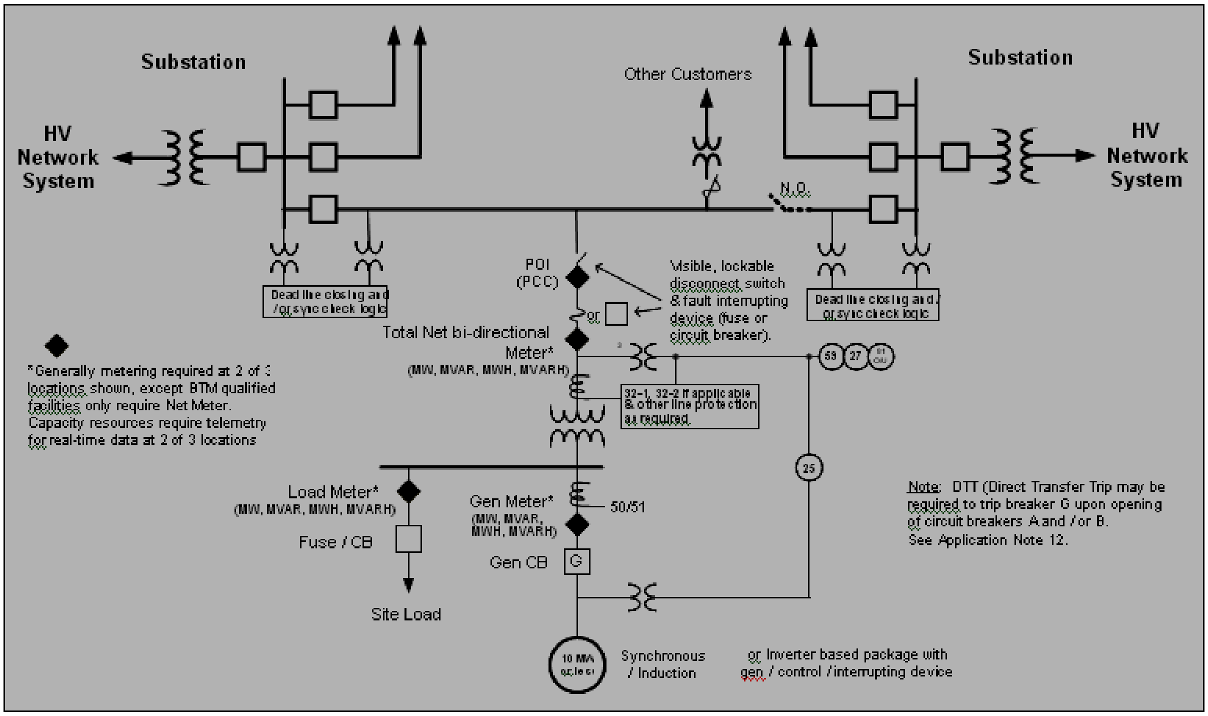


Figure A.20—One-line diagram for an example interconnection with a radial system

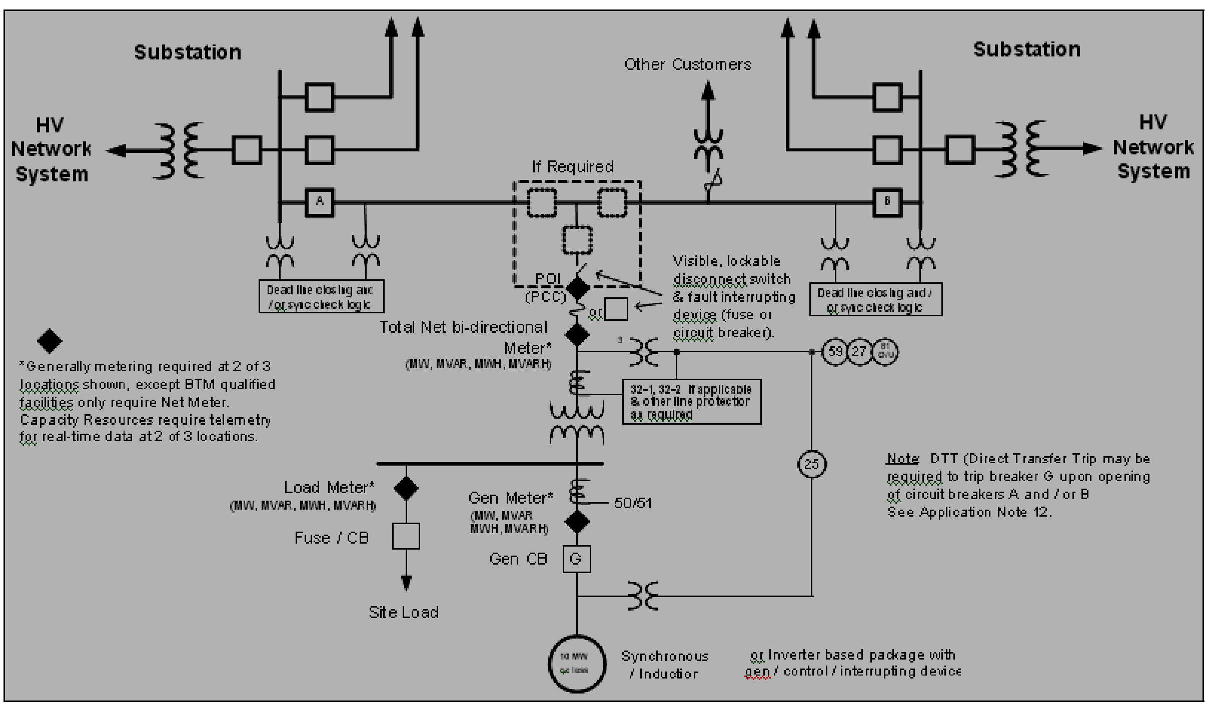


Figure A.21—One-line diagram for an example interconnection with a looped (network) system

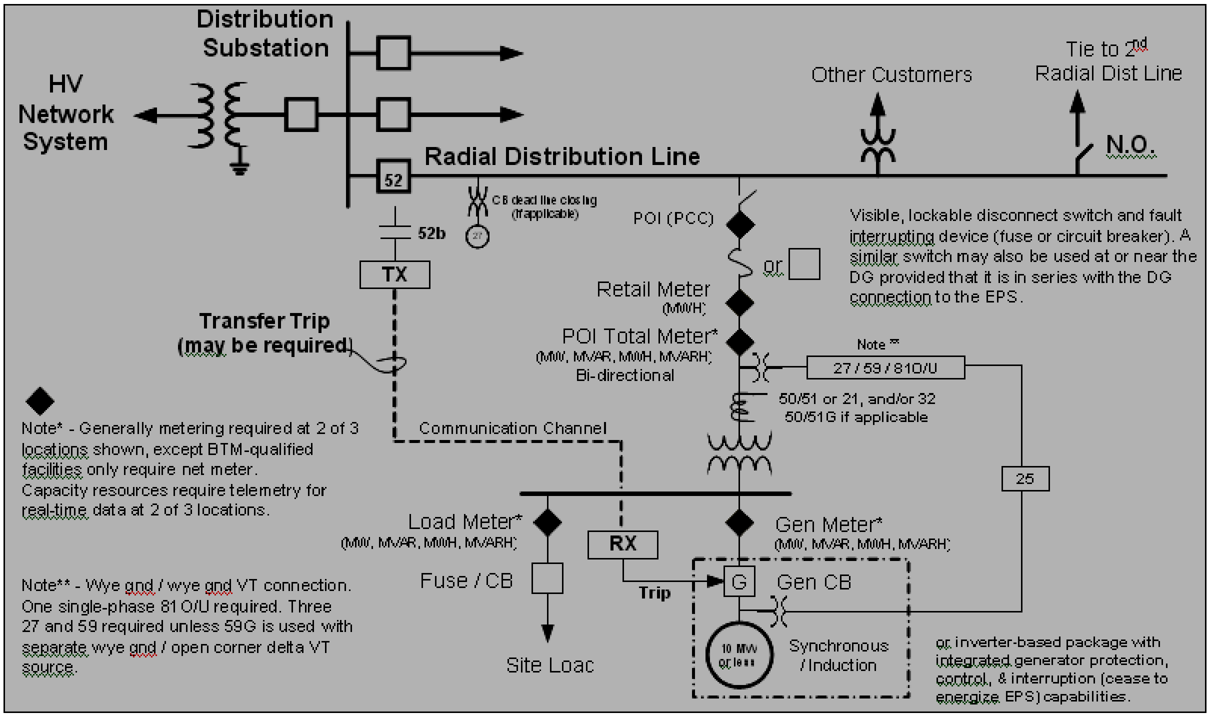


Figure A.22—One-line diagram for an example interconnection with a radial distribution system

Annex B

(informative)

Prime movers

B.1 Types of prime movers

B.1.1 Reciprocating engines

Reciprocating engines were developed more than 100 years ago and were the first fossil fuel-driven DR technology. Both Otto cycle (spark-ignition) and Diesel cycle (compression-ignition) engines have gained wide acceptance in almost every sector of the economy and can be found in applications ranging from fractional-horsepower units that power small handheld tools to 60 MW base load electric power plants.

Reciprocating engines are a subset of internal combustion engine. In reciprocating engines, pistons move back and forth in cylinders. Smaller reciprocating engines are designed primarily for transportation applications, but they can be converted for power generation with little modification. Larger engines, in general, are designed for electric power generation, mechanical drive, or marine propulsion. Some utilities operate large reciprocating engines in remote community power plants and are very familiar with their operation.

Reciprocating engines are available from many manufacturers in all size ranges. For DR applications, reciprocating engines offer low costs and good efficiency; however, they require a lot of maintenance. In addition, diesel-fueled units have emissions issues. Reciprocating engine applications also may use landfill gas as fuel, which has environmental benefits and may be considered a renewable energy source.

Engines are characterized by factors such as size, rotational speed, fuel type, and end-use application. They range up to 18 MW for four-stroke engines and up to 65 MW for two-stroke engines. Two-stroke units normally operate at approximately 125 rpm; four-stroke units range from 300 rpm to 2000 rpm. For a given unit, the more the revolutions per minute, the higher the power output is. Therefore, virtually all backup units are high-speed (diesel) with higher power-to-size and power-to-cost ratios than their lower-speed counterparts. However, there is generally a trade-off between revolutions per minute and durability, longevity, and frequency of maintenance. Therefore, most continuous-duty units are medium- to low-speed. Speed also influences the type of fuel used. Lower-grade units allow more time for burning fuel and therefore can be run on lower-grade fuel than higher-speed units. For this reason, heavy fuel oil is often an option for low-speed diesel and two-stroke engines.

B.1.2 Combustion turbines

Combustion turbines have been used for power generation for decades. They range from simple-cycle units that start at about 1 MW to units larger than 100 MW. Units from 1 MW to 15 MW are generally referred to as *industrial turbines,* a term that differentiates them from larger utility-grade turbines and smaller microturbines.

Combustion turbines offer relatively low installation costs, low emissions, heat recovery through steam, and infrequent maintenance, but simple-cycle units achieve low electric efficiencies. Because of these traits, combustion turbines are typically used for cogeneration applications in which a continuous supply of steam or hot water and power is desired, as peaking units, and in combined-cycle configurations. In applications in which local demand for heat exceeds local demand for electricity, it may be necessary to feed electricity back to the area EPS for economic viability. This may require coordination with the EPS operator.

B.1.3 Microturbines

Microturbine technology is derived from aircraft auxiliary power systems, diesel engine turbochargers, and automotive designs. A number of companies manufacture units for small-scale distributed power generation in the 30 kW to 500 kW range.

Simple microturbines consist of a compressor, a combustor, a turbine, and a generator. The compressors and turbines are typically radial flow designs that resemble automotive engine turbochargers. Most designs are single-shaft and use a high-speed, permanent magnet generator to produce variable-voltage, variable-frequency ac power. A solid-state inverter is employed to produce 60 Hz ac power. Most microturbines are designed for continuous-duty operation, and many potential applications are sited in large commercial buildings—typically in dense urban locations. Their installation and operation may therefore require detailed coordination with the local EPS network.

B.1.4 Wind turbines

Windmills have been used for years to harness wind energy for mechanical work such as water pumping. But before the Rural Electrification Act of 1936 provided funds to extend electric power to outlying areas, farms also used wind turbines to produce their own electricity.

Wind turbines were first used to produce utility power in Denmark during the World War II. After the oil embargo and the “energy crisis” of the 1970s, the Danish government encouraged renewed wind energy research. As a result, Denmark—a country of fewer than 6 million people—now supplies more than half of the world’s utility-size wind turbines. The average installed size is more than 1 MW, and new units are being built in the 4 MW range. In Denmark, wind turbines are usually operated by local cooperatives or individual farmers and are installed in small clusters of less than a dozen.

In North America, early wind development focused on three valleys in California. Winds that originated over the Pacific Ocean and moved toward the interior deserts were very predictable and coincided with peak demand for electricity. Here, the wind turbines were installed in so-called *wind farms* of hundreds of machines. New wind farm development has moved to the Midwest to tap its enormous potential. Most large turbines being installed in the U.S. are a part of wind farms, which are from 40 MW up to several hundred megawatts and interconnected with the transmission system through a dedicated substation. This type of installation is not covered in IEEE Std 1547-2003.

Almost all early wind turbines featured induction generators. However, to optimize the aerodynamic speed of the blade relative to the wind, some machines adopted two-speed generators. Wind turbines that use various forms of variable-speed technology are commonplace today. This improves the energy capture by optimizing the blade speed for the given wind speed and reduces mechanical stress in the drive train.

Denmark has a goal to generate 20% of its own electricity from wind by the year 2010. It is well past the 10% mark. With this penetration of wind energy on the area EPS, there are times when generation from one end of the country is transmitted to the other end of the country—only to have the situation reversed a few hours later. The problems of transmission with high-penetration wind energy have largely been solved. In fact, with more accurate forecasting of wind speed and location, wind-generated electricity likely will become much easier to schedule on the bulk electric system.

B.1.5 PV systems

PV cells generate electricity directly from light—hence, the name. "Photo" relates to a light source, and "voltaic" relates to electrical output. The conversion process uses a renewable energy source, it produces no harmful byproducts, and because it has no moving parts, the PV cell is very durable. Cells are interconnected in series and parallel to obtain the desired voltage and current and then encapsulated in glass for environmental protection. The basic generating unit is referred to as a *photovoltaic module.* Modules, in turn, are connected in series and parallel to match the input requirements of the load or, in the case of a utility-interactive system, a solid-state inverter.

The silicon crystal PV cell was developed in Bell Labs in the 1950s. Its first application was as a power source for space satellites. Since then, the cost and the applications have come down to Earth. The first terrestrial applications were for remote communication stations, remote homes, and water pumps—places beyond distribution lines. However, the sun provides distribution free of charge. PV is also considered a source of electricity in remote locations for developing countries with abundant sunlight.

Since 2002, more than half of the PV market has shifted to interactive applications. Given the technology's environmental attributes, there are widespread efforts to develop it as a viable supplementary source of utility power. Countries such as Japan, Germany, and the Netherlands have implemented so-called "solar roof" programs, which have resulted in the installation of hundreds of thousands of residential PV systems. These systems range from 50 W ac modules to a 2 MW roof over a Netherlands farmers' market.

Unlike most electric power generators, PV systems can be installed in urban areas close to load. In fact, the industry is focusing on the development of building-integrated systems. PV modules are being designed to form roof shingles and building walls. Given the fact that the systems are close to the load and that output is at its maximum at mid-day, often during peak demand from air conditioning loads, PV-based DR may reduce loads on local distribution systems.

Most future PV systems are likely to be small and widely distributed. Their operation will be passive, and the inverter (the interface with the EPS) will be required to meet conditions specified in UL 1741 [B68].

B.1.6 Fuel cells

Although the first fuel cell was developed in 1839 by Sir William Grove, the technology was not put to practical use until the 1960s, when the National Aeronautics and Space Administration (NASA) used fuel cells to generate electricity on Gemini and Apollo spacecraft. Today, many types of fuel cells are under development, including phosphoric acid, proton exchange membrane, molten carbonate, solid oxide, alkaline, and direct methanol models.

Each fuel cell technology has its own characteristics, such as operating temperature and ability to meet rapidly changing power demand. These characteristics will ultimately influence suitability for utility applications. A key market for some manufacturers is the residential market, in which a fuel cell could provide both heat and electricity.

Fuel cells require hydrogen for operation. However, in today's environment, it is generally impractical to use hydrogen directly as a fuel source. Instead, it is extracted from hydrogen-rich sources such as gasoline, propane, and natural gas using a reformer. The fuel cell, however, remains a key component in the long-term goal of a "hydrogen economy."

B.1.7 Storage technologies

Storage technologies can help smooth the demand for electrical generation and thereby improve efficiency and reliability. During periods of low demand, excess generation can be used to charge an energy storage system. The stored energy can then be used to provide electricity during periods of high demand. Because storage is a tool for improving utility operation, it is likely most storage systems will be coordinated with utility operations and that their scheduling will be well coordinated with the rest of the EPS.

Storage can be a useful addition to renewable resources, such as wind and solar, that may not always be available. Storage can also be used to store energy during low-price periods and then dispatch it during high-price periods. Several storage technologies are in use, and many are under development.

Pumped hydro is a large-scale storage technology that is familiar to many electric utilities. The operation is quite similar to conventional hydropower generation. Off-peak electricity can be used to pump water from a lower reservoir into a higher one. In this fashion, the energy can be stored for long periods of time and in large quantities as potential energy. The water is then released when it is needed and passed through hydraulic turbines to generate electricity.

Batteries are charged through an internal chemical reaction that can be reversed when the stored chemical energy is needed. Batteries are the most common energy storage devices for small electric systems. A relatively small number of large-scale battery energy storage facilities for utility applications have been placed in service. Fuel cells that, in principle, operate like a battery but do not run down or require electrical recharging are being tested in storage applications.

There are many other storage schemes, including compressed air, flywheel, and supercapacitor systems. Some are in prototype stages; others are in demonstration systems throughout the world.

B.2 Distributed resource equipment and flicker

B.2.1 Wind turbine generators

Wind turbine generators (WTGs) can cause voltage flicker because their power output can vary substantially over time. Flicker from wind systems can be caused by the following:

— Switching events

  Switching events can cause flicker, depending on the WTG technology used. For wind turbines that use induction generators, switching events such as starting or stopping a generator or switching between a small generator and a large generator can cause flicker. Each time a WTG synchronizes with a line, there is a surge of magnetizing current and, sometimes, a surge of power. The initial surge of current can vary from 75% of to several times the nameplate current rating. SCRs are often used to limit these initial currents, which cause the distribution line voltage to drop. A surge of power causes the voltage to rise. Likewise, switching between a small generator, used at lower wind speeds, and a larger generator, used at high speeds, causes a sudden change in power level. The change in voltage might be 1% to 4% in magnitude. These occur somewhat infrequently, perhaps once every 5 min to 15 min, depending on the WTG controller settings.

— Blades

  Flicker also can be caused by rhythmic fluctuations in power output when the blades pass the tower. When a blade passes the tower, its torque is reduced because of the interference of the tower. Lattice towers with upwind blades have the least change in torque; tubular towers with downwind blades have the most change. For three-bladed wind turbines, this pulsing power is called the 3P effect because there are three pulses in power for each revolution of the rotor. WTGs that use standard induction generators translate this drop in torque directly into a dip in the power output. WTGs designed for variable-speed operation usually translate the change into a change in rotational speed, thus smoothing out the dip in power. Manufacturers have been designing turbines to reduce this type of flicker. The frequency of the 3P effect varies with rotor revolutions per minute, which are inversely proportional to

WTG size. A small, 50 kW wind turbine would have a 3P flicker frequency of about 10 Hz, and a large, 700 kW wind turbine would have one of 1.5 Hz. These frequencies are in a range that is very noticeable to the typical customer.

— Turbulent and gusty winds

This type of flicker is proportionately reduced as more wind turbines are connected together because of the non-coincident nature of wind gusts. It is most prevalent in a single-turbine system. Figure B.1 illustrates how the power can vary from a single wind turbine during variable wind conditions over a 1 h period. Each data point is the average generation for a 1 min period. Sub-minute variations are also quite variable. This wind turbine has a fixed-blade pitch and uses a simple fixed-speed induction generator.

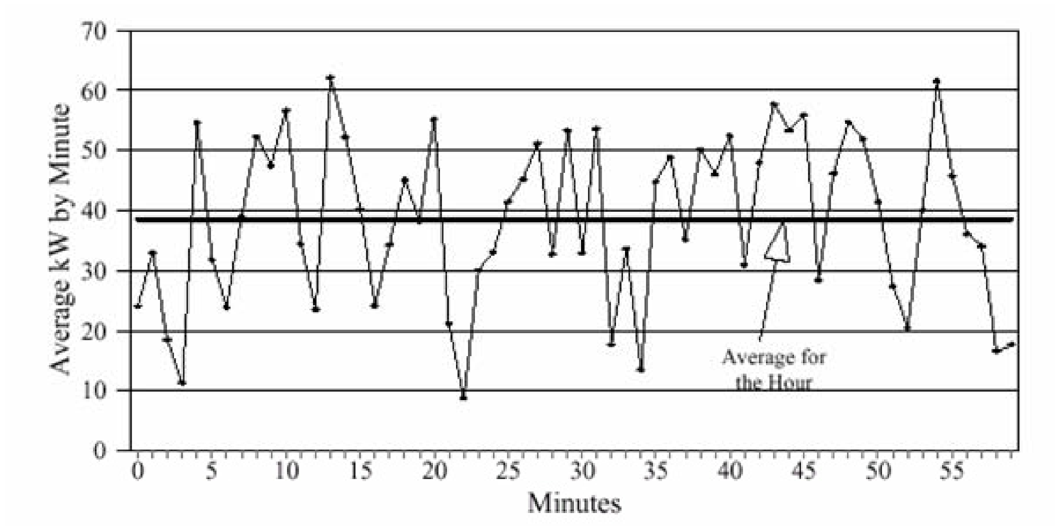


Figure B.1—Example of fluctuations in power output for an 80 kW WTG

Adding to this complicated array of factors is the variety of generator characteristics. The generators may be induction with fixed or variable poles, variable-speed through a back-to-back inverter with or without pitch control, variable-speed using double-fed generators, direct-connected synchronous generators, or synchronous generators connected through back-to-back inverters. The type of generator and interconnection can strongly affect flicker. For example, double-fed and inverter-interconnected wind turbines can regulate voltage or power factor with very fast response, which can reduce flicker effects.

B.2.2 Engine-driven synchronous or induction generators

Flicker caused by the generator or prime mover characteristics (with the exception of resynchronizing transients) is rarely an issue for DR interconnections. However, there are two special cases that the application engineers should be mindful of when selecting prime mover characteristics.

B.2.2.1 Low-rpm engines

Flicker could be caused by a pulsating power condition for a low-rpm machine. The Westinghouse transmission and distribution book [B6] presented an example for a 300 rpm, four-cylinder diesel engine running at full load. For this machine, there are only 300 x 2 power strokes per minute. This results in a pulsation frequency of 10 cycles per second. For the example, the terminal voltage change was 0.7%, which, for that pulsation frequency, places the flicker well within the flicker threshold of objection.

Such machine applications are not very prevalent, but they are still encountered. In a paper, Anderson and Mirheydar [B2] tabulate five diesels with the combination of revolutions per minute and number of cylinders that could produce visible pulsation frequencies. In this paper, they provide the basis for the following formula, Equation B.1, which can be used to determine if the power pulsation frequency, in cycles per minute (cpm), is low enough to fall in the visible flicker range:

$$\text{cpm} = 4N(\text{rpm})/k \tag{B.1}$$

where

rpm = the synchronous speed of the prime mover
N = the number of cylinders
k = a constant of 2 for a two cycle engine and 4 for a four cycle engine

For example, an eight-cylinder diesel designed to operate at 360 rpm and interconnected to the North American power grid would have a pulsation frequency of 2880 changes per minute. Because this is still in the visible flicker range, the system stiffness ratio at the PCC and pulsation deviations for specific generator prime mover sets would have to be checked to ensure they did not produce voltage fluctuations that could fall in the objectionable region.

It is tempting to dismiss the misfiring of engines as an abnormal operating condition. However, Anderson and Mirheydar make a persuasive case, at least for methane recovery plants, that occasional misfires may be a design consideration in interconnection planning. In fact, the intake of pockets of gas of poor caloric quality should be anticipated. The case studied was a 12-cylinder, 900-rpm diesel engine. By Equation B.1, the power pulsation frequency is 90 cycles per second, which is clearly above the visible flicker rate. However, the power stroke frequency for each cylinder is 90/12, or 7.5 cycles per second. Thus, a misfire injects a 7.5-cycle-per-second pulse, which is in the most sensitive flicker rate range.

Again, drawing an equation from the Anderson-Mirheydar paper, it can be shown that the power stroke frequency, in cycles per minute, per cylinder is determined by Equation B.2:

$$\text{cpm} = 4(\text{rpm})/k \tag{B.2}$$

Thus, if inconsistent fuel caloric content is a design consideration, then the 360 rpm, eight-cylinder, four-cycle engine might be an appropriate compromise. Although the power pulsation frequency is 2880 changes per minute, the power stroke frequency moves down to only 360 changes per minute. Because these two frequencies move out of the most sensitive range, they may be acceptable, depending on local system conditions.

B.2.2.2 Synchronizing (starting) transients

Bringing any direct-connected synchronous or induction machine online will cause some voltage dip. Because flicker is sensed as changes in light level, there are two distinct portions of this flicker source: the sudden drop in voltage because of the addition of inductive load and the slow rise in voltage as the machine comes up to speed. The sudden drop is effectively the rectangular step change from which the flicker response curves were derived. If the machine is spun up to speed by its prime mover before connecting with the EPS, the magnitude of the transient dip will be small, and the dip will normally disappear in a second. If the machine is line-started from standstill, the initial magnitude of the dip will be much greater, and recovery to full voltage will take seconds.

However, most machines that are designed to be line-started, unless very small, are rated to do so only two or three times per hour. Because these dips are generally limited to less than three per hour, they are only considered an objectionable flicker if the voltage dip exceeds 6% by U.S. practice.

Note that, for low-voltage buses or large machines that connect to medium-voltage buses, it may be necessary to include the resistance of any sources with X/R less than 5.

B.2.3 PV systems

The PV power source, although not constant, is generally slow to change relative to the change rates involving flicker. It had been a concern that cloud-caused irradiance changes could produce objectionable flicker. However, data show no flicker is encountered from cloud-caused irradiance.

The principal source of data on this subject came from the Gardner Project, which is described in a paper by Kern, Gulachinski, and Kern [B54]. This paper describes a test of 28 PV units, totaling 56 kW, installed on a 13.8 kV feeder. The purpose of the test was to measure the change and rate-of-change of output of the PV units resulting from clouds passing over the installation. The results showed a relatively slow change (approximately 3% per second) for the total installation, so no flicker was encountered. It is important to note that a change in magnitude of voltage in the form of a sine wave produced half the flicker effect as that of the rectangular step for which the flicker curves were drawn.

Annex C

(informative)

Power conversion technologies

C.1 Synchronous generators

Most generators in service today are synchronous generators. Synchronous generators are ac machines in which the rotational speed of normal operation is constant and in synchronism with the frequency of the EPS with which they are connected. The field excitation of synchronous generators is supplied by a separate motor-generator set, a directly coupled self-excited dc generator, or a brushless exciter that does not require an outside electrical source. Therefore, these generators can run either stand-alone or interconnected with the EPS. When interconnected, the generator output is exactly in step with the EPS voltage and frequency. Note that separately excited synchronous generators can supply sustained fault current under nearly all operating conditions.

Synchronous generators are driven at high speed by combustion or steam turbines, at intermediate speed by internal combustion engines, and at low speed by water turbines. They are readily controlled by power and power factor or by frequency and voltage. They have limits on block loading capabilities because of the driver but are suitable for non-disturbing EPS interconnection.

A synchronous generator requires more complex control than an induction generator—both to synchronize it with the EPS and to control its field excitation. It also requires special protective equipment to isolate it from the EPS under fault conditions. Significant advantages include its ability to provide power during EPS outages and allow the DR owner to control the power factor at the facility by adjusting the dc field current.

Electrical power is generated in a synchronous machine by the conversion of applied shaft torque into the synchronous interaction of magnetomotive forces (mmf), which arise from the electromagnetic fields created in the machine. The rotor is enveloped by line frequency-driven fields that originate in the stator, and the rotor is furnished with controlled dc current in its windings to create its field excitation. The interaction of these fields causes a mechanical torque that opposes the applied shaft torque; it also causes the stator terminals to source electrical power into the EPS. The electrical power generated is controlled by the action of the governor on the prime mover connected to the shaft of the synchronous machine. Power is increased by applying more shaft torque, which tends to advance the synchronously rotating field of the rotor compared with the fixed rotation of the stator field. This causes increased current to flow in the stator and results in a power increase to the EPS. The angular difference between the synchronously rotating fields of the stator and rotor is called the *torque angle,* and it directly reflects the level of power generated by the machine. Any incremental change in the speed of the rotor because of shaft torque changes causes a corresponding change in the torque angle and the instantaneous electrical power output of the machine.

Synchronous generators are constructed in two basic designs: the cylindrical rotor uniform air gap synchronous machine and the salient pole rotor synchronous machine. The cylindrical rotor design has slots cut into its rotor to accept the field windings. Once assembled, the iron rotor and the installed field windings combine to yield a nearly perfect and smooth cylindrical shape to the overall rotor, as shown in Figure C.1(a)[43] for a four-pole design. This results in a nearly uniform distribution of electromagnetic air gap flux between the stator and the rotor. The salient pole rotor synchronous machine, in contrast, is assembled from separate pole pieces fastened to the rotor. A four-pole salient pole rotor machine is shown in Figure C.1(b).

[43] *Electric Machines: Dynamics and Steady State,* Thaler, G. J.; and Wilcos, M. L. [B65]. Copyright © 1966 John Wiley & Sons Inc. Reprinted with permission of John Wiley & Sons, Inc.

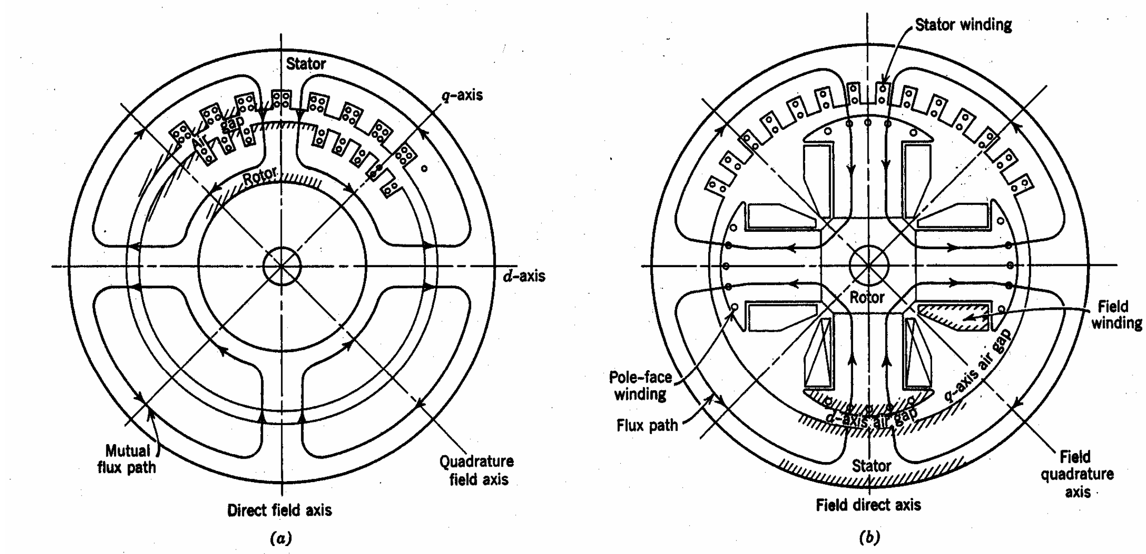


Figure C.1—Basic synchronous generator construction: (a) cylindrical rotor (b) salient pole

Both designs function in the same manner. A dc excitation current is applied to the field winding. As the rotor is driven at synchronous speed by the prime mover, the dc field flux interacts with the line frequency fields synchronously rotating in the stator armature windings. These fields, or mmfs, interact and cause electrical power to be generated and sourced into the EPS. As more power is generated, higher levels of polyphase ac current flow from the stator terminals into the EPS. The current flowing in the stator windings is termed *armature reaction current* because it arises from the interaction of the opposing rotational forces on the shaft from the prime mover and the resultant mmf of the air gap flux in the machine. The mmf, because of the resultant air gap flux in the machine, is a vector summation of the mmf because of the applied field excitation current and the mmf of the armature reaction current. This leads to an important equivalent circuit model for the synchronous machine.

Figure C.2 shows an important standard diagram of the combination magnetic and electric equivalent circuit model for the uniform air gap cylindrical rotor synchronous machine. The figure is a one-line voltage phasor and flux representation of a balanced three-phase generator under steady-state operating conditions. As done in the two-axis theory of electrical machines, the phasors are resolved into components directly in line with the field axis poles of the machine and components in quadrature or at right angles to this axis representing conditions in the interpolar space between the field poles of the machine. In Figure C.2, the phasor e_t is the voltage at the generator terminals, and i is the armature current in the machine with direct axis component i_d and quadrature axis component i_q. The generator is supplying real power to the EPS corresponding to the torque angle δ. It is also supplying reactive power to the EPS with a lagging current at phase angle θ between the terminal voltage e_t and the generator current i. Armature resistance and leakage reactance voltage drop phasors, ir and ix_L, respectively, combine with terminal voltage e_t by vector addition to produce the phasor e_L. The phasor e_L is the voltage produced by the air gap flux Φ, which leads e_L by 90º. The level of field current required to produce flux Φ is the field current phasor I_t, which is in time phase with flux Φ and can be taken from the no-load saturation curve of the generator (see Anderson and Mirheydar [B2]).

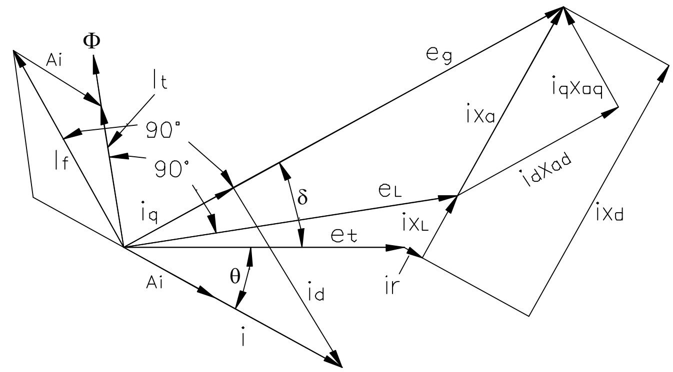


Figure C.2—Synchronous generator machine flux and phasor relationships: cylindrical rotor

In addition to the dc field flux, the armature reaction current i also produces an mmf field flux that combines with the applied dc field. This is represented by A_i, which is in time phase with armature current i. This alters the effective field in a way that the field structure adjusts itself for the net air gap flux Φ driven by field current I_t to an angle and magnitude as represented by phasor I_f, which results from the combination by vector addition of armature reaction flux represented by A_i and field excitation represented by I_t. Phasor I_f leads voltage phasor e_g by 90º similarly as the field excitation phasor I_t leads phasor e_L by 90º. Phasor e_L is the voltage behind the leakage reactance drop of the machine, but it does not include the effects of armature reaction. Phasor e_g, however, does include the effects of the field structure adjustment caused by the mmf of armature reaction, as is shown in Figure C.2. Phasor e_g is the voltage behind the synchronous reactance of the machine. Further analysis of this fundamental diagram shows how the basic model of equivalent circuit parameters for a synchronous machine is developed.

Phasor e_g is the machine open circuit terminal voltage that corresponds to a level of field current represented by excitation phasor I_f. Phasor ix_a is proportional to the armature current and is called the drop of armature reactance. Armature reactance voltage drop ix_a is combined with leakage reactance voltage drop ix_L to yield the phasor ix_d, which is the synchronous reactance voltage drop. Thus, a fundamental parameter for a synchronous generator, the machine synchronous reactance x_d, is given by Equation (C.1):

synchronous reactance $$x_d = x_a + x_L \tag{C.1}$$

In addition, Figure C.2 shows the basis for modeling the equivalent circuit of a synchronous generator as a voltage source behind a reactance. Figure C.2 shows that the combined internal voltage drops because of armature resistance and the leakage reactance of the machine alone are not sufficient to describe the behavior under load because armature reaction effects in the generator are not included. However, armature reaction flux represented by A_i is proportionally reflected in the synchronous reactance voltage drop phasor ix_d along with the leakage reactance voltage drop in the machine. Thus, the net air gap flux in the machine, including the contribution from the mmf of armature reaction because of load current, is reflected by the vector summation of the terminal voltage e_t and the internal machine voltage drops. This gives the fundamental result shown in Equation (C.2):

$$e_g = e_t + ir + j\,ix \tag{C.2}$$

Except for the small resistive voltage drop, this yields the basic model of a synchronous machine as a voltage source behind a reactance. That is, the open circuit terminal voltage e_g is applied to the connected load or EPS through a reactance, the synchronous reactance x_d, with performance in the steady state as depicted in Figure C.2. The driving voltage e_g for the generator while supplying power and current to the EPS can be found from the air gap line of the no-load saturation curve for the machine for a level of field current corresponding to the resultant excitation I_f (see Anderson and Mirheydar [B2]). Synchronous reactance x_d is commonly given in its constituent parts resolved along the direct and quadrature axes.

Referring to Figure C.2 and taking leakage reactance to be equal on both axes, the direct axis synchronous reactance x_d and the quadrature axis synchronous reactance x_q are given by the Equation (C.3):

$$x_d = x_l + x_{ad} \tag{C.3}$$

$$x_q = x_l + x_{aq}$$

For a cylindrical rotor machine, x_d and x_q are nearly equal because of the uniformity of the resultant flux wave in the air gap across the virtually smooth cylindrical face of the rotor. In fact, however, because of the rotor slots on the cylinder face, a slight fringing of the flux occurs that tends to alter the quadrature axis reluctance and results in a somewhat smaller synchronous reactance along this axis.

For the salient pole rotor synchronous machine, Figure C.3 shows an equivalent standard diagram that depicts the combination magnetic and electric equivalent circuit model. In this machine, the field poles protrude prominently into the air gap along the direct axis. Thus, because of the stronger permeance on this axis, the salient pole machine has a preferred air gap magnetization along the direct axis.

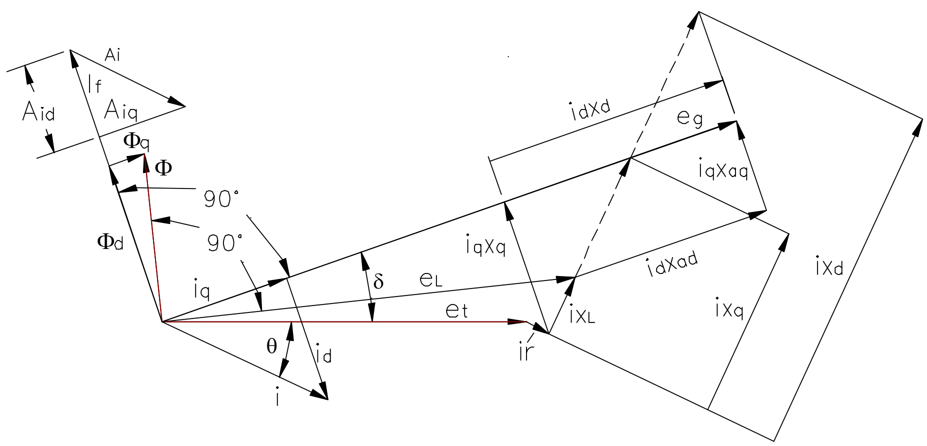


Figure C.3—Synchronous generator machine flux and phasor relationships: salient pole rotor

The air gap direct and quadrature axis component mmf waves sweep both axes with a generally sinusoidal form. However, because of the high reluctance of the air gap between the field poles, the quadrature axis flux experiences significant distortion and has a high third harmonic content of flux in the interpolar space between the direct axis field poles. Compared with the direct axis, this results in a much reduced fundamental component of flux along the quadrature axis. The magnetizing reactance along this axis is therefore less, and this is reflected in the quadrature axis synchronous reactance for the salient pole machine. In a similar fashion to the cylindrical rotor model of Figure C.2, voltage phasor e_g in Figure C.3 is the voltage behind the synchronous reactance of the machine and includes the effects of the field structure adjustment caused by the mmf of armature reaction. Armature current reaction voltage drops are shown as the components along the direct axis i_dx_{ad} and the quadrature axis i_qx_{aq}. In combination with equal components on both axes of the leakage reactance voltage drop ix_L, the armature current reaction voltage drops add vectorially to produce the direct axis synchronous reactance voltage drop $i_d$xd and the quadrature axis synchronous reactance voltage drop i_qx_q. It is shown in Figure C.3 that quadrature axis synchronous reactance voltage drop phasor i_qx_q is much less than the direct axis synchronous reactance voltage drop phasor i_dx_d. Quadrature axis synchronous reactance x_q is typically 60% to 70% of the direct axis synchronous reactance x_d for a salient pole machine.

Direct axis synchronous reactance x_d and quadrature axis synchronous reactance x_q describe the machine in the steady state under balanced operating conditions. These parameters also define the level of fault current possible under sustained conditions for symmetrical three-phase faults on the generator. Immediately following a fault, however, the balanced flux in the machine is greatly disturbed, and these parameters do not describe the effective internal impedances of the machine under these temporary conditions. For the initial time after a fault, complementing parameters for the transient and subtransient time periods immediately following the upset event are defined. These are the direct axis transient reactance $x_{d'}$, quadrature axis transient reactance $x_{q'}$, direct axis sub transient reactance $x_{d''}$, and quadrature axis subtransient reactance $x_{q''}$. The subtransient time period lasts for a few cycles, while the transient time period may persist for several seconds or more. These parameters derive from analyses of the armature reaction flux similar to the relationships of Figure C.2 and Figure C.3; however, they account for the imbalances, saturation, and dc offset effects internal to the machine during these short time periods. For unsymmetrical faults such as single line-to-ground, phase-to-phase, or double line-to-ground faults, the method of symmetrical components is applied to further refine these sets of parameters into positive, negative, and zero sequence constants to solve for fault-current magnitudes.

Figure C.4 depicts a control panel function for reactive power generation for a synchronous generator. It shows that if the machine excitation is increased, the generator will supply more reactive power to the EPS with which it is interconnected. It also shows that if the machine excitation is decreased below its nominal midpoint, the generator will absorb reactive power from the EPS with which it is interconnected. During conditions of light loading on the EPS, the system may appear more capacitively reactive than inductively reactive, and in this case, voltampere-reactive absorption may be in order—as opposed to reactive power generation, which is the normal routine requirement. Figure C.4 also shows that when a synchronous generator is supplying reactive power to the EPS, the generator itself is operating with a lagging power factor (capacitive). When it is absorbing reactive power, its power factor (inductive) becomes leading.

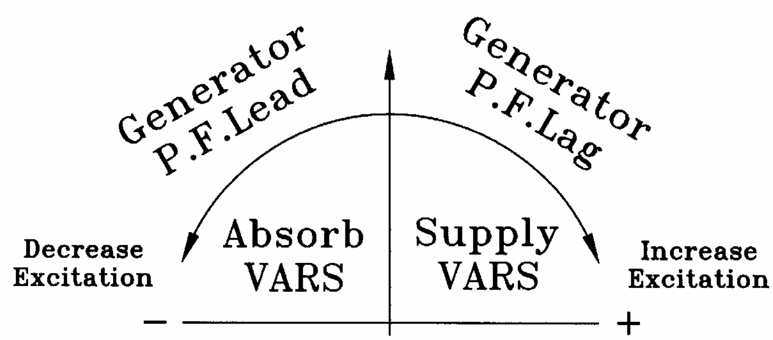


Figure C.4—Reactive power control for a synchronous generator

This particular relationship is also demonstrated in Figure C.5, which shows phasor diagrams for a synchronous generator supplying and absorbing reactive power with the interconnected EPS. The reactive power capability of the machine is controlled by varying its field excitation. This causes the internal machine voltage behind the synchronous reactance of the machine, Eg in Figure C.5, in contrast to the terminal voltage Et fixed by the external system, to either increase or decrease in proportion to the field excitation. Figure C.5 shows that the result of this process forces the stator current I to either lag or lead the stator terminal voltage Et, which, in turn, causes the synchronous generator to either supply or absorb reactive power relative to the interconnected EPS. In Figure C.5, note that the machine is supplying the same level of real power in both cases because the torque angle δ is constant. But as the machine is varied to either supply or absorb reactive power, the phase angle θ of the machine varies fully from lagging to leading relative to its terminal voltage Et.

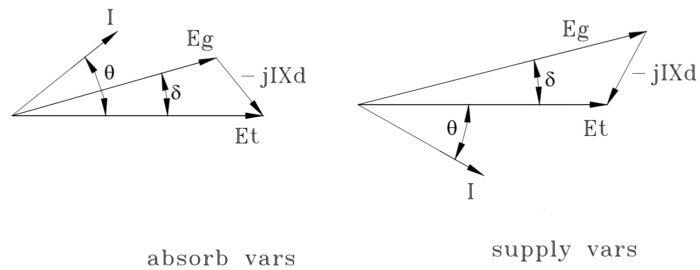


Figure C.5—Reactive power phasor relationships for a synchronous generator

As the internal machine voltage Eg in Figure C.5 adjusts in response to the excitation, it is observed also that the voltage difference between Eg and terminal voltage Et is absorbed across the synchronous reactance Xd and reflected in the angle of the synchronous reactance voltage drop jIXd. Because the real power generated does not change in Figure C.5, the synchronous reactance voltage drop phasor jIXd experiences only an angular adjustment because the stator current I remains constant.

In a synchronous rotating machine, speed and voltage can be separately adjustable and made to match the associated area EPS very closely. Rotation needs to be correct, and synchronized connection cannot be achieved unless the DR rotation matches the area EPS rotation. Synchronizing without disturbing the area EPS requires the DR to match the rotation, frequency, magnitude, and phase angle of the voltage of the area EPS with which it is to connect. When these are matched, connection can be made without any flow of current and without any disturbance.

Satisfactory connection can be made with some tolerance (i.e., difference) on these conditions, depending on the size and type of the DR equipment. The consequences of any mismatch are predictable. If the magnitude of the DR voltage exceeds that of the EPS at the moment of connection, the DR will deliver reactive current. If it is less, the DR will absorb reactive current. If the phase angle of the DR voltage is leading that of the EPS at the moment of closure, the DR will deliver real power. If it is lagging, the DR will absorb real power. The larger any of these currents is, the greater will be the disturbance of the area EPS and synchronous generator.

Once a unit has synchronized, the unit average speed will match that of the EPS. There will be brief excursions in the instantaneous speed each time there is a change of either, or both, real and reactive current. To avoid any disturbance of the EPS, any changes in power or voltage should be made gradually. As an example, change might be limited to an average rate of 0.05 p.u. per second if the DR size is a significant fraction of the area EPS load.

The voltage regulator used with a synchronous machine will normally show different response rates and damping for voltage increases and decreases, but standard equipment is faster than is usually required. The most common power purchase contract covers only the exchange of real power, so a DR voltage regulator will control at power factor = 1.0. If the contract requires operation at a fixed voltage or with the delivery of a fixed reactive current, the regulator will be set accordingly.

C.2 Induction generators

An induction generator is an asynchronous machine that requires an external source to provide the magnetizing (reactive) current necessary to establish the magnetic field across the air gap between the generator rotor and stator. Without such a source, an induction generator cannot supply electric power and always operates in parallel with an EPS, a synchronous machine, or a capacitor that can supply the reactive requirements of the induction generator.

Another type of machine is the DFAG, which allows variable-speed operation over a considerable range above and below synchronous speed. This type of generator is also known as a DFIG. Its characteristics, however, differ substantially from an induction generator. It is discussed separately in C.3.

Induction generators operate at a rotational speed that is determined by the prime mover and slightly higher than that required for exact synchronism. Below synchronous speed, these machines operate as induction motors and, thus, become a load on the EPS.

Torque-versus-speed curves are readily available in textbooks. An example torque-versus-speed curve for an induction machine is shown in Figure C.6. It shows the rotor torque the machine can develop in both the motoring and generation regions as a function of the speed of the rotor as it approaches synchronous rotational speed. At synchronous speed, the machine has zero slip, s, as indicated in Figure C.6, and it is the point of mechanical speed where the rotation of the rotor pole windings is exactly in synchronism with the sweeping rotational magnetizing flux applied to the stator from the fixed frequency of the connected EPS. At the point of synchronous speed, there is no induced current in the rotor because the sweeping stator flux is negated by an exactly moving rotation of the rotor poles. Therefore, for an induction machine as a motor, the point of synchronous speed is uniquely unstable, and the motor cannot operate there because, at that point, the rotor does not produce an interacting flux with the stator to drive the mechanical rotation. Synchronous speed for an induction machine in revolutions per minute is given by 2xfx60/N, where f is the fixed frequency of the connected EPS and N is the number of poles in the machine. Thus, for example, on an EPS of 60 Hz frequency, a two-pole induction machine has a synchronous speed of 3600 rpm, and a four-pole machine has a synchronous speed of 1800 rpm.

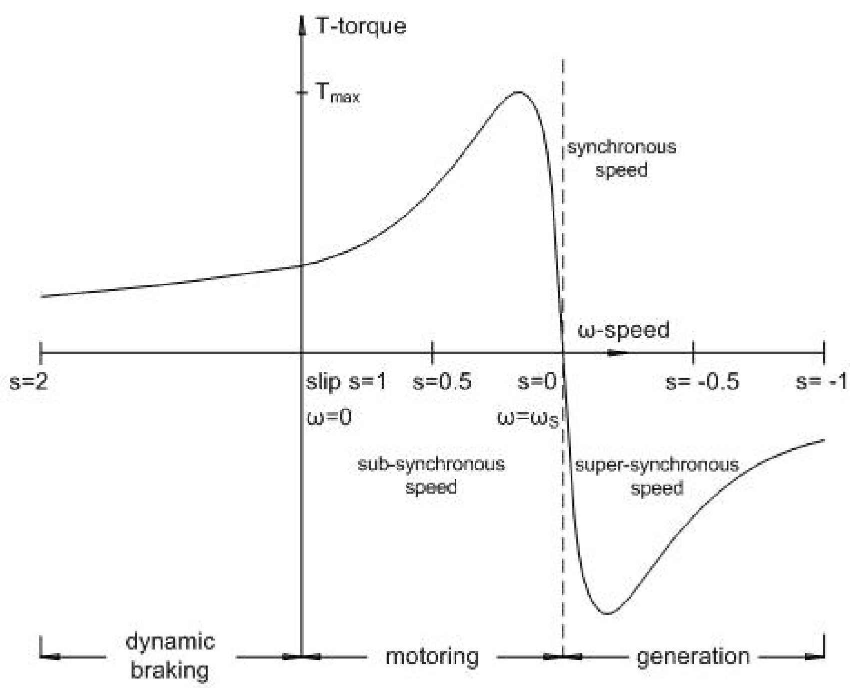


Figure C.6—Example induction machine speed torque curve with motoring to generation transition

As a motor, the induction machine operates slightly below synchronous speed at a slip speed typically 2% to 3% of the rated synchronous speed of the machine. When used as a generator, however, the machine is not required to operate at a point at which there is sufficient induced rotor current to produce an interacting flux to propel the shaft rotation because the prime mover now provides this force. The prime mover pushes the machine rotor to a speed from the typical motoring region slip speed through the synchronous speed point at a slip of zero and then to a rotational speed above the rated synchronous speed for the machine.

This is shown in Figure C.6 with the classic smooth transition from motoring to generation for an induction machine.

In the generation region, the slip becomes slightly negative because the rotor speed is higher than the synchronous frequency rotational speed of the EPS with which it is connected, and the stator ceases to draw real current from the EPS. Instead, with the machine rotor speed now exceeding the sweeping rotational magnetizing flux applied from the stator by the fixed frequency of the connected EPS, the resultant air gap flux driven by the force of the rotor field causes a real component of current to flow in the stator windings. The stator thus now sources real current into the connected EPS, and the machine turns itself around into a source of real power generation, propelled by the prime mover driving the rotor above synchronous speed.

An induction generator, regardless of load supplied, draws reactive power from the EPS and may adversely affect the voltage regulation on the circuit with which it is connected. The induction generator is then consuming reactive power from the system; it is important to consider the addition of capacitors to improve power factor and reduce reactive power draw.

In certain instances, an induction generator may continue to generate electric power after the EPS source is removed. This phenomenon, known as *self-excitation,* can occur when there is sufficient capacitance in parallel with the induction generator to provide the necessary excitation and when the connected load has certain resistive characteristics. This external capacitance may be part of the DR system or may consist of power factor correction capacitors located on the EPS circuit with which the DR is directly connected.

An induction generator needs only a very basic control system because its operation is relatively simple. It does not require special procedures to synchronize with the area EPS because this occurs essentially automatically. It will normally cease to operate when an EPS outage occurs. However, if stranded with sufficient capacitance (e.g., for power factor correction), it may continue to operate with indeterminate regulation.

A disadvantage of induction generators is their response when some types are connected with the area EPS at speeds significantly below synchronous speed. In this case, potentially damaging inrush currents and associated torques can result.

An asynchronous rotating machine can be brought to synchronous speed but normally will depend on the EPS for its excitation. The magnetizing inrush will be similar whether the machine is started as an induction motor or brought to near synchronous speed before connection. The speed at the moment of connection only affects the duration. The current can be limited by an auxiliary controlled impedance such as a soft starter that can restrict the rate of rise of the current. The voltage of an asynchronous machine is controlled by its excitation source. It is unregulated except when supplied by an adjustable capacitive source.

All of this applies to an induction generator directly coupled with an EPS. In this case, the EPS and induction machine interact as described to produce power generation. Another variation of using an induction machine to generate power, however, exists when a static power converter system is interposed between the induction generator and the area EPS. In this variation, the induction machine is not governed directly by the synchronous frequency rotational speed of the EPS with which it is connected.

Reactive magnetizing current is still necessary to establish the magnetic field across the air gap between the generator rotor and stator, and in this case, it is not drawn directly from the EPS. It has to be supplied by some other means. For instance, capacitors may be located directly at the stator terminals of the induction generator to supply the reactive magnetizing current to the machine.

The prime mover driving the rotor causes the field generated in the rotor by the interaction of the stator inductance and the connected capacitance to sweep the stator windings with a reaction flux and produce stator terminal voltage and cause real current to flow in the stator windings and into any connected load. This portion of the arrangement is similar to the self-excitation described previously, except here it is intended and controlled. The power is generated asynchronously. It is then rectified and applied to an inverter for conditioning and application to a connected area EPS.

In another possible scheme, back-to-back inverters are arranged between the induction generator and the EPS. The stator mains of the induction machine are tied to the ac terminals of the first inverter, which furnishes the reactive magnetizing current required and runs at an asynchronous frequency compatible with the speed of the prime mover. This inverter shares a dc link for power transfer with a second inverter, which is tied to the fixed-frequency EPS. Power is again generated asynchronously, and the frequency of the induction machine generator side of the arrangement does not need to match the frequency of the EPS to which the generated power is exported. Alternatively, a cycloconverter could offer the same power transfer functionality—all within the control of a single switching matrix static power converter. The schemes to this point, however, need to have static power converters rated for full stator current and power. Cost could limit the size of practical induction generator arrangements with these methods.

C.3 Double-fed asynchronous generators

DFAGs, also known as DFIGs, are a distinct class of asynchronous generators. These generators operate with a variable rotational speed while creating a synchronous voltage, as a result of ac excitation applied to the generator rotor.

Unlike an ordinary induction generator, a DFAG can supply or absorb reactive power. Both the real power output and either the power factor or net reactive power output can be precisely controlled with a high speed of response. This also offers mitigation of any shaft torque transients that might otherwise be imposed on a relatively inflexible fixed-speed machine by sudden attempted speed changes by the prime mover energy system.

The rotating electrical machine is physically the same as a wound-rotor induction motor. The stator is tied directly to the area EPS. However, the rotor currents are controlled by power converters instead of simply induced by the stator magnetic field, as is the case for a simple induction generator. Two static power converters are arranged in a back-to-back configuration, with a shared dc link, to transfer power to and from the rotor at a variable ac frequency, as shown in Figure C.7. The ac side of one converter is tied to the rotor of the machine via slip rings; the other converter is tied to the fixed-frequency area EPS. The variable-frequency ac current in the rotor causes the rotor's magnetic field to have an apparent speed faster or slower than the physical rotor speed, depending on the phase rotation of the field current. The frequency of the field current establishes the relative speed of rotation of the magnetic field relative to the rotor, and the phase sequence establishes the direction of rotation. The rotor current is controlled by the converter such that the sum of the apparent rotation of the rotor magnetic field, with respect to the rotor, plus the physical speed is always at the synchronous speed of the area EPS frequency. The physical rotational speed of the generator can be varied over a wide range—both faster and slower than the synchronous speed. When rotating faster than synchronous speed, the direction of real power flow is out of the rotor, into the rotor-side converter, through the dc link, and through the line-side converter to the EPS. When rotating at less than synchronous speed, the direction of power flow is into the rotor.

Typical speed variation capability for the system compared with base speed at synchronism on a 60 Hz system is ±20 Hz. In these systems, about two-thirds of the generated power is coupled to the EPS directly through the stator mains without a converter. Only about one-third is transferred through the rotor circuit via the static power converter. Thus, the static power converter can be greatly reduced in size and cost yet still support an equivalent level of asynchronous power generation applied to a fixed-frequency EPS. In addition, it can allow the prime mover to have variable speed.

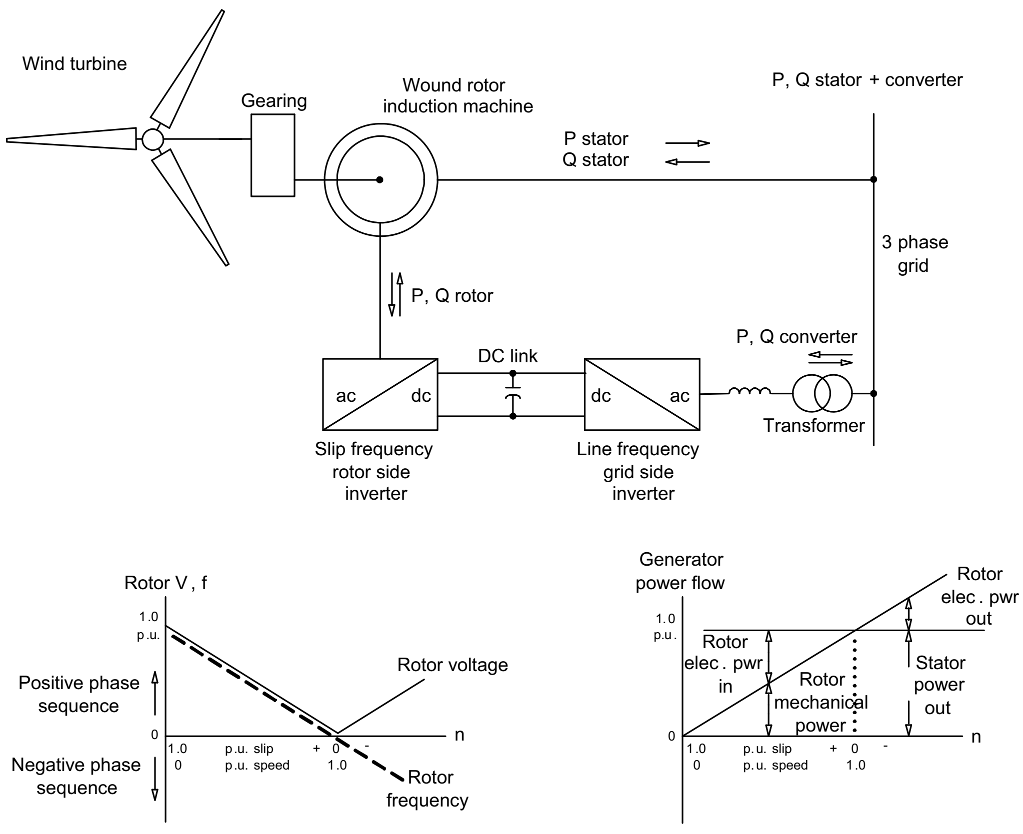


Figure C.7—Example double-fed asynchronous generator

C.4 Inverters and static power converters

Some DR installations produce electric power with voltages that are not in synchronism with those of the area EPS with which they are to be connected. The purpose of a static power converter is to provide an interface between the non-synchronous DR output and the area EPS so that the two may be properly interconnected. Two types of non-synchronous DR output voltages are as follows:

— DC voltages generated by dc generators, fuel cells, PV devices, storage batteries, or an ac generator through a rectifier

— AC voltages generated by a synchronous generator running at non-synchronous speed or by an asynchronous generator

Correspondingly, two categories of static power converters can be used to connect the DR to the area EPS as follows:

— DC-to-ac power converters

In this case, the input voltage to the device is generally a nonregulated dc voltage. The output of the device is at the appropriate frequency and voltage magnitude, as specified by the area EPS. This is the dominant means of small and renewable DR interconnection.

— AC-to-dc-to-ac electric power converters

In this case, the input frequency or voltage magnitude to the device, or both, does not meet area EPS requirements. The output of the converter device is at the appropriate frequency and voltage magnitude, as specified by the area EPS. This format is commonly seen in microturbine applications, which may have alternators that generate electric power at approximately 1 kHz.

In cases in which dc power can be used directly—as in the profusion of data centers and other customers that use essentially dc power supplies (such as the power supplied by electronic ballasts)—some of these DR systems have opened the door to direct dc or other converter systems.

Static power converters are built with diodes, transistors, and thyristors, with ratings compatible with DR applications. These solid-state devices are configured into rectifiers (to convert ac voltage into dc voltage), inverters (to convert dc voltage into ac voltage), or cycloconverters (to convert ac voltage at one frequency into ac voltage at another frequency). Some types require the area EPS source to operate; others may continue to function normally after a failure. The major advantages of solid-state converters are their higher efficiency and potentially higher reliability compared with rotating machinery converters. In addition, this technology offers increased flexibility with the incorporation of protective relaying, coordination, and communications options.

An inverter has almost no inertia, and its response is limited by its source. It will respond very quickly in combination with a storage source such as a battery, but a primary source such as a fuel cell will require a ramped change. With respect to synchronizing, a self-commutated inverter matches the EPS voltage and phase angle just as a synchronous machine does, but the tolerances can be wider because there is no mechanical inertia involved. A line-commutated inverter has to match only voltage magnitude because it follows the EPS frequency after connection. Both types of inverters may be phase angle-adjustable after connection. Any isolated local EPS needs to match the area EPS voltage (as for a synchronous machine), and the acceptable tolerance may be smaller because of the greater mechanical inertia.

The voltage regulator of an inverter is very fast, and it may control across the full power factor range from 0.0 leading through 1.0 to 0.0 lagging. The most common power purchase contract covers only the exchange of real power, so a DR voltage regulator will control at power factor = 1.0. If the contract requires operation at fixed voltage or with the delivery of a fixed reactive current, the regulator will be set accordingly.

Many inverters in DR packages use waveform synthesis switching frequencies of several kilohertz, nominally 3 kHz to 6 kHz. Compared with 60-cycle line frequency, this allows the inverter to sample and control it output currents and waveforms at rates approaching 100 times in one line cycle. This is why its regulation is very fast. Because of the opportunity for fast computations afforded by microprocessors, inverters are very successful at limiting their output currents under short-circuit conditions. Relative to the EPS, this may be an advantage for protection coordination, but it also may be a disadvantage for fault clearing.

Line-commutated converters (inverters) were among the earlier designs of solid-state-based units. They are based on thyristor switching devices. Because of the relative simplicity of the gate firing control and the favorable cost advantage of thyristors, these designs tend to offer some of the highest power ratings for static power converters. Line frequency self-commutated static power converters typically employ gate turn-off thyristors.

Self-commutated static power converters may also be arranged as voltage source converters coupled to the ac system through an inductive reactance. This reactance can occur naturally as leakage reactance in a coupling transformer, or it may be added purposely between the converter output and the ac system. Such converters may be further divided into stepped square wave converters or switch-mode converters.

The stepped square wave converter is typically a multi-pulse arrangement (such as 18-pulse or 24-pulse) that uses various techniques such as multiple-phase shifted transformer windings and phase-displaced operation before final combination and connection to the ac system to achieve harmonic cancellation benefits. These embodiments, because of cost economies, are at the high end of the power range.

Switch-mode converters are the other alternative configuration of the inductively coupled voltage source converter. They are widely used in present-day DR systems. They employ PWM techniques for internal ac waveform synthesis. The preferred switching device for this arrangement is the insulated gate bipolar transistor (IGBT). For the stepped square wave and the switch-mode converter, the operating philosophy for real and reactive power control is similar. Each follows the traditional model of internal machine or torque angle control and field excitation control, just as in a synchronous rotating machine.

In a conventional rotating synchronous generator, real power is controlled by the internal machine angle, and reactive power is controlled by the field excitation, which sets the internal voltage of the machine. Inductively coupled voltage source static power converters control the flow of real and reactive power in the same manner. If the converter internal voltage before the coupling reactance X is Vg, the system terminal voltage is Vs, and δ is the angle by which Vg leads Vs, then the real power P supplied to the ac system and the reactive power Q drawn from the ac system by the converter, neglecting resistance, are given by Equation (C.4) and Equation (C.5):

$$P = [VgVs \sin(\delta)] / X \tag{C.4}$$

$$Q = Vs^2 / X\,[1 - (Vg/Vs) \cos(\delta)] \tag{C.5}$$

Real power transfer from the DR converter is accomplished by controlling the power angle δ by which the converter voltage leads the ac system. Reactive power drawn by the converter is directly influenced by the ratio of the internal voltage Vg to the system terminal voltage Vs and the power angle δ. Thus, the converter can be controlled to draw zero voltamperes reactive and operate at unity power factor if it holds the relationship shown in Equation (C.6):

$$Vg \cos(\delta) = Vs \tag{C.6}$$

By increasing its internal voltage Vg above the system terminal voltage for a given real power transfer, the converter can reverse a reactive power draw from the system and instead supply a flow of reactive power to the system. In this manner, the DR facility can supply not only real power through the interconnection but also reactive support to the system.

Phasor relationships for an inductively coupled voltage source converter are shown in Figure C.8 and Figure C.9 for an inverter-based DR operating in parallel with the area EPS. In Figure C.8, the three-phase set of phasors created by the DR inverter is Vg, and a three-phase area EPS is represented by Vs. The inverter remains in locked synchronism with the EPS, as shown in Figure C.8. In the figure, the DR inverter leads the system voltage Vs, and, thus, the DR is exporting power to the EPS. If Vg were to lag Vs, the inverter would be importing power from its ac area EPS side and forced to transfer power backward to its dc side. Operational considerations for some DR systems may include such transfers during portions of the operating sequence. In Figure C.8, the cosine projection of Vg onto the Vs reference axis is nearly equal to Vs, and therefore, by Equation (C.6), the inverter represented in Figure C.8 would be expected to be operating at near unity power factor. Figure C.9 shows a DR inverter operating at two power levels. The inverter internal voltage Vg has the same magnitude in both figures. Therefore, the electrical power produced and exported to the EPS is greater for the inverter operating conditions in Figure C.9(b). Note also that in Figure C.9, without making any other adjustments to the inverter operating parameters, the DR system of Figure C.9(b) is operating closer to unity power factor and supplying less reactive power to the system.

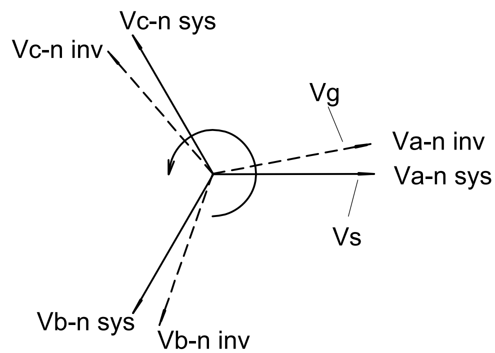
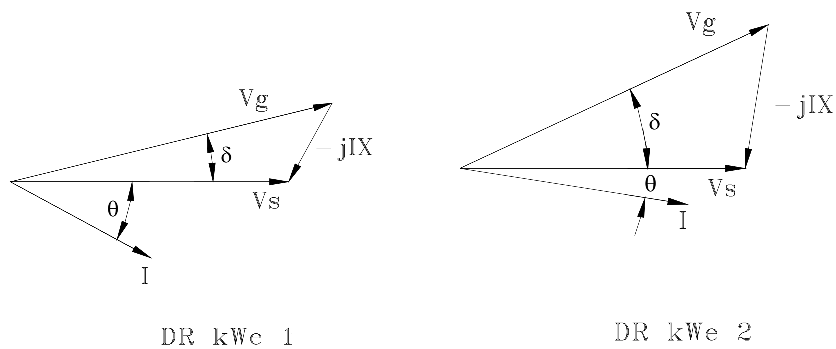


Figure C.8—Voltage phasors relationship of an inverter-based DR with area EPS



(a) (b)

Figure C.9—Phasor diagrams for an inverter-based DR operating at two power levels

The mechanism for operation of an inverter to convert dc to ac for coupling and transfer to the EPS is shown in the following figures. An elementary single-phase inverter that employs IGBT switching devices is shown in Figure C.10. It is not interconnected with the EPS. Switching devices Q1 and Q2, along with Q3 and Q4, are configured to comprise a so-called H bridge, with resistor R1 connected between its two poles at points a and b. Idealized operation of this rudimentary inverter is shown in the figure and proceeds in the following sequence. Q1 and Q4 are both turned on and admit current Idc from the dc-side source, which is at voltage Vdc. This causes Idc to flow from point a to b in the H bridge. Next, Q1 and Q4 are turned off, and Idc goes to zero. Immediately following this, Q3 and Q2 are turned on, and Idc again is admitted from the dc source. At this time, however, Idc is flowing from point b to a in the H bridge. On the dc side of the H bridge, Idc continues to flow in the same direction as it did when Q1 and Q4 were turned on (i.e., out of the positive polarity of the dc source). Next, Q3 and Q2 are turned off, and Idc goes to zero. Immediately following this, Q1 and Q4 are once again turned on, which causes Idc to flow from a to b through R1. This pattern repeats itself indefinitely. It is shown in this sequence of operation that the current through R1 is caused to repetitively alternate its direction of flow while the direction of current flow from the dc source is maintained in the same direction, flowing out of the positive polarity of the dc source. Thus, it is shown in Figure C.10 that an elementary inverter is created, which causes a power transfer from the dc source to the ac-side connection created and applied across resistor R1. The ac voltage across R1 is given by the product of R1 and the time function trace of current flowing through R1, as shown in Figure C.10.

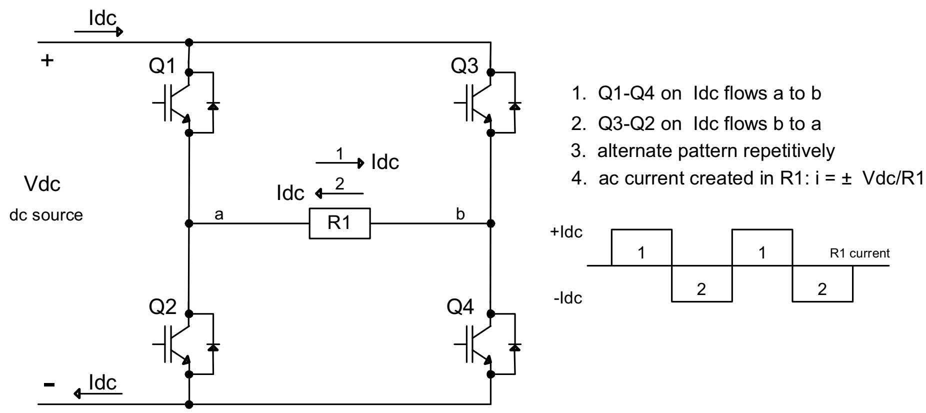


Figure C.10—Elementary single-phase inverter

In Figure C.11, resistor R1 is replaced with a single-phase transformer T1. The T1 secondary winding is connected between points a and b in the inverter H bridge, and the primary winding of T1 is connected to the area EPS. The inverter circuit of Figure C.11 has the same basic switching pattern for devices Q1-Q4 and Q3-Q2 as the inverter of Figure C.10. In Figure C.11, transformer T1 is connected between the two poles of the inverter and has the same base current pattern injected into the secondary winding connected between points a and b. Alternatively, this can be thought of as an ac voltage with peak amplitude Vdc, which is applied across T1, that gives rise to the current injected into transformer T1. The controls stage of the inverter will establish an exact clocking and power gating or turn-on of the power switching devices Q1, Q2, Q3, and Q4 based on precise timing driven by the line frequency of the area EPS. With the switching patterns of Q1-Q4 and Q3-Q2 as described, and with precision timing locked into the line frequency of the area EPS, this constitutes in an elementary manner a synthesis of ac voltage phasors created by the inverter. Before devices Q1-Q4 and Q3-Q2 are turned on, however, the inverter controls stage first will align its phasors control precisely with signals from the area EPS for voltage rotation, amplitude, and phase to achieve exact synchronism with the EPS. Once this is accomplished, the inverter is free to release its gating, in the described pattern, to the power switching devices Q1, Q2, Q3, and Q4. In this fashion, the inverter circuit of Figure C.11 synthesizes a set of ac phasors in a single-phase equivalent to the phasors of Figure C.8. Therefore, with the control of its phase angle with respect to the ac area EPS voltage as depicted in Figure C.8, the inverter in Figure C.11 is able to transfer power in a controlled manner from its dc side to the ac area EPS connected to the inverter through transformer T1.

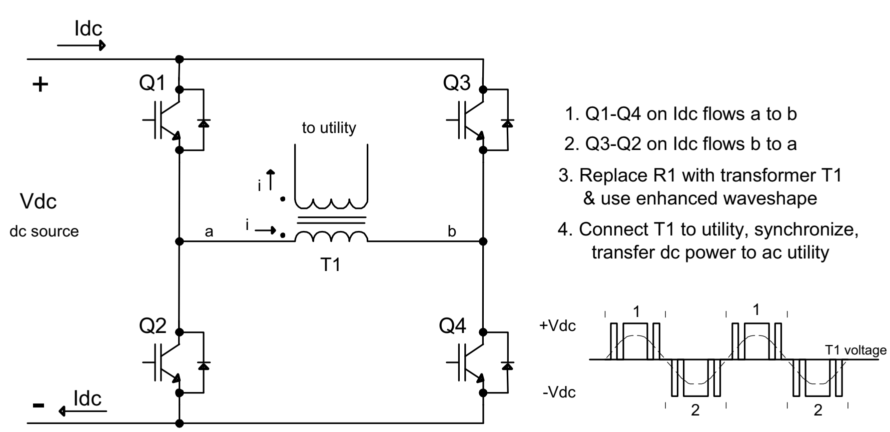


Figure C.11—Elementary single-phase inverter with parallel area EPS connection

The base switching pattern from Figure C.10 also is used in the inverter of Figure C.11. However, extra current switching notches are added into the base pattern in Figure C.11 to improve the harmonic content of the current waveshape. This is done to better use the switching devices for power transfer at the fundamental line frequency and enhance the interconnection with the ac source. That is, the extra switching notches have the effect of increasing the presence of the fundamental component of the line frequency in the total switching pattern while tending to decrease the presence of the higher-order current harmonics of the fundamental line frequency in the current waveshape that is injected into the ac area EPS. The enhanced waveshape also begins to approximate a pulse width modulated pattern, which is widely used in industry today for these reasons.

Furthermore, note the designations of the windings of T1 as secondary and primary. If this were not a DR generator operated parallel with the area EPS but rather just a simple load fed through a transformer, the primary and secondary side designations would be certain. The ac area EPS side would supply the transformer magnetization current and be termed the primary. However, in the case of a parallel DR transformer such as T1, its magnetization current is sourced from the DR side of T1 at points a and b in Figure C.11 once it transitions from drawing any load it may demand from the ac area EPS to driving power from the DR into the ac area EPS. Thus, the designation of primary and secondary side windings becomes somewhat blurred because the two windings, in a functional way, change roles.

Also in Figure C.11, the inclusion of transformer T1 is not mandatory. Description of the circuit in Figure C.11, though, easily transitions from the replacement of R1 in Figure C.10 with an equivalent impedance element T1 in Figure C.11. The single-phase H bridge inverter can convert dc to ac and transfer power into the ac area EPS without a transformer connected between its poles at points a and b. That, however, would eliminate many functional aspects that accrue to the circuit of Figure C.11 that includes T1. Among those aspects are DR ground isolation, short-circuit fault withstand levels, harmonic attenuation, EMI containment, and control of dc current injection into the ac area EPS.

The single-phase H bridge inverters of Figure C.10 and Figure C.11 can be extended into a three-phase equivalent form based on the same concepts used in the simple single-phase inverters. A three-phase inverter bridge tied to the ac area EPS is shown in Figure C.12. It has a dc side or intermediary dc link input, which sources dc power to the inverter bridge in exactly the same way as the single-phase circuits. In this case, it has three inverter poles, which are connected to the three phases of the ac system at the points a, b, and c in Figure C.12. Two additional switching devices, Q5 and Q6, are added to create the three-phase bridge. In Figure C.12, the dc current flow Idc is shown with current leaving the positive polarity of the dc source, and, thus, power transfer is from the dc source to the three-phase ac system. The controls stage of the inverter synthesizes and creates a set of three-phase phasors Vg, as shown in Figure C.8. In Figure C.12, because power is transferred from the dc source to the ac area EPS, the inverter ac phasors Vg of Figure C.8 slightly lead the ac system phasors Vs.

The inverter bridge of Figure C.12 is not limited, however, to operation with power flow in this direction. If operational needs of the DR require power to flow in the reverse direction, then the inverter controls stage makes the Vg set of phasors operate slightly lagging relative the ac system phasors Vs of Figure C.8. This causes power to flow from the ac system to the dc side of the inverter and also causes a reversal of the dc current flow Idc, which now flows into the positive polarity of the dc source. In this case, the IGBT switches would not conduct the current because they can carry current only in their forward direction. The inverter bridge diodes connected in anti-parallel around each switching device Q1, Q2, Q3, Q4, Q5, and Q6 in Figure C.12 would conduct the current to the dc source while the switching devices Q1, Q2, Q3, Q4, Q5, and Q6 would create the slightly lagging voltage phasors necessary to admit reverse current through the inverter bridge in a controlled manner.

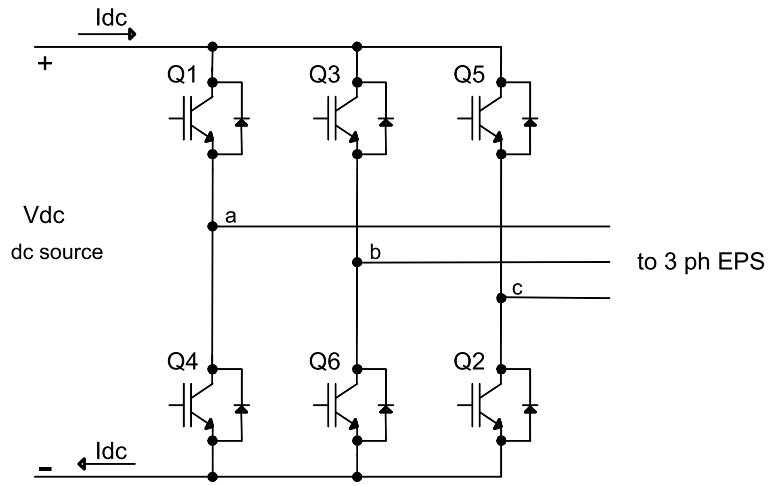


Figure C.12—Three-phase inverter bridge with power transfer from dc side to ac system

The switching pattern of the three-phase inverter bridge power devices Q1, Q2, Q3, Q4, Q5, and Q6 in Figure C.12 is done in a manner completely analogous to the single-phase bridges of Figure C.10 and Figure C.11. In the single-phase case, though, the alternate switching of Q1-Q4 and Q3-Q2 to fabricate the base pattern results in a waveshape and alternating time trace of current through the inverter bridge that is easily followed and understood. The conduction periods of Q1-Q4 and Q3-Q2 in the single-phase case occur separately in time and do not exist simultaneously. Thus, a natural switching pattern for Q1, Q2, Q3, and Q4 to synthesize the single-phase ac voltage phasors is easily seen. In the three-phase case, however, the natural phase displacement and time interleaving of the three phases in the ac system needs to be exactly matched and synthesized by the inverter, and this results in a more complex sequence to define the natural switching pattern for the inverter. Note that, in Figure C.11, the first leg of the bridge is formed by Q1-Q2, and the second leg is formed by Q3-Q4. However, the third leg of the three-phase bridge of Figure C.12 is not formed by a Q5-Q6 combination. The power switching devices Q1-Q4, Q3-Q6, and Q5-Q2 in the three-phase circuit of Figure C.12 form the three poles of the inverter. The numbering is identified in a pattern that matches the natural firing sequence required to properly create the three-phase ac phasors within the inverter bridge. The inverter controls stage fabricates the phase displacement and natural time interleaving of the three phases of the ac system along with the commutation of the maximum driving force voltage potential from one set of phases to another that occurs naturally within a three-phase ac system. This is necessary to accurately synthesize the Vg phasor set of Figure C.8 and enable the full operation of the three-phase inverter bridge.

Figure C.13 shows a plot of time traces for a set of three-phase ac voltages—a, b, and c—with Phase a highlighted. Centerlines are drawn on Phase a at its points of maximum voltage amplitude. Inspection of Figure C.13 shows a symmetry of time periods for the voltage of Phase a above Phase b and the voltage of Phase a above Phase c. Also, the most positive voltage difference of Phase a compared with Phase b or c changes or commutates at the peaks of Phase a where the vertical centerlines are drawn. To the left of these centerlines, Vab is greater than Vac. To the right of these centerlines, Vac is greater than Vab. Of course, identical relationships exist if Phase b or c is highlighted. Thus, a driving force commutation of the most positive voltage of one phase compared with another naturally exists in a three-phase ac system. As shown in Figure C.13, a commutation of system driving force because of the most positive voltage difference between phases occurs in the sequence ab ac bc ba ca cb and then repeats again with ab.

Therefore, the controls stage for the three-phase inverter bridge of Figure C.12 needs to synthesize a set of balanced three-phase voltages, each displaced by 120º from each other, with a driving force commutation or phase-firing sequence identical to the driving force commutation pattern shown in Figure C.13. At the start of operation, the inverter controls would not create any angle between its Vg phasor set and the system phasors Vs, as shown in Figure C.8. Instead, it would first align itself at zero angular difference with sensing signals from the three ac system phase voltages and set its control signals for the described firing pattern in exact phase synchronism with the ac system voltages. Once it accomplishes phase-locked synchronism with the ac system three-phase voltage phasors Vs, it is free to release its gating or drive signals to the bridge power devices Q1, Q2, Q3, Q4, Q5, and Q6 and respond to power transfer commands by way of its angular control of Vg relative to the ac system.

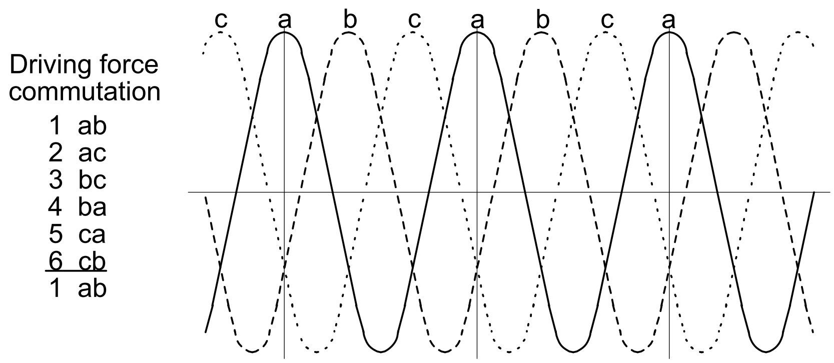


Figure C.13—Three-phase system time traces showing natural driving force commutations

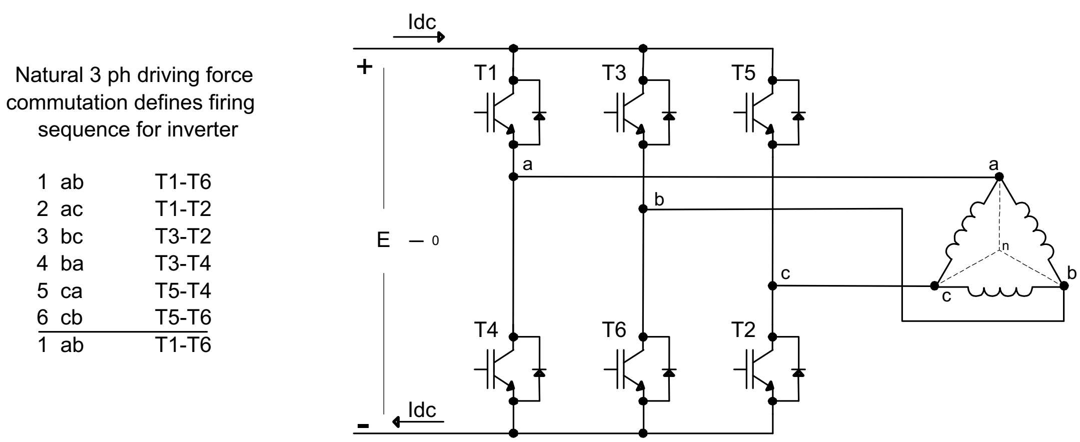


Figure C.14—Three-phase inverter bridge with power export to parallel area EPS connection

A three-phase inverter bridge connected to the ac area EPS through the delta side of a three-phase transformer is shown in Figure C.14. It has a dc source with voltage magnitude E and a midpoint reference at 0. It is shown exporting power to the ac side of the inverter because Idc is flowing from the positive polarity of the dc source. In Figure C.14, the power-switching devices alternatively are labeled T1, T2, T3, T4, T5, and T6 but otherwise are identical to Q1, Q2, Q3, Q4, Q5, and Q6 in Figure C.12. The firing sequence for T1, T2, T3, T4, T5, and T6 is listed in Figure C.14 and is identical to the driving force commutation sequence of Figure C.13. The turn on or firing sequence for power devices T1, T2, T3, T4, T5, and T6 in the three-phase inverter bridge of Figure C.14 follows the natural driving force commutation sequence for a three-phase ac system. Using a phase rotation of a b c for the external ac system, the inverter bridge operates in the following manner. It is helpful to think of the three phase voltages as having nominal designations a-b, b-c, and c-a, which signify the initial portions of each positive half cycle for each phase, as shown in Figure C.13.

Thus, Figure C.14 shows that when T1 and T6 are turned on, current flows from Point a to b in the inverter bridge. This causes current to flow through the a-b winding of the delta transformer and builds the positive half cycle of the a-b line cycle. Next, T2 is turned on while T1 remains on, which causes current to flow from Point a to c in the inverter bridge. This results in current flow in the winding of the delta transformer in the direction a to c, which is opposite its nominal c-a polarity and thereby builds the negative half cycle of the c-a line cycle that the inverter bridge creates.

Then T3 and T2 are turned on, and this causes current to flow from Point b to c in the inverter bridge through the b-c winding of the delta transformer and builds the positive half cycle of the b-c line cycle. While T3 remains on, T4 is turned on, and current flows from Point b to a in the inverter bridge and through the a-b winding of the delta transformer in the reverse direction of its nominal polarity a-b. In like fashion to the previous sequence, this builds the negative half cycle of the a-b line cycle that the inverter bridge creates. Then T5 and T4 are turned on, and current flows from Point c to a in the inverter bridge through the c-a winding of the delta transformer and builds the positive half cycle of the c-a line cycle. While T5 remains on, T6 is turned on, and current flows from Point c to b in the inverter bridge and through the winding of the delta transformer in the reverse direction of its nominal polarity b-c. Similar to the previous sequence, this builds the negative half cycle of the b-c line cycle created by the inverter.

Therefore, this sequence continues for steps 1 through 6, as shown in Figure C.14, and then repeats as T1 and T6 are once again turned on. Note that each phase will conduct simultaneously with each of the other two phases. For example, with T1 and T6 on, current flows from Phase a to b. Next, with T1 and T2 turned on, the Phase a current also begins to flow to Phase c. Thus, the requisite 120º phase-displaced natural interleaving of the phase voltages is created in this manner.

Waveforms for the three-phase inverter bridge circuit of Figure C.14 operating in a square wave or stepped-mode manner are shown in Figure C.15. However, the inverter bridge of Figure C.14 is not constrained to operate solely in stepped-mode fashion. In fact, a more likely operation mode for such a three-phase inverter bridge composed of IGBT power switching devices would be a PWM method. Despite this, insight to the basic tenets of how the three-phase inverter bridge circuit operates and may be deployed in modular constructs is well served first by a discussion of these circuits operating in square wave mode.

In Figure C.14, let three functional sets of power-switching devices each work in a pure square wave mode or 180º of conduction per set, and let each set be displaced from the others by 120º. These three sets are (1) T1 T6 T2, (2) T3 T2 T4, and (3) T5 T4 T6. With these three switching sets operating on a square wave basis, the waveshapes of Figure C.15(a) and Figure C.15(b) result. The voltages that the inverter generates for each pole in the inverter bridge are shown in Figure C.15(a) for phases a, b, and c, with each phase displaced by 120º. Note that the bridge voltages are referenced to the zero or midpoint of the dc source voltage E and are drawn with an amplitude of positive and negative E/2 about the zero reference. Therefore, each of the three waveshapes in Figure C.15(a) is the voltage created by that particular pole of the inverter bridge and represents seemingly a line to neutral voltage for each phase, except the reference is the midpoint of the dc side of the bridge. When these individual voltages are combined and applied to the delta winding of the transformer, line-to-line voltages across the delta winding are created by the inverter bridge. Figure C.15(a) shows that when each individual voltage or inverter pole voltage in all of its steps is referenced to its succeeding phase—a-b, b-c, and c-a—the waveshapes of Figure C.15(b) are created. Thus, the line-to-line voltages generated by the inverter bridge are shown in Figure C.15(b) and are identified as six pulse waveforms. These are well-known theoretical voltage waveshapes for a six-pulse, three-phase bridge inverter operating in stepped mode or square wave fashion. A sine wave fundamental line frequency component is easily discerned in the six pulse waveforms. The lowest order harmonics in these waveshapes are the 5th and the 7th. If the power level for the system application is not too high, these harmonics can be removed readily with passive filtering tuned to these harmonic frequencies, respective of the fact the inverter is constrained to square wave operation for the present discussion.

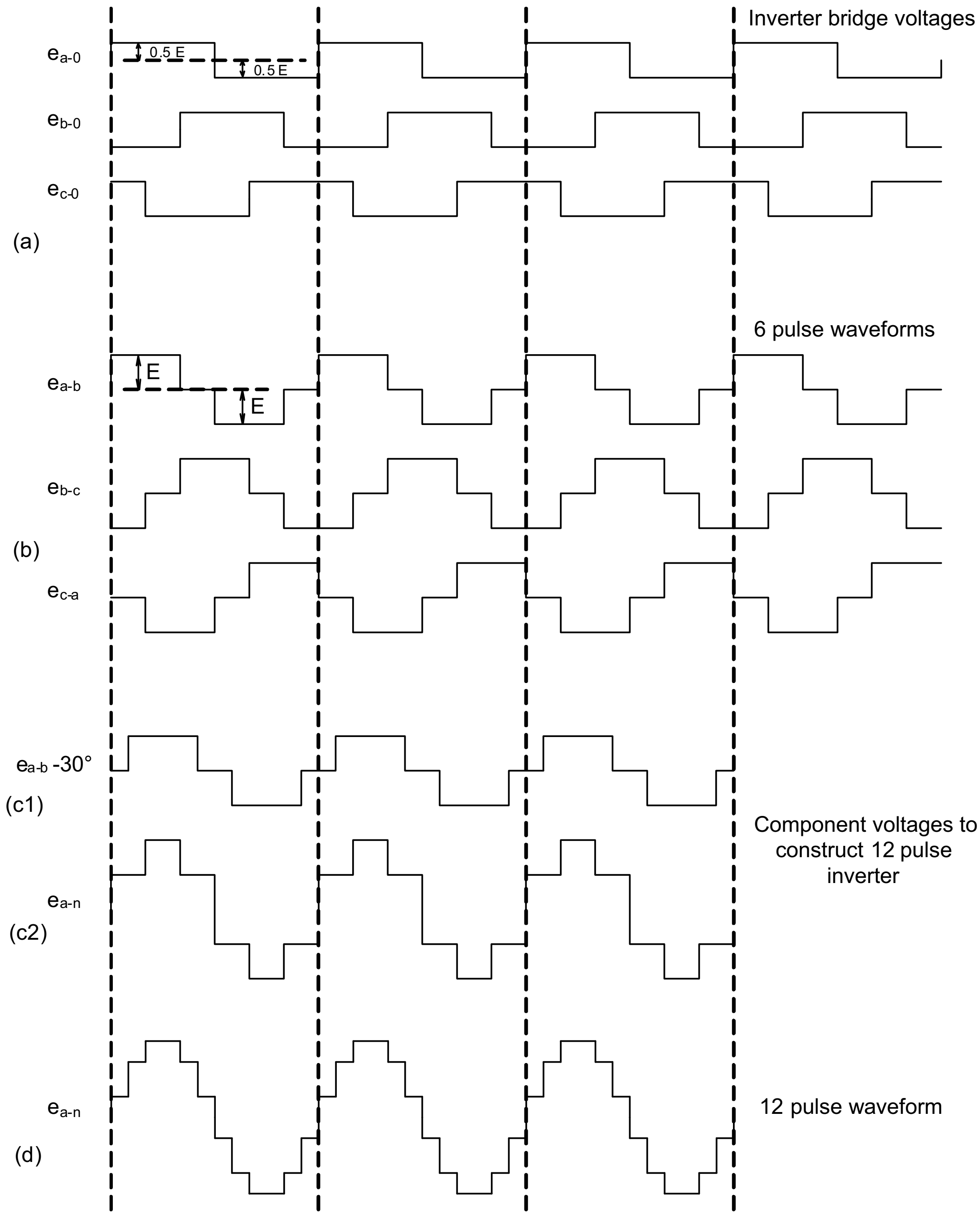


Figure C.15—AC waveform synthesis for stepped square wave inverters

For higher-power-level system applications, it would not be efficient to continue to filter these low-order harmonics. Instead, combination techniques are employed of multiple three-phase inverter bridges to achieve harmonic cancellation benefits.

As an example, a three-phase stepped square wave mode inverter circuit can be constructed that operates at an order of twelve pulse if two identical six-pulse, three-phase inverter bridge circuits, as shown in Figure C.14, are arranged and operated in the following manner.

The two inverter bridges are connected in parallel at their dc inputs, and each bridge is coupled to the ac area EPS through a three-phase transformer. One transformer has a delta secondary on the inverter bridge side, as shown in Figure C.14, and the other transformer has a wye secondary on its inverter bridge side. Each transformer has a primary-side wye winding, and the two primaries are connected in series on the ac area EPS side. The two inverter bridges are operated identically, with the exception that the one with the delta secondary transformer is phase-displaced by π/6 from the one with the wye secondary transformer. The phase-displaced waveshape is shown in Figure C.15(c1), and it is the line-to-line voltage created by the six-pulse bridge, as shown in Figure C.15(b) but with a delay of 30° introduced. By applying this waveshape to a delta secondary, the coupling transformer naturally captures the line-to-line voltage generated by the inverter bridge. The other six-pulse bridge is applied to the ac area EPS through a wye secondary, and thus, the voltage driving this transformer core is the composite of the six pulse waveshapes $e_{a\text{-}b}$ and $e_{a\text{-}c}$, which together create the phase-to-neutral voltage produced by the inverter. The driving voltage of Phase a to neutral is shown in Figure C.15(b) as the summation of $e_{a\text{-}b}$ and $e_{a\text{-}c}$ or, alternatively, the summation of the $e_{a\text{-}b}$ and $e_{c\text{-}a}$ traces. The summation of the $e_{a\text{-}b}$ and $e_{c\text{-}a}$ traces in Figure C.15(b) yields the trace in Figure C.15(c2), which is the Phase a voltage-to-neutral created by the six-pulse bridge, as seen by the secondary of the wye-wye transformer. For clarity following the summation, the result in the Figure C.15(c2) waveshape is not shown with the 1/1.732 reduction that occurs for line-to-neutral voltages. With the wye primaries of the two transformers connected in series, the secondary side applied voltage waveshapes of Figure C.15(c1) and Figure C.15(c2) with the natural 1/1.732 line-to-neutral reduction now applied cause the primary side voltages to add together and produce on the primary side the waveshape shown in Figure C.15(d). This is the characteristic 12-pulse voltage waveshape for a three-phase stepped square wave mode inverter circuit. It is shown only for Phase a, with phases b and c being identical in shape but simply shifted in time by 120°.

Figure C.15(d) shows that the 12-pulse voltage waveshape more closely resembles a smooth sine wave than do the 6-pulse waveshapes of Figure C.15(b). The lowest-order harmonics in the 12-pulse waveshape are the 11th and the 13th. For various applications, the voltage waveshapes generated by the 12-pulse stepped square wave mode inverter may be sufficiently adequate with little or no filtering added to attenuate these higher-order smaller harmonics. Thus, by combining the outputs of two modular six-pulse inverters with the proper operational and transformer structural arrangements, a 12-pulse inverter is readily created that is able to produce a much smoother waveshape than the six-pulse inverter.

This method can be carried still further by combining even more modular inverter circuits by these same techniques to achieve even greater harmonic cancellation benefits. For example, if two 12-pulse inverter circuits are created as described, each 12-pulse modular circuit is operated with a 15° phase displacement relative to the other, and the transformer windings are arranged to cause in-phase addition on the primary side of the transformers, a 24-pulse stepped-mode square wave inverter can be created. The lowest-order harmonics in the 24-pulse waveshape are the 23rd and the 25th, and, therefore, the waveshape created is even smoother than the 12-pulse waveshape. Thus, the 24-pulse waveshape even further resembles a smooth sine wave than does the 12-pulse waveshape. Depending on the application and the power level, the higher-order inverter circuits such as the 24-pulse may be readily justified because of the harmonic cancellation benefits they deliver by these described techniques.

So far, the description of the inverter circuitry has been constrained to stepped square wave mode inverters. These types of inverters typically use SCR or gate turn-off thyristor switching devices and are used in higher-power applications (because of the costs and complexities they involve) in which their harmonic cancellation benefits and lower switching loss performance justify their selection.

In contrast to stepped square wave inverters, switch-mode inverters are typically built around transistor switching devices such as IGBT switches, as shown in the inverter bridge circuit of Figure C.14. Because of the advancement of IGBT switching devices, the power level at which switch-mode type inverters can operate has steadily increased and can easily reach several megavoltamperes through bridge circuit paralleling methods. Switch-mode inverters that employ PWM waveform synthesis in fact dominate the present practice in industry—especially for DR applications. These inverters have a much higher frequency switching rate for their bridge switch devices than the stepped square wave mode inverters, and this strongly distinguishes their performance and characteristics.

Figure C.16(a)[44] shows the control buildup for a PWM inverter, and Figure C.16(b) shows the resulting pulse width modulated conduction periods that constitute the synthesis of the ac sine wave, which the switching bridge produces. The generation of three-phase line-to-line voltages created by the PWM switching bridge is shown in Figure C.17.[45] In Figure C.16(a), the triangular waveshape sets the frequency at which the inverter bridge switches and is referred to as the *carrier frequency.* The sine wave in Figure C.16(a) is the reference control signal or modulation signal, and it has a frequency equal to the fundamental frequency of the ac sine wave that the inverter bridge is trying to create. For DR applications, this would be the fixed line frequency of the area EPS.

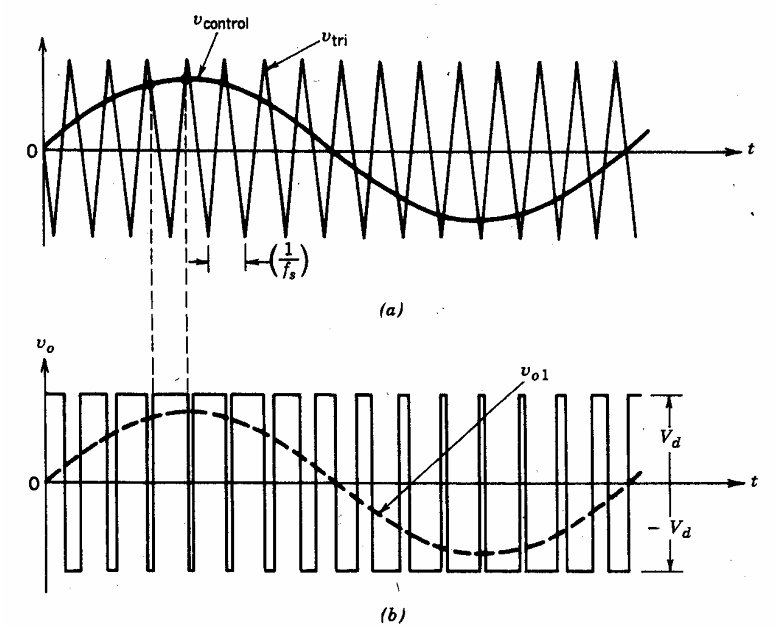


Figure C.16—AC waveform synthesis for switch-mode inverters

Figure C.16 shows that the switching devices are controlled to be on and then off as the reference control signal exceeds and then drops below the level of the triangular wave. The ratio of the peak of the reference control signal to the peak of the triangular waveshape signal is referred to as the amplitude modulation ratio m_a. This is typically set at around 0.85 to 0.9 to keep the switching bridge safely in a linear region in which it can replicate the reference signal. The frequency modulation ratio m_f is defined as the ratio of the frequency of the carrier signal or triangular waveshape to the reference control signal frequency. For DR applications of several kilowatts or more, the frequency modulation ratio m_f would be set to cause the inverter bridge to operate not higher than about 6 kHz in consideration of excessive switching losses as m_f is increased.

In Figure C.17(a), control reference signals are shown for each of the three phases, and the results of the switching modulation and line-to-line voltage difference for phases a to b is shown in Figure C.17(b). The fundamental line frequency is strongly present in the synthesized waveshapes that the switching bridge creates.

[44] *Power Electronics: Converters, Applications, and Design,* Mohan, N.; Undeland, T. M.; and Robbins, W. P. [B55]. Copyright © 1989 John Wiley & Sons, Inc. Reprinted with permission of John Wiley & Sons, Inc.
[45] See Footnote 44.

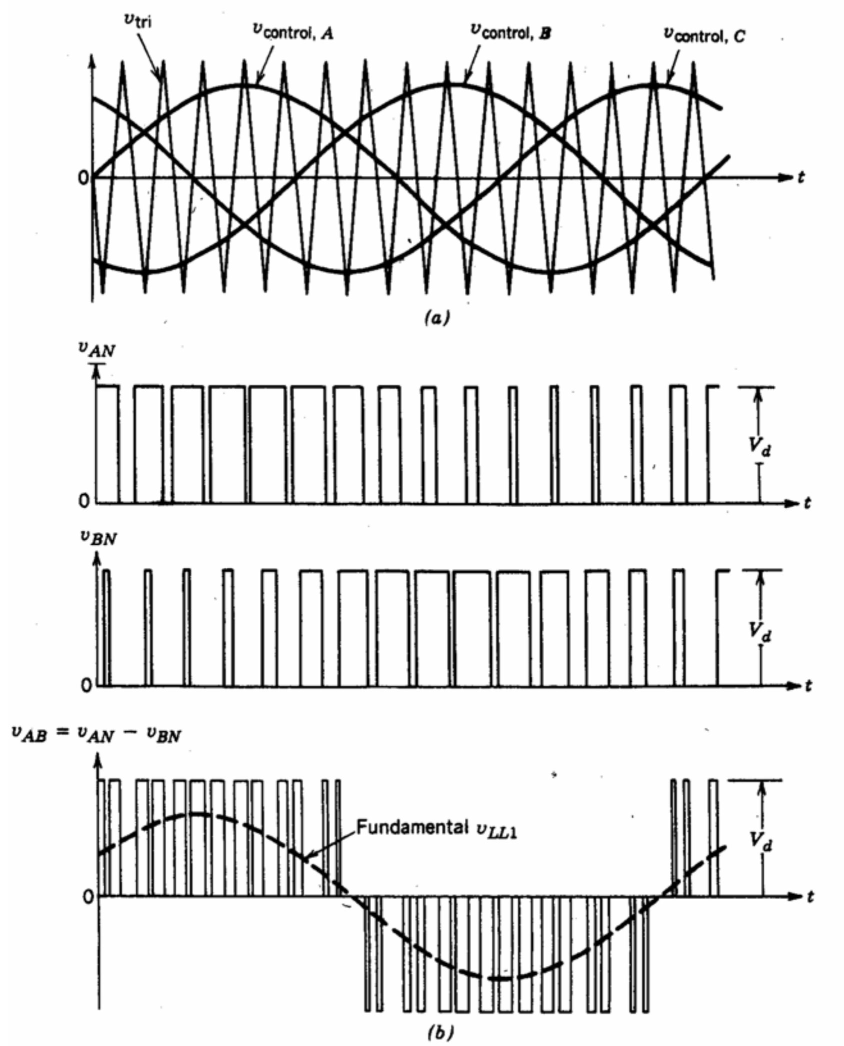


Figure C.17—Three-phase ac waveform generation for switch-mode inverters

If the three-phase inverter bridge circuit of Figure C.14 is now released to operate in a switch-mode type manner, the following events occur. First, the firing sequence for the bridge switching devices, as identified in Figure C.14, remains unchanged so that the PWM inverter can maintain phase synchronism with the natural driving force commutations of the three-phase area EPS, as described earlier.

In this case, however, within each step of the firing sequence, a switching pattern is sent to the selected devices that replicates the PWM control, as shown in Figure C.16. The traces of Figure C.15(a) that depict the inverter bridge voltages still apply as an envelope at least for the basic PWM pattern of Figure C.16. With these basic timing envelopes and the applied PWM patterns within each step of the sequence, the switching bridge is able to synthesize a full set of three-phase fundamental line frequency voltage phasors from the generated waveshapes. Unlike the stepped square wave inverter, though, the PWM switching inverter is able to create ac sine waves of sufficient quality with a single switching inverter bridge.

The control reference signals of the switch-mode type inverter modulate the carrier frequency triangular wave to establish base switching patterns, which are sent to the inverter bridge switching devices. The base switching patterns may be stored in memory in a lookup table, and the inverter control may adjust the basic PWM switching pattern as it samples voltage and current at a downstream regulation point. Changes in real and reactive loads supplied by the inverter or three-phase load imbalances may distort the waveshapes produced by the inverter. In response to such distortions, the inverter control may either select from its memory lookup table or create in real time adjusted PWM switching patterns to send to the bridge switching devices, which act to minimize the distortions at the point of regulation.

The PWM switching inverter for DR applications will operate typically with a carrier or switching frequency of several kilohertz selected to be an odd multiple of the fundamental line frequency to eliminate certain harmonics and minimize output voltage distortion. Thus, the frequency modulation ratio m_f is a relatively high integer. Harmonics in the output voltage waveshape of the inverter occur around multiples of m_f and their sidebands. Thus, although not a perfect sine wave, the output voltage of the PWM inverter has only higher-order harmonics and high-frequency distortions left in its output waveshape.

Various computational methods and algorithms are devised and used to enhance the inverter switching patterns. These adjusted patterns then are gated on to the output power devices of the inverter switching bridge to further eliminate the remaining harmonics and distortions in the output voltage waveshape. Also, if multiple bridges are present in the application for power sharing, they can be arranged and operated in phase opposition to one another and force cancellation of the harmonics.

Despite these methods to further improve the output voltage waveshape, though, the basic inverter switching bridge for a PWM switch-mode inverter contains only higher-order harmonics and distortions, which can be filtered relatively easily with basic circuit filtering means such as those shown in Figure C.18. Because the remaining harmonic content and distortion components of the waveshape are of higher-order frequencies, the filtering hardware can be much less complex than if low-order frequency components were present in the output voltage waveshape.

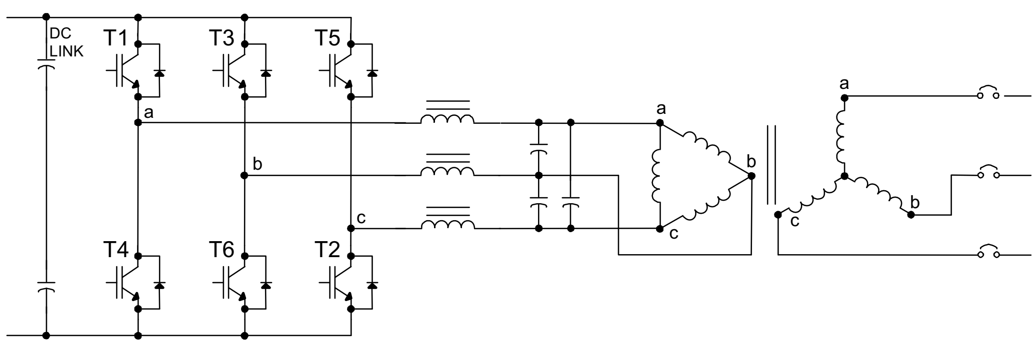


Figure C.18—Grid-connected PWM switch-mode inverter with output filtering

The PWM inverter circuit in Figure C.18 is a simple three-phase bridge arrangement that includes hardware output filtering between the switching bridge and the output transformer that is interconnected with the area EPS. The LC circuit connected to the output of the switching bridge is a low-pass filter that is designed to shape and admit only the fundamental line frequency component of the inverter output voltage waveshape. The other high-order harmonic components in the output voltage waveshape are significantly attenuated and shunted before the voltage drive of the inverter bridge is applied to the delta of the output isolation transformer. The output transformer itself as a line frequency power transformer also tends to impede the high-frequency harmonics in the circuit—at least, to some measure. Thus, a PWM switch-mode inverter can be constructed in a circuit with a single switching bridge, and its remaining high-order harmonic and distortion content can be dealt with and sufficiently mitigated by a simple output hardware filtering circuit such as the one shown in Figure C.18. Furthermore, the synthesized ac waveshapes produced by this total circuit are of a quality that is compatible with directly interconnecting the inverter with an area EPS circuit.

C.4.1 Line-commutated inverter

These inverters are limited to line-interconnected systems only because of the absence of self-commutation capability. A controlled rectifier circuit that contains SCRs and operates with firing angles of more than 90º electrical permits power to flow from the dc side to the ac side. The external ac line voltage is required to commutate the SCRs. This is necessary because this inverter uses the reversal of ac voltage to commutate the SCR devices. For this reason, this inverter is called a *line-commutated inverter.* Without an external line voltage, the SCR-based inverter cannot operate. Another major disadvantage is degradation of the ac-side power factor as well as the generation of harmonics—a consequence of phase control. The commutation of the SCRs is completed before the next zero crossing of line voltage, at which the commutating voltage changes polarity. If this condition is not satisfied by this time, the current in the SCR pair that is being turned off would begin to increase, keeping the pair on. This leads to a dc voltage source short circuit and could be disastrous in consequences. To prevent commutation failure, the line-commutated inverters operate with a minimum firing angle, called the *margin angle,* which is a function of line reactance, load current, and SCR recovery time. The frequency of operation of the SCR-based inverters is limited to a relatively long recovery time and long current tails. They are gradually being replaced by IGBT-based self-commutated inverters.

C.4.2 Self-commutated inverters

The self-commutated inverters do not have the restriction of providing an external voltage source for commutation purposes. One alternative is to use auxiliary circuits to force the commutation of thyristors, although this increases circuit complexity. A more popular method involves the use of fully controllable switches, such as gate turn-off thyristors or IGBTs. The use of high-frequency switching devices, such as IGBTs, minimizes voltage or current harmonics. These types of static inverters may operate as voltage or current types. When interconnected with an external ac power system, only the current type of inverter can be used because the output voltage is fixed by the ac power system. The output power is controlled generally through a change in duty cycle of the inverter switches.

C.4.3 PWM inverters

Ongoing advances in switching device technologies have created new opportunities in the design of PWM switched inverters. Two major types of PWM waveform control are as follows:

- Programmed-waveform PWM

  A fixed, periodic switching pattern is fed to the inverter’s switches. The pattern is designed to produce the least harmonic distortion in the output waveform at a given number of switching operations per cycle.

- Carrier-modulated PWM

  A reference sine wave is compared with a triangular (or sawtooth) signal with a fixed frequency much higher than that of the fundamental. Switching of the power devices occurs at zero crossing of these two signals. Distortion of the output waveform occurs at the carrier frequency and its sidebands as well as at multiples of the carrier frequency and its sidebands. Depending on whether the carrier frequency is synchronized with the fundamental, this distortion may be harmonic. The magnitude of the distortion depends on the modulation index (the ratio of the sine wave peak to the carrier peak value). The lower the modulation index, the higher the distortion magnitude.

Currently, there are no IGBTs that can withstand high voltages (6 kV or more). They need to be placed in series to meet the voltage requirements.

However, there are numerous advantages of using PWM inverters. They:

- Do not require use of the power line to maintain switching devices commutating with power system terminal voltage.

- Have the ability to control the output waveform to be more sinusoidal in shape. (This reduces the harmonic content of the output voltage.)
- Can achieve low EMI because of their high switching frequency.
- Can achieve higher and more constant power factor levels. (In effect, higher efficiency of the inversion system can be attained.)
- Can more easily filter constant and harmonic frequencies with small (size and weight) filters.

The main disadvantages of PWM inverters are its:

- High switching losses

  The switching losses of the PWM inverter are proportional to the switching frequency, dc bus voltage, and load current. In practice, the switching frequency of the PWM inverter should be at least 10 times more than that of the fundamental to maintain the above advantages.

- High conduction losses

  The forward voltage drop of the IGBTs available on the market is higher than that of SCRs of the same ratings. This adds to the total losses of the inverter.

For DR interconnected with the external larger power system, the controller of the PWM inverter needs to keep its output voltage at the same level as that of the power system. The inverter, in addition, may be required to provide a specified amount of current into a short circuit. This necessitates the inverter to be capable of cutting back the output voltage to nearly zero.

C.4.4 Output harmonics

Harmonics not only reduce the overall power factor of the ac side, but they also are often a source of electromagnetic noise that interferes with proper operation of the inverter or external equipment. Active harmonic reduction control methods are commonly used to minimize harmonics while minimizing filtering effect on the phase shift and attenuation of the fundamental. The harmonics may be eliminated or cancelled. The first method is based on such control of the switches that certain harmonics are eliminated. This is called *harmonic elimination.* The second method uses multiple converters' outputs together to cancel certain harmonics. This is called *harmonic cancellation.*

Annex D

(informative)

Design, construction, configuration, operation, and concerns of area and local EPSs

D.1 Area EPS

D.1.1 Area EPS distribution systems

D.1.1.1 Distribution primary circuits

A primary distribution circuit is served from a distribution substation transformer fed from one transmission line. If loads are large or are critical in nature, a second transmission feed and transformer may be installed. Most existing primary distribution circuits are overhead construction, but much new construction is underground—especially in residential and commercial areas. Most primary distribution circuits are operated in a radial configuration, with one source used per circuit at any given time. Feeders in urban and suburban areas typically have an alternate source available via a normally open tie to another feeder. In rural areas, it is common for feeders to have a strictly radial design without an alternate source.

The trend to higher distribution voltages means more load may be served from each distribution circuit. This would normally imply reduced reliability because more customers are affected by clearing faults on the distribution circuit. However, automatic switching and protective relaying devices mitigate this effect.

D.1.1.2 Distribution secondary systems

The secondary system is the portion of the distribution system between the primary feeders and the customer premises. The secondary system is composed of distribution or service transformers, secondary circuits, customer services, and revenue (billing) meters to measure energy usage. In some cases, the demand and power factor are also measured. The secondary circuits connect the customer service to the low-voltage side of the distribution transformer. Although secondary systems are predominantly single-phase, three-wire, three-phase secondary systems are used where a combination of large commercial and small industrial loads are located in a residential area.

There are several secondary system configurations, as follows:

— Radial secondary

— Solid-banked secondary

— Loose-banked secondary

— Spot network

— Grid network

The radial secondary system is the most common configuration. Secondary banking[46] is infrequently used in areas in which loads are close together and there is a need to reduce voltage flicker because of motor starting.

Low-voltage ac networks were first developed in the 1920s to provide highly reliable electric service to concentrated load centers—primarily in the downtown areas of major cities. There are two types of low-voltage networks: spot networks and grid networks (also referred to as *area networks* and *street networks*). A spot network consists of two or more network transformers connected by a common bus low-voltage side at a single location. A grid network can be thought of as several spot networks tied together with secondary cables (sometimes called *secondary mains* or *street ties*). A minimum of two primary feeders are required to supply a network. The number of feeders to a network depends on the load requirement of the grid network or the spot network load.

The grid network may consist of multiple areas operated independently from one another within a city. Customers in a low-voltage network area typically take service from the network at the grid's voltage level. A spot network supplies grid-like service to a particular customer installation to achieve a high level of reliability and is designed to carry full load with a minimum of n–1 primary feeder out of service. To achieve high reliability, the faulted primary feeder or transformer connection to the low-voltage network is isolated within a few cycles.

All the components that make up the distribution system described here—including wire conductors, transformers, and switches—have a limit on the amount of electricity that can safely pass through them. Therefore, as an area EPS service territory becomes more populated and electricity demand grows, the distribution system components may need to be upgraded or replaced to prevent operation over capacity. Traditionally, new transmission and distribution equipment is oversized to meet peak demand, although the average base load may be much less. As such, the area EPS equipment ratings, and therefore capital costs, are primarily driven by peak load.

Consumers in different regions have differing load profiles. Therefore, the load profile of one primary distribution feeder may vary from the next. For example, the first feeder may supply a residential area with small but predictable load growth. The second feeder may deliver electricity to a commercial park with highly volatile demand based on factors such as production level, number of working shifts, the economy, and occupancy. The substation's load profile is the sum of load profiles of all primary feeders that leave the substation. Because the load profiles of diverse loads may not peak at the same time, coincident peak load is typically less than the sum of the individual, diverse feeder peak loads.

Because of greater exposure to the elements, overhead distribution systems experience higher overall outage frequencies than do underground distribution systems. However, average outage duration is longer for underground than overhead systems. This is because overhead systems can be visually inspected to determine the outage cause and overhead facilities take less time to repair, on average.

Various operation, maintenance, and design measures can improve the reliability of overhead and underground distribution circuits. Example design measures include improved protective device coordination, additional circuit reclosers, alternate feeder sources via ties to other feeders, and various feeder automation schemes.

A three-wire system comprises three-phase conductors, and single-phase distribution transformers are connected phase-to-phase. For three-phase load service, transformers with an ungrounded primary connection (closed delta, open delta, or floating wye) are used.

[46] *Banking* means paralleling on the secondary side a number of distribution transformers that are connected to the same primary. Banked transformers are a form of radial distribution because they are connected to one primary feeder. This configuration should not be confused with a secondary network configuration in which the distribution transformers are connected to two or more primary feeders.

A four-wire circuit has three-phase wires and a common neutral wire, which is typically grounded at multiple locations along the circuit. The common neutral is located on the secondary level and can be shared with the secondary. Single-phase transformers are typically connected phase to neutral. Three-phase loads are most frequently served using grounded-wye-wye transformers. However, transformers with an ungrounded primary connection (floating wye, closed delta, or open delta) may also be used.

D.1.1.3 Transformer connections and primary circuits

The interaction of the local EPS and the area EPS and the impacts each system may have on the other are influenced by the transformer connections between the local EPS and the area EPS as well as the wiring configuration of the area EPS primary distribution circuit. Area EPS primary distribution circuit wiring configurations are typically one of the four types shown in Figure D.1.

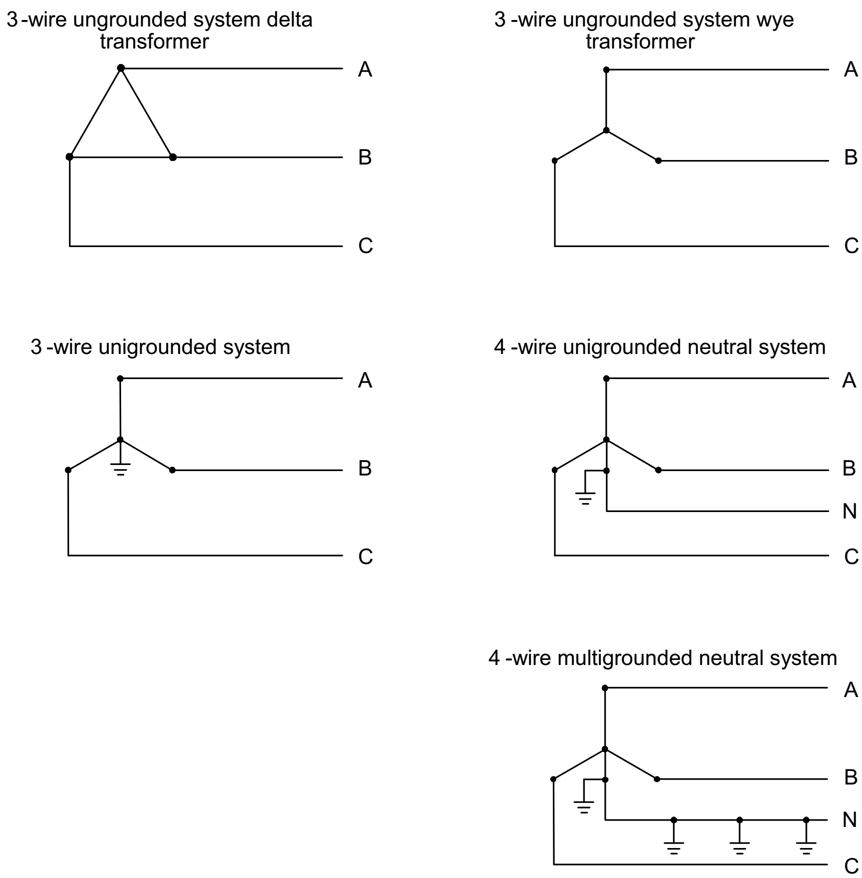


Figure D.1—Types of area EPS primary distribution circuit systems

The four common types of primary distribution circuits are as follows:

— Three-wire ungrounded, served from delta or wye transformers

— Three-wire unigrounded

— Four-wire unigrounded neutral

— Four-wire multigrounded neutral

In the U.S., distribution primary circuits are typically of four voltage classes: 5 kV, 15 kV, 25 kV, and 35 kV line-to-line. The 15 kV class is most common and includes the common nominal primary voltage systems of 12.47 kV, 13.2 kV, and 13.8 kV. The loading in the primary feeder circuits can vary greatly, but peak load for a 15 kV class circuit is typically 4 MVA to 6 MVA. It is 7 MVA to 10 MVA for a 25 kV class circuit and 10 MVA to 16 MVA for a 35 kV class circuit. Prospective fault currents vary with the voltage and the distance from the substation and can range from as low as 300 A or less at the end of a long line to 20 000 A or more at or near a substation where transformers might be paralleled. More typical levels across the distribution primary system range from 1000 A to 8 000 A.

Both three-wire and four-wire primary distribution circuits are used in area EPSs, but the most widespread system in the U.S. is the four-wire multigrounded neutral system. In this system, the neutral is grounded at least every 1/4 mile and at the equipment stations of distribution transformers, surge arresters, capacitors, voltage regulators, and like equipment.

A variety of transformer connections are available to interface a local EPS with DR units to the area EPS. Each has strengths and may include drawbacks, depending on the configuration of the installation, the size of the DR units relative to the feeder load, and the satisfaction of grounding requirements on either side of the interconnection.

For three-wire, ungrounded primary systems, transformer connections may include the following:

— Delta high side to delta low side
— Delta high side to grounded-wye low side
— Floating-wye high side to delta low side

For four-wire, multigrounded neutral primary systems, transformer connections may include the following:

— Grounded-wye high side to delta low side
— Grounded-wye high side to grounded-wye low side
— Delta high side to delta low side
— Delta high side to grounded-wye low side
— Floating-wye high side to delta low side

Ungrounded (delta and floating-wye) connections on the high side of a four-wire, multigrounded neutral system are fraught with the concern that the DR may form an island, with a faulted portion of a primary feeder temporarily separated from the substation circuit breaker that is attempting to clear a phase-to-ground fault. If the DR generation can supply the separated load without its voltage collapsing, then while a phase is faulted to ground or neutral potential, the phase-to-neutral voltage on the separated feeder primary can suddenly rise to the level of phase-to-phase voltage. Thus, the classic damaging 1.73 overvoltage on single-phase loads, arresters, and other equipment is set up and puts all equipment at risk. Therefore, this connection type has to be carefully studied.

Grounded-wye connections on the high side of a four-wire, multigrounded neutral system with a delta low side or a grounded-wye low side do not present this concern if the DR generator is effectively grounded. Thus, an islanded DR with this transformer connection can present itself to the primary circuit as a ground source under this fault scenario and help limit the potential overvoltage.

A grounded-wye connection on the high side of a four-wire, multigrounded neutral system with a delta low side connection is a well-regarded choice for interconnecting DR with this type of primary distribution circuit. Because it acts as a ground source, large circulating currents may occur in the secondary delta as well as in the neutral of the wye, which might cause overheating in the transformer. To counter this potential problem, a grounding impedance can be placed in the high-side wye neutral connection to ground to limit excessive circulating currents but maintain effective grounding of the DR system.

One argument against the use of a grounded-wye connection on the high side of a four-wire multigrounded neutral system with a delta low side connection is that multiple ground sources on the feeder pose the risk of desensitizing upstream protection devices and causing coordination problems during ground faults. The ground source transformer banks can create a sink for some of the unbalanced ground-fault currents to disappear into and never reach the upstream ground-fault protective relaying. Another issue with a grounded-wye high-side to delta low-side transformer connection is that it might not be the existing local EPS interface transformer to the area EPS at a site where DR installation is being considered. The most prevalent secondary transformer connection for three-phase loads is four-wire grounded-wye.

Network transformers are typically liquid-filled (e.g., oil-filled) and air-cooled, although some dry-type network transformers have been used. The network transformer may have a manually operated primary oil switch located directly on it, and this can be in the closed, opened, or grounded position. A network protector is mounted directly on the network transformer or within close proximity of it. In the latter case, it is cable-connected to the transformer. Typical network transformer secondary voltages are 208Y/120, 216Y/125, and 480Y/277. The primary of the network transformer may be connected in delta or grounded-wye. The secondary of the network transformer is usually connected ground-wye to supply 208Y/120 or 480Y/277 voltage to the grid network or the spot network customer.

D.1.1.4 Grounding guidance for distributed resources

DR units need to be grounded in a manner compatible with the grounding of the primary and secondary distribution systems. For recommended grounding configurations, refer to Table D.1.

Table D.1—Grounding recommendations for distributed energy resources

Primary distribution type	Secondary distribution type	DR grounding practice
Three-wire, ungrounded system or high-impedance grounded system	Four-wire, grounded	DR should be ungrounded or high-impedance grounded with respect to the primary and effectively grounded with respect to the secondary.
	Three-wire, ungrounded	DR should be ungrounded or high-impedance grounded with respect to the primary and secondary system.
Four-wire, multigrounded neutral system	Four-wire, grounded	DR should be effectively grounded with respect to the primary and the secondary system. [a]
	Three-wire, ungrounded	DR should be effectively grounded with respect to the primary system and ungrounded or high-impedance grounded with respect to the secondary system.

[a] One criterion for effective grounding is that a phase-to-ground fault will not cause a voltage rise on unfaulted phases exceeding 125% of the nominal line-to-neutral system voltage to avoid damaging other connected equipment and causing lightning arrester failures.

D.1.1.5 Integration of area EPS and DR grounding

An important safety consideration for the operation of an EPS is the grounding of the distribution system in the primary and secondary circuits. Figure D.2[47] shows an example system that includes grounding connections in both the primary and secondary circuits of the distribution feeder in the area EPS. It also shows how the grounding system extends into the customer premises in the local EPS.

[47] *Electric Machines: Dynamics and Steady State,* Thaler, G. J.; and Wilcos, M. L. [B65]. Copyright © 1966 John Wiley & Sons Inc. Reprinted with permission of John Wiley & Sons, Inc.

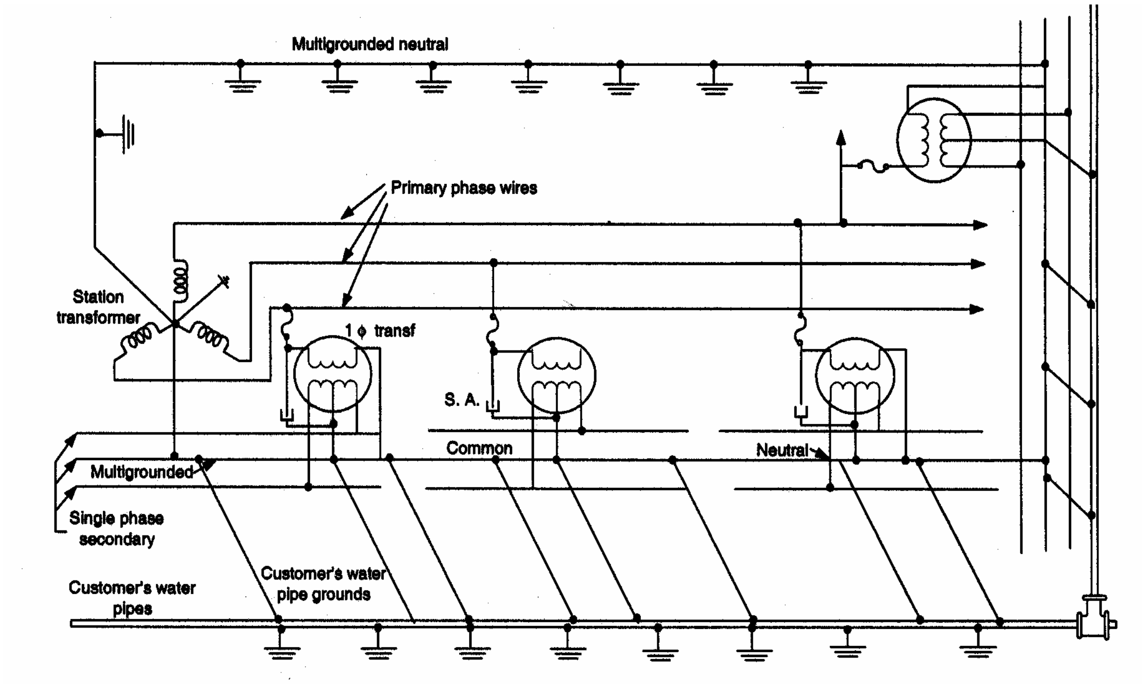


Figure D.2—Distribution system primary and secondary grounding arrangements

As DR units are interconnected with the area EPS, the integration of grounding on both sides of the interconnection is critical. Many parts of this guide focus on issues surrounding this subject. Depending on the kilovoltampere rating of the DR, it will tend to interconnect with the distribution system either at the primary or secondary system level.

The primary distribution circuit operates at voltage levels of 4.2 kV to 34.5 kV. The distribution system secondary system is the part of the distribution system between the primary feeder circuits and the customer's premises. It includes the distribution transformers, secondary circuits, customer services, and metering. The secondary circuits operate at levels of 600 V and less for three-phase service and at 120/240 V for single-phase service.

Primary distribution circuit arrangements vary, but the most common one is the four-wire, multigrounded neutral system. Figure D.2 shows this system in use with multiple 120/240 V single-phase distribution transformers. It is common for this type of feeder for the primary circuit and secondary circuit to be tied together and share a common neutral conductor, as shown in Figure D.2. This method is specified by IEEE Std C62.92.1™-2000 [B49], IEEE Std C62.92.2™-1989 [B50], IEEE Std C62.92.3™-1993 [B51], and IEEE Std C62.92.4™-1991 [B52].

Figure D.2 also demonstrates how the shared neutral from the area EPS relates to the premises grounding within customer buildings. An independent ground reference for electrical service entering a building, or derived separately by isolation transformers within the premises, is required by building electrical safety codes such as the NEC [B57] and CSA C22.1 [B7]. To satisfy this requirement, the 120/240 V service from any one of the four distribution transformers in Figure D.2 is grounded at its neutral to the customer water pipe once the service enters the building.

Furthermore, these codes stipulate that the premises grounding can be done only once for any service entering the building or any separately derived service. This prevents neutral current from circulating in grounded metallic systems within the building if more than one ground connection were created. This is an interesting contrast to the multigrounded neutral system used by the area EPS.

D.1.1.6 Example area EPS

An EPS consists of one or more sources of generation, transmission lines, distribution lines, and multiple loads. Historically, the generation sources have been large units congregated in central generating stations. The power produced is delivered to transmission substations by transmission lines that usually operate at 138 kV or more. The transmission substations reduce the voltage and send the power on to distribution substations over subtransmission lines that usually operate between 46 kV and 138 kV. The distribution substations further reduce the voltage to primary distribution levels, which range from 4.2 kV to 34.5 kV. Individual loads may be served at the most appropriate of the available voltages from transmission through distribution to secondary voltages as low as 120/240 V, depending on the size of the load. The voltage for each section is generally proportional to the amount of power and the distance involved. The nominal voltage of each section is selected by each system from ANSI C84.1 [B3]. These voltage levels have been established to facilitate standardization to provide the least-owning cost for typical installations.

Figure D.3 shows a distribution substation supplied from the subtransmission system through a transformer(s) that sets the substation bus voltage for the primary distribution circuit voltage level at 4.2 kV to 34.5 kV.

Three primary distribution feeder circuits are shown in Figure D.3. Each of the three circuits is supplied from the substation bus through its own circuit breaker to create the primary distribution circuit feeder. As depicted by the first primary circuit, individual large loads may be served directly from the substation at primary voltage levels. A large office building, for example, may be supplied this way.

Multiple dense loads may be supplied from a single substation circuit breaker comprising the second primary feeder, as shown in Figure D.3. These may be large load blocks such as light industrial and large commercial customers, as depicted or crossover feeds through normally open switches without transformation to other primary distribution circuits.

The third feeder in Figure D.3 represents a more diverse set of loads that may be spread out over a large area and located miles from the substation. In this case, fused branch circuits off the main three-phase backbone of the feeder may be deployed as indicated. These may be both three-phase and single-phase laterals serving commercial and residential customers.

Because of the distance the primary feeder may extend from the substation, unacceptable levels of line voltage drop may occur under varying loading conditions because of the impedance of the distribution circuit. Thus, feeder voltage regulators may be installed in the circuit to compensate for this, as indicated in Figure D.3. These units typically are stepped autotransformers with integral load tap changing units. They may simply sense voltage locally and seek a set point within a band with time delay, or they may be equipped with a line drop compensator. The line drop compensator includes an impedance model of the downstream feeder and, in response to loading conditions, can automatically maintain a target voltage at a remote regulation point downstream from the voltage regulator location.

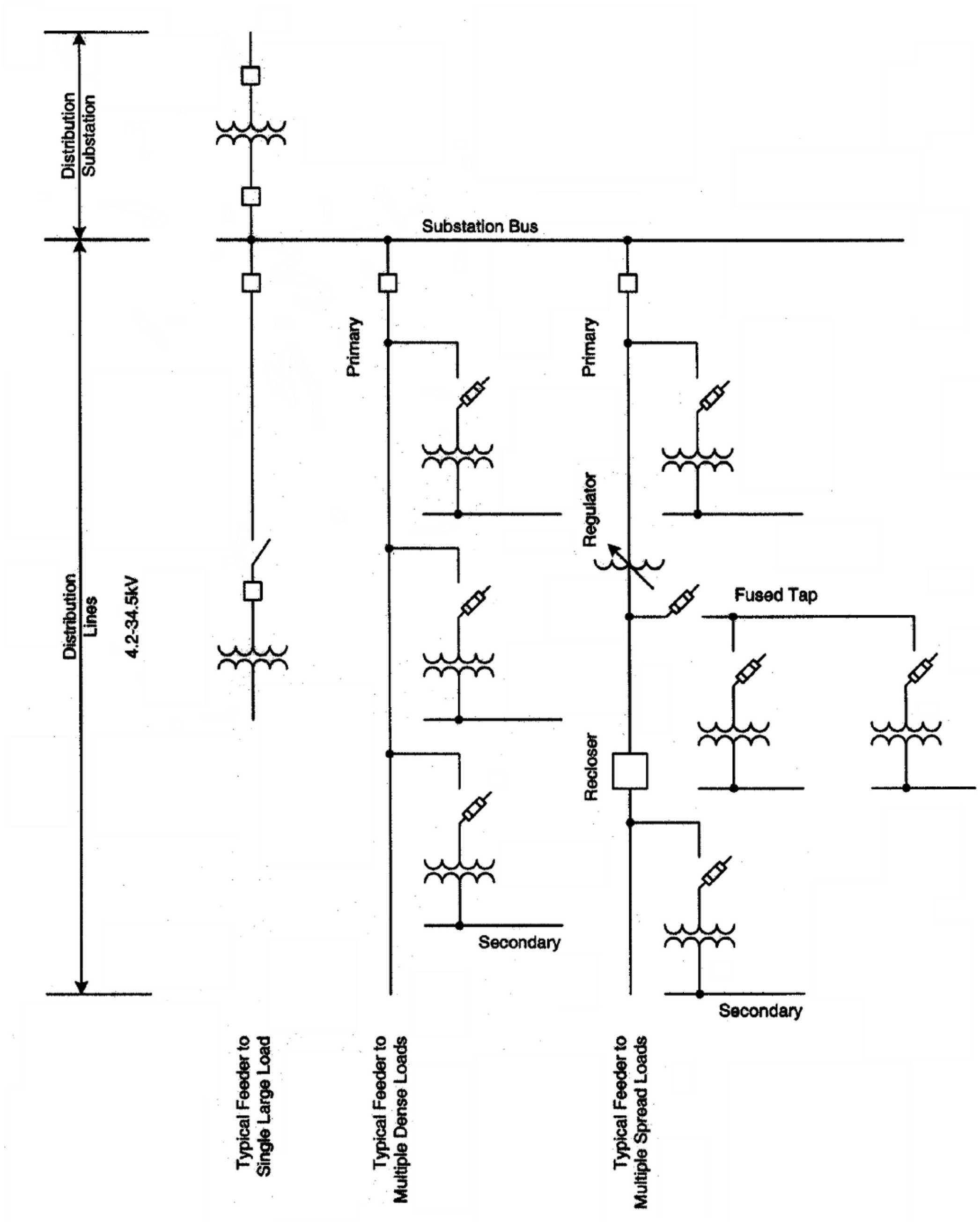


Figure D.3—Example primary distribution system with diverse load feeders

Automatic circuit reclosers also may be deployed in the feeder circuit to clear faults and quickly restore service on the feeder. Reclosers reenergize the circuit automatically immediately after a trip resulting from a feeder fault. They may operate on the feeder breaker at the substation or be located at remote locations away from the substation, as shown in Figure D.3. The trip-reclose sequence may be initiated by reclosing relays controlling the corresponding feeder breaker at the substation or by pole-mounted reclosers or sectionalizers located on the feeder away from the substation. Pole-mounted reclosers or sectionalizers are strategically placed to limit the number of customers affected per given feeder fault. Automatic reclosing allows immediate testing of a previously faulted portion of the feeder and makes it possible to restore service if the fault is no longer present. Depending on the fault magnitude, the first reclosing try can occur very quickly, sometimes within 0.2 s for an instantaneous trip followed by an instantaneous reclosing. Furthermore, area EPS operators use multi-shot reclosers. That is, a feeder breaker or a recloser/sectionalizer can reclose not only once but two or three times for a permanent fault. Typically, this takes place in a period of roughly 1 min to 3 min.

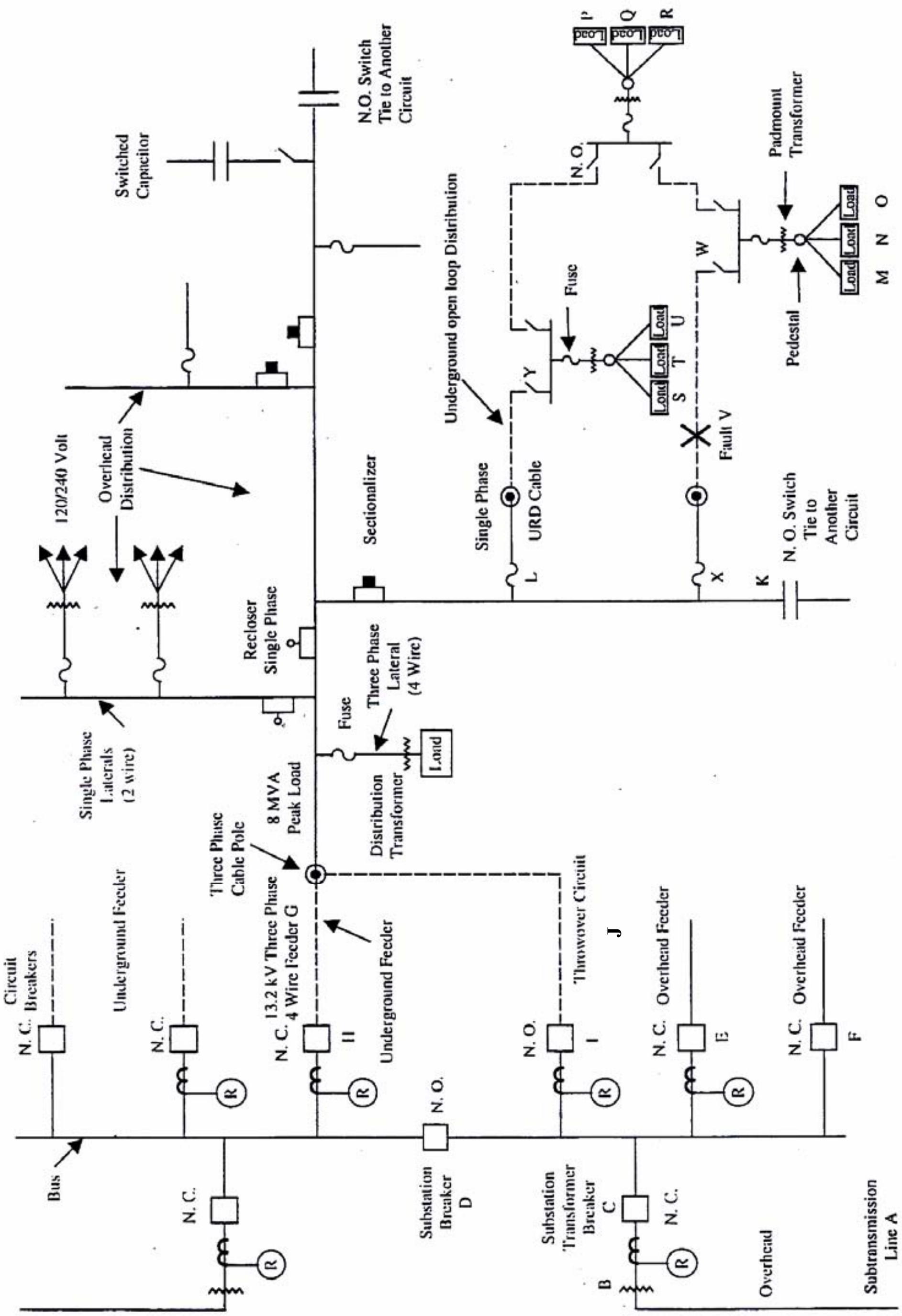
Another representation of a radial primary distribution circuit is the typical radial 13.2 kV distribution circuit and distribution substation one-line shown in Figure D.4.[48] For improved reliability, this diagram shows two subtransmission line feeds and two substation transformers. For the loss of either one subtransmission line (A) or a substation transformer (B), the substation transformer secondary breaker (C) opens, and the normally open section breaker (D) closes, thus restoring service to circuits (E) and (F). Otherwise, circuits (E) and (F) would be out of service for the loss of subtransmission line (A) or substation transformer (B).

Most existing primary distribution circuits are overhead construction, but much new construction is underground, especially in residential and commercial areas. Most primary distribution circuits are a radial design with one source per circuit. In Figure D.4, a three-phase, four-wire feeder extends from the substation breaker to a feed point. This feeder may be overhead or underground construction. Many of the laterals are two-wire, single-phase with one phase conductor and one multigrounded neutral conductor. Other laterals are three-phase with three-phase conductors and one multigrounded neutral conductor. To increase the reliability of the feeder, some area EPS operators use a throw-over circuit (J) as a redundant feed. For example, when a permanent feeder fault occurs on feeder (G), breaker (H) opens and breaker (I) closes to restore service to feeder (G) after the faulted portion of feeder (G) is isolated.

Another popular single-phase, underground distribution circuit design is the open loop concept, shown in Figure D.4. The underground design requires more time to find faults on and repair circuits compared with overhead circuits. Here, two fused radial underground circuits (K and L) are tapped off the single-phase overhead lateral and form a normally open tie point. Customers M, N, O, P, Q, and R are served from circuit K, and S, T, and U customers are served from circuit L. Switches in these two circuits allow the isolation of any cable section. Therefore, a fault at V would cause fuse X to blow, and switch W would isolate the X-to-W cable section. Customers M, N, O, P, Q, and R would be out of service until the normally open switch near loads P, Q, and R is closed to restore service. The other circuit protective relaying devices—such as fuses, reclosers, and sectionalizers—shown in Figure D.4 are elements added to a typical distribution feeder to isolate and clear faults, improve reliability, and maximize service availability to the greatest number of customers when fault conditions occur.

As an area EPS improves and expands, there is a tendency to use higher primary distribution voltage levels. Thus, more load is aggregated on a primary circuit, and more customers are potentially affected by faults on any one feeder. This suggests a reduction in reliability; however, methods of automated distribution can minimize the number of customers who lose service during fault conditions.

[48] Reprinted with permission from Murray Davis from a presentation at the PES Cogeneration Conference, Feburary 19, 2003, Las Vegas Nevada.



NOTE 1—NC = normally closed.

NOTE 2—NO = normally open.

Figure D.4—Example primary distribution system

One automated distribution scheme, for example, consists of multiple remote-controlled pole-top switches tied together by radio control links in the three-phase circuit backbone that extends from the substation line circuit breaker to a normally open remote-controlled switch connected to an adjacent substation circuit. In addition, several manually controlled pole-top switches are installed in the three-phase backbone of the feeder. Faults between any of the remote-controlled switches are isolated quickly after the substation line breaker opens, and the outaged load on the unfaulted portion of a line between a manually controlled switch and a remote controlled switch is restored to service promptly. Also, the normally open remote-controlled switch at the end of the feeder can be closed to tie unfaulted sections of the line to other adjacent circuits to restore the remaining load.

Another automated distribution design consists of a three- or five-recloser loop sectionalizing system. Here, two normally closed reclosers are installed on the three-phase backbone at the midpoint of two adjacent circuits, and a normally open recloser is installed at the tie point. If a fault occurs between the midpoint recloser and the substation circuit breaker, the breaker and recloser automatically clear the fault, and the remaining distribution transformers on the unfaulted section of the backbone are returned to service when the normally open recloser closes, thus providing service through the adjacent circuit. Hybrid configurations of remote-controlled pole-top switches, manual switches, and recloser loop sectionalizing are also used to improve service reliability.

In general, at any primary voltage level, a simple radial feeder configuration is the least costly to build. All of the common adaptations to secure multiple paths into the simple radial feeder are driven by either a need to supply loads greater than expected or a need to increase the reliability of supply for existing loads. This extends also to varying methods to regulate voltage, options for circuit materials and construction, and strategies to clear and isolate faults and maximize service availability. Fortunately, standardized ratings and practices have reduced the process to selection from a limited set of options. The final selection will include practice, judgment, and bias, but it is the result of a procedure. This result can vary from EPS to EPS, EPS circuit to EPS circuit, and over time. The range of possibilities, each separately justified, ensures there is no standard EPS circuit.

D.1.2 Operation of area EPS distribution systems

The operation of the area EPS distribution system requires proactive planning to anticipate and take appropriate action to avoid future problems and meet customer needs and reactive activities to correct unplanned operating conditions as they develop.

The electric power grid, which includes the area EPS distribution system, has been recognized by the National Academy of Engineering as one of the top 20 engineering triumphs of the 20th century and is one of the most—if not *the* most—complex machines ever created by man. It is a machine that was not created at one time, but on an as-needed basis. Parts of the area EPS are very old, but new facilities are being added and old facilities are being replaced each workday. Some of the technology in use on the area EPS is very old. However, new state-of-the-art technology is also being deployed. Electric power is a “just in time” commodity, but it cannot be delivered safely, with proper quality and efficiency, unless the area EPS is efficiently operated, maintained, and improved.

D.1.2.1 Work on the area EPS

Paramount to the operation of the area EPS distribution system is safety. Without proper precautions, electricity poses a safety hazard to the public and to workers. Therefore, safety is intrinsic to all facets of operation of the area EPS distribution system. Typically, day-to-day operation of the area EPS is controlled by a dispatching or operating authority (operators). Operators monitor conditions on the area EPS and initiate appropriate actions to maintain proper operation and address abnormal conditions. They direct various work activities, including the oversight of switching and tagging and coordination of service restoration, maintenance, and construction work on the area EPS.

The area EPS employs automatic devices to control voltage, maintain circuit power factor within limits, and sense and isolate faulted line sections and equipment. Some portions of the area EPS have SCADA to facilitate remote monitoring and control of equipment. With SCADA, the operator can remotely control some equipment. This enables the operator to take some actions to operate the system without calling on field personnel. If the operator determines that conditions on the circuit require field work, then qualified personnel are dispatched.

Before any work can begin on lines or equipment, the operator authorizes personnel to proceed in accordance with operating procedures. Formal switching procedures are developed and used when complex switching operations are required. The operator may authorize personnel to reconfigure a circuit or a portion of a circuit by opening and closing switching devices under the direction of the operator. With complex switching procedures, the operator is in direct communication with the field personnel performing the switching. The operator directs each worker performing switching. The workers repeat instructions back to the operator before tasks are performed and verify that the task was properly completed.

Depending on circumstances, various methods are employed to perform work on area EPS lines and equipment. A very common method involves working on lines or equipment when all potential sources of electric power have been de-energized, tested as de-energized, and grounded. Clearance procedures are used to coordinate activities to ensure that the proper work sequence is followed and devices are not inadvertently closed or opened. Hold tags, under the control of the dispatching authority, are placed at each point where switches or other devices are opened to establish visible open points. Once the line or equipment is properly isolated and authorization has been given to proceed, then work can begin on the line or equipment. When work is completed, the operator coordinates activities to return the area EPS to its normal configuration or to a planned new configuration. With proper protective equipment, tools and procedures, work can sometimes be performed on energized facilities (i.e., hot line work procedures). However, using hot line work procedures can take much more time, requires more specialized equipment, and leaves less room for worker error.

The operating practices of most area EPS operators do not allow the use of automatic equipment to provide safe isolation of a potential source of electric power. Experience has shown that even properly maintained automatic equipment can malfunction. Therefore, other safeguards are commonly employed to avoid dependence on the operation of automatic equipment for personnel safety. For area EPS operators, a DR represents a potential source of electric power that needs to be properly isolated before work can be performed (unless hot line work methods are used). When required by area EPS operating practices, the DR isolation device is to be used by the area EPS operator to facilitate acceptable isolation of the DR from the area EPS, as explained in 8.1.7.

There are two basic arrangements for distribution system operation: radial and network circuits.

D.1.2.2 Radial circuits

In radial distribution circuits, at any given time, there is only a single path from any point on the system to the source substation. Often, and particularly in urban and suburban areas, there may be multiple paths available via switches, which are normally open. When a system is reconfigured to use an alternate path to the source, the radial characteristic is maintained by opening other switches to provide one path to the source.

Radial circuits may be 100% overhead, 100% underground, or any combination in between. A radial circuit design that contains a combination of overhead and underground facilities is the most common. Other characteristics of radial circuits can vary widely. For example, distribution circuit primary voltage levels can range from 2.4 kV to 69 kV, per ANSI C84.1 Table 1 medium voltage class. The distance of a distribution circuit from its source to the farthest customer may range from less than 1 mi to more than 20 mi. The available short-circuit current on circuits can range widely.

In a radial circuit design, power flows out from the area EPS source substation to loads along the three-phase main line of the circuit. Three-phase protective devices, in most cases, protect the main line of the circuit, but single-phase devices may also be used. Multiple three-phase, two-phase, and single-phase lines tap the main line at various points to serve area loads. These single-, two-, and three-phase tap lines are typically protected by single-phase reclosers or fuses.

The area EPS is designed to provide automatic clearing of temporary faults and automatic isolation of permanent faults. The protective devices (e.g., relays on the circuit breaker, reclosers, and fuses) are coordinated for unidirectional power flow. The automated actions of protective devices allow the area EPS to return customers to service quickly after temporary faults and minimize the number of area EPS customers inconvenienced by a permanent fault by isolating the faulted section. Because the majority of faults on overhead lines and equipment are temporary, the circuit breaker and reclosers that protect overhead systems are set to clear temporary faults and automatically reclose to limit outage time. Overhead facilities are the most prone to temporary faults. Such faults may be caused by the flashover of an insulator from a lightning surge, a tree limb that falls across two overhead line phase conductors, or an animal that moves across an insulator and shorts the insulator to ground.

Typically, fuses are used for single-phase taps. Some area EPS operators use single-phase reclosers for taps, and some three-phase reclosers that protect overhead facilities are set up for single-phase tripping. Because most faults are single line-to-ground faults, the use of single-phase reclosers on three-phase lines and three-phase reclosers with single-phase tripping allows temporary line-to-ground faults to be cleared and service to be restored on the faulted phase without affecting service to customers who take power from the unfaulted phases.

The installation of DR units on radial distribution circuits can affect the operation of protective devices. These effects are detailed in this document.

D.1.2.3 Networks

The network configuration provides maximum reliability and operating flexibility because it is designed with redundant facilities. Any single equipment failure will not result in a service outage. Usually, to isolate a permanent fault on a radial distribution circuit, only a single protective device is required to trip and lock open. When a circuit that feeds a network experiences a fault, all of the protective devices associated with that circuit automatically disconnect from the network. Because multiple circuits serve the network, the loss of a single circuit has little effect on the network, except for changes in load flow.

Networking can be at the primary or secondary voltage level. Primary voltage networks are uncommon, and interconnection will likely require special configurations and consultation with the owner of the system. Secondary voltage networks are more common. Secondary networks come in two forms: spot networks and grid networks. Both use network transformers and network protectors. Each network is served by at least two circuits (network feeders), generally from the same substation. Network feeder voltages range from 4 kV to 34.5 kV. The 15 kV class voltage is the most common.

Each network feeder serves one or more network transformers. Secondary network transformers are three-phase transformers specially designed for network service. They may be submersible, vault type, or, less often, dry type. Network transformers transform the network feeder voltage to the network voltage. Secondary network voltages are either 208Y/120 V or 480Y/277 V; 208Y/120 V is most common for area networks, while 208Y/120 V and 480Y/277 V are common for spot networks. Each network transformer has a network protector connected to its secondary winding.

The network protector is an electrically operated low-voltage air circuit breaker with self-contained protective devices for controlling operation. The network protector automatically connects and disconnects its transformer to and from the network in response to pre-determined electrical conditions on the network feeder or transformer. The network protector automatically disconnects the transformer from the network when power flows from the secondary network to the transformer. Each network protector is equipped with a set of fuses to provide backup protection if the protector should fail to trip. Certain fault conditions create very small levels of reverse power flow and needs to be sensed and cleared by the network protectors; therefore, the reverse power pickup settings of the network protectors needs to be very sensitive. The sensitivity of network protector reverse power pickup and their potential reclosing under non-synchronous conditions are major concerns when DR units are applied to a network.

A secondary circuit ties the network protector to the network mains. On area networks, these network mains generally form a grid from which customer services are tapped. The grid generally follows the geographical pattern of the load area, under streets or alleys. The available fault current from the network can be several hundred thousand amperes. In some area networks, the protective devices may operate with available fault current very close to their rated interrupting rating. The addition of DR units could, in some cases, increase the available fault current above the interrupting rating of some area EPS devices.

Cable limiters are installed on network mains and service cables to protect the cables from extensive damage because of severe overload and faults. The limiters will blow to isolate the faulted cable from the rest of the network. Presently, there are few remote monitoring systems to report the status of cable limiters, network protectors, or cables to alert operators of abnormal conditions. The operator is dependent on field inspections and field tests. Many network feeders have SCADA, and if so, the operator has good information about the status of the network feeders. However, the operator has limited information about the status of cables, network protectors, and limiters in the network at any given time.

D.1.2.4 Changes to the area EPS

The area EPS distribution system is dynamic, and new facilities and system improvements are added each workday. A new customer that adds a new local EPS will also require the installation of some form of new area EPS distribution system facilities. Depending on the local EPS load requirements and other factors, the new area EPS facilities may vary from a new service lateral from an existing transformer bank to a major addition such as a new substation and new distribution circuits.

The operator of the area EPS monitors conditions on the system. Plans for system improvements are developed and implemented to maintain adequate capacity and quality of service for existing customers. System improvements can vary from a new voltage regulator to a new substation and reconfiguration of several existing circuits.

Networks are designed to provide satisfactory service when any single network feeder is out of service (for small networks) or when two network feeders are out of service (for larger networks). Careful planning is required to maintain this criterion as networks grow because individual feeders need to be removed from service for additions and extensions and cable and equipment failures. Repair or replacement requires relatively long periods of time to complete.

D.1.2.5 Operation during normal configuration

D.1.2.5.1 Radial circuits

Radial circuits are designed to be fed from a single source. As noted previously, all protection devices are coordinated for proper operation when supplied from this source. Faults on the single-phase taps will typically operate the tap fuses. Some area EPSs use a "fuse saving" scheme in which the operation of the tap fuse is coordinated with the operation of the first upstream recloser. Under this scheme, the recloser will sense and clear temporary faults downstream from the tap fuse without damaging the fuse. However, if the fault is permanent, the recloser will reenergize the line so the fuse will operate to remove the fault. The recloser will then reclose so that only customers beyond the fuse experience loss of power.

Faults on the main three-phase section of the line are protected by the substation breaker or downstream reclosers, depending on the location of the fault. All of these devices are coordinated to limit the number of customers interrupted by a fault. If the area EPS uses single-phase tripping on three-phase devices or single-phase reclosers, the DR may experience serious unbalances when the protective device opens. Operation of the DR will be affected by the actions of protective devices on the area EPS.

D.1.2.5.2 Networks

The operation of a network is similar to the operation of a radial distribution circuit. However, with multiple sources, more than one protective device normally operates to de-energize a fault. In addition, the network may continue to operate with some low-magnitude faults present. All three-phase protective devices will operate as three-phase devices and avoid serious unbalances on the network. The operation of cable limiters or backup fuses in network protectors could expose some customer loads to unbalanced conditions. Network feeder outages and burned-off cables or cleared cable limiters because of previous faults within the network will cause load flow changes that are not readily detected. The redundancy of sources connected to the network generally prevents any customer from experiencing poor power quality.

In normal operation of the area EPS, the network feeders are closed, the network protectors are closed, and all the secondary cables are in service at both peak and light load times. Although this is the preferred method of operation, secondary cable faults, which are cleared by limiters or burn clear, can occur at any time. Unless the loss results in a low-voltage complaint or overloading of in-service cables with resultant smoke, fire, or other noticeable activity, the faulted cables cannot be detected without a physical inspection of the area EPS. Network protectors can be out of service for maintenance, a primary feeder fault, or a failure of the protector to close (typically caused by a burned-out close motor). Unless protectors are supervised, a protector that fails in the open position cannot be detected without a physical inspection. A primary feeder can trip open because of a fault, and this will cause all the protectors connected to that feeder to open. If SCADA is present at the substation, this is detected immediately. However, if SCADA is not present and the feeder serves only network load, this is not detected until a physical inspection of the substation is performed. All of these possible abnormal conditions can occur during normal operation of networks.

Network feeders are radial feeders that normally do not have ties on the primary to other feeders. Typically, there are no sectionalizing switches installed on the network feeders supplying network transformers except for the disconnect switch on the primary of the network transformer. If a fault occurs on a network feeder, the feeder will be out of service until the fault is located and repaired. Prior to repair, the protector is verified open. If the transformer primary switches are available, they put into the grounded position.

If an entire grid network (secondary) goes down, it can be a lengthy process to restore it. Typically, there are no switches on the secondary cables in the grid. It may be necessary to make secondary cable cuts or unbolt secondary cables from buses to start picking up the grid in pieces. In some cases, it may be possible to do a simultaneous group close of all the feeders in the grid. In addition, the overcurrent protection setting should consider the impact of the additional inrush current associated with an extended outage of the grid network.

Unique problems are associated with the interconnection of DR units with networks. These problems vary and depend on where the interconnection is made and the size and type of DR.

D.1.2.6 Operation during abnormal configuration

D.1.2.6.1 Radial circuits

In normal operation, power flows from the normal-source circuit breaker. However, there are several possibilities for abnormal operation.

— A portion of the line could be transferred to an alternate source if a normally open point is closed and a sectionalizing device such as a switch or recloser is opened on the line.

— The entire line could be transferred to an alternate breaker at the source substation. This may be referred to as a *transfer bus operation* or an *alternate breaker operation.*

— The entire line may be carried from another substation if a normally open tie point at the end of the main line is closed and the source circuit breaker is opened.

In all of these cases, the normal source feed for the line has been modified, and these modifications could affect the operation of the DR. When the line is fed from an alternate source, some functions may not coordinate for the alternate connection.

— Voltage blocking that may have been installed on the normal supply may not have been installed on the alternate supply.

— A DTT may have been installed on the normal supply but is not generally installed on an alternate supply.

— The coordination of protective devices will be altered, and the change in available fault current may lead to serious mis-coordination when the DR is connected to the alternate source.

— The voltage profile may be vastly different, especially if the alternate source is the end of the line. In this case, the operation of a DR may require a different power factor.

In addition, some customers may have two feeds to their facility. Under these arrangements, the customer may be able to switch between the sources or split load across the sources. In most cases, the area EPS operator has an agreement with the customer that details how the customer may operate these feeds. In some cases, paralleling the two sources is prohibited unless special protection is installed. The interconnection of a DR with such a service arrangement can be complex because each feed may be subject to various alternate feed configurations by the area EPS operator.

D.1.2.6.2 Networks

Abnormal network configurations may result from the loss of one or more of the sources feeding the network, the loss of a network component, a reduction in cable capacity because of the operation of one or more cable limiters, or abnormal or unanticipated customer loading conditions. Abnormal configurations will occur when individual feeders are removed from service for additions and extensions and when cable and equipment failure requires repair or replacement. Many abnormal conditions last for relatively long periods of time. Again, the redundancy of sources connected to the network generally prevents any customer from experiencing poor power quality during periods of abnormal configuration. However, the loss of additional network components during periods of abnormal configuration greatly increases the risk of cascading failure.

D.1.2.7 Operation during abnormal conditions

D.1.2.7.1 Radial circuits

When the distribution system is fed from an alternate source, area EPS protective device coordination will generally be compromised. The fault current may be in the opposite direction of and of a considerably different value than normal. The addition of a DR could easily aggravate this situation. Reclosing times may need to be modified in case the DR does not trip before the normal first reclosure. Operation of fuses or single-phase reclosers for permanent faults may present the DR with larger-than-normal unbalances. The DR needs to consider these possibilities.

D.1.2.7.2 Networks

A fault on the primary system, at the substation, or on the transmission system will tend to cause the DR to create reverse power flow through many or all of the network transformers. Under light loading conditions, this could result in operation of all protectors because of reverse power flow. As a result, the DR can be isolated with the secondary load. Most likely, the DR will not be able to support the load, and the voltage will collapse. If the DR is able to support the load and the network protectors attempt to reclose but are out of synchronization with the DR, then the most reliable of all power distribution configurations is rendered unreliable. Network protector failure can occur because of duties that exceed protector design requirements and standards.

A DR interconnected with a network may be subject to very high available fault currents. Networks are designed to continue to operate when certain low-magnitude faults are present. A high-magnitude fault on either a network feeder or the network grid will dip the voltage. This voltage dip could trip a DR off-line. Secondary faults could cause cable limiters to operate or cause cables to burn off, and the failure of a network protector to clear a fault could cause one or more of the network protector's backup fuses to operate. Depending on the location of these devices relative to the DR, the unbalances created could trip a DR off-line.

D.1.3 Area EPS concerns

D.1.3.1 Introduction

The interconnection of DR presents concerns to the area EPS operator because DR interconnection may adversely affect the area EPS operator's primary goals. These goals are as follows:

- Minimize safety risks to the general public and area EPS operator employees
- Comply with regulations established by government entities
- Provide for the reliability and quality of electric service provided to customers
- Control the costs associated with providing electric service
- Avoid damage to area EPS and customer equipment

D.1.3.2 Minimize safety risks to the general public and area EPS operator employees

The interconnection of DR units can present concerns about public safety and the safety of area EPS operator employees. DR introduce another source of electrical energy into an otherwise radial area EPS. The addition of DR creates two safety concerns:

— Desensitization of the area EPS protection scheme

  Circuit breakers, reclosers, and fuses can be desensitized by unplanned DR fault-current contribution. This unplanned contribution may result in slower clearing of faults on the area EPS. Slower clearing provides more time for a person to come in accidental contact with an energized part when a fault involves damage to the area EPS (e.g., a broken conductor from a tree falling into the line, a broken pole from a vehicle hitting a pole, or an accidental dig into an underground cable).

— Creation of an unintentional island

  An unintentional island can form when a portion of the area EPS is inadvertently separated from the remainder of the area EPS and the DR continues to supply power. In such a condition, an area EPS worker may mistakenly believe the islanded portion of the area EPS is de-energized because the device that provides the area EPS feed to the islanded portion of the system would be open.

D.1.3.3 Comply with regulations established by government entities

The interconnection of DR can make it more difficult for the area EPS operator to comply with regulations established by government entities. Federal, state, and local government units establish laws and regulations that govern a range of activities associated with operating an area EPS. Besides the safety-related concerns addressed in D.1.3.2, laws and regulations deal with such matters as service standards, obligation to serve, rates and tariffs, and environmental concerns. The area EPS operator has multiple constraints that might affect the timely evaluation of a DR project.

Each new interconnection of DR adds complexity to the area EPS that the area EPS operator takes into account when planning and operating the area EPS. This complexity makes it more difficult for the area EPS operator to meet its obligation to serve and meet service standards.

D.1.3.4 Provide for the reliability and power quality of electric service

Each new interconnection of a DR adds another element to the area EPS that can affect service reliability[49] and the quality of the electric service provided to customers served from the area EPS.

D.1.3.4.1 Reliability

The addition of a DR provides no reliability benefits to customers beyond the local EPS.[50] In general, the addition of a DR interconnection will degrade the service reliability of other customers served by the area EPS. The addition of DR may cause improper operation or coordination of area EPS protective devices, which may result in additional customers being interrupted or prolonged customer outages. The addition of a DR may extend the time to restore service following an outage of the area EPS. Such a delay in service restoration is due to the additional sectionalizing work required to (1) isolate additional potential sources of "backfeed" power to minimize the safety risks to workers repairing the area EPS and (2) limit the magnitude of cold load pickup demand to prevent excessive loading of protective devices and equipment.

[49]Service reliability is the degree to which the electric service of a customer or group of customers on an area EPS is affected by sustained interruptions over a time period. A sustained interruption is generally defined as an interruption longer than 5 min. Power quality is affected by momentary interruptions of electric service, voltage sags, voltage swells, voltage impulses, and harmonic currents or voltages. Momentary interruption events are generally defined as interruptions of 5 min or less.

[50]Some DR installations may provide enhanced reliability for customer loads within the local EPS. When the DR interconnection and area EPS are properly configured and designed and agreements are in place to allow for intentional islanding, some customer loads can be served from the interconnected DR during certain outage events on the area EPS. Currently, such intentional islanding arrangements are rare.

D.1.3.4.2 Power quality

Some power quality effects from the interconnection of DR can be beneficial to the area EPS. For example, certain voltage source inverter designs can provide transient voltage stabilization and reduce the magnitude of a voltage sag event or provide some mitigation of voltage flicker. However, the interconnection of DR can also result in several power quality concerns. Paralleling a DR unit with the area EPS may result in a substantial voltage dip if the DR unit is not in synchronism with the area EPS. DR units may inject harmonics or direct currents into the area EPS. DR with rapidly changing power output (e.g., wind turbines in gusty wind conditions, misfiring diesel generators fed by contaminated fuel, or PV systems in conditions of rapidly changing cloud cover) may generate objectionable voltage flicker. If conditions allow the formation of an unintentional island, the voltage within the island may not be maintained within the limits of ANSI C84.1 Range A.

D.1.3.5 Control of costs associated with providing electric service

The recovery of many costs will be regulated by the AHJ, and a detailed discussion is beyond the scope of this document. However, the following should be reviewed:

- The rules, regulations, and rates for selling power or sending power back to the area EPS.
- The effect of the operation on the overall power bill of the facility. The DR may fully offset facility power use, but there is still a minimum bill. In some locations, this can be more than half of the typical bill.

DR interconnection-related expenses fall into two broad categories: pre-interconnection costs and post-interconnection costs.

- Pre-interconnection costs
  - The area EPS operator incurs expenses to set up and maintain an interconnection request fulfillment process. These expenses can include such tasks as the following:
    - Developing and maintaining standards, agreements, and policies
    - Participating in rulemaking proceedings
    - Developing DR interconnection materials to answer inquiries from prospective developers or installers of DR
    - Training personnel on the interconnection request fulfillment process
    - Developing the means to document and track the status of interconnection requests
    - Developing reports for regulatory authorities
  - The area EPS operator incurs expenses to perform the interconnection request fulfillment process. These expenses can involve such tasks as the following:
    - Answering inquiries related to DR interconnection
    - Receiving applications requesting interconnection
    - Assigning personnel to process requests
    - Tracking progress until requests are completed
    - Evaluating proposed DR interconnection systems for compliance with technical and business requirements
    - Determining system impacts
    - Resolving negative system impacts as necessary

  - Processing interconnection agreements
  - Adding interconnection information to operating records and maps
  - Advising operations personnel of new interconnections
  - Inspecting DR installations and observing testing of DR interconnection systems
  - Making changes to metering or billing arrangements
  - Authorizing parallel operation of DR installations

- Post-interconnection costs

  The area EPS operator also incurs expenses after the interconnection request fulfillment process has been completed. These expenses can include such tasks as the following:

  - Switching and tagging to isolate the DR so that work can be safely performed on the area EPS
  - Factoring the impact of DR interconnected with the area EPS into planning studies that determine the timing and extent of area EPS improvements necessary to maintain adequate system protection, service reliability, and power quality
  - Coordinating planned outages that will affect interconnected DR
  - Investigating and resolving complaints related to DR interconnection
  - Monitoring the status of periodic DR interconnection testing
  - Administering DR interconnection agreements
  - Factoring the impact of DR interconnected with the area EPS into plans to enhance area EPS performance or to serve proposed new block load increases on the area EPS

D.1.3.6 Avoid damage to area EPS and customer equipment

The interconnection of DR with an area EPS can introduce the risk of damage to area EPS equipment and the equipment of customers connected to the area EPS. These risks depend not only on the design and protection of the DR but also on the specific characteristics of the area EPS.

The ways a DR might potentially pose a risk to area EPS and customer equipment include:

- A DR may contribute current to an area EPS fault, or a fault in the local EPS of another customer, to the degree that the resulting total fault current exceeds the capabilities of equipment.
- A DR may cause excess operations of switching devices, which may lead to their premature failure. The vulnerable devices include switches that control shunt capacitors and the tap-changing mechanisms of step-voltage regulators. Excess operating frequency is a particular issue when DR output is highly variable, such as when a renewable power source (e.g., a wind turbine) is used. (See 8.1.1.)
- Power or short-circuit current flow from DR into an area EPS can result in misoperation of area EPS control and protection equipment, which can result in equipment damage. One example is flow into a secondary network type of area EPS that results in network protectors operating to island the secondary network and then causing the protectors to reclose in an out-of-phase condition. (See 8.1.4.)
- Excess voltage magnitudes can be caused by the interconnection of DR, and surge arresters and load equipment are the most vulnerable to failure. Excess voltages can be subdivided into steady-state overvoltages and short-term (temporary or transient) overvoltages. Export of real or reactive power to the area EPS by the local EPS can cause a steady-state voltage rise. Power flow reversal through area EPS step-voltage regulators with "reverse power sensing" controls can cause incorrect operation of the regulators and result in sustained overvoltage conditions. Interconnection of a DR that does not

provide a ground source may result in inadequate grounding of an area EPS and result in temporary overvoltages during faults. (See 8.1.2.) Islanding of a DR with a portion of the area EPS can result in particularly severe overvoltages. If the islanded portion of the area EPS has a large amount of shunt capacitance connected, compared to the rating of the DR maintaining energization of the island, severe self-excitation overvoltages may occur. If an adequate ground source is not present in the island, a ground fault can result in voltages that exceed 173% on the unfaulted phases. Note that a ground fault in an ungrounded system will have very little fault current and may not be detectable by the DR or its protection systems. Reclosing of the interconnection between an islanded portion of the area EPS, where energization is maintained by DR, to the remainder of the area EPS can result in severe transient overvoltages if the island is out of phase with the remainder of the area EPS.

— If DR continue to energize an islanded portion of the area EPS when the island is reclosed to the remainder of the area EPS and the island had drifted out of phase, then the reclosing will cause an abrupt and potentially large change in voltage phase angle. This can result in large transient torques applied to motors connected to the islanded area EPS and their mechanical systems (e.g., shafts, blowers, and pumps), which could result in damage or failure. (See 8.2.2.)

D.2 Local EPS

D.2.1 Design, construction, and configurations of the local EPS

Most local EPSs are simple radial designs with one service from the area EPS and one DR. However, some local EPSs are complicated and include multiple services and multiple DR units. A local EPS is designed to serve specific loads but should be flexible enough to meet future needs and expansions. The load on the local EPS may include the following:

— Lighting
— Receptacles
— Space-conditioning equipment
— Plumbing equipment
— Fire protection equipment
— Transportation systems
— Data-processing equipment
— Food preparation equipment
— Medical equipment
— Industrial equipment

Design considerations for the local EPS include the following:

— Load characteristics
— Voltage drop
— Wiring systems
— System protection

The occupancy of the facility is a primary design consideration. There are significant differences among the designs of a residence, a retail store, a healthcare facility, and an industrial facility. A residential service may have a 120/240 V, 100 A service from the area EPS, a panel board with a main circuit breaker, and multiple branch circuit breakers. A small commercial customer may have a 240/120 V or 208Y/120 V, three-phase service. The main switchboard or panel board may have feeder circuit breakers that extend to additional panel boards. A large commercial customer or small manufacturing customer may have a 480Y/277 V, three-phase service. The main switchboard or panel board will have feeder circuit breakers that extend to additional panel boards and transformers.

College campuses, military installations, and large industrial customers may take service at the area EPS distribution or transmission voltage and extend the medium-voltage or high-voltage system throughout the facility.

D.2.2 Operation of local EPS distribution systems

A local EPS is a set of facilities arranged to deliver electric power to an individual load or multiple loads contained within a single site or group of sites. As defined, a local EPS does not need to include onsite generation, and its distribution system may range from a simple residential dwelling electrical system to a large electrical plant in an institutional complex. At either end of the range, the user/customer has the expectation of very reliable electric service with almost perfect availability for a cost that is competitive economically.

The user may take steps to increase the electrical reliability of the local EPS. For example, in large commercial or industrial electrical distribution systems, multiple levels of sub-distribution voltage feeders and redundancies from different substation primary distribution feeders may be deployed. Standby backup generators with transfer switches may be installed in commercial as well as home applications. An array of local EPS distribution schemes can be configured to foster the expected reliability of electric power service.

When the prospect of onsite generation that can operate in parallel with the area EPS is added, the potential scope of local EPS operation becomes much greater. In fact, such local EPS configurations with parallel generation are not new, but they have been developed essentially one by one and represent unique interconnection designs. Parallel interconnection of the local EPS under the auspices of IEEE Std 1547-2003 will at least create the minimum set of common requirements for these kinds of systems.

Users of DR in local EPSs install onsite generation for a variety of reasons. These DR systems may or may not be set up to run parallel with the area EPS. Table D.2 shows six types of distributed generation systems that may be found in local EPSs and how they might relate to parallel operation with the area EPS.

Table D.2—Interface configurations used for DR applications

	No interconnection (not covered by IEEE Std 1547-2003)	Isolated DR operation with automatic transfer to area EPS (not covered by IEEE Std 1547-2003)	Parallel operation to area EPS, no power export	Parallel operation to area EPS, power export to area EPS
Prime power	✓	✓	✓	✓
Combined heat and power/cogeneration	✓	✓	✓	✓
Peak shaving		✓	✓	✓
Emergency/backup power		✓	✓	✓
Premium power	✓		✓	✓
Remote power	✓			

Prime power systems (also known as *baseload power*) can supply a varying load for an unlimited amount of time. They may consist of a single DR unit rated for prime power use and sited within a local EPS or multiple DR units with an aggregate capacity of several megawatts to support a distribution feeder by the area EPS. As shown in Table D.2, prime power units can be arranged to export power to the area EPS, run parallel without power export, operate behind a transfer switch without paralleling capability, or run stand-alone without a tie-in to the area EPS. Table D.2 shows that of these four possible modes of operation, the first two are not controlled by IEEE Std 1547-2003. The last two are.

Combined heat and power, also called cogeneration, is the simultaneous production of electrical power and a form of useful thermal energy from a single fuel-consuming process. It is a highly efficient process, with overall efficiencies (electric + thermal) of as much as 80% to 90% or higher. It is widely used throughout industry and employs reciprocating engines, combustion turbines, and steam turbines for large processes and fuel cells as prime mover elements, along with appropriate converters for ac electricity generation. It is used in a variety of systems, including food and beverage production, refractory processes, and central heating plants. The electrical generation component of combined heat and power, as indicated in Table D.2, may export power to the area EPS or run parallel without power export and serve in a peak-shaving role. In these uses, it is governed by IEEE Std 1547-2003. It may not relate to IEEE Std 1547-2003 if it operates in stand-alone mode or with only a momentary paralleling (<100 ms) transfer switch. Table D.2 shows major DR applications and possible interface configurations.

Peak shaving covers virtually all types of distributed generation used in alternative energy systems that can operate grid-parallel. Such systems in local EPSs may operate interconnected with an area EPS to offset energy and power demand and may include power export. Both of these cases are controlled by IEEE Std 1547-2003. Alternatively, peak shaving systems might be set up to separate load from the area EPS under high load conditions and during outages. Under these configurations, as Table D.2 shows, IEEE Std 1547-2003 does not apply.

Similarly, if onsite generation is intended for emergency backup only via automatic transfer switches during area EPS outage conditions, then IEEE Std 1547-2003 does not cover its operation. However, if the emergency backup equipment is arranged such that it can be pressed into service to operate grid-parallel and support peak-shaving operations, then the rules of IEEE Std 1547-2003 do apply to its interconnection operation.

The distributed generation categories of peak-shaving and emergency/backup power inherently imply a tie point connection to an area EPS, whether parallel connected or not, and thus are not considered to operate stand-alone.

Premium power systems provide uninterrupted electrical power that is virtually free of all frequency variations, voltage transients, sags, and surges. It typically requires power conditioning and DR technology in the form of emergency or larger, more powerful standby generators as well as other DR technologies and parallel grid feeds to support the loads. It may draw on source power with the parallel grid feed to the area EPS, or it may operate stand-alone. Users of premium power systems are businesses—such as airlines, banks, brokers, telecommunication companies, and large health care facilities—with large, mission-critical computer systems and industrial plants that cannot tolerate power quality problems in their production processes.

Other DR users require onsite generation in a local EPS that is remote from and not interconnected with an area EPS. These DR interface configurations are inherently stand-alone systems and are not under the direction of IEEE Std 1547-2003.

D.2.2.1 Operation during normal configuration

Normal configurations refer to the arrangement and operating status of the area EPS distribution circuits with which the local EPS and DR generator interconnect. The area EPS distribution feeders in this status are in the normal operating conditions. A local EPS with DR generation is able to function fully and in the way it is intended and designed to operate.

This may include any of the types of DR applications summarized in Table D.2. During normal configurations of the area EPS distribution system, a local EPS with DR may operate in parallel with full interconnection with the area EPS primary feeder circuit on which it is normally assigned to operate. This may include power export and dispatch capability if this is part of the interconnection agreement with the area EPS operator.

D.2.2.2 Operation during abnormal configuration

Abnormal configurations refer to the arrangement and operating status of the area EPS distribution circuits with which the local EPS and DR generator interconnect. The area EPS distribution feeders in this status are not in fault condition but are in off-normal operating condition. A local EPS with DR generation during abnormal configuration may be connected back to the distribution substation through a different primary circuit than it is normally interconnected with. In this status, the area EPS may create paths from the point of interconnection of the DR through the primary distribution system that are different from the normal primary path. Looped radial primary distribution circuits routinely function is this manner. These other paths, because of varying feeder designs, might react differently to the presence of DR, and this could impact area EPS operations and service. Also, loading profiles on these abnormal primary circuit paths might be different enough from the normal configuration to impact the operating conditions of a local EPS with DR generation.

As a result, in this situation, a local EPS with DR generation may be able to function fully and in the way it is intended and designed to operate, provided that supervision and interlocking direction is given by the area EPS operator. If the full, normal operation of the DR is not possible, the local EPS with DR generation may be required to adjust its configuration to a mode that is compatible with the abnormal configuration of the area EPS until interconnection with normal circuit configurations can be reestablished. Power export or dispatch, for example, may have to be reduced or curtailed in response to this condition.

Alternatively, the local EPS may be able to reconfigure its loads and DR generation balance to meet the off-normal needs of the interconnection. Temporarily, onsite load might be added for this purpose, or DR power generation may be decreased in a way that is appropriate for the generation system.

Conversely, the circumstances of the area EPS abnormal configuration could be reversed. An opposite response might be indicated for a local EPS with DR generation, in which it is called to shed load where possible or increase power export to the area EPS within the operating constraints and capability of the local generation system.

D.2.2.3 Operation during abnormal conditions

Operation of the local EPS with DR generation during abnormal conditions on the area EPS involves the total response of the local EPS to faults or other service interruptions on the area EPS. In these states, the local EPS with DR generation will respond to the outage of the area EPS per the interconnection requirements of IEEE Std 1547-2003. However, this response is directed only at the interconnection with the area EPS. The local EPS and DR, in this period, lose grid-parallel operating status with the area EPS, and this may have consequences for the local EPS. Without DR, this would mean a temporary loss of service [except in the case of loads served by an uninterruptible power supply (UPS) or operated with an automatic transfer switch and backup generator]. With DR present, this still may be the case if the DR generation is used only for peak shaving operations in parallel with the area EPS. The parallel operation with the area EPS acts as a load for the DR in this arrangement. If the interconnection with the area EPS becomes unavailable, then the DR loses its electrical loading and cannot deliver its power.

If a DR that normally runs interconnected with the area EPS is to provide service to the local EPS during an area EPS outage, then it is likely that both the local EPS and the DR will have to be reconfigured. In this case, one of the first issues is how the DR is controlled. This assumes, first of all, that the DR electrical converter is a type that can operate in stand-alone mode without a parallel grid connection.

In its normal condition, interconnected with the area EPS, the electrical converter operates in a mode of power delivery. The level of power it places on the EPS main connection is determined by internal control loops that respond to operator set points and the level of power available from the prime mover system. While parallel with the area EPS, the DR is capable of supplying full power up to its rating. The local EPS main connection along with the area EPS interconnection can act as a sink for all the power the DR has available. Once separated from the grid, though, this does not hold true. Now, the local EPS may be starved for electrical power or, potentially, have an instantaneous excess of power from the DR. Neither result is acceptable. The former would collapse the voltage from the DR, and the latter could create dangerously high voltage from the DR if nothing were changed in the controls of the electrical converter. Therefore, the controls of the electrical converter have to be switched immediately from power output set points to bus voltage set points to maintain constant voltage at its output terminals, regardless of the power level of the load that remains attached to the DR generator. This may prove difficult on a transient basis. Schemes may have to be set up to temporarily deal with the power surge because of the transient load swings in the DR generation system. Once the control transition is accomplished, however, the DR electrical converter holds its bus voltage constant and then supplies variable power to local EPS loads up to its power rating capability.

If the DR in the local EPS has an excess of generation over load, then it would have to shut down part of its generation system while the outage persists. It is more likely, though, that the local EPS load exceeds available DR generation, and therefore, the loads would have to be reconfigured. The loads to be powered in this period would be separated and remain with the DR system while the rest of the loads would be isolated from the DR generator bus.

The local EPS load that remains powered from the DR generator bus during the outage period has additional issues. First, the separated local EPS with the DR no longer has the same level of reactive power availability it enjoyed while connected to the area EPS. Therefore, not all of the power rating of the local DR is available to supply real load. A part of the DR system kilovoltampere frame rating would need to be available to furnish the reactive power required in the remaining local EPS. Motor starting in the local EPS during the outage, for example, would have to be carefully considered to ensure a sufficient supply of reactive power to start motors that remain connected to the DR generator bus. Another issue during the outage period is available short-circuit current. There has to be a sufficient level of short-circuit current available within the separated local EPS and DR system to clear short-circuit faults. The separated local EPS and DR system has to provide enough fault current to operate the protective devices—including circuit breakers, fuses, and fault protection relays—in the system.

Another issue for the local EPS during this period is grounding. Depending on how the DR is constructed within the local EPS, there could be grounding conflicts set up in the installation. If the DR is sited in such a way that it serves the local EPS from beyond a building electrical service entrance, then this prospect is less likely. However, if the point of interconnection for the DR occurs within a building inside of a service entrance, then this issue is likely to be a concern. When abnormal conditions are not in effect, such a DR installation operates in parallel with the grid inside of a grounded service entrance to a building. Under normal conditions, the DR generator is a grounded source because it receives a ground reference from the grounding of the electrical service at the service entrance to the building, as required by building codes. Those codes also require that the service be grounded only once at the service entrance to the building. Thus, a local grounding of the DR generator elsewhere in the building premises is prohibited. When abnormal conditions do occur and the DR separates from the area EPS and the grounded service, the DR generator suddenly loses its independent ground reference. At this time and until it reconnects in parallel with the grounded service and the area EPS, the DR generator and the separated loads of the local EPS operate ungrounded unless measures are taken to remedy this condition.

D.2.3 Local EPS concerns

D.2.3.1 Introduction

The interconnection of DR can also present concerns to the local EPS operator. The goals of the local EPS operator are as follows:

— Minimize safety risks to the general public and local EPS operator employees
— Comply with regulations established by government entities
— Provide reliability and power quality
— Control costs

D.2.3.2 Minimize safety risks to the general public and local EPS operator employees

Safety is the most important factor in the design of a local EPS. Regulatory authorities usually establish minimum safety requirements for electrical systems. These safety requirements are for the safeguarding of persons and property. Safety of personnel and the general public and property preservation are critical considerations.

Whereas the area EPS is typically insulated or isolated from the general public, the local EPS is more accessible. The general public routinely comes in contact with local EPS electrical facilities. The addition of DR will increase the available fault current in the local EPS and the area EPS.

D.2.3.3 Comply with regulations established by government entities

Local EPSs are usually required to meet electrical codes such as the NEC [B57] and National Electrical Safety Code® (NESC®) (Accredited Standards Committee C2-2007) [B1]. The International Code Council also publishes the International Code Council Electrical Code—Administrative Provisions [B53].

The NEC specifies conductor ampacity and overcurrent protection for conductors and equipment. The NEC specifics requirements for grounding and bonding because grounding and bonding are essential for a safe electrical system. In addition to a grounded conductor, the NEC also requires a separate equipment grounding conductor for bonding to electrical equipment. This grounding conductor provides an effective ground-fault current path. Extreme care is required in the design of the grounding system for a DR.

The NEC has specific requirements for generators, solar PV systems, fuel cell systems, emergency systems, legally required standby systems, optional standby systems, and interconnected electric power production sources. The local EPS typically requires an inspection by a recognized inspection agency before electric service is turned on.

D.2.3.4 Ensure reliability and power quality

The demand for reliability and power quality varies across the customer base. As we become more dependent on electricity, the need for reliable, quality power increases.

D.2.3.4.1 Reliability

Residential customers may be concerned with inconvenience and nuisances such as having to reset flashing clocks, but residential customers also have tangible costs (such as frozen pipes because of unavailable heating and spoiled food in inoperative refrigerators) associated with electrical outages. And some customers on life support depend greatly on reliable electric service.

Commercial customers are particularly concerned with electric reliability because of lost revenue, wasted materials, and lost opportunity. In fact, some commercial customers use small uninterruptible power supplies to maintain their point-of-sale terminals and other computerized equipment. Some manufacturers use three-phase, three-wire delta circuits with a ground detection scheme so that internal phase-to-ground faults provide an alarm and allow time for the maintenance staff to locate and correct the problem or conduct an orderly shutdown. Data centers are so dependent on electricity that they install large parallel uninterruptible power supplies to ensure computer equipment can withstand the slightest electrical disturbances. This equipment also has high heat loads, which require continuous cooling. Communication customers use large battery plants to maintain communications equipment during power outages. All classes of customers may have onsite generation for emergency systems or standby systems.

D.2.3.4.2 Power quality

Most power quality issues relate to electronic equipment. The Information Technology Industry Council (ITI), formerly known as the Computer and Business Equipment Manufacturers Association (CBEMA) published a curve that describes the ac input voltage envelope that electronic equipment can tolerate. This curve is shown in Figure D.5.[51]

D.2.3.5 Control costs

Cost is a necessary consideration for any electrical system. Local EPS operators control expenses to meet economic goals. The initial installation cost and the cost of operating and maintaining the system are important. Commercial books and software products are available for estimating the cost of installing and maintaining electrical systems.

The support of a DR interconnection creates additional expenses for the local EPS operator. These expenses can include the following:

- Reviewing requirements for DR established by the area EPS and regulatory authorities (The area EPS operator may have different requirements for different sizes of DR units.)
- Meeting with representatives of the area EPS (Area EPSs typically employ interconnection persons that the local EPS operator does not normally deal with.)
- Reviewing environmental siting restrictions and permitting requirements
- Preparing additional design details to satisfy the requirements of the area EPS operator
- Reviewing the tariff of the area EPS operator (The area EPS operator may impose additional costs of service because of the interconnection.)
- Preparing the application for interconnection (There is typically a fee for submitting the application. The fee may increase with the size of the DR and the location of the DR in the area EPS.)
- Tracking progress of the application until the request is completed
- Training personnel on the interconnection agreement
- Training personnel on the operation of the interconnection equipment
- Switching and tagging to isolate the DR

[51] ITI curve reprinted with permission from the Information Technology Industry Council.

— Coordinating planned outages that affect interconnected DR

— Investigating and resolving complaints related to DR interconnection

— Performing periodic DR interconnection testing

— Administering the DR interconnection agreement

— Factoring the impact of the area EPS into plans to enhance local EPS performance

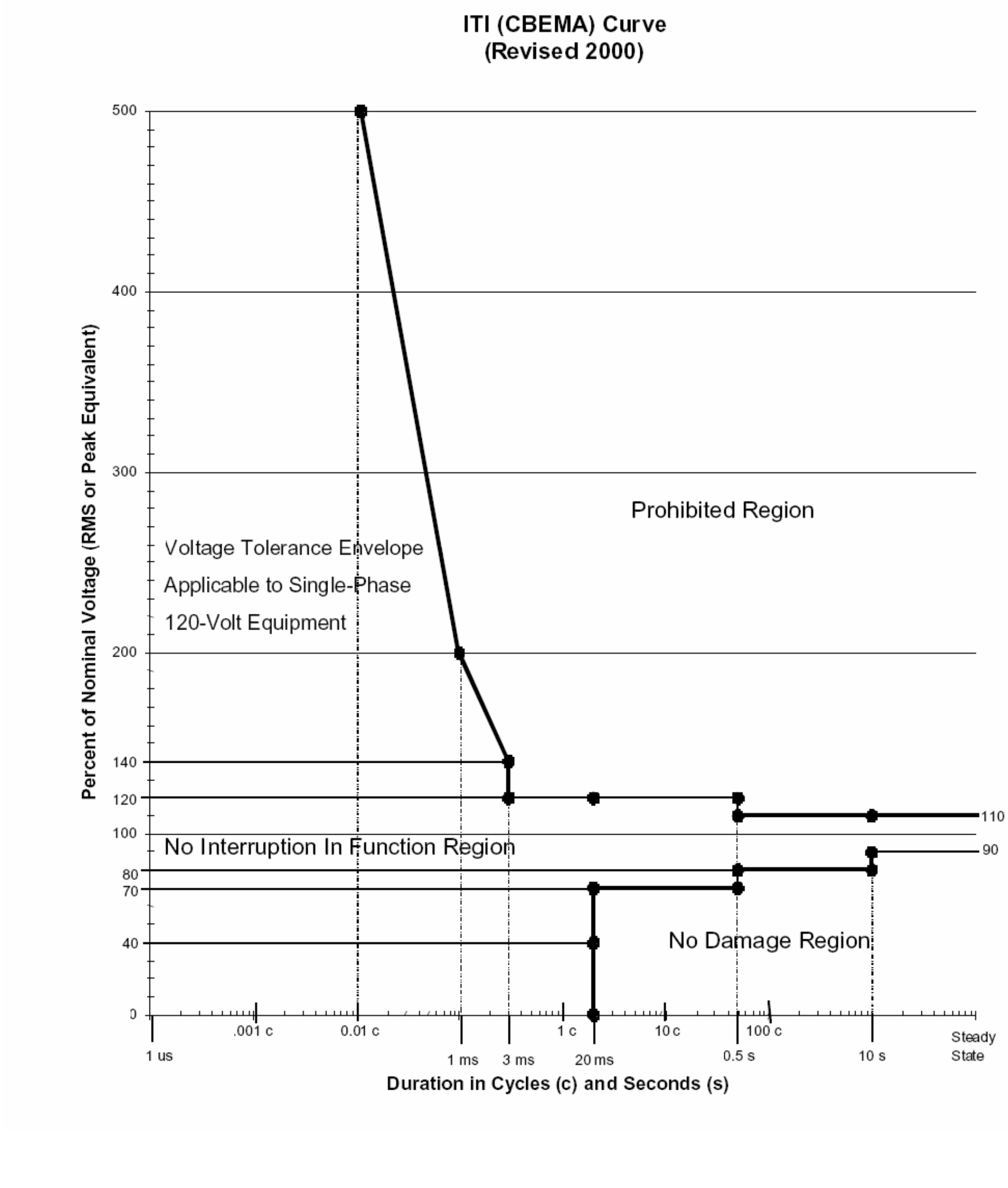


Figure D.5—ITI curve

Annex E

(informative)

Area and local EPS impacts

The introduction to IEEE Std 1547-2003 states that "It is beyond the scope of this standard to address the methods used for performing EPS impact studies, mitigating limitations of the area EPS, or for addressing the business or tariff issues associated with interconnection." System impact should be reviewed for both area and local EPSs. Impact tends to increase with the size of the DR and the capacity of the DR relative to the capacity of the EPS, and it may be more serious for non-inverter DR applications. For more information about system impact identification and studies, see Annex F.

A non-exhaustive list of parts of the area EPS affected by the DR follows. Many relevant system impacts and methods to mitigate them are identified here, but the responsibility for mitigation of impacts as well as funding is strictly an issue to be addressed in contractual agreements or regulatory action.

Many of the following issues are addressed, to some respect, by IEEE Std 1547-2003; others are not. These impacts were extracted from the Edison Electric Institute Distributed Resources Task Force Interconnection Study [B9]. They specifically address impacts on the area EPS. Many of these may also affect the local EPS; a distinction between area and local EPS will only be made when applicable.

— **Improper protective device coordination**

  Fault-current contributions from the DR can impact the coordination of fault protective devices on the area EPS. IEEE Std 1547-2003 4.1.2, while addressing detection of faults on the area EPS by the DR, does not address the impact on the area EPS itself.

  These impacts should be evaluated by protective device coordination studies using analytical tools that can accurately model the bidirectional nature of the fault-current flow and reflect the addition of the DR. The impacts can usually be mitigated by recalibration of affected protective devices, but it may sometimes be necessary to replace protective devices on the EPS.

— **Area EPS protection desensitization**

  Fault-current contributions by the DR may cause the feeder protection by the area EPS equipment to be desensitized. This problem increases as the size of the DR relative to the area EPS load increases. This problem can usually be mitigated, but it first needs to be recognized and evaluated. Evaluation and mitigation methods are similar to those suggested for improper protective device coordination.

— **Nuisance fuse blowing**

  Frequently, the area EPS applies fuses and other protective devices on the distribution system such that, for a fault downstream from a fuse, an upstream device operates once quickly and recloses to attempt to clear a momentary fault without causing an extended outage. The fault-current contribution from a DR may disturb this relationship and, if the DR is downstream from a fuse, cause the fuse to operate for an upstream fault. This can particularly be a problem for single line-to-ground area EPS faults if the DR is a source of ground-fault current.

  This impact can be evaluated using the same methods as for improper protective device coordination, but mitigation will usually require that the fuses be removed (or replaced with another type of protective device such as a sectionalizer, recloser, or circuit breaker) or that the EPS in the vicinity of the DR be reconfigured. After evaluation, it may, in some cases, be decided to accept nuisance fuse blowing.

— **Reclosing**

Area EPS reclosing practices are designed to restore service to as many customers as possible as quickly as possible following an interruption for a momentary fault. If the area EPS reclosing devices attempt to reclose before the DR is separated from the area EPS, area EPS and DR equipment may be damaged.

IEEE Std 1547-2003 requires that the DR cease to energize the area EPS before reclosure by the area EPS. If the clearing times specified in IEEE Std 1547-2003 satisfy this requirement, the area EPS reclosing practices would not be expected to be impacted.

If the clearing times specified in IEEE Std 1547-2003 do not cease to energize the area EPS before reclosure by the area EPS, the impact may be evaluated by reviewing the area EPS reclosing practices in comparison with the interconnection system. If the DR cannot coordinate with the current reclosing scheme, it may be necessary to alter the interconnection system or modify the reclosing on the area EPS. Modification of area EPS reclosing may require the replacement of reclosing devices or the installation of supervisory relaying to inhibit reclosing if the DR has not disconnected.

— **Fuse-saving schemes**

For many cases in which portions of the area EPS are protected by fuses, fuse-saving schemes (sometimes called *sequence coordination*) are implemented on distribution reclosers. These schemes result in the recloser tripping very quickly for initial faults—more quickly than fuses can respond. For subsequent tripping for the same fault, the recloser may operate on a much slower, time-delayed characteristic. Fault-current contributions from DR can cause the fuse to operate much more quickly than it otherwise would and, thus, disrupt the fuse-saving scheme.

— **Islanding**

IEEE Std 1547-2003 requires that the DR cease to energize an unintentional island on the area EPS. In some cases, this can be accomplished easily. In other cases, however, this may be difficult to achieve in practice.

See Clause 8 for further discussion and guidance.

— **Equipment overvoltage**

Depending on the grounding methods of the DR, the DR may cause steady-state overvoltages on the area EPS for difficult-to-detect ground-fault conditions.

— **Resonant overvoltage**

Depending on the grounding methods of the DR and the construction characteristics of the area EPS, the DR may cause conditions that result in a resonance between transformers (including transformers associated with the DR) and capacitance on the area EPS.

— **Harmonics**

Inverter-based DR technologies, because of the methods used to form the ac waveform from dc, produce various harmonics of the power system frequency. If the DR complies with IEEE Std 1547-2003 4.3, harmonics are not expected to be a problem.

— **Sectionalizers**

Sectionalizers are relatively inexpensive devices that are frequently installed on the area EPS to minimize the number of customers affected by a permanent fault. These devices count the number of complete power interruptions (usually characterized by zero-voltage events) in a given period of time. If a DR does not cease to energize the area EPS as required by IEEE Std 1547-2003, sectionalizers will not sense zero-voltage conditions as expected by area EPS design processes and, therefore, will not "count" as expected. Sectionalizing scheme operation may be disrupted.

To evaluate this impact, the DR and the coordination with the area EPS reclosing needs to be evaluated. If the DR coordinates with the area EPS reclosing, this impact will usually be mitigated.

— **Nondirectional area EPS relaying**

Because of the traditional radial nature of distribution systems, most protective devices on the area EPS are nondirectional in nature (i.e., the devices respond to a given value of current without regard to the direction of flow of that current). Because DR produces fault current of various magnitudes for faults on the area EPS, the traditional radial nature of the distribution system is disrupted, and nondirectional relays may misoperate for faults on the portion of the area EPS that is "behind" the relays in a traditional sense.

This impact can be evaluated using the same tools and methods as those used to evaluate improper protective device coordination. If this impact is a problem, it will usually be necessary to replace the nondirectional relaying on the area EPS with relays that have directional characteristics.

— **Power relaying**

DR can cause reverse-power relays on the area EPS to misoperate. For example, if directional power relays are applied on the EPS to automatically reconfigure the EPS, the addition of the DR may cause these relays to misoperate.

— **Line drop compensation**

Many voltage-regulating devices (voltage regulators and load-tap-changing transformers) on traditional area EPSs are equipped with line drop compensators. Line drop compensators sense the current flow through the regulating device and are adjusted to regulate the voltage based on the calculated voltage drop downstream of the regulating device based on load current. Application of DR downstream of these voltage-regulating devices will reduce the current observed by the line drop compensator and cause the voltage at the voltage-regulating device to be adjusted incorrectly, which may cause voltage instability of the area EPS.

In some cases, the improper behavior of line-drop-compensating devices may be correctable by recalibration. In other cases, it may be necessary to replace the voltage-regulation equipment with equipment that can accommodate downstream DR. In extreme cases, it may be necessary to establish communications methods such that the voltage-regulation equipment can compensate for the actual real-time output of the DR.

— **Feeder loading capability**

Most customer loads will remain connected to a de-energized area EPS feeder following an interruption of the feeder at the area EPS source. When the area EPS feeder is reenergized, many of these loads will demand higher current than their steady-state load current, which is usually referred to as *cold load pickup*. If the area EPS assumes a level of DR penetration, and all DR are disconnected during an outage, the area EPS feeder loading capability may be exceeded by the cold load pickup when reenergized.

It is not highly probable that, with low penetrations of DR, this will be an issue because the area EPS will be designed to serve the connected load without the DR present. It typically becomes an issue only if the DR is being used by the area EPS as a significant load resource.

This impact should be evaluated by performing load-flow calculations to reflect the variety of conditions that can result from the addition of DR and that should account for cold load pickup conditions. Mitigation may require significant upgrades of the area EPS to allow for this condition or load-shedding.

— **DR undervoltage relay operations**

Close-in faults on other feeders fed from the same bus can cause voltage dips on non-faulted feeders and cause the DR on those feeders to trip on undervoltage.

This impact will usually be mitigated by delaying the undervoltage tripping on the affected DR. However, doing so may adversely affect the DR's ability to detect an unintentional island and cease to energize the area EPS in such a manner as to coordinate with area EPS reclosing practices.

— **Equipment short-circuit duty**

As additional DR are added on a circuit, switchgear ratings on existing equipment can be exceeded—both on the area EPS and other local EPSs (which may or may not have DR).

This impact can affect the ability of equipment to carry fault current for the brief periods that a fault persists and its ability to interrupt downstream faults. Equipment in nearby customer facilities can be affected, as can area EPS equipment.

If the DR affects the area EPS in this fashion, equipment on the area EPS or within nearby customer facilities may fail. Such failure can present a serious hazard to personnel and property.

This impact is evaluated by performing fault studies that reflect the addition of the DR. If the DR has a relatively small fault-current contribution to the area EPS or if the DR cannot produce short-circuit current, it may not be necessary to perform such studies.

This impact can be mitigated by replacing the impacted switchgear or limiting the short-circuit current to a value less than the maximum equipment capability.

— **Area EPS reactive power support**

Induction generators and inverters may require capacitive reactive power from the area EPS to provide their excitation system requirements. Deficiencies in capacitive reactive power can cause significant undervoltage problems on the area EPS.

This issue is related to IEEE Std 1547-2003 4.1.1. This impact can be evaluated by considering the reactive power requirements of DR equipment within the area EPS load flow. One solution is for the DR to add capacitors such that they are operating at unity power factor (as a minimum) or, preferably, at a slightly leading power factor. However, such capacitors can cause a self-excitation problem, which may interfere with unintentional island detection.

— **Induction generator self-excitation**

Induction generators with capacitors can self-excite under temporary or permanent islanding conditions.

— **DR unit stability**

The area EPS can be considered to be an infinite source from the viewpoint of the DR operator. There are no reasonable cases in which the DR will cause instability of the area EPS. However, if there is sufficient impedance between the DR and the area EPS, the DR might have stability concerns. Classical analysis using the power transfer curve can show when the DR is approaching an operational angle of 45º or more. At this angle, faults on the area EPS may result in a loss of synchronization with the DR facility.

A complete analysis is beyond the scope of this document. The DR operator needs to be aware that, under the correct circumstances, the DR facility could slip out of synchronism with the area EPS. Concerns increase with increased DR size or smaller (higher-impedance) area EPS facilities.

— **DR unit loss of synchronism**

DR may not maintain stability for faults on adjacent feeders fed from the same area EPS bus during and immediately after fault-clearing operations. See 8.2.5 for additional discussion on this subject.

— **Induction generator startup current inrush**

Current inrush on induction machines without rotor flux can cause voltage dips on a feeder. The induction generator may initially appear like a large induction motor and cause significant voltage drops.

— **DR nuisance trips because of capacitor switching**

Capacitor switching on the area EPS may cause nuisance trips of inverters and other voltage sensitive DR.

— **Underfrequency disturbances**

Underfrequency relaying with a wide tolerance band can cause DR to trip while load remains. From a practical consideration, coordination is usually not applied to generators smaller than 20 MW. However, a delay in isolation of the DR for momentary islands may cause misoperation of area EPS underfrequency load-shedding schemes.

— **Distribution automation circuit reconfiguration**

Distribution automation circuit reconfiguration schemes require extensive system protection coordination and should be studied for normal and emergency-state conditions. Remote control switches with intervening manual switches and hybrid three- and five-recloser loop schemes that incorporate DR may require additional DR protection and coordination.

— **Area EPS voltage variations because of DR**

When significant loads are energized or de-energized by the area EPS, considerable voltage variations because of changes in load current are possible across the area EPS before the voltage-regulating equipment can respond. The evaluation and design of the area EPS associated with connection of these loads compensates for this. DR can cause similar problems on the area EPS, during synchronizing and disconnecting, and these issues need to be mitigated to avoid problems for other customers. Operation of the DR is adjusted to minimize voltage changes immediately after synchronization or disconnection.

Annex F

(informative)

System impact studies

This annex was prepared by the IEEE Working Group on Distributed Resources Integration. This working group is a part of the Power Engineering Society Transmission and Distribution Committee Distribution Subcommittee.[52]

F.1 Introduction

A system impact study identifies the electric system impacts that will result if a proposed DR is interconnected without project or electric system modifications. The study focuses on potential adverse effects to the operation, safety, and reliability of the area EPS. For more information about potential impacts, see Annex E.

A system impact study can take many forms. It can range from a simple comparison of the attributes of the DR and the area EPS to a detailed, comprehensive analysis that employs a variety of traditional power system studies.

F.2 Simple impact studies

Simple impact studies compare only the attributes of the DR and the area EPS and are primarily focused on making a subjective determination of whether IEEE 1547 requirements can be easily met. This determination can generally be made by considering the use of certified or listed DR equipment, the propensity to create an undetected island, the propensity to adversely affect protection and power quality on the area EPS, and the propensity to cause the area EPS to operate in excess of its ratings under both normal and fault conditions.

F.2.1 Use of certified or listed DR equipment

The use of appropriately certified or listed equipment greatly simplifies the process of determining the impact of a proposed DR installation.

F.2.2 Propensity to create an undetected island

For interconnection of a proposed DR with a radial distribution circuit, it is generally agreed that an undetected island cannot be created if the aggregated generation, including the proposed DR, on the circuit does not exceed 15% of the line section annual peak load as most recently measured at the substation. If the minimum line section load is known, 50% of that value could be used. A line section is that portion of the area EPS connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

[52] See http://grouper.ieee.org/groups/td/dist/dri/ for more information.

F.2.3 Propensity to adversely affect protection and power quality on the area EPS

It is generally agreed that there is little chance of interfering with the power quality of the area EPS if the proposed DR, in aggregation with other generation on the distribution circuit, does not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high-voltage (primary) level nearest the proposed point of change of ownership. This ensures that the fault current from the DR does not desensitize protection equipment on the area EPS, and any voltage disturbances that may occur because of normal or abnormal operation of the DR are not likely to have a significant effect on voltage supplied to other customers.

F.2.4 Propensity to cause the area EPS to operate in excess of its ratings under both normal and fault conditions

Determine the maximum current contribution of the DR to the area EPS under both normal and fault conditions, and verify that, when taken in aggregate with all other generation on the distribution circuit, the DR will not cause any equipment on the distribution circuit to exceed a specified percentage of its short-circuit interrupting or its withstand capabilities. The value used is commonly between 85% and 90%. For example, the Federal Energy Regulatory Commission used the concise value of 87.5% in its Small Generator Interconnection Order (see Federal Energy Regulatory Commission [B11]). This verification applies to all protection devices and equipment on the distribution circuit, including but not limited to substation breakers, fuse cutouts, and line reclosers. Proposals for installing DR on area EPS circuits already loaded beyond the specified threshold are not good candidates for simple impact studies.

F.3 Detailed impact studies

A detailed impact study is an engineering exercise that carefully reviews the potential effect of a DR unit on the area EPS. The concerns of this study are similar to those of the simple study, but the size, type, or location of the equipment precludes the possibility of validating the site without careful study.

Detailed impact studies may include analyses of power flow, short circuit conditions, voltage drop and flicker, protection and control coordination, and grounding to identify system reliability criteria violations, equipment overstress, power quality impacts, stability problems, and other issues relevant to the proper operation of the area EPS. The detailed studies may furthermore identify feasible mitigation measures for identified problems, provide recommendations for facility modifications, and include good-faith estimates of cost and construction time.

Detailed impact studies involve gathering data about the DR and area EPS, building and running models based on those data, interpreting the results, and proposing mitigation measures for any adverse impacts identified.

All detailed impact studies begin with an evaluation of the specific situation to determine the scope of work necessary to validate the DR installation. Therefore, it may not be necessary to carry out all of the steps described below.

F.3.1 Sample outlines of detailed impact studies

This subclause presents example outlines of engineering work that may be included in impact studies.

F.3.1.1 Outline of a system protection study

The typical steps of a system protection study are as follows:

- Determine the design features and characteristics of the DR and area EPS interconnection circuit and DR source.
- Verify that the DR will not support an unintended island in compliance with IEEE Std 1547-2003. For example:
  - The DR aggregate capacity is less than one-third of the minimum load of the local EPS.
  - The DR is certified to pass an applicable non-islanding test.
  - The DR installation contains reverse or minimum power flow protection, sensed between the point of DR connection and the PCC, which will disconnect or isolate the DR if power flow from the area EPS to the local EPS reverses or falls below a set threshold.
  - The DR contains other non-islanding means, such as (a) forced frequency or voltage shifting, (b) transfer trip, or (c) governor and excitation controls that maintain constant power and constant power factor.
- Produce a short circuit study.
- Evaluate area EPS circuit equipment for fault duty.
- Evaluate the area EPS circuit conductor and equipment ratings for resulting load flow when the DR is in operation.
- Consider the effect of any upstream fusing and the possibility of single-phasing the DR.
- Review the impact on the fault sensitivity of each upstream protective device.
- Review the impact of the DR on upstream overcurrent protection devices, and for each device:
  - Based on the generator grounding scheme and transformer connection type, determine whether single line-to-ground faults will result in overvoltage conditions when upstream protective devices operate.
  - Determine whether the protection is to be made directional.

F.3.1.2 Outline of a steady-state performance study

A study of steady-state performance includes voltage control and loading at various points along the feeder. Load and DR generation cycles have to be considered. The impact on capacitor switching and voltage regulator tap operations should also be considered. Typical steps are as follows:

- Build the area EPS and DR models in a power flow program.
- Obtain typical time profiles of load on the feeder and DR generation.
- Simulate the area EPS load flow conditions over the time profiles of load and generation. If the tool does not perform this automatically, weighted histograms of the load and generation may be developed, and the combinations could then be simulated manually.
- Evaluate whether reverse power flow conditions have an adverse effect on regulator tap changers or line drop compensator settings.
- Evaluate whether the DR adversely affects local capacitor bank control.
- Ensure the area EPS voltage profile remains within ANSI C84.1 Range A for normal operations and no equipment is overloaded.
- Evaluate whether the DR power factor, or its reactive power dispatch, might be specified to improve the area EPS voltage profiles.

F.3.1.3 Outline of a power quality study

A study of power quality impacts includes transients, harmonics, ferroresonance, and temporary overvoltages, which may cause equipment damage or customer disturbances. For DR equipment such as wind turbines and solar panels, flicker should also be evaluated. Typical steps are as follows:

— Build the area EPS and DR models in an electromagnetic transients program (EMTP). For harmonic studies, a specialized harmonic analysis program could be used instead. For flicker evaluations, a short-circuit program, supplemented by manual calculation, could be used.

— Simulate fault-and-clear operations at various area EPS and DR operating conditions. Evaluate the resulting transients and temporary overvoltages against equipment insulation and surge arrester capabilities.

— Simulate capacitor switching and DR switching operations, along with startup of nearby motors. Evaluate the transients for proper DR operation and impact on nearby customers.

— If single-phase fault interruption can occur, simulate this to evaluate the possibility of ferroresonance.

— Estimate the flicker contributed by the DR, per IEEE Std 1453-2004 [B40].

— Estimate the harmonics contributed by the DR, per IEEE Std 519-1992 [B29].

F.3.1.4 Outline of a system stability study

The Federal Energy Regulatory Commission’s small generator interconnection procedures do not require stability studies. However, a stability study may be justified for high-impedence EPSs or intentional island systems.

A system stability study evaluates DR impact on a system’s transient and oscillatory response to a disturbance. Most fundamentally, a system and connected synchronized machines must withstand transient events. Transient stability is generally demonstrated by maintaining synchronism (first swing test). The DR generator characteristics (such as internal machine voltage, impedance, and inertia) are key variables that affect transient response. Dynamic stability considers the longer-duration effect of DR exciter and governor action. Dynamic stability is demonstrated if machine and system oscillatory responses are positively damped {i.e., reduced in a reasonable time—6 s per IEEE Std 399™-1997 (*IEEE Brown Book*™) [B25]}. For DR connected to relatively strong systems with high short-circuit duty, DR effects on wider system stability are typically not a concern and are usually not a bounding constraint.

Following are the general steps of a system stability study. These are described in greater detail in IEEE Std 399-1997 8.6.

— Simulate the system.

— Simulate the disturbance.

— Obtain results.

— Interpret results.

If a power flow or short-circuit duty study have been performed, the stability study may be able to leverage and reuse the system and basic machine data. However, additional data will be required for the stability study. These include the following:

— DR generator transient and subtransient reactances

— The DR inertia H constant

— A DR governor model

— A DR exciter model

F.3.2 System modeling

F.3.2.1 Modeling the area EPS

An electrical model of the distribution feeder and substation source should be available in the area EPS operator's engineering analysis software package. This model should include overcurrent protective device settings, capacitor control settings, and tap changer control settings.

For some types of studies, a model of the local subtransmission or transmission system may also be required. Typically, these models are maintained in a different software package or database.

Load profiles or load duration curves, along with customer class information, should be obtained. Existing nearby harmonic or flicker sources should also be identified and quantified.

F.3.2.2 Modeling the DR installation

The model of the DR installation will likely include a model of the generator and any other sources as well as the interconnection and protection equipment. This model requires the following:

— Generator impedance data and grounding method

— Generator transformer data, type connection, and impedance

— Generator facility one-line diagram

— Generator facility operation description

— Generator protection equipment list

— Point of interconnection protection equipment

The generator data may be provided in the form of a dynamic or transient stability machine model, if it is appropriate to the DR technology. Vendors can sometimes provide more detailed models that include schematics and block diagrams.

F.3.2.3 General comments on system modeling software

Detailed system impact studies are generally carried out using simulation software. A typical commercial engineering analysis software package for distribution systems addresses power flow (i.e., voltage drop) and fault current issues on radial feeders with unbalanced impedances and loads. Typical power flow applications include conductor sizing, ampacity checks, voltage-drop checks against ANSI C84.1 limits, regulator tap settings, line drop compensator settings, and capacitor bank impacts. Typical fault-current applications include equipment rating checks and coordination of relays, reclosers, sectionalizers, and fuses. All of these are important in DR impact studies.

Software models for distribution systems may need to consider system imbalance, and thus may need data beyond the sequence impedances.

Some of the advanced engineering analysis applications have included reliability estimates, capacitor bank optimization, open tie switch optimization, load allocation, load balancing, and arc flash hazards. These are indirectly related to DR.

For DR impact studies, the more important advanced engineering analysis capabilities include a variety of DR interface models, support for user-written models, a robust solution for three-phase meshed networks, and automatic solutions over a load or generation profile curve. An appropriate advanced optimization feature would suggest DR locations and sizes to minimize overloads or unserved energy.

F.3.2.4 Cross-platform compatibility of software models

Because of incompatibility between various engineering analysis applications, it will sometimes be necessary to develop the engineering analysis modeling data from the raw system and generator parameters.

Area EPS data can be transferred through an exchange of engineering analysis program data files when compatible engineering analysis software is used. Otherwise, standard exchange platforms such as MultiSpeak® [53] and the Common Information Model (CIM) can be used, although these are still evolving. Engineering analysis software packages specify whether they support these exchange formats, and because they are still evolving, manual intervention by the user may still be required.

Detailed DR models have sometimes been developed for a specific engineering analysis package. Some transmission-oriented engineering analysis packages support power flow, fault analysis, and dynamics for user-written DR models. Electromagnetic transient programs also allow custom-written DR models to a greater level of detail. These model implementations are proprietary and generally cannot be used in a different engineering analysis package without a significant model translation effort by a specialist. The availability or nonavailability of a DR model could sometimes mandate the use of a particular engineering analysis tool for the impact study.

Standard modeling languages could facilitate such model transfers. Support for standard modeling languages is not widespread in the electric power industry. However, there are simulators that support these models and that may be suitable for a subset of DR impact studies (i.e., those that can be performed with a reduced area EPS model but require a detailed DR model).

F.3.2.5 Other software tools

F.3.2.5.1 Power flow

The power flow, or voltage drop, program calculates the voltages and currents at all points during a steady-state, non-faulted system condition. A variety of load and generator characteristics versus voltage may be used. Most power flow programs include a constant power/constant voltage model for generators, but this is not appropriate for DR because DR is not supposed to actively regulate voltage. Depending on the DR technology, a constant PQ, constant Z, or constant I model could be more appropriate. Constant power factor operation may also be represented with a constant PQ model.

The settled response of any voltage control elements, such as capacitor banks and tap changers, must be included in the power flow solution. For time-varying DR, it is helpful to have a time-sequenced power flow solution over a DR generation profile. For economic and constraint evaluations, automatic solutions over different load and generation profiles would save time completing the study.

[53] MultiSpeak is a registered trademark owned by the National Rural Electric Cooperative Association. This information is given for the convenience of users of this standard and does not constitute an endorsement by the IEEE of these products. Equivalent products may be used if they can be shown to lead to the same results.

F.3.2.5.2 Short-circuit analysis

The short-circuit analysis is a steady-state solution of the voltages and currents during a fault condition. This is typically a short circuit, but it may also include open conductors. For DR impact studies, it is important that the DR short-circuit contribution be properly represented. Some DR technologies do not behave like classical synchronous generators or induction machines, which most engineering analysis packages can handle.

Coordination of overcurrent protective devices has traditionally been within the scope of short-circuit analysis software. This is usually done with time-current curve overlays to verify current and time settings. A large library of device characteristics and time-current curves is necessary to support this function. A rule-based routine for device settings may also be provided. When considering the impacts of DR on reclosing, for example, a quasi-static, time-sequenced, or event-based solution mode is useful. This will help verify proper system response throughout the fault event, not just the first fault detection and clearing operation.

The voltages during short-circuit conditions can be used to estimate voltage sag magnitudes experienced by other customers, including any effects of the DR.

F.3.2.5.3 Dynamics

A dynamics program is also sometimes referred to as a *transient stability program.* It simulates the electromechanical dynamics of several generators in a meshed network. For DR impact studies, a dynamics program could be used for islanding studies or low-voltage ride-through studies.

Transmission dynamic software usually assumes a balanced-phase system, which limits representation to the positive sequence only. It may also ignore stator transients in the machine models, which can be a significant limitation for DR impact studies. There are some generalized packages, for industrial applications, that work in the phase domain. Distribution-oriented dynamic software is also evolving. Therefore, the specific technical capabilities of a dynamics program have to be verified before it is used in an impact study.

F.3.2.5.4 Harmonic load flow and frequency scan

This type of program calculates driving point and transfer impedances versus frequency for the area EPS. It also evaluates the flow of harmonics in the area EPS given specified current injection sources. The applications include harmonic filter design and estimates of harmonic voltage distortion at various points in the area EPS. The solution method is similar to a fault analysis or, less commonly, power flow. The main differences are that the solution is performed at several frequencies, and thus the frequency dependence of component impedances are represented, and output reports are specialized to harmonics.

F.3.2.5.5 Electromagnetic transients

This type of program simulates high-frequency transients in the time domain with a full unbalanced system model in phase coordinates. These are commonly referred to as electromagnetic transients programs or EMTPs. However, several variants exist, and they are not all compatible with one another. EMTP is necessary for some transient and power quality studies. It can also be used for harmonic evaluations.

Some of the DR detailed models are available only for EMTP, which can lead to using an EMTP for analyses that have usually been done with other tools. Examples are fault analysis and overcurrent device response, flicker and harmonics, dynamic stability, and islanding.

F.3.3 Data requirements for impact studies

Detailed impact studies will require data for both the area EPS and the DR installation. Because these data typically reside in different places and in different formats, the study engineer may need to use multiple software tools or undertake time-consuming data translations to complete the impact studies.

F.4 Using the results of impact studies

Based on the detailed study characteristics described in F.3, this subclause lists mitigation techniques for issues that might be identified. Note that many issues could be mitigated through limits on DR size, but this option may not be available or desirable. Also note that if problems are expected to occur only a few hours per year, on average, the risk might be accepted along with appropriate operating restrictions.

F.4.1 Mitigation of system protection concerns

Possible examples of measures to address system protection concerns are as follows:

- Intermediate circuit fuses between the generator site and the source substation can be replaced with three-phase interrupting devices such as automatic line reclosers.
- Distribution system protective devices may need to be modified to include directional protection characteristics or replaced with protective devices with directional protection characteristics.
- A trip of the source circuit can send transfer trip from the source substation to the generator to solve one or more of several protection concerns. Transfer trip requires a reliable communications channel.
  - If the local generator protection is unable to detect an islanding condition, transfer trip can be installed from the upstream protective device to the generator.
  - If overvoltage conditions can occur for single line-to-ground faults after the upstream protective device opens, a transfer trip can be installed from the upstream protective device to the generator. The time for the transfer trip communication, plus the time for the DR trip to be interrupted, should be compared with the operating time of the upstream protective device. It is possible that the upstream device will interrupt before the DR, and overvoltage conditions may exist for a period. A delay of the upstream device operation may resolve this gap. The auto-reclosing of the source line substation breaker and the auto-reclosing of any intermediate line automatic reclosers can be controlled such that reclosing will take place only if the downstream generator has tripped. Generator breaker open acknowledgement via the transfer trip channel or downstream three-phase voltage sensing could be used for this reclose supervision.
- The source substation protection schemes can be modified to include tripping of the feeder terminal breaker on those circuits that have interconnected generation.

F.4.2 Mitigation of steady-state performance concerns

The issues identified might include voltage limit violations, equipment overloads, and adverse voltage control interactions. Some possible mitigation methods are as follows:

- Add reconductor feeder segments or upgrade substation transformers to eliminate overloads or voltage violations.
- Move the DR closer to the substation source.

— Replace temperature- or time-controlled capacitor switching with local voltage control, current control, or reactive power control. Centralized capacitor dispatch may also be used, with installation of appropriate communications.

— Modify voltage regulator settings or provide voltage regulators designed to operate properly with reverse power flow to operate correctly in the presence of DR.

F.4.3 Mitigation of power quality concerns

The issues identified might include excessive harmonic or flicker contributions from the DR or equipment damage from transients or temporary overvoltage.

— For harmonics or flicker problems, a different DR interface technology, or vendor tuning of the interface controls, may reduce the levels.

— For harmonic problems, filters might be considered.

— For flicker problems, relocating the DR closer to the substation might help.

— For temporary overvoltage problems, the surge arrester voltage ratings might need to be increased from normal levels, subject to maintaining adequate protective margins for the insulation. A change in transformer connection type or supplemental grounding transformers might be considered. DR control tuning might also help.

— Flicker and voltage sags could be mitigated with dynamic-responding VAR compensation equipment.

F.4.4 Mitigation of system stability concerns

Concerns that may be identified by the stability study may include loss of synchronism, excessive transient voltage deviation, excessive transient frequency deviation, and under-damped oscillations (voltage, current, frequency/speed, power, and torque).

A candidate mitigation option is implementation of protective schemes so that faults or devices are cleared/isolated before a system becomes unstable. If a stability concern is identified, the stability study should also determine the critical clearing times needed to clear faults or isolate devices for the identified concerns. This information must be provided to the protection engineer for incorporation into the protection plan/systems developed and implemented for the DR interconnection.

At the machine level, the mitigation options are not trivial. For example, options may include adding a power system stabilizer, changing DR inertia, and using a more aggressive exciter or governor. For DR, the prime mover, generator, exciter, and governor may be integrated and not discreet, external devices that are interchangeable.

Annex G

(informative)

Electrical distribution system disturbances

G.1 Definition of voltage disturbance

Based on characteristics such as duration, disturbances are identified by a variety of technical terms (see Table G.1).

Table G.1—Example of some voltage terminology differences

Term	Meaning
Transients	Pertaining to or designating a phenomenon or a quantity that varies between two consecutive steady states during a time interval that is short compared with the time scale of interest. A transient can be a unidirectional impulse of either polarity or a damped oscillatory wave with the first peak occurring in either polarity.
Notch	A switching (or other) disturbance of the normal power voltage waveform, lasting less than 0.5 cycles, that is initially of opposite polarity from the waveform and is thus subtracted from the normal waveform in terms of the peak value of the disturbance voltage. This includes complete loss of voltage for up to 0.5 cycles (see IEEE Std 487-2000 [B27]).
Momentary interruption	The complete loss of voltage (<0.1 p.u.) on one or more phase conductors for a time period between 0.5 cycles and 3 s.
Sustained interruption	Any interruption not classified as a momentary interruption.
Sag	A decrease to between 0.1 and 0.9 p.u. in rms voltage or current at the power frequency for durations of 0.5 cycle to 1 min. Typical values are 0.1 p.u. to 0.9 p.u.
Surge	IEEE Std 1159™-1995 [B38] identifies surge as a term to avoid in relation to the measurement of power quality phenomena. Within the context of IEEE Std 1547-2003, surge is a term used to define an overvoltage transient event such as a transient wave.
Swell	An increase in rms voltage or current at the power frequency for durations from 0.5 cycles to 1 min. Typical values are 1.1 p.u. to 1.8 p.u.

Source: IEEE Std 1159-1995 [B38].

G.2 Causes of momentary disturbances

Area EPS and utilization supply systems are designed to provide adequate and reliable voltage supply to meet the basic needs of all users. Normally, both systems used for the production and distribution of electricity are subjected to unexpected momentary variations from natural and man-made disturbances. As a result, most electrical systems experience voltage disturbances.

Some electric and electronic equipment, because of special sensitivities, may require a voltage supply with fewer momentary disturbances. The nature of the disturbances as well as their severity, incidence rate, effects on sensitive equipment, and degree of control will vary. Many disturbances are generated at the user facility by user equipment or by user-owned equipment on adjacent circuits. Others result from events—such as lightning and equipment switching—on the area EPS. Momentary voltage disturbances are generally caused by the following:

— Lightning

— Faults (short circuits)

— Switching

— Motor-starting

— Cyclic and variable loads

— Tap-changing

See Table G.2 for more detail.

Table G.2—Description of momentary disturbances

Disturbance	Description
Lightning	Lightning-related surges in the low-voltage system can be caused by direct strikes to the customer service or induction from strikes elsewhere. Lightning can cause surges at loads and commonly leads to sags or momentary interruptions as a result of temporary faults. Some lightning-induced transients cause the tripping and automatic reclosing of protective switchgear. Such operations are similar to those caused by line-to-ground faults from tree limbs and other objects grounding or short-circuiting transmission or distribution lines.
Faults	Faults (short circuits) on the area EPS are classified as temporary or permanent. The normal area EPS overcurrent protective practice is based on the fact that most faults (on overhead systems) are temporary or can be selectively isolated to restore the remainder of the system. Permanent (long-term) faults may be due to equipment failure, vehicle accidents, or falling tree limbs. They result in service interruptions that can last from minutes to hours. During a permanent-fault condition, the breaker is usually programmed to operate three or four times in an attempt to reestablish power before it locks open. The fault then needs to be located and repaired before service is restored to all customers.
Switching	Most switching operations, both area EPS and user, result in momentary voltage disturbances. These operations include fault-clearing, rapid-clearing, load-transfer, fault-closing, and current-chopping. Although most users of sensitive equipment are aware that the equipment may be subjected to transients, many are not aware of the magnitude or source of the transients or of the specific sensitivities of the equipment. Transients from within the customer premises occur with load-switching or fault-clearing. The transient voltage results from the rapid rate of change of current through the inductance of the wiring. The magnitudes of these transients can be quite high.
Capacitor switching	In addition to voltage regulators and load tap changers, most area EPS operators and many industrial and commercial users employ shunt capacitor banks to help control the power factor or voltage profile by supplying reactive power to inductive loads such as motors. Placed strategically on a circuit, shunt capacitors also reduce the losses associated with the primary circuit while improving the power factor. To accommodate widely varying load conditions, most capacitor banks are switched automatically. When capacitor banks are energized, the transient oscillation between the capacitor and the system inductance produces transient voltages that are as high as two times normal at the capacitor location. The magnitude of the overvoltage is usually less than this because of damping provided by system loads and losses. Certain sensitive loads may not be able to tolerate the normal switching transients associated with routine capacitor switching.
Motor starting	The starting of large motors is accompanied by a voltage sag that results from the inrush current flowing through the system impedance. The maximum voltage sag occurs at the motor terminals and can have a noticeable or even objectionable effect on other customers in the area or nearby load sensitive to sags.
Cyclic and variable loads	These loads include automatic spot welders and reciprocating compressors. The human eye is particularly sensitive to this type of disturbance. At six fluctuations per second, the objectionable voltage flicker limit is only 0.5%.

G.3 Sensitive loads

Digital electronic devices, and particularly those with a memory, are extremely sensitive to even very short-duration power disturbances. These momentary disturbances, impulses, and transients may result in customer complaints unless adequate ridethrough capability is provided. Computers, electronic cash registers, and data terminals are a few examples of sensitive loads that often fall victim to momentary voltage disturbances. These disturbances can interrupt the operation of sensitive circuitry and cause memory loss, system malfunction, or component failure. The leading categories of sensitive customer loads are presented as follows.

G.3.1 Computers

Computer equipment is more sensitive to voltage disturbances than most other equipment. Computers generate harmonic distortion and typically are not very sensitive to it unless the voltage waveform is very distorted. Distortion of the voltage near the zero-crossings can cause timing errors. The ability of computer equipment to withstand voltage disturbances was first described in 1987 by a group called the Computer and Business Equipment Manufacturers Association (CBEMA) and was illustrated with an over and undervoltage chart that is typically referred to as the CBEMA curve. This curve was refined in 1997 and is now generally referred to as the ITI curve. See Figure D.5.

G.3.2 Process control

Commercial facility management systems typically include sensors for input data, remote terminal units, the central processor, and man-machine interface devices. The managed functions can include heating, ventilating, and air conditioning; security; access control; and energy management. Industrial flexible manufacturing systems are assemblies of machine tools, cutting tools, and work piece-handling devices that are employed to process finished parts.

Process control systems exhibit voltage sensitivities that are similar to those of computer equipment. In addition, motor starters, contactors, relays, and other devices held closed by a coil and magnetic structure are especially sensitive to short-time interruptions and voltage sags. As a guide, a voltage sag to 60% or 70% of rated voltage for 0.5 s will de-energize many of these devices. Many control relays, sealed in by their own contacts, will drop out if voltage is lost for 0.5 cycle or more.

G.3.3 Telecommunications

Most critical telecommunications equipment uses uninterruptible power supplies to buffer disturbances and interruptions of area EPS service, so short-term transients normally have little or no effect. However, the individual terminals that connect to the public telecommunication networks often connect directly to the area EPS and are subjected to disturbances.

G.3.4 Electric arc lighting

High-intensity discharge lighting includes mercury, metal halide, and high-pressure sodium lamps used for security and street-lighting applications. In the event of a power interruption or voltage sag that lasts more than 1 cycle, high-intensity discharge lamps extinguish and do not restart for several minutes. The exact magnitude of the voltage drop that causes this condition depends on the lamp ballast.

G.3.5 Consumer electronics

An ever-increasing variety and number of digital electronics are found in microwave ovens, stereos, televisions, and clocks. Some have backup systems (e.g., batteries) that prevent disruptions to timer/clock functions when power is lost for short periods. Others do not.

G.3.6 Adjustable-speed drives

Adjustable-speed drives are used to control the speed, torque, acceleration, and direction of rotation of a motor. Unlike constant-speed systems, adjustable-speed drives permit the selection of an infinite number of speeds within their operating range. Adjustable-frequency ac drives convert three-phase, 60 Hz input power to an adjustable-frequency and voltage source for controlling the speed of squirrel-cage induction motors or other ac motors. Problems have been documented with nuisance tripping of some manufacturers' ac drives because of switching transients associated with capacitors on the customer system or area EPS.

Annex H

(informative)

Interconnection process information

H.1 Flowchart

The typical screening process determines if a project qualifies for expedited or simplified processing. For expedited processing, a DR installation is usually required to be less than a specific size, a self-contained installation, and certified by a nationally recognized testing laboratory. There may be other screen requirements. Installations that meet this screen typically do not need additional review. The DR developer is expected to supply the necessary documentation and drawings for the facility. Simplified projects typically fail one or two of the screens but pass sufficient screens to limit the work the area EPS does on the project.

The following categorizations are based on Federal Energy Regulatory Commission Order 2006 [B11] regulations and state implementations. Local regulations may differ. These regulations are based on a screening process. Other locations may use a different approach. Also, terminology may differ.

- Expedited project
  - The DR is typically less than 10 kVA and inverter-based.
  - The facility uses certified equipment.
  - The DR passes any required screens.
- Simplified (fast-track) projects
  - The DR is typically less than 2000 kVA.
  - The DR passes any required screens.
  - The facility uses certified equipment.
- Full-process projects
  - The DR is typically more than 2000 kVA.
  - The DR has failed previous screens.
  - The DR does not use certified equipment.

Figure H.1 shows s a typical project flow for a full-process project.

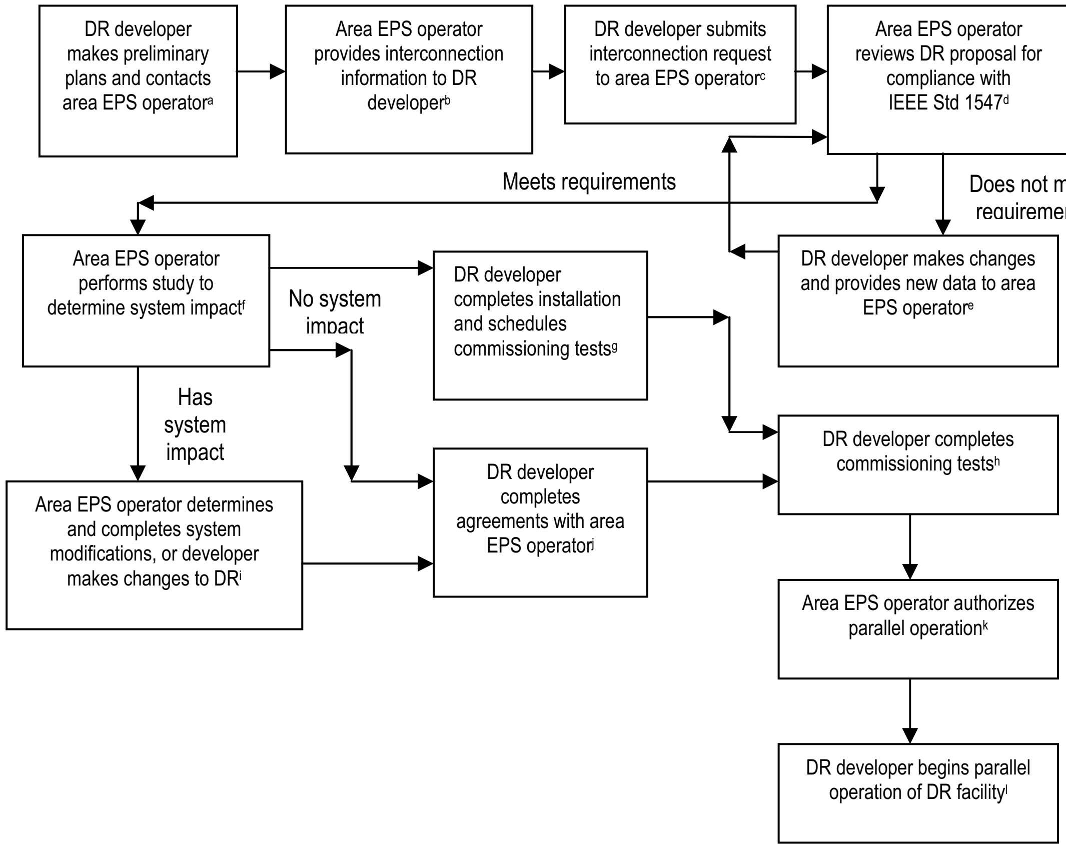


Figure H.1—Process flow

a) The DR developer contacts the local area EPS operator for initial requirements for the proposed installation.

b) The area EPS operator provides interconnection requirements, the initial project information form, and other general information such as rate tables and metering options.

c) The DR developer fills out the project information form and provides additional information about the project as well as documentation required for the expedited and simplified project screens.

d) The area EPS operator reviews the provided information and provides feedback if it does not meet requirements. The area EPS operator also provides feedback to the DR developer about any required studies.

e) There is continuing dialogue between the DR developer and the area EPS operator to provide complete understanding of the project and its associated protection and controls.

f) The area EPS operator performs any required studies and informs the DR developer of the results.

g) The systems have little or no impact and, therefore, proceed directly to the construction and commissioning phases.

h) The DR developer, working with the area EPS operator, completes the commissioning tests and provides the results to the area EPS operator and any AHJ that requires the data.

i) The area EPS operator provides details of required system modifications. These should include estimated cost, estimated completion time, outage considerations, and other project or construction constraints.

j) The DR developer and area EPS operator agree to system modifications. The required system modifications are completed *prior* to the operation of the DR facility. All parties come to an agreement on project schedule for both the area EPS work and the DR work.

k) The area EPS operator and any AHJ requirements are met, all testing is completed, and the area EPS approves the project for full operation.

l) The DR developer begins operation and provides final documentation and closes the project. Final documentation is typically a set of "as built" drawings for the facility.

H.2 Expedited projects

Expedited projects pass an initial screening process to show that the installation is small, uses certified equipment, and has limited effect on the area EPS.

Expedited projects are typically installations that are less than 10 kW and include protective functions as part of the overall system. Small wind generators, PV installations, and microturbines are typical of these types of systems, which use variable-frequency or dc generators and inverters. These systems typically adhere to IEEE Std 929-2000 [B34] or UL 1741 [B68] and, therefore, incorporate the protective functions typically required for parallel operation of the DR.

— Typical project flow is greatly simplified. At a minimum, the area EPS operator will require a one-line of the facility and, possibly, the installation of a suitable visible-break disconnect switch and documentation of the IEEE 929-2000, IEEE Std 1547-2003, or UL 1741 compliance certificate.

— These facilities are typically 10 kW or smaller and can be installed without studies or other considerations.

— The use of certified equipment should satisfy all area EPS requirements for this type of project.

— There is a commitment by the DR developer to maintain the original IEEE/UL compliance through the life of the installation.

H.3 Simplified projects

Simplified projects are not able to pass expedited screening but do pass the simplified project screen for faster review.

— The typical project flow is similar to that for expedited projects. However, there may be a need for a system impact study because of the size of the facility. More information about system impact study components and procedures can be found in Annex F.

— There may be local differences for similar installations because of local area EPS constraints.

— The use of certified equipment should satisfy the area EPS requirements for this type of installation. However, there may still be a need for a final field verification test.

H.4 Full projects

— These projects typically require one, two, or three studies, depending on the agreement between the DR developer and the area EPS operator. Typically, feasibility, impact, and facility studies are required. More information about study components and procedures can be found in Annex F. The DR developer can decide to stop or proceed after each study is completed. In some cases, the DR developer may be willing to take on the risk of doing two or more studies in parallel.

— As DR facilities increase in size, the impacts to the area EPS increase. This can lead to restrictions or additional requirements to the DR based on the location of the facility with respect to the area EPS.

- These facilities typically are assembled from components and, therefore, require additional field certification testing.
- There may be a significant impact on the fault duties because of the installation of large DR facilities.
- Typically, system studies are required.
  - System modification studies review the possible needed modifications to the area EPS for interconnection of the DR. This could include, but is not limited to, replacing line equipment and modifying recloser operation, transformer connection, grounding, and supply circuit breaker operation. Line equipment may be overdutied or not suitable for operation with both sides energized.
  - Recloser operation may need to be altered if the DR can form an island or slow the decay rate of the load voltage during a fault. Either of these cases may require the recloser closing operation to be delayed.
  - Many area EPSs use instantaneous reclosing on the substation supply circuit breakers. This is done to minimize the impact of a temporary fault on area EPS customers. The circuit breaker operation may need to be altered *if* the DR can form an island or slow the decay rate of the load voltage during a fault.
- The area EPS owner may specify the use of DTT or similar communications equipment to provide suitable protection and coordination. DTT can be implemented over a variety of communications media; however, both ends will need to install compatible equipment.
- These large units may require SCADA equipment. Many area EPSs will have an installed base of equipment and support for a limited number of protocols. The interface of the independent power producer SCADA with the area EPS SCADA system will need to be discussed.

H.5 Tariff issues (revenue metering and net metering)

Tariff issues are completely outside the scope of IEEE Std 1547-2003. However, they have such a large potential impact on the economics of the project that a short discussion is provided.

- The DR developer may find considerable differences between typical revenue metering and net revenue metering. For this reason, the DR developer may need to review the impact of these differences on the project.
- There may be specific revenue metering requirements based on the contractual arrangement and the arrangements for the purchase and sale of power.
- In many jurisdictions, the AHJs have established specific procedures and rules to facilitate the DR interconnection process. In addition to these procedures and rules, other business issues may need to be considered and addressed if the DR interconnection is to meet the business objectives of the DR developer. Many stakeholders may have interactions with DR systems as they relate to their interconnection with the area EPS. These stakeholders may include the area EPS operator, the DR aggregator, the DR maintainer, the DR operator, the area EPS maintainer, the DR manufacturer, the interconnection system manufacturer, the DR owner, the DR developer, power marketer, the ISO or regional transmission organization, and regulators. For very small DR units, many of the business issues may be covered by a tariff offered by the area EPS operator, and only a simple agreement between the DR developer and the area EPS operator may be necessary. For large DR units, several legal agreements may be necessary, and in some cases, the DR developer may need to provide additional hardware and software. For example, an ISO may require facilities to enable it to remotely monitor a large DR unit.
- If the DR owner expects to sell the power to an entity other than the area EPS at the PCC, a wheeling agreement and associated wheeling charges may be necessary for the power flowing to the other entity or the bulk power system.

H.6 Key information in application forms

Application forms may vary by jurisdiction and area EPS operator. Contact the relevant public utility commission and/or area EPS operator (e.g., the utility) for specific forms.

As an example, a typical application form will require the following:

- The DR owner's name, address, and phone number
- The name of the DR project (if it is different from the owner)
- Area EPS location information for the DR project (This could be a pole number, grid coordinate, account number, existing customer account, or something similar.)
- Additional contacts (e.g., the contractor and architect/engineer if appropriate)
- Identification of the type of generation equipment (e.g., induction, synchronous, inverter, or other)
- Generation equipment data (e.g., impedance data, time constants, short-circuit contribution, and grounding method)
- The fuel source (e.g., wind, solar, hydro, or gas)
- The size of the unit and number of phases
- The transformer type and connection, if supplied
- Transformer data (e.g., impedance and voltage ratings and taps)
- A one-line diagram
- Identification of local load, if known
- Identification of intent to back-feed or sell power beyond the PCC

H.7 Checklist

Following is an example checklist. It may need to be reduced for small projects or augmented for larger projects. It is a sample list provided from a single regional transmission organization-area EPS combination.

Checklist of items to be completed prior to energization of the non-utility generator facility

NOTE—All interconnection equipment associated with the DR installation should be energized prior to the connection of the DR. The items below are not presented in any particular order.

- The field test of the protection package and DR controls associated with all the associated circuit breaker controls (and/or low-side breakers, if appropriate) must be completed. Small facilities are typically self-contained and certified to IEEE Std 1547.1-2005 or UL 1741 [B68].
- All circuit breakers and associated controls directly involved with generation or connection to the area EPS must be completely functional.
- The revenue metering equipment needs be completely installed and functional, as the primary equipment will be energized.
- SCADA, either the DR or the area EPS, should be functional if required for this installation.
- The power supply for the protection package equipment must be completed and functional to provide adequate protection for initial energization.

- Large installations tend to have additional protective equipment associated with each piece of primary equipment. All associated protection equipment must be placed in service for other pieces of primary equipment (e.g., buses and transformers) as the primary equipment is placed in service.
- The area EPS must have a complete set of up-to-date, approved drawings prior to the initial energization of the DR equipment.
- For three-phase installation, the DR should have a detailed procedure for area EPS review of the initial phase-out and synchronization. This should include a step to verify zero potential across the synchronizing device prior to closing the device.
- Large facilities may require the area EPS to more fully understand the overall operation of the DR facility. When this is the case, a description of operation of electrical equipment should be provided. The description should cover the following:
  - All circuit breakers associated with the generation
  - All circuit breakers between the generator and the area EPS supply line
  - Controls associated with the above circuit breakers
  - Any other equipment that connects to the above breakers
- The DR developer and the area EPS operator should discuss the tap settings on all transformers.
- To maintain coordination, the proposed settings of relays or fuses associated with the following equipment may need to be discussed:
  - Main transformer (if protected by relays)
  - Low-side bus (if protected by relays)
  - Generator
  - Largest motor (if protected by relays)
- Occasionally, the area EPS operator may need an access procedure for access to the DR facility protection package cabinet. This is usually the case when area EPS equipment, such as SCADA, is installed at the DR facility.
- There may be requirements for an electrical inspection, by an independent agency, prior to the energization of the DR facility.
- Occasionally, the high-side breaker may use SF6, which, if it leaks out, can affect the insulation capability as well as the interrupting capability. In this case, an isolation procedure is generally required so that both the DR and area EPS understand how to isolate the breaker.
- After synchronization, all megawatt and mega voltampere-reactive meters must be checked for correct readings and correct direction of flow.
- A final set of “as built” drawings, up to date with all field revisions, is required.

H.8 Items to be discussed during the project

These items need to be addressed during a typical project. This list is designed to cover up to and including large DR projects with major area EPS impacts. Therefore, some items are not applicable to all DR projects. The list should be reviewed with the area EPS operator. The items are not listed in any particular order.

— **Electrical inspection**

The area EPS operator and local municipal authority may require electrical inspections for newly installed equipment.

— **Programmable logic controllers**

Programmable logic controllers should be designed and tested for retention of program and settings during a momentary loss of power. Also, when a momentary loss of power occurs, the programmable logic controller-based controls should return the facility to a “safe” condition. The DR developer and area APS operator can discuss the concept of return to a “safe” condition.

— **Periodic relay tests**

Typically, the area EPS or AHJ has requirements for the periodic testing of relays or protective functions, how the test results should be documented, and who is allowed to do the testing.

— **DR facility access**

For small DR installations, access will typically be limited to the disconnect switch. This switch should be located in an area that allows easy area EPS access and be clearly labeled. Large DR facilities may have area EPS equipment such as DTT or SCADA installed that the area EPS operator will need to access periodically.

— **Voltages at the DR facility**

In general, the DR is expected to operate at or near unity power factor. There may be situations in which the operation of the DR is specified as some value other then unity. IEEE Std 1547-2003 states the DR is not to actively control the area EPS voltage. However, in cases in which the DR has a significant effect on the area EPS, the DR may be required to operate at a specific power factor to limit the impact.

— **Energization date**

For most DR facilities, this is the date that the area EPS supply for the DR facility must be available. The requirement for energization may be driven by equipment other than the generation equipment. This date always precedes the initial synchronization date.

— **Initial synchronization date**

This is the date that the generation equipment will first be paralleled with the area EPS. This date is always after the energization date and before the commercial operation date. This date also defines the beginning of the test phase for larger DR facilities.

— **Commercial operation date**

This is the date when all DR generation equipment testing has been completed and the facility is ready for commercial operation. This date is always after the energization date and the initial synchronization date.

— **Area EPS grounding**

IEEE Std 1547-2003 states the DR facility ground must be compatible with the area EPS grounding. The DR operator should notify the area EPS operator about the proposed transformer connection and the DR facility grounding.

— **Drawing review one-line**

All DR installations should have a one-line drawing. For small units, this will probably be the only drawing required. Figure A.9 through Figure A.18 provide examples.

— **Revenue metering equipment**

Metering is outside the scope of IEEE Std 1547-2003; however, it is an important aspect of the DR facility. The DR developer and area EPS operator need to discuss the purchase and sale of power because this will affect the amount, type, and location of metering equipment.

— **Voltage reduction**

Some area EPS operators take voltage reductions at times of very high loading in an effort to control system loading. Under these circumstances, it is advantageous to *not* have the DR trip off because of low voltage. The DR operator should be made aware of this situation, and this should be considered in the design of the DR facility.

Annex I

(informative)

Glossary

For the purposes of this document, the following terms and definitions apply. These and other terms within IEEE standards are found in *The Authoritative Dictionary of IEEE Standards Terms* [B19].

area electric power system (area EPS): An EPS that serves local EPSs.

NOTE—Typically, an area EPS has primary access to public rights-of-way, priority crossing of property boundaries, etc., and is subject to regulatory oversight. See Figure I.1.

area electric power system operator (area EPS operator): The entity responsible for designing, building, operating, and maintaining the area EPS.

NOTE—When applicable, it includes an assembly of control elements required to detect overcurrents and control the recloser operation.

automatic circuit recloser: A self-controlled device for automatically interrupting and reclosing an ac circuit, with a predetermined sequence of opening and reclosing followed by resetting, hold-closed, or lockout operation.

automatic transfer switch: Self-acting equipment for transferring one or more load conductor connections from one power source to another.

capacitor: An energy storage device that can supply reactive power.

capacitor bank: An assembly of capacitors and all necessary accessories used to supply reactive power.

cease to energize: Cessation of energy outflow capability.

circuit breaker: A switching device capable of making, carrying, and breaking currents under normal circuit conditions and making, carrying for a specified time, and breaking currents under specified abnormal conditions such as those of short circuit.

design test: Test of one or more devices made to a certain design to show that the design meets certain specifications.

directional power relay: A relay that operates in conformance with the direction and magnitude of power.

distributed generation: Electric generation facilities connected to an area EPS through a PCC; a subset of DR.

distributed resources (DR): Sources of electric power that are not directly connected to a bulk power transmission system. DR includes both generators and energy storage technologies.

NOTE—See Figure I.1 and Figure I.2.

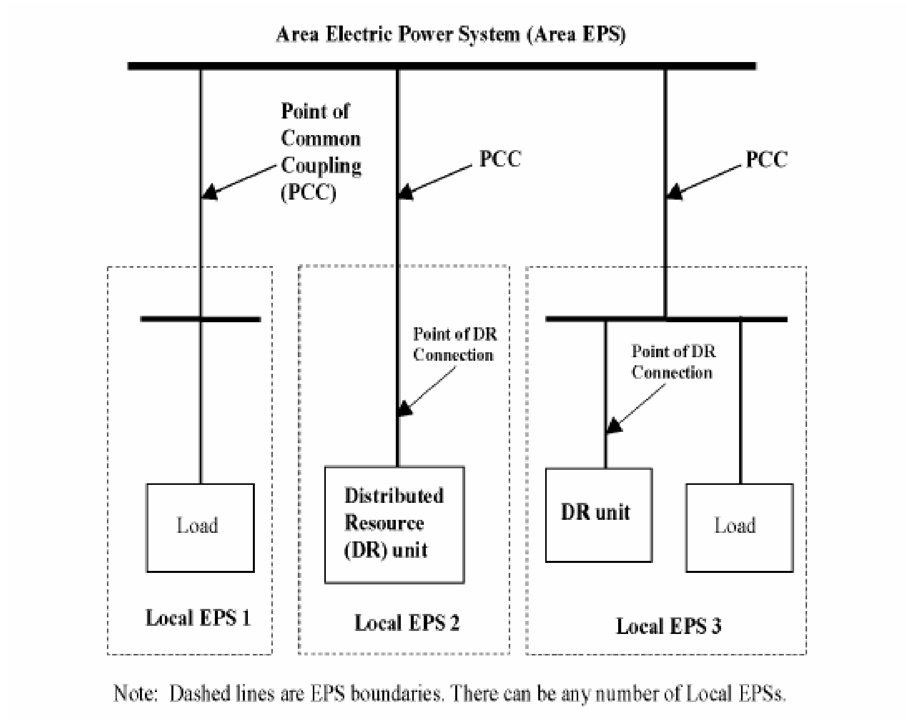


Figure I.1—Relationship of interconnection terms

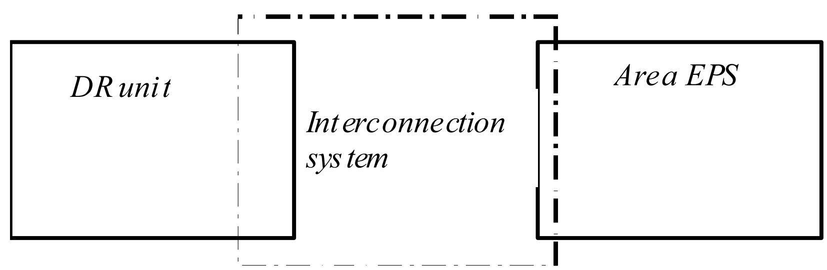


Figure I.2—Schematic of interconnection

distribution feeder: *See:* **primary distribution feeder**; **secondary distribution feeder**.

distribution system: That portion of an electric system that delivers electric energy from transformation points on the transmission or bulk power system to consumers.

distribution transformer: A transformer for transferring electrical energy from a primary distribution circuit to a secondary distribution circuit or consumer's service circuit.

effectively grounded: Grounded through a grounded connection of sufficiently low impedance (inherent, intentionally added, or both) that fault grounds that may occur cannot build up voltages in excess of limits established for apparatus, circuits, or systems so grounded.

electric power system (EPS): Facilities that deliver electric power to a load.

NOTE—This may include generation units. See Figure I.1.

fault: A physical condition that causes a device, a component, or an element to fail to perform in a required manner (e.g., a short circuit, a broken wire, or an intermittent connection).

four-wire, multigrounded-neutral system: A three-phase system that consists of three phase conductors and a neutral conductor grounded at multiple points.

grid network: A secondary network system with geographically separated network units and the network-side terminals of the network protectors interconnected by low-voltage cables that span the distance between sites. The low-voltage cable circuits of the grid networks are typically highly meshed and supplied by numerous network units. Also referred to as *area network* or *street network.*

harmonic distortion: Nonlinear distortion of a system parameter characterized by the presence of frequencies that are integer multiples of the fundamental frequency of the sinusoidal wave.

independent power producer: An entity other than the utility that operates a generator interconnected with the area EPS.

induction generator: An induction machine, when driven above synchronous speed by an external source of mechanical power, used to convert mechanical power to electric power.

NOTE—Induction generators may draw reactive power from the EPS.

intentional island: A planned island.

interconnection: The result of the process of adding a DR unit to an area EPS.

NOTE—See Figure I.2.

interconnection equipment: Individual or multiple devices used in an interconnection system.

interconnection system: The collection of all interconnection equipment and functions, taken as a group, used to interconnect a DR unit(s) to an area EPS.

NOTE—See Figure I.2.

interrupting device: A device capable of being opened and reclosed whose purpose is to interrupt faults and restore service or disconnect loads. These devices can be manual, automatic, or motor-operated. Examples include circuit breakers, motor-operated switches, fuses, and electronic switches.

inverter: A machine, device, or system that changes dc power to ac power.

island: A condition in which a portion of an area EPS is energized solely by one or more local EPSs through the associated PCCs while that portion of the area EPS is electrically separated from the rest of the area EPS.

lagging reactive power: The condition in which the current in a circuit is delayed in phase relative to the voltage. Inductive loads (motors) draw lagging reactive power.

leading reactive power: The condition in which the current in a circuit is preceding in phase relative to the voltage. Capacitors draw leading reactive power.

line-commutated inverter: An inverter that is designed such that its line source frequency reference is provided by an external source of generation.

line drop compensator: A device that causes the voltage-regulating relay to vary the output voltage by an amount that compensates for the impedance drop of the circuit between the regulator and a predetermined location on the circuit (sometimes referred to as the *load center*).

local electric power system (local EPS): An EPS contained entirely within a single premises or group of premises.

non-islanding: Intended to prevent the continued existence of an island.

non-utility generator: A generator interconnected with the area EPS that is owned and operated by an entity other than the utility power system (area EPS).

paralleling switchgear: Devices that perform paralleling and synchronizing functions between the DR (or multiple DR units) and the area EPS.

point of common coupling (PCC): The point where a local EPS is connected to an area EPS.

point of distributed resources connection (point of DR connection): The point where a DR unit is electrically connected in an EPS.

power circuit breaker: *See:* **circuit breaker**.

power factor: Ratio of real to total apparent power (kilowatts/kilovoltamperes) expressed as a decimal or percent.

power factor correction: The process of bringing the power factor closer to a desired value.

primary distribution feeder: A feeder that operates at primary voltage and supplies a distribution circuit.

NOTE—A primary feeder is usually considered that portion of the primary conductors between the substation or point of supply and the center of distribution.

reactive power: The reactive power Q is defined as the square root of the square of the apparent power S minus the square of the active power P. Reactive power is developed when there are inductive, capacitive, or nonlinear elements in the system. It represents energy that cannot be extracted from the system but can cause increased losses and excessive voltage peaks.

recloser: *See:* **automatic circuit recloser**.

relay: An electric device designed to respond to input conditions in a prescribed manner and, after specified conditions are met, to cause contacts operation or similar abrupt changes in associated electrical control circuits.

secondary distribution feeder: A feeder that operates at secondary voltage to supply a distribution circuit.

self-commutated inverter: An inverter that is designed such that its frequency reference is internal to the power inverter and is independent of any external source of generation.

spot network: A small network, usually at one location, that consists of two or more primary feeders, with network units and one or more load service connections.

static power converter: An electronic device with control, protection, and filtering functions used to interface an electric energy source with an area EPS. It is sometimes referred to as a *power conditioning subsystem, power conversion system, solid-state converter,* or *power conditioning unit.*

static transfer switch: Self-acting solid-state equipment for rapidly transferring one or more load conductor connections from one power source to another.

steady-state voltage: The condition of the voltage at a time when no transients are present.

supervisory control and data acquisition (SCADA): A system to collect data and provide control of a remote location via a communication system.

surge current: A transient current, which usually rises rapidly to a peak value and then falls more slowly to zero, that occurs in electrical equipment or EPSs.

switchgear: A general term covering switching and interrupting devices and their combination with associated control, instrumentation, metering, protective and regulating devices, also assemblies of these devices with associated interconnections, accessories and supporting structures used primarily in connection with the generation, transmission, distribution, and conversion of electric power.

synchronous generator: A synchronous ac machine that transforms mechanical power into electric power. (A synchronous machine is one in which the average speed of normal operation is exactly proportional to the frequency of the system to which it is connected).

total demand distortion: The total root-sum-square harmonic current distortion, in percent of the maximum demand load current (15 min or 30 min demand).

type test: *See:* **design test**.

unintentional island: An unplanned island.

uninterruptible power supply (UPS): A system designed to automatically provide power, without delay or transients, during any period when the normal power supply is incapable of performing acceptably.

voltage flicker: A condition of fluctuating voltage on a power system that can lead to noticeable fluctuations in the output of lighting systems.

Annex J

(informative)

Bibliography

These resources are listed to provide additional useful information. At the time of publication, the editions indicated were valid. All standards and specifications are subject to revision, and readers are encouraged to investigate the possibility of applying the most recent editions of the references listed below.

[B1] Accredited Standards Committee C2-2007, National Electrical Safety Code® (NESC®).[54]

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