



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

IEEE Standards Coordinating Committee 21

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IEEE Standards Coordinating Committee 21 on
Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage

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

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**IEEE Standards Coordinating Committee 21 on
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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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/>).

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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.

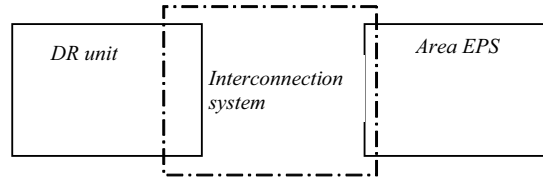


Figure 1—Schematic of interconnection

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

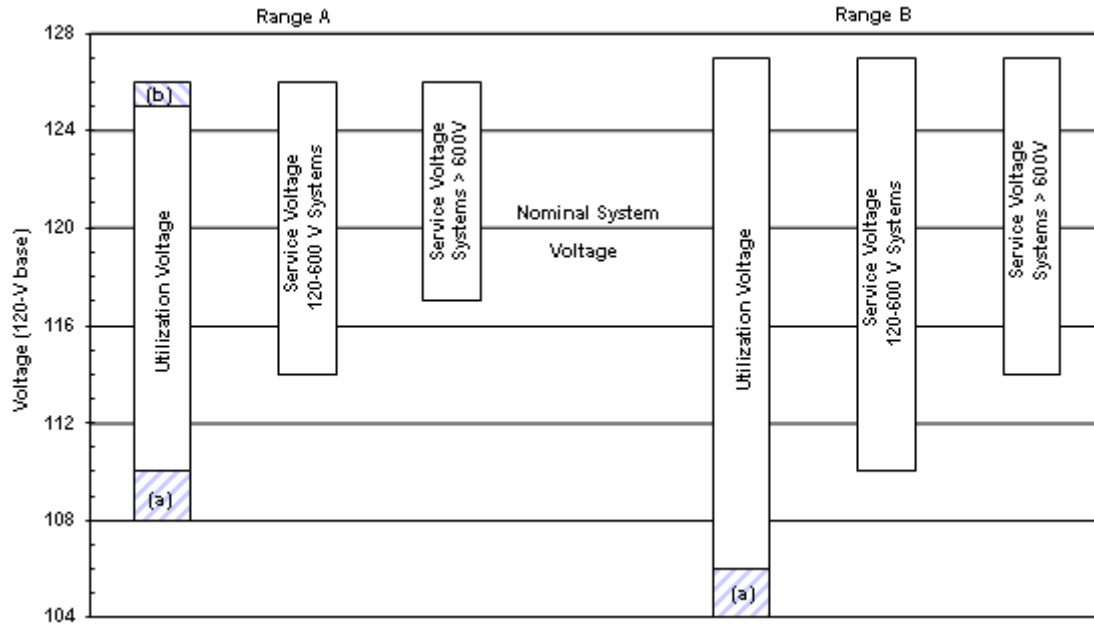
Voltage regulation describes the process and equipment to maintain voltage within acceptable limits. The primary objective of area EPS voltage regulation is to provide each customer connected to the area EPS with voltage that conforms to the design limitations of the customer's utilization equipment. 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 2⁶ 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

⁸Voltage 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.

⁹Automatic 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.

¹⁰Shunt 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 ungrounded 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 ungrounded systems

In three-wire ungrounded 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

¹¹In 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 ungrounded systems

A similar concern exists for phase-to-ground overvoltage in four-wire or three-wire ungrounded 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.

— Ungrounded and three-wire ungrounded systems

DR interconnections with area EPS primary feeders of three-wire ungrounded 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 ungrounded 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.

¹²Grounded 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 $\pm 5\%$ 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 interconnection¹⁴ (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].”

¹³NEMA MG-1 [B56] contains an acceptable method for determining inrush current.

¹⁴Some 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

¹⁵Synchronizing 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 P1547.6¹⁶ 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 networks¹⁷ (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.

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.

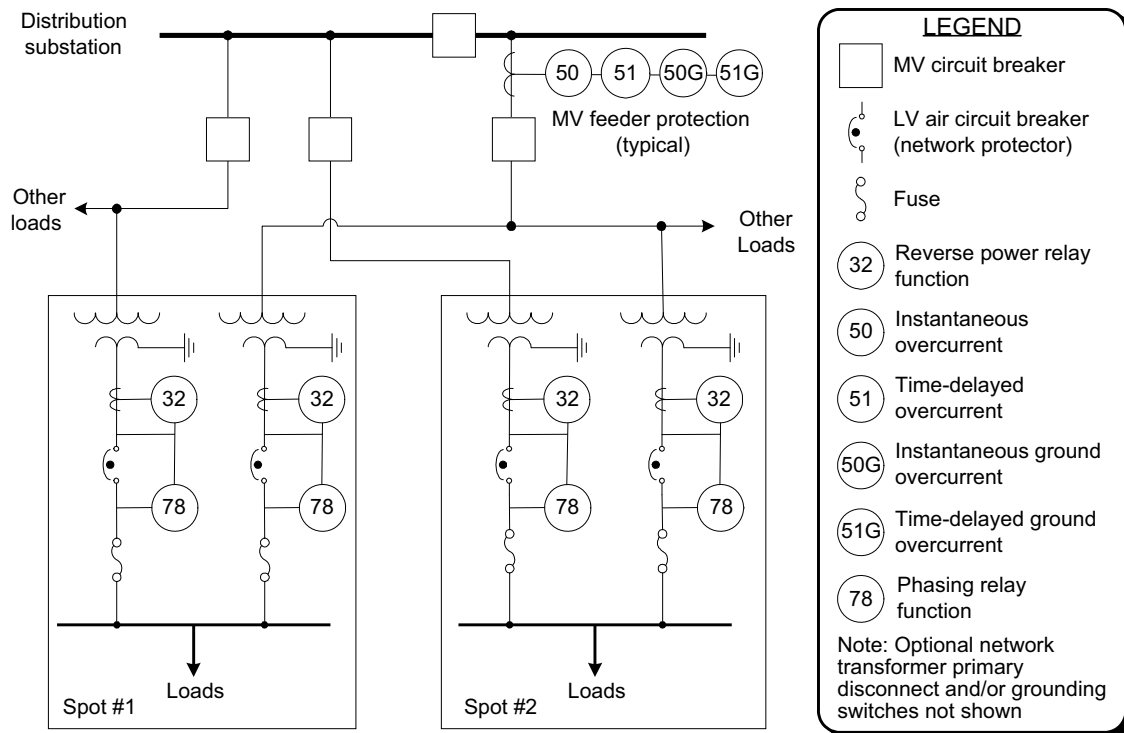


Figure 3—Example secondary spot network

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 4¹⁹ 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.

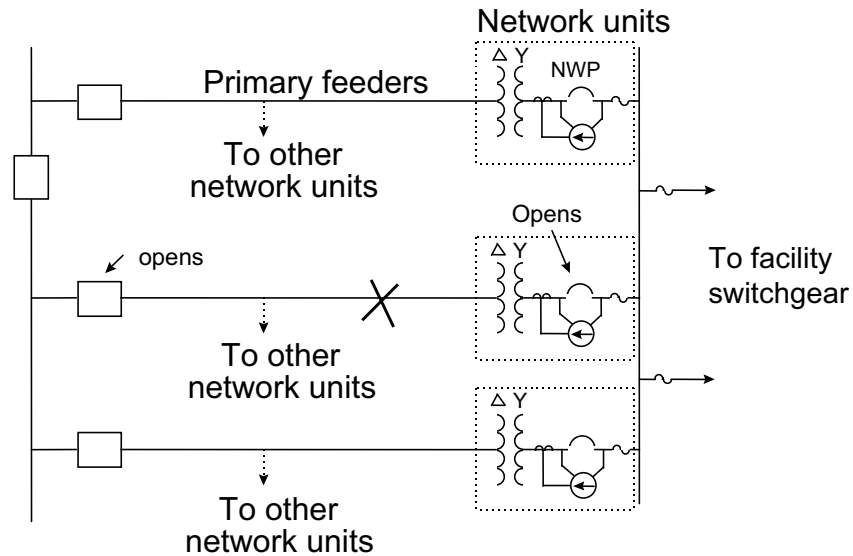


Figure 4—Network primary feeder fault

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 180° 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.

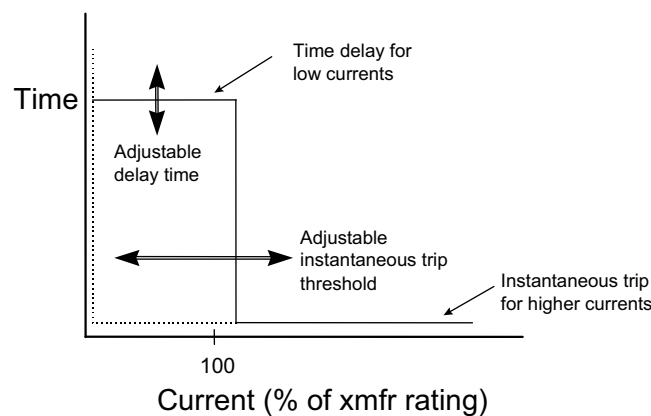


Figure 5—Adjustable reverse-power characteristic

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.

²⁰UL 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 transceivers²¹ (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.