

IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection

IEEE Standards Coordinating Committee 21

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

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IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection

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Abstract: IEEE Std 1547.7™ is part of the IEEE 1547™ series of standards. Whereas IEEE Std 1547™-2003 provides mandatory requirements for the interconnection of distributed resources (DR) with electric power systems (EPS), this guide does not presume the interconnection is IEEE 1547™ compliant. Further, this guide does not interpret IEEE Std 1547™ or other standards in the IEEE 1547™ series, and this guide does not provide additional requirements or recommended practices related to the other IEEE 1547™ documents. However, DR interconnection may contribute to resultant conditions that could exceed what was normally planned for and built into the distribution system. This guide provides alternative approaches and good practices for engineering studies of the potential impacts of a DR or aggregate DR interconnected to the electric power distribution system. This guide describes criteria, scope, and extent for those engineering studies. Study scope and extent are described as functions of identifiable characteristics of the DR, the EPS, and the interconnection. The intent includes promoting impact study consistency while helping identify only those studies that should be performed based on technically transparent criteria for the DR interconnection.

Keywords: distributed energy resources, distributed generation, distributed power, distributed resources, distribution grid, distribution system, electric power systems, energy storage, federal utility grid, fuel cells, grid interconnection requirements and specifications, IEEE 1547.7™, interconnection, microturbines, national, photovoltaic power systems, public utility commission, regulations, renewable energy, rulemaking, regional, utility grid, utility grid dispersed generation

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Introduction

This introduction is not part of IEEE Std 1547.7™-2013, IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection.

With the advent of IEEE Std 1547™-2003, modern interconnection equipment has made great gains by having universal interconnection and test requirements focused at the point of common coupling. Additionally, since the adoption of IEEE Std 1547™, there has been significant experience gained related to inter-related technology systems and operational concepts to properly integrate distributed resources (DR) into electric power systems (EPS). Traditionally, however, utility electric power systems were not designed to accommodate active generation and storage at the distribution level. The addition of DR to an EPS will change the system and its response in some manner. Increased adoption of distributed resources throughout distribution systems often results in the need to perform a distribution system impact study. This guide provides a common technical platform based on engineering knowledge to address study methods for performing DR-EPS impact studies. This document includes an overview of general considerations, operational considerations, configuration considerations, preliminary review criteria, conventional and special impact studies methodologies, tools and technical issues, data requirements, and examples of mitigation techniques. A sample methodology for using the guide is also provided. The intended audience will gain a common technical understanding as well as an increased understanding of the potential impacts of DR interconnection. The guide addresses engineering studies from a technical perspective rather than a regulatory perspective. This document establishes guidance including multiple approaches (alternatives/choices) using engineering studies based on engineering best practices, including engineering characteristics, engineering studies methodologies, and engineering parameter criteria to understand and use the engineering studies results.

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1. Overview

1.1 Scope

This guide describes criteria, scope, and extent for engineering studies of the impact on area electric power systems of a distributed resource (DR) or aggregate distributed resource interconnected to an area electric power distribution system.

1.2 Purpose

The creation of IEEE Std 1547TM-2003 has led to the increased adoption of DR throughout distribution systems.^{1,2} This document describes a methodology for performing engineering studies of the potential impact of a DR interconnected to an area electric power distribution system. Study scope and extent are described as functions of identifiable characteristics of the DR, the area electric power system, and the interconnection. Criteria are described for determining the necessity of impact mitigation.

Establishment of this guide allows DR owners, interconnection contractors, area electric distribution power system owners and operators, and regulatory bodies to have a described methodology for when distribution

¹ IEEE publications are available from The Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, NJ 08854, USA (<http://standards.ieee.org/>).

² Information on references can be found in Clause 2.

system impact studies are appropriate, what data are required, how they are performed, and how the study results are evaluated. In the absence of such guidelines, the necessity and extent of DR interconnection impact studies has been widely and inconsistently defined and applied.

1.3 Intended audience

This document is intended for use by a broad spectrum of individuals ranging from those having detailed expertise in defined areas, to others having broad knowledge and interest. The intended audience includes Area electric power system (EPS) operators, Area EPS owners, Area EPS planners, Area EPS designers, Area EPS dispatchers, DR developers, DR owners, equipment manufacturers, regulators, and other knowledgeable parties.

The intended audience will gain a common technical understanding as well as an increased understanding of the potential impacts of DR interconnection. The guide addresses engineering studies from a technical perspective rather than a regulatory perspective. The document establishes guidance including multiple approaches (alternatives/choices) using engineering studies based on engineering best practices—engineering characteristics, engineering studies methodologies, and engineering parameter criteria—to understand and use the engineering studies results.

1.4 Limitations

This guide applies to all DR technologies at the point of common coupling (PCC)—the point where a Local EPS is connected to an Area EPS—that are interconnected with an Area EPS at typical primary or secondary distribution voltage.

- 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 addresses distribution system configurations typical to North America. However, the methodologies as well as most of the evaluation criteria, studies, and mitigation techniques are pertinent worldwide.
- 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.
- This guide does not interpret IEEE Std 1547™ or other standards in the IEEE Std 1547™ series.
- This guide does not provide additional requirements or recommended practices related to other IEEE Std 1547™ standards.
- This guide does not presume the DR interconnection is compliant with IEEE Std 1547™.
- This guide does not specify time frames to do the necessary impact studies.
- This guide is not intended to address particular study issues pertinent exclusively to secondary grid and spot networks in detail (IEEE Std 1547.6™-2011 [B9]).³ However, this guide is relevant for many of the study requirements for DR on secondary grid and spot networks.
- This guide is not intended to address particular study issues pertinent exclusively to DR on intentional islands (IEEE Std 1547.4™-2011 [B8]). However, this guide is relevant for many of the study requirements for DR on intentional islands.

³ The numbers in brackets correspond to those of the bibliography in Annex A.

- This guide does not address particular study issues pertinent exclusively to high penetration of vehicle-to-grid applications. However, this guide is relevant for many of the study requirements related to vehicle-to-grid applications.
- This document does not address controls and communications security requirements.
- This document does not address the impacts of distribution system interconnected DR on sub-transmission and transmission systems.

1.5 Document structure

1.5.1 Introduction

Increased adoption of DR throughout distribution systems often results in the need to perform a distribution system impact study. Various attempts by regulatory authorities to develop common procedures have improved understanding of this process. However, as experience has been gained since the adoption of IEEE Std 1547™, a collective knowledge has been developed of criteria that is important to consider when determining what studies need to be considered. This document provides and describes engineering knowledge that is used for conducting impact studies.

This guide promotes impact study consistency and performing studies only when determined necessary. It provides and describes the criteria, scope, and methodology for determining which engineering studies need to be performed to assess the potential impact of DR interconnected to an Area EPS distribution system. It provides descriptions of study types and tools, methodologies in using them for evaluation, and the knowledge that will be gained from performing them. This guide also describes criteria for determining the necessity of impact mitigation and provides sample mitigation techniques.

This guide provides the criteria DR owners, interconnection contractors, distribution power system owners and operators, and regulatory bodies should consider. The evaluation of the criteria will provide guidance in determining the appropriate distribution system impact studies, what data are required, how they are performed, and how the study results should be applied. It is focused on maintaining IEEE Std 1547™ requirements and consistency with IEEE Std 1547.1™-2005 and IEEE Std 1547.2™-2008.

1.5.2 Overview of the guide

This guide provides an overview of general considerations, operational considerations, configuration considerations, preliminary review criteria, conventional and special impact studies methodologies, tools and technical issues, data requirements, and examples of mitigation techniques. A sample methodology for using the guide is also provided.

General considerations, operational considerations, and configuration considerations are important to understand to determine the issues that may affect DR installation and operation. In addition, the current state and anticipated state of the system when the DR comes online are important. These considerations take into account the DR, local electrical system, and Area EPS issues.

The preliminary review criteria should be used to determine if conventional and special impact studies are needed and as an initial determination of what impact studies need to be performed. The preliminary review uses a tiered evaluation approach based on established evaluation criteria to determine appropriate extent of what impact studies are to be undertaken. It provides multiple approaches to study potential issues.

The impact studies are categorized as conventional distribution studies and special system impact studies. Each of these sections of the document describes the details of each impact study and the expected results of the study.

The data requirements section establishes the identification of sets of data requirements based on different studies, situations, and constraints on sources of data. The data requirements clause is organized to facilitate the data needs for preliminary review and for particular impact studies.

The mitigation techniques clause provides examples of techniques used by various Area EPS operators to solve the issues identified by the various impact studies. This clause is organized in the same way as the preliminary review criteria to provide ease of cross reference.

This guide does not address cost issues and regulatory issues. Where these are mentioned they are intended as an example of techniques used to determine the appropriate impact studies and mitigation techniques.

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 1547TM, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.⁴

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

IEEE Std 1547.2TM, IEEE Application Guide for IEEE Std 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

3. Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary Online* should be consulted for terms not defined in this clause.⁵

3.1 Definitions, acronyms, and abbreviations

line section: The smallest Area electric power system (EPS) section that could be energized by the distributed resource (DR).

3.2 Acronyms and abbreviations

CAIDI	customer average interruption duration index
CT	current transformer
DFAG	doubly-fed asynchronous generator
DFIG	doubly-fed induction generator

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⁵ *IEEE Standards Dictionary Online* subscription is available at:

http://www.ieee.org/portal/innovate/products/standard/standards_dictionary.html.

DMS	distribution management system
DR	distributed resource
DTT	direct transfer trip
EDA	electronic design automation
EMS	energy management system
EMTP	electromagnetic transients program
EPS	electric power system
ISE	interconnection system equipment
kVA	kilovolt-amperes
kVAr	kilovolt-amperes reactive
LTC	load tap changer
LVRT	low-voltage ride-through
MVA	mega volt amperes
NRTL	nationally recognized testing laboratory
PCC	point of common coupling
PID	proportional, integral, and derivative
PLC	programmable logic controller
PV	photovoltaics
PT	potential transformer
PPE	personal protective equipment
PU	per unit
SCADA	supervisory control and data acquisition
SCCR	short-circuit current contribution ratio
SOP	system operating procedure
SSC	short-circuit capacity
THD	total harmonic distortion
TOV	temporary overvoltage
UL	Underwriters Laboratory

VR	voltage regulator
VT	voltage transformer (also known as “PT” potential transformer)
vars	volt-amperes reactive

4. General considerations for DR impact studies

An impact study identifies potential problems and allows the Area EPS operator to determine the modifications to the Area EPS facilities that could correct the problems identified in the impact study. In some cases, the Area EPS operator may also prepare system-level studies to assess the cumulative or combined impacts of multiple DR interconnections.

The impacts of the interconnection of DR at a particular location within the Area EPS depend on the specific characteristics of the DR, the proposed interconnection, the proposed point of interconnection within the Area EPS, and the specific characteristics of the Area EPS itself. The bigger the DR, the more effect it is likely to have on the distribution system. For particular types of DR, such as inverter-based photovoltaics (PV) or synchronous generation, there are technology-specific considerations that determine the impact of the DR on the Area EPS. Characteristics of the DR that derive from its source of primary energy, such as its variability, its predictability of operation under different circuit or EPS operating conditions, and its dispatchability (or the ability to alter output as needed), also help determine the impact of the DR on the EPS. Clause 5 provides additional discussion of attributes of the DR that affect interconnection.

Accordingly, a tiered evaluation procedure provides the most efficient method for DR starting with an understanding of the type and size of the DR under consideration, system limitations at the proposed location of the DR, and the level of control or monitoring of the DR that will be available to the EPS operator. Clause 6 outlines such a tiered approach, beginning with a preliminary evaluation of the interconnection, a determination of the need for additional studies, then detailed studies as needed.

DR interconnection can impact an Area EPS at any level of “penetration” of DR. However, as the aggregate output of DR approaches or exceeds the nearby load simultaneously served within the Area EPS, this can materially affect local power flow and voltage within the Area EPS. The potential impact of each DR addition on the Area EPS may require study. Thus, the impact on the Area EPS of an otherwise identical DR may be different due to previously interconnected DR in the Area EPS.

DR interconnection can impact any Area EPS. However, DR interconnections at “weak” locations, such as may be found on islands or at PCCs near the end of long, radial circuits, are more susceptible to DR impacts than DR interconnections in strong interconnected systems with large generation sources. Evaluation of the potential impacts of a particular DR on an Area EPS also requires a detailed understanding of the characteristics of the nearby Area EPS itself. For example, some Area EPSs have automatic sectionalizing equipment that divide the feeder into sections with automatic restoration devices. This equipment is used in schemes intended to limit customer outages by isolating a permanently faulted section of a feeder and restoring power to customers not directly connected to the faulted section. Since these sectionalizing schemes break the feeder into smaller load sections, smaller DR installations can create viable islanding situations. Also, the automatic transfer of isolated load sections has potential system concerns. Clause 5 provides a more detailed discussion of how particular attributes of the Area EPS affect DR interconnection.

Evaluation of the impact of the interconnection of a particular DR on an Area EPS at a particular point of interconnection may be a multi-step process to direct efforts to known or likely issues in order to avoid unnecessary studies. In such a process, the first technical evaluation is a preliminary review to determine if the DR can be safely interconnected with a simplified evaluation. Clause 7 includes a more detailed discussion of approaches to preliminary review of a DR interconnection and the conditions under which

such an evaluation is adequate. Clause 8 includes a more detailed discussion of approaches to a conventional detailed impact study. In some cases, an impact study for the interconnection of a particular DR may be indeterminate, necessitating special studies that go beyond the scope of a conventional impact study or go into greater depth on particular issues. Clause 9 includes a more detailed discussion of special studies.

4.1 Potential DR impacts on the Area EPS

A DR interconnection may impact the Area EPS in several general technical areas; these are described in the following subclauses. A given DR to be interconnected with the Area EPS represents a unique set of conditions. Not every DR will have the same impacts in these technical areas, nor is the following intended as a complete list. The impact studies for a given DR interconnection, whether preliminary, conventional, or special, are aimed at determining the impacts of the proposed interconnection on the Area EPS.

4.1.1 Unintentional islanding

Area EPS operating practices may isolate a section of the EPS by using sectionalizing and/or disconnecting devices. Unintentional islands can be established when a section of the Area EPS is isolated from the source while the load is supported by DR within the isolated section that continues to provide power. Unintentional islands pose a threat to proper Area EPS system operation for a number of reasons.

- Many radial systems include interrupting devices that are designed to trip and clear a fault and automatically reconnect to restore load. Therefore, upstream Area EPSs might attempt to reconnect into the island unsynchronized with voltage, frequency, and/or phase angle, which can damage switchgear, power generation equipment, and customer equipment.
- An unintentional island can increase public exposure to unsafe, energized downed conductors.
- Line crews working on power restoration following storms or other events may encounter unintentional energized islands, making their job more hazardous and slowing down the power restoration process.
- Unintentional islands do not have their generators set up with the proper controls to maintain power quality conditions adequate to the customer loads, which may result in damages.

IEEE Std 1547™ specifies DR systems detect the formation of an island and cease to energize the Area EPS within two seconds. Anti-islanding protection can be accomplished through passive or active detection, or by using communications methods. When passive or active anti-islanding is used, anti-islanding techniques may not adequately detect island formation and cease to energize the Area EPS within a suitable amount of time when DR output is close to the simultaneous or pre-fault load served within the Area EPS.

Another potential impact of the DR unintentional islanding function is described in the following: Large amounts of DR could be prone to tripping during severe transmission system disturbances that typically affect a wide geographical area because of passive anti-islanding that is set to disconnect DR in the event that the network voltage or frequency goes outside of predefined limits.

4.1.2 Area EPS equipment loading

Historically, Area EPSs at the distribution level were designed for unidirectional power flow, and unidirectional short-circuit contribution, from the substation or primary source to the loads. Equipment should operate within its planned rating and according to the Area EPS operating policies. DR may change the power flow and appear to reduce loading. The loss of either the load or the DR may cause equipment overloading.

The potential for impacts on Area EPS equipment loading has to take into consideration the active and reactive power injected in the Area EPS by all DRs. These impacts may be more prevalent at off-peak periods than during peak periods when nearby loads absorb the generation (e.g., PV without storage would not generate power during night hours).

4.1.3 Protection design, coordination, and fault rating

Area EPS protection systems are designed to reduce the impact of faults that can be caused by lightning or other problems on the Area EPS system. DR systems also need to coordinate with the protection systems employed on distribution circuits. Typically a distribution system will employ a protection scheme that consists of fuses, circuit breakers, sectionalizers, and automatic restoration devices that are coordinated in the load direction to operate with a minimum number of customers affected. Adding DR to the distribution circuit may affect coordination. Protection settings can be over sensitized (false trip) or desensitized (no trip or delayed trip) by DR fault current contributions, depending on the location of the DR relative to the existing protective device. This can cause issues depending on distribution circuit characteristics [B13]. Additionally, the connection of generation resources to a distribution feeder can introduce sources of short-circuit current contribution to the distribution system. This could potentially result in increased short-circuit currents, potentially reaching damaging levels and protection desensitization and a potential breach of protection coordination. Consequences of reverse power flow also need to be assessed.

Some Area EPS operators have work practices that include performing work on energized equipment. Some of these Area EPS operators have adopted the use of protective relays and automatic restoration devices to limit the arc flash energy and to not permit reclosing of the protective device. These relays and automatic restoration devices limit the arc flash energy to levels that will allow personnel to work on energized equipment while wearing protective clothing that does not restrict movement. The arc flash energy is determined by the amount of fault current and the time it takes to extinguish the arc caused by the fault (measured in calories/cm²). The addition of DR may increase both the fault current and clearing time associated with the arc flash energy. This arc flash energy may exceed the rating of protective clothing which will dis-allow working on the energized equipment if the DR is operating. The DRs may need to be disconnected from the Area EPS while live line work is being performed.

4.1.4 Voltage regulation and reactive power management

Steady state voltage is the voltage of the power system over a sustained period of time, usually considered as several minutes in duration as defined in Annex I of IEEE Std 1547.2™. Area EPS operators require generation on the distribution system to be operated in a manner that does not cause the service voltage for customers on the EPS to go outside the applicable limits. In addition, operation of the DR should be designed to avoid causing interference with the normal operation of the Area EPS's voltage regulation equipment. Where generation is variable in nature, the resultant voltage fluctuation may cause adverse effects on voltage regulation equipment such as premature wear due to increased operations. Voltage regulator controls may need to be modified or replaced when power may be injected from the load side of the device.

DR also impact voltage levels when it injects power into the grid; this may cause abnormal voltage conditions as DR serves a greater share of nearby Area EPS load. For example, induction generators may lower the voltage, whereas PV may raise the voltage. Reactive power exchange at the PCC has an impact on voltage regulation. DR output changes may occur more rapidly than the dead time and response time of circuit voltage controls, in which case voltage fluctuations of approximately one minute or less can occur in the Area EPS. These DR output changes could be due to faults, changes in energy availability, or startup and shutdown. Additional concerns and costs associated with interconnecting DR at the distribution level include wear and tear on transformer tap changers and power factor control equipment. Studies may be needed to predict the voltage fluctuations of the Area EPS with large amounts of variable DR. Multiple power flow simulations including time series or quasi-static simulations may be needed to fully study the impacts of DR on Area EPS voltage.

Finally, multiple DRs can have a cumulative effect on the voltage of the Area EPS. Impact studies should therefore consider all DR present in the Area EPS.

4.1.5 Power quality

Impacts of DR on power quality include potential overvoltage, undervoltage, sags, swells, and flicker due to specific events or rapid fluctuations in output of the DR and harmonic distortions.

Repeated, rapid changes in DR output can cause flicker. See IEEE Std 1453™ and IEEE Std 1453.1™. As an example, solar and wind-based DR may contribute significantly to flicker. When connected to a weak location within the Area EPS, wind turbines' and photovoltaic plants' contribution to flicker may become problematic. This problem can arise with wind turbines due to rapid changes in wind conditions (e.g., wind gusts), or with PV generation due to fast changes in irradiance caused by moving cloud cover.

Harmonics are distortions in the power system frequency sine wave. Power electronic based-switching devices such as inverters can cause harmonics. Too much harmonic distortion can cause adverse operation of customer and Area EPS equipment. Harmonic contribution from DR can be difficult to predict. Furthermore, the same level of harmonic current from a DR may result in different levels of harmonic voltage distortion depending on the Area EPS characteristics.

4.2 DR primary energy source-related considerations

A DR's source of primary energy affects its potential impact on the Area EPS through the DR's predictability, variability, and dispatchability.

4.2.1 Predictability

Predictability refers to the ability of the DR to operate consistently in a forecasted manner. As an example, chemical or combustible fuels as primary DR energy sources are generally very predictable (and may also be dispatchable depending on contractual terms between the owner and the Area EPS operator). From the perspective of the primary energy source, combustible fuel-based DRs may operate at any time, day or night, and are not limited by their primary energy source to operation in certain periods. Combustible fuel-based DRs are typically not subject to short-term variation in output due to unpredictable fluctuations in primary energy availability. However, when and how a fuel-based DR may operate and how these affect the Area EPS may be more subject to institutional considerations. For example, a digester or combined heat and power unit may be scheduled to operate during certain periods to support operational practices of the host that are wholly independent of Area EPS operational considerations.

4.2.2 Variability

Variability refers to unpredictable and uncontrollable short-term variation in the DR output. Solar energy, for example, is a variable, as-available energy source. While solar energy is predictable in that it operates during the day and never at night when Area EPS loads are typically at their minimums, it is also variable in that it is subject to rapid changes in output due to changes in solar radiation. Further, solar DR projects may have group exposure to output changes due to a cloud passing. Multiple solar DRs on a circuit may smooth the impacts of a single DR.

Wind energy is also a variable, as-available energy source. And wind energy is also less predictable than other primary energy sources. Wind DR projects may experience their maximum output at night during minimum load periods, and may also experience minimum output during heat storms, simultaneous with

maximum Area EPS loads. Wind energy is subject to both seasonal and rapid changes in output. Wind DR projects may have group exposure to output changes due to changing weather conditions.

4.2.3 Dispatchability

Dispatchability refers to the ability of the Area EPS operator to dictate or influence the electrical output of the DR; dispatchability derives from contractual terms as well as the DR's source of primary energy. A variable, as-available power source, such as wind or solar, may be dispatchable to reduce its output, but not to increase it. On the other hand, if energy storage is combined with a variable power source, it may become partially dispatchable, subject to the amount of energy stored at any given time.

4.3 DR technology-specific considerations

DR systems are generally classified by the type of generator that interfaces the system to the grid: 1) inverters, and 2) rotating machines, including induction generators, doubly-fed asynchronous generators, and synchronous generators. As they relate to interconnection to the Area EPS, these different DR systems are distinguished by their fault current contribution, the ability of the DR to provide voltage support, and the potential contribution to harmonic distortion. Further information on DR technology-specific considerations is provided in 5.1.

4.3.1 Inverter-based generation

An inverter is a power electronic device that converts dc power from the primary energy source to ac power suited to the grid. Inverters are typically associated with solar PV generation, microturbines, fuel cells, some wind turbines, and battery energy storage systems. Inverter output current is limited and/or actively controlled, so they typically contribute little ac fault current in excess of their full load rating. Inverter-based DRs may be designed to be inherently capable of changing their output very rapidly. Inverters typically detect EPS faults by voltage, current, and frequency measurements at their terminals. Inverters compliant with IEEE Std 1547™ use various active anti-islanding measures to detect when they are feeding an island. Modern inverters typically have high quality sinusoidal output current waveforms, but their output filter capacitors appear in parallel with the grid and should be taken into account when assessing the potential for resonance.

Presently, inverter-based generation in UL Listed operating modes operates at a fixed, often unity power factor and function as a current source when connected to the EPS. In this configuration, inverters do not participate in active voltage regulation or reactive power management schemes. However, inverters have the potential to do so.

4.3.2 Asynchronous (induction) generation

Induction generators are essentially induction motors used in a generating application. Since motors are proven rugged technology and available in mass production, they are good candidates for DR applications in ratings to 750 kW, corresponding to a motor size of 1000 hp. Induction generators need an external source of reactive power to provide the rotor magnetization. They cannot control voltage or power factor. They typically produce fault current for only a few cycles after a fault. In normal operation, induction generators create little or no harmonic distortion. Induction generation has been in operation for decades due to its capability to handle small change in input speeds, low cost compared to synchronous generation, and small impact during faults.

4.3.3 Doubly-fed asynchronous generators

Doubly-fed asynchronous (induction) generators (DFAGs), also known as doubly-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. DFAGs are widely used in wind turbine applications.

4.3.4 Synchronous generation

A synchronous or ac generator is a rotating electrical machine designed to convert rotating mechanical energy into ac electrical energy. Synchronous generators generate electricity by passing an armature through a magnetic field. Synchronous generators have historically been driven using a source of primary energy providing stable speed, such as combustion fuel, to generate electricity at nearly constant voltage and constant frequency.

When connecting to the EPS, synchronous generators need to be synchronized to the EPS to avoid equipment damage to both the generation equipment and the EPS. Synchronous generators normally provide stable voltage, stable real and reactive power, and low levels of harmonic distortion. These machines tend to behave as constant ac voltage sources due to their electromagnetic design, and as stable frequency sources due to the rotational inertia associated with the mechanical mass. Therefore, synchronous generators can run islanded (intended or not) because of their controls, built-in stability, and the inertia in the rotating machine. When a fault occurs, they typically provide high fault current.

4.4 Area EPS-related considerations

Area EPS characteristics at the proposed point of common coupling also affect the DR's potential impact on the Area EPS. These topics will be further discussed in 5.2 and are discussed briefly below.

4.4.1 Locally-served load

If the DR is to be connected on a radial distribution circuit, the load served on the circuit when the DR is operating relative to the DR's output will have a bearing on the DR's potential to contribute to an unintended island in the event of a fault. This load-to-generation relationship will also have a bearing on the DR's potential impact on system voltage and system protection schemes.

4.4.2 System configuration

The configuration of the primary circuit at the point of common coupling (e.g., delta or wye-ground) may have a bearing on the appropriate interconnection equipment.

4.4.3 EPS equipment ratings

The potential for the DR to exceed continuous current ratings as well as short-circuit capacities of Area EPS equipment (e.g., line conductor, regulating equipment, reclosers, fuses, and step-down transformers) needs to be considered under all operating scenarios, including during peak load, light load, and in the event of loss of load.

4.4.4 System stiffness or weakness

System stiffness is the ability of an Area EPS to resist voltage deviations caused by DR or loading. The stiffness ratio is generally used as an indicator for PCCs. The stiffness ratio is the relative strength of the area EPS at the PCC compared with the DR, expressed in terms of the short-circuit (SC) kilovolt-amperes (kVA) 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.

$$\text{Stiffness ratio} = \frac{\text{SC kVA (Area EPS)} + \text{SC kVA (DR)}}{\text{SC kVA (DR)}} = \frac{\text{SC kVA (Area EPS)}}{\text{SC kVA (DR)}} + 1 \quad (1)$$

where

SC kVA (Area EPS) is the short-circuit contribution in kilovolt-amperes of the Area EPS (including all other sources)

SC kVA (DR) is the short-circuit contribution in kilovolt-amperes of the DR being evaluated

System stiffness is different at every point in the Area EPS. System stiffness or weakness is generally indicated by the impedance within the Area EPS between the primary, or strong, source and the point of interconnection of the DR. High impedance in a circuit between the circuit's primary source and DR point of common coupling suggests that the DR may have greater potential to affect system voltage, power quality, and system protection schemes. Such a location within a circuit may be referred to as weak, or non-stiff, and may be indicated numerically by relatively low fault current, ratio of the Area EPS short-circuit kVA to the kVA rating of the DR, or stiffness ratio.

If the circuit in which the DR is proposed to be interconnected has other interconnected DR, the combined output of these DRs and possible interactions between these DRs may have a bearing on the potential impacts of the DR in question.

4.4.5 Voltage control measures

Existing voltage control measures within the Area EPS such as automatically switched capacitors, line voltage regulators, or transformer tap changers on the circuit in which the DR is proposed to be connected may have a bearing on the circuit's ability to maintain system voltage and accommodate the DR.

4.4.6 Automatic restoration schemes

If the circuit in which the DR is proposed to be connected has automatic restoration features, the DR may affect these schemes or the DR may have to be adapted to accommodate these schemes.

4.4.7 EPS topology

If the DR is to be connected to the Area EPS within a shared secondary, this may have a bearing on the means available to address any impacts.

If the DR is to be connected to the Area EPS within a secondary network, this introduces a special set of issues that is addressed in IEEE Std 1547.6™.

4.4.8 Distribution automation

If the DR is to be connected to the Area EPS in an area with distribution automation features, particularly automatic reconfiguration, the DR may affect the likely success of the reconfiguration attempted by the scheme. Further, these reconfigurations may affect the protection schemes to accommodate the DR. There could be a significant safety issue created, for example, when a reconfiguration results in short-circuit duties that place equipment in jeopardy.

5. Operational and configuration considerations

5.1 DR attributes affecting interconnection

Integration issues exist related to the interface requirements for connection of DR to the Area EPS. There is concern with the connection of such systems to the grid from the standpoints of personal safety, system reliability, and system performance. If there is a failure in the Area EPS, customer-connected DR should cease to energize the Area EPS. In addition, there is a concern with customer-connected DR potentially degrading the reliability or quality of the area electric power system to which these devices are connected.

There are several factors that affect the nature and performance of DR interconnection. Each will be described in some depth in the following subclauses. The specific combination of these factors along with engineering judgment will help determine the system studies to consider.

5.1.1 DR primary energy source

Distributed generation often produces electrical energy at, or close to, the location where it is to be used. A DR's source of primary energy affects its potential impact on the Area EPS through its predictability, variability, and dispatchability. Predictability refers to the ability of the DR to be able to operate consistently in a forecasted manner. Variability refers to unpredictable short-term variation in the output of the DR. Dispatchability refers to the ability of the Area EPS operator to dictate or influence the output of the DR; dispatchability derives from contractual terms as well as the DR's source of primary energy.

5.1.1.1 Fuel-based generation

A significant share of on-site power is produced by generators using fuel-driven combustion engines as the energy source. Types in common use include reciprocating internal combustion engines, external combustion Stirling engines, and rotary engines generally referred to as turbines.

Fuel cells convert chemical energy from a fuel source directly into electrical energy. Fuel cells generally produce dc power, which is converted to ac power with an inverter.

Power from combustion engines is produced in the form of ac power either through a synchronous generator operated at the desired frequency directly or through a conversion process involving an inverter to produce ac at the desired frequency.

As a primary energy source for DR, combustible or chemical fuels are generally very predictable, non-variable, and may be dispatchable depending on contractual terms between the owner and the Area EPS operator. From the perspective of the primary energy source, fuel-based DR may operate at any time, day or night, and are not limited by their primary energy source to operation in certain periods. Fuel-based DR are typically not subject to short-term output variation due to unpredictable fluctuations in primary energy availability. However, when and how fuel-based DR may operate and how these affect the Area EPS may

be more subject to institutional considerations. For example, a digester or combined heat and power unit may be scheduled to operate during certain periods to support operational practices of the host that are wholly independent of Area EPS operational considerations.

5.1.1.2 Wind energy

Most wind energy in North America is generated in large-scale wind plants, interconnected at the transmission level. However, individual wind turbines, or small groups of turbines, are sometimes interconnected at the distribution level as DR. To limit mechanical loads on the wind turbine, typically some form of asynchronous generation, such as induction generators, doubly-fed generators, or generation coupled to the grid via power converters is used. In the case of full-conversion designs, the actual generator can be synchronous, permanent magnet, or induction; however, this is virtually irrelevant to the grid interconnection because the power converter establishes the grid interaction attributes, not the generator which is electrically decoupled. Used less frequently is a design using synchronous generators coupled to the wind turbine with a variable speed mechanical drive (torque converter). Induction generators, directly coupled to the grid, are capable of only a small amount of speed variation. The mechanical efficiency of wind turbines is enhanced if the wind turbine can be operated over a wide range of rotational speeds as a function of wind velocity. Therefore, wind turbines using doubly-fed generators or full power conversion are becoming increasingly common.

Wind energy is an inherently variable source that is less predictable than fuel- or hydropower-based energy sources. Wind generation output is often not well-correlated to system load demand. In many locations, peak wind generation is at night. On a seasonal basis, generation output is often lowest during the hot summer months. Meteorological conditions leading to maximum load demand, such as hot humid conditions, are often the same conditions leading to low wind speeds and thus minimal wind generation output.

In addition to the longer-term daily and seasonal variations in wind generation output, wind generation is susceptible to short-term variations caused by wind gusts. Compared to large-scale wind plants, where geographic diversity tends to greatly mitigate gust variability, small distribution-connected wind generation can be highly variable. This can cause significant voltage variations in the Area EPS and possibly result in excessive operating duty of line voltage regulators, substation transformer on-load tap changers, and capacitor bank switches. In addition to gust variations, which may be of sufficient magnitude and frequency to cause flicker, wind turbines can cause flicker due to other phenomena. Mechanical power variations caused by the turbine blades passing by the tower can cause small electrical power variations in the 0.5 Hz to 2.0 Hz range where flicker sensitivity is high. This is primarily an issue with induction wind generators, which have relatively stiff coupling between mechanical power input and electrical output. For wind turbine types with wider speed range, such as doubly-fed and full-conversion types, this blade passage flicker is generally insignificant. Another type of voltage variation is caused by the initial energizing of induction wind generators. Inrush current to support magnetization of the induction generator is highly reactive and can cause significant voltage disturbance. During low wind conditions, wind turbines may cut in and out often as the wind dithers about the critical startup speed. Doubly-fed and full conversion wind turbines do not have appreciable cut-in transients and are not affected by this issue.

Induction and synchronous generators produce harmonics due to the spatial distribution of windings and the discrete nature of stator slots. The power converters of full-conversion wind generators use pulse-width modulation technology with switching frequencies typically in the several-kHz range. These harmonics are easily filtered by the series and shunt filters of the power converter due to their high frequency. For wind generator technologies, harmonic injection is quite small and is generally not significant compared to the relatively large amounts of distortion caused by a wide variety of Area EPS nonlinear loads.

5.1.1.3 Water energy

Water energy has been used for centuries as a prime mover for industrial machinery. Hydroelectric and pump storage plants have been in operation for many years. They range in size from a few watts to many megawatts. Research is well advanced on utilizing the power of currents in rivers, the horizontal flow of ocean tides, and the oscillation of ocean waves to produce electricity.

5.1.1.4 Solar electric energy

PV panels convert sunlight directly into dc electrical energy; PV energy systems generally use inverters to convert dc power to ac power suitable for the grid. Solar thermal systems convert solar thermal energy to mechanical energy to drive an electrical generator; examples include conventional turbine-generators and Stirling engine-driven generators.

Solar energy is a variable, as-available energy source. Solar energy is predictable in that it operates reliably during the day and never at night when Area EPS loads are typically at their minimums. It is variable as it is subject to rapid changes in output due to changes in solar radiation; further, solar DR projects may have group exposure to output changes from passing clouds. Multiple solar DRs on a circuit may reduce the effective impact on the Area EPS of the variability of the individual DRs.

5.1.1.5 Energy storage systems

Energy storage systems provide electrical energy previously taken from an external source and stored. Accordingly, storage appears to the Area EPS as a load as well as an energy source. In general, energy storage as an energy source is inherently highly predictable, non-variable, and dispatchable to where energy storage systems may be used to follow load, stabilize voltage and frequency, manage peak loads, improve power quality, and defer Area EPS upgrade investments. At the same time, energy from a storage system is dependent upon the availability of stored energy, so a storage system can somewhat address the predictability, variability, and dispatchability of its ultimate primary energy source if the operation of the storage system is associated or paired with a particular energy resource. However, except when a localized issue is to be mitigated by storage, pairing of storage with a particular variable energy resource is inherently less efficient, from both capacity and loss perspectives, than operating the storage to modify the aggregate of all resources and loads to meet grid operating objectives.

Adding energy storage to a DR system can alter or improve DR variability and predictability and, under close coordination with the Area EPS operator, can reduce the potential impact of these attributes on the Area EPS.

Common types of energy storage systems that use different ultimate primary energy sources include the following:

- Batteries: Electrochemical systems store energy by using some sort of a chemical reaction, and this energy can be reconverted to electrical energy in a manner and at a rate dependent on the underlying technology. Battery storage systems are rated in terms of power delivery capability (capacity) and energy storage capability (duration of discharge) and charge/discharge rates.
- Pumped storage: Water is elevated to a higher level and the potential energy is retrieved on demand.
- Compressed air: Air may be compressed for storage using turbines driven by electricity (or some other form of available energy), and the process may be reversed at a later time to retrieve the stored energy for generating electricity.
- Flywheel: Electrical energy is stored as kinetic energy in a flywheel and retrieved on demand.

- Supercapacitors: Supercapacitors store electrical energy in the form of an electrostatic field (in a manner analogous to energy being stored by inductors in a magnetic field). They differ from conventional capacitors essentially in their construction such that the storage density is orders of magnitude greater than conventional capacitors. This stored energy can be retrieved on demand at a rate and in a manner governed by the underlying technology.
- Hybrid systems: On-site power facilities designed to utilize and combine several energy sources: wind and solar. An internal combustion engine-powered generator may also be designed into the system to supplement or replace the power from the windmill and/or PV cells.

5.1.2 Power generation technology at the PCC

From an interconnection perspective, DR systems are classified by the type of generator that interfaces the system to the grid (e.g., inverters or rotating machines including inductive machines, doubly-fed asynchronous machines, and synchronous machines). As they relate to interconnection to the Area EPS, these different DR systems are distinguished by their fault current contribution, the ability of the DR to provide voltage support, and the potential contribution to harmonic distortion.

5.1.2.1 Inverters

Inverter technology is one of the key methodologies for converting electrical energy from alternative energy sources such as solar energy, wind power, flywheel energy storage, variable frequency generators, microturbines, fuel cells, and superconducting magnetic energy storage to a form that can be used by the EPS. Solar panels generate dc power, which is inverted into ac power to be linked to the Area EPS. Microturbines spin at high speeds and generate high frequency ac power that is converted to normal power frequencies. Some wind turbines use inverters for a similar purpose; in these machines the output frequency of the turbine as well as the available power varies with wind speed. Inverters are used to convert the varying speed into constant frequency power. The speed of a flywheel varies with the amount of kinetic energy stored in its spinning mass. Therefore, the output frequency of a generator attached to a flywheel is constantly changing as it discharges and recharges. Flywheel energy storage devices use bi-directional inverters to interface with normal Area EPS power.

Inverters are minimal sources of fault current by design. Inverters intended to be connected and operated in parallel with an Area EPS (termed grid-interactive mode of operation) are designed to behave as current sources at power frequency as seen by the Area EPS. This is achieved through pulse-width modulation of power-electronic switches using one of a variety of switching algorithms typically implemented in high-speed microprocessors with the objective of causing the output current to continually track a sinusoidal waveform of a targeted magnitude and at a desired phase angle relative to the Area EPS power frequency voltage phasor. Both the magnitude and the phase angle set points can be changed automatically by internal controls, essentially on a power frequency cycle basis, to meet a desired objective. For instance, to regulate the ac power delivered to the Area EPS (active, reactive, or both), the set points are adjusted in response to variations in the power frequency ac voltage phasor at the inverter terminals. Alternatively they may be adjusted in response to operating limitations imposed by the prime mover energy source.

A parallel design objective implemented in inverter controls is the task of safeguarding the solid-state switches against thermal overload. Since these switches have modest inherent thermal mass, they tend to overheat very quickly when subjected to current levels beyond their continuous rating. High bandwidth feedback controls are therefore incorporated to actively prevent overcurrents from exceeding permissible values, such as disturbances in the Area EPS including nearby faults. Studies reported in literature for a selected number of commercial designs suggest that fault current contributions can be limited to 120% of the inverter's continuous rating within a fraction of a cycle.

On three-phase inverters, controls are generally designed so the delivered three-phase current remains essentially balanced irrespective of any unbalance that may exist in the three-phase voltage at the device's

terminals (or at the PCC), whether on an ongoing basis due to normal Area EPS operations or on a temporary basis due to unbalanced faults in the Area EPS [B12].

The use of inverters in grid-connected generation applications has increased significantly since 2000. Some standards for grid interface with inverters have been developed and others are being developed. These are: IEEE Std 929™-2000 (withdrawn); UL 1741; IEEE Std 1001™-1988 (withdrawn); and Article 690 (Solar Photovoltaic (PV) Systems) of NFPA 70. Guidelines are also established in the IEEE 1547™ series of standards.

As technical interconnection issues were being debated in the 1990s, attention was given to whether these devices needed the additional familiar protection relays used for rotating generators. Through the process of developing the earlier version of UL 1741, and IEEE Std 929™ (withdrawn), a predecessor to IEEE Std 1547™, it was determined that these solid-state devices could be tested to assure that they could reliably provide some standard Area EPS protective functions (voltage and frequency trip), as well as additional safety features such as anti-islanding at low penetrations. Large inverters may have additional system reliability requirements, such as low-voltage ride-through, that may conflict with the current IEEE 1547™ compliance methodology. The UL 1741 standard addresses the electrical interconnection design of various forms of generating equipment. IEEE Std 1547™ and IEEE Std 1547.1™ further improved upon those test procedures and applied them to machine-based interconnection systems. For grid-connected systems, UL 1741 (2005) supplements and is to be used in conjunction with IEEE Std 1547™ and IEEE Std 1547.1™.

5.1.2.2 Utility-interactive inverters

Utility-interactive inverters or grid-tied inverters use the EPS voltage waveform as a reference to match the frequency of the output sinusoidal current to this waveform while exerting explicit control over its magnitude with a high degree of precision (i.e., at a high control bandwidth). Some inverters may have a designed-in capability of switching automatically between standalone and utility-interactive modes, either in response to an external control command or based on internal prescribed criteria. However these types of applications are beyond the present scope of this guide.

5.1.2.3 Stand-alone inverters

Stand-alone inverters are not the subject of Area EPS interconnection studies and lie outside the scope of this document. Stand-alone inverters or off-grid inverters create their own reference voltage and frequency and need to be capable of load following. These inverters are designed to supply power to an islanded system while regulating voltage and frequency within specified limits. In general, the current delivery capacity of stand-alone inverters needs to be larger than the maximum expected load demand in the island (i.e., rated load current) to accommodate momentary overloads associated with initial energization of certain loads (e.g., inrush current upon motor startup).

5.1.2.4 Induction generators

When an induction machine is driven above its synchronous speed, it becomes a generator and produces electric energy. The same machine, when operated as a motor, uses electric energy to drive a mechanical load at an asynchronous speed.

Traditional induction generators require an outside voltage source to support the magnetic field that converts the prime mover mechanical power to electric generation. Area EPS operators typically supply the voltage from synchronous generation on the Area EPS. Under conditions when the DR using an induction generator is isolated from other generation in the Area EPS, the magnetic field in the induction generator is expected to collapse and the DR should stop exporting power. In this manner, the Area EPS operator is assured that the DR is not providing unregulated power to other customers in the isolated section. Isolated

induction generators can become self-excited when the reactive power produced by the capacitors is larger than the reactive power consumed by the induction generator. While this effect decays with the resistance in the circuit, damage can result on other customer equipment in the isolated section of the Area EPS. Capacitors may be needed for DR with induction generators because induction generators have low power factor. Detailed analysis of integration and operation of those capacitors is needed.

Some induction generator facilities are designed to be self-excited using capacitors, inverters, or synchronous generators to independently support the magnetic field. These induction generator facilities may require the same types of protection as synchronous generators and more complex analysis so they will not create an island when disconnected from system generation.

5.1.2.5 Doubly-fed asynchronous generators

This type of generator uses ac excitation of its rotor, via a two-way power converter, to allow physical rotation of the rotor at a speed substantially above and below synchronous speed, thus providing variable speed operation. Although the rotor turns at a speed different than synchronous speed, the magnetic field created by the rotor has an apparent rotation speed equal to the synchronous speed. These generators are capable of very fast control of the real and reactive current injection to the grid. Therefore, performance under normal operating conditions is similar to an inverter. However, during severe faults in the grid, the rotor is normally “crowbarred”⁶ to protect the power converter. When crowbarred, these machines essentially become induction machines. The duration of the crowbar condition is a function of the fault type and severity, as well as the details of the machine design.

5.1.2.6 Synchronous generators

A synchronous or ac generator is a rotating electrical machine designed to convert rotating mechanical energy into ac electrical energy. Synchronous generators generate electricity by passing an armature through a magnetic field created by a permanent magnet or electromagnetic field. Axial generators can generate power by passing an armature through a field using a side-by-side motion.

Synchronous generators are available with a permanent magnet rotor or a wound rotor. Synchronous generators have historically been driven using a prime mover providing stable speed to generate electricity at nearly constant voltage and constant frequency.

Where variable speed operation is required, synchronous generators are interfaced to the EPS using back-to-back power converters that act as a buffer to regulate the output voltage and frequency.

When connecting to the EPS, synchronous generators need to be synchronized to the EPS to avoid equipment damage to both the generation equipment and the EPS. Wound rotor synchronous generators have voltage control capabilities by means of explicit excitation of the rotor circuit.

Synchronous generators normally provide stable voltage, stable real and reactive power, and low levels of harmonic distortion. These machines tend to behave as constant ac voltage sources due to their electromagnetic design, and as stable frequency sources due to the rotational inertia associated with the mechanical mass. Therefore, synchronous generators can run islanded (intended or not) because of their controls, built in stability, and the inertia in the rotating machine. When a fault occurs, they typically provide high fault current.

⁶ **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.

5.1.3 Connection, disconnection, and reconnection of DR

Generally, connection, disconnection, and reconnection of DR with the Area EPS for durations of greater than 100 ms are mandated to comply with IEEE Std 1547™ and other applicable standards as grid-connected generation, and the impact of sudden connection or loss of the source on the Area EPS is a consideration. Standby generators that operate parallel to the grid for less than 100 ms or that serve islanded systems not connected to the Area EPS are outside the scope of this guide. When standby generation operates in grid parallel for longer than 100 ms to serve customer requirements, then IEEE Std 1547™ applies, and an impact study may be needed. Open, fast, and soft transitions are the common ways to transfer from one power source to the other. The transition may affect the voltage on the Area EPS.

5.1.3.1 Open transition contactor or switch

Open transition is a break-before-make transfer between the on-site power system and Area EPS. The two power sources are never connected together. This may be relevant to smart grid applications in the future as capacity may be valued in certain situations. Impact studies are generally not performed for these systems.

5.1.3.2 Closed transition

Closed transition is a make-before-break transfer that allows the on-site generation to be paralleled with the Area EPS for some period of time—either as a soft transition or as peak shaving generation. Closed transition systems need review.

5.1.3.3 Fast transition

Fast transition is a make-before-break transfer between the on-site power system and the Area EPS. The two power sources are paralleled for no greater than 100 ms. This document does not address fast-transition issues.

5.1.3.4 Soft transition

Soft transition is a gradual power transfer between the on-site power system and the Area EPS. The two power sources are paralleled, and the load is transferred from one power source to the other at a controlled ramp rate. This mode typically employs paralleling switchgear. Impact studies are generally performed on these systems.

5.1.4 Modes of synchronization

Any closed transition of the DR should synchronize properly.

5.1.4.1 Passive (sync check) synchronization

A system with a passive synchronizer does not actively control the on-site power system. It acts as a permissive allowing paralleling of the generator with the area EPS. When the synchronizer indicates the on-site power system is synchronized to the Area EPS, the system can perform a closed transfer or a fast transfer.

NOTE—Systems do not have to be in synchronism for open transitions. However, the system residual voltage from directly coupled rotating machines may be of concern with fast transfer schemes.⁷

⁷ Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.

5.1.4.2 Active synchronization

A system with an active synchronizer will control an on-site power system and bring it into synchronism to the Area EPS. When the synchronizer indicates the on-site power system is synchronized to the Area EPS, the system can perform closed transfer, fast transfer, or soft transfer.

5.1.4.3 Active power enhancement (on-line uninterruptible power supply)

Instead of adjusting the on-site power system, the power electronics adjust to synchronize.

5.1.5 DR control systems

Controls need to be appropriate for the application. Slow controls can be an issue in some cases, such as the following:

- Programmable logic controllers (PLC) can be difficult to coordinate
- Governor synchronizing
- Control coordination
- Multiple units
- Voltage regulation and power factor control

Almost all DRs have one or more control systems. These systems are in place to monitor generator operating parameters and to control and/or regulate various systems to maintain safe and efficient generator operation per the DR owner's intended mode of operation.

Some, but not all, DR control systems have interrelationships with the interconnection or the Area EPS. Typically the interrelated control systems are in the areas of synchronizing, voltage and reactive power control and/or regulation, and real power flow control and/or regulation.

Area EPS operators should, as part of their impact study efforts, carefully consider whether or not the DR design may require active and maintained transfer of signals or information between the DR and Area EPS equipment for proper operation. Simplicity of design should be considered, and a connection between DR and Area EPS control systems should only be sought out when necessary for safe and efficient operation of the DR and/or Area EPS. When necessary, design specifications should be clearly documented between parties to assure proper and intended operation of the interconnection. Communications timing, delays, control wiring voltage drop, etc. should all be carefully considered and documented. PLC, for example, may have inherent delays associated with their operation that need to be accounted for in the overall system design.

Proper synchronization is generally the responsibility of the DR. Both the Area EPS operator and DR owner should expect to share and discuss synchronization parameters as part of an impact study.

DR equipment impacts voltage and reactive power exchange, as they are naturally electrically interrelated, in either an active or passive way. One important aspect of an impact study is that it should document the impact on the voltage levels and reactive power flows within the Area EPS. The impact study also should consider how the existing voltage regulation scheme in the Area EPS and possible voltage regulation schemes of the DR can be properly integrated to assure safe and efficient operation of the DR and/or Area EPS. Typical issues to consider are whether or not the DR will operate with active voltage regulation (seeks to maintain voltage near a set point through variable reactive power output or variable output power factor), or with a fixed power factor (regardless of the voltage at the PCC or in the Area EPS).

The DR owner will likely have an intended mode of operation with respect to real power exchange with the Area EPS. The nature of the primary source (predictable, variable, or dispatchable) often determines the nature of real power flow across the interconnection. Some Area EPS operating practices may include active monitoring of electrical values at the interconnection to maintain proper system operation.

5.1.6 Operating mode of DR

The primary DR operating mode consideration for interconnection is whether the unit is expected to export power across the PCC. For example, where a DR unit is sized to offset a portion of the load served at the same location (particularly one with features to prevent inadvertent export), then that will not change the direction of power flow in the Area EPS, and that simplifies the evaluation of impacts of the interconnection. Synchronizing requirements will be needed for all paralleling (closed transition) of DR with the EPS regardless of the time that the systems are paralleled.

The Area EPS authority may specify the active power and reactive power control modes for interconnected DR. For small DR, this may be an “as available” mode for active power and “fixed power factor set point” for reactive power with a set point of 1, meaning no reactive power contribution. Some Area EPS operators may request the capability to modify the mode of operation in real-time, such as when a DR is curtailed because of feeder congestion. The major operating modes are as follows.

Active power control modes may include the following:

- As available: In this mode, the DR is allowed to inject active power in the Area EPS up to its nominal capacity without restrictions.
- Fixed set point: In this mode, the DR injects a specified amount of active power as long as its primary energy source is available.
- Fixed delta: In this mode, the DR injects active power corresponding to a control signal minus a predefined value. This method may be used when the DR is intended to offset a load.
- Peak shaving: In this mode, the DR injects active power only when a control signal exceeds a specified set point. When the set point is exceeded, the DR contributes the amount by which the set point is exceeded. The control signal is updated in real-time.
- Rate of change limitation (dP/dt): In this mode, the rate at which a DR increases or decreases its active power production is limited to a specified rate. This method may be used to limit sudden voltage variation at the PCC.
- Dependent of time: In this mode, the DR adjusts its active power limit as a function of time and/or date.
- Dependent of Area EPS frequency: In this mode, the DR adjusts its active power limit as a function of Area EPS frequency.
- Dependent of Area EPS voltage amplitude: In this mode, the DR adjusts its active power limit as a function of Area EPS voltage amplitude.

Reactive power control modes may include the following:

- Fixed power factor set point: In this mode, the DR adjusts its reactive power contribution to meet a specified power factor set point at the PCC.
- Fixed var set point: In this mode, the DR injects a specified and constant amount of reactive power.
- Fixed voltage set point at the PCC: In this mode, the DR adjusts its var contribution for the voltage at the PCC to meet a specified value. This is often called closed-loop voltage control as a control loop is used in the DR to determine in real-time the amount of vars to meet the voltage set point.

- Dependent of active power: In this mode, the DR adjusts its reactive power contribution as a function of active power. It can take the form of a lookup table or of a slope function. It may specify a var or a power factor contribution as a function of active power production.
- Dependent of time: In this mode, the DR adjusts its reactive power limit as a function of time and/or date.
- Dependent of Area EPS voltage amplitude: In this mode, the DR adjusts its reactive power limit as a function of Area EPS voltage amplitude.

Export modes may include the following:

- As-available supplemental energy export.
- System peak shaving.
- System capacity support-dispatchable and integrated into the Area EPS operations. Traditionally, generators are expected to provide a minimum level of system capacity support commensurate with the generator size.
- System voltage support dispatchable and integrated into Area EPS operations and typically under Area EPS control. Traditionally, generators are expected to provide a minimum level of system voltage support commensurate with the generator size.
- Intentional islanding with other Area EPS customers; planned, designed, and engineered based on agreed upon parameters with the Area EPS and non-DG customers on the island.

Non-export modes may include the following:

- Facility peak load shaving-operation.
- As-available supplemental energy production for facility use.
- Emergency generator operations: There is open transition transfer where the generator is never paralleled with the Area EPS, and no system impact when applied with the double-throw transfer switch since the generator is never connected to the Area EPS. The Area EPS operator may review the transfer switch design to verify that the switch design will prevent any accidental parallel.
- Closed transition transfer parallel operation for 100 ms or less or as permitted by Area EPS operator where the generator is paralleled with the system. Means of back-up generator separation may be needed.
- Closed transition transfer (parallel operation greater than 100 ms). Additional requirement is dependent on the Area EPS operator practices. Only this type of emergency generator is covered by IEEE Std 1547™.

Standby generator applications may include the following:

- In open transition transfer schemes when the generator is never paralleled with the Area EPS, there is no system impact and no Area EPS impact study is required. However, the Area EPS operator may review the transfer scheme design to verify that the generator will not accidentally parallel.
- For closed transition transfer schemes of less than 100 ms duration, although the impact study is not generally needed, the synchronizing will be required and a means of back-up generator separation may be needed.
- Area EPS practices may allow a longer transition time than 100 ms, in which case an impact study may be necessary.

In general, the non-export mode of operation simplifies interconnection evaluation since the distribution system is still operating within its original design parameters under normal loading conditions. For normal loading conditions, this operating mode has the same effect on the Area EPS as load reduction. But for fault conditions, the DR will back feed fault current in addition to the motor back feed. The fault contribution

effects on the existing distribution equipment will then need to be evaluated even for a non-export mode of operation. The voltage profile will change on the distribution feeder when the DR comes on and off and those need to be evaluated.

More extensive interconnection evaluation is suggested for export mode of operation since the Area EPS was likely not designed to have reverse current flow under normal and fault conditions. The protection and control devices on the feeder will need to be evaluated for the reverse flow impact.

5.1.7 Single-phase considerations

Most large DRs have three-phase outputs, however single-phase DRs are common up to about 10 kVA. A single-phase DR is a good application for small kVA DRs and in locations where three-phase power is not economically available.

Two major problems that may occur with single-phase DR are

- Current imbalance
- Faults

Single-phase DRs create the potential for imbalanced current flow on three-phase circuits. In areas where most of the DR equipment is located on one or two phases, excessive current may flow through neutral and ground points. In addition, excessive circulating current may flow in three-phase transformers. The latter may cause overheating and/or saturation of these transformers.

Imbalanced current may lead to voltage imbalances. These voltage imbalances may create circulating currents and operational difficulties with three-phase equipment such as three-phase transformers and three-phase motors. For these reasons, single-phase DR equipment is typically placed on different phases in order to attempt to balance the three-phase current flow. This task should take into account the coincidence of DR generation and expected DR output.

The need for balanced DR is dependent on the amount of power exported by the DR and the amount and balance of single-phase loads on each particular circuit where the DR is located.

It is anticipated that most single-phase DRs will be inverter controlled and therefore provide little fault current contribution. However, the controls on these single-phase DRs may not be able to properly sense all faults due to system configurations and therefore may contribute to fault current while continuing to operate. The same issue may occur with a single-phase DR that is not inverter controlled depending on the protection installed. In both cases, appropriate protection considerations could alleviate this issue.

Large differences of voltages between phases can affect Area EPS equipment and Area EPS customers' transformers and motors. The resultant overheating can cause equipment damage or can cause the equipment to self-protect by tripping off-line.

There are several methods to protect against operation with excessive phase voltage and current imbalance. Negative sequence relays watch for large imbalances in current. Voltage balance relays provide protection against voltage imbalance.

There are several transformer configurations that can be used for connecting a single-phase DR. Single-phase DRs can be directly connected to three-phase transformers line-to-line or line-to-neutral. Phase currents need to be balanced to avoid imbalance issues.

Single-phase transformers often used for residential and commercial service have center taps providing additional voltages (e.g., 12 470 V to 120 V/240 V transformers). A DR connected on the center tap has the additional concerns of overloading individual windings on the single-phase transformer.

Single-phase DR contribution to faults is dependent on the transformer configuration. The DR may contribute to faults on phases other than the phase to which it is connected. The sensitivity to these faults is highly dependent on transformer configuration and protection incorporated in the DR.

5.1.8 DR transformer connection type

Transformers may be used to connect DR to the EPS distribution system. Transformers are needed when the DR voltage is different than the Area EPS voltage at the PCC. Transformers are also used to create electrical isolation between the DR and the Area EPS. This isolation is dependent on DR technology used and its effect on EPS protection systems and grounding. The impact of the DR interface transformer configuration on the DR is beyond the scope of this guide. The Area EPS line configuration (3-wire or 4-wire system) at the point of interconnection may dictate the type of transformer configuration. This is discussed further in 5.2.

Standard distribution transformers are designed with the intention of having power flow from the primary, or the Area EPS, to the secondary, or the load side. When the direction of power flow is reversed, as in a DR application, the voltage on the secondary side is elevated beyond what it would be otherwise, given that the voltage on the primary side is regulated by the Area EPS. Since the primary side voltage sometimes approaches maximum permissible operating limits (e.g., under light load conditions, particularly at points on the supply system close to regulating apparatus), a potential exists for voltage on the secondary winding to exceed this limit in the presence of reverse power flow. The transformer secondary should be adequately rated for such circumstances. Failure to do so risks subjecting the transformer core to flux levels beyond its continuous capability. Potential consequences include additional heating of the core laminations causing potential damage, voltage waveform distortion due to increasingly distorted magnetization current, and higher leakage flux around the winding assembly causing additional copper (eddy-current) losses and ultimately higher operating temperatures for the entire transformer assembly. All of these examples cause accelerated aging of insulation and therefore reduce the transformer's service life.

5.1.9 Generator grounding methods

Generally, generator grounding methods (the ground of the generator) should not be an issue related to a DR impact study unless the DR interface is made without a step-up transformer or is made with a transformer configuration that allows the pass-through of zero sequence current (such as wye-grounded/wye-grounded interface transformers).

There are several generator grounding methods:

- Ungrounded: This scheme is typically used with generators that are delta connected to provide high reliability. The first accidental ground will not cause any fault current since the generator is not grounded. The second ground on another phase will cause high phase-phase fault current. This scheme should be used in conjunction with a ground fault detection system so that the first ground can be identified and fixed promptly before the second ground occurs and potentially damages the generator. Another issue is capacitive and inductive path-to-ground even if the generator is not intentionally grounded. Therefore, there are operating issues associated with “ungrounded” systems, including transient overvoltages that may result in voltages many times line-to-line voltage. Transient overvoltages may occur if arcing ground faults occur typically due to cable failure or other conductor failure. A well-designed ground detection system can help to avoid such occurrences.
- Impedance ground (reactance and resistance ground): Impedance grounding limits zero sequence ground fault currents. Zero sequence fault levels produced by some generators may exceed three-phase fault levels, potentially exceeding equipment ratings. If impedance grounding is not used, zero sequence fault currents produced by the system may result in mis-operation of Area EPS ground fault protection.

- Solid ground: This is typically used for small generators with lower fault current. The advantage is simplicity and safety.

Per IEEE Std 1547™, “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.” Also, see IEEE Std 62.90.2™ and IEEE Std 62.92.3™.

5.1.10 Remote control, monitoring, and protection of DR by Area EPS

IEEE Std 1547™ states that DR larger than 250 kVA “... shall have monitoring provisions for monitoring its connection status, real power output, reactive power output, and voltage at the point of DR connection.” Under certain conditions, depending on the size, impact, location, and local practices, some Area EPS operators may specify remote control and monitoring of the DR.

Ultimately, the results of studies may lead the Area EPS operator to specify remote control and monitoring of the DR. The ability to remotely control the DR may help to avoid or mitigate the impact of the DR on the Area EPS.

Integrating DR into the Area EPS creates special challenges for system dispatchers because DR units are usually geographically dispersed. A major challenge is the proper integration of DR units as resources in energy management systems (EMS), distributed management systems (DMS), and Supervisory Control and Data Acquisition (SCADA) systems of the Area EPS.

5.1.10.1 Operation status

The Area EPS may require that operating status signals (connected or disconnected) are sent from the DR to the Area EPS. To that end, the Area EPS may assume the state of the DR main breaker to be the state of the facility.

5.1.10.2 Monitoring

Real-time remote monitoring of DR active and reactive power contribution and voltage at the PCC may be required by the Area EPS. This is specifically the case when the DR contribution is integrated in the EMS and DMS.

5.1.10.3 Control

Even where DR is not dispatchable as a contractual matter, real-time remote control of DR set points may be required by the Area EPS. This requirement can be motivated by the impact of the DR on the Area EPS.

There are possible issues of remote control by the Area EPS to the DR. Remote control by the Area EPS may reduce the overall energy output of the DR, may be costly and labor intensive, and the DR may not be available to the Area EPS when needed. Furthermore, the Area EPS may require remote opening and locking of the DR main breaker.

5.1.10.4 Protection

The Area EPS protection scheme (see 5.2.5) may use transfer tripping features for the DR main breaker. This can be motivated by requirements, the islanding risk, or temporary overvoltage risks. Transfer tripping

of the DR main breaker is different from remote control. Transfer tripping is automatic and is normally executed on the order of milliseconds.

5.1.11 DR anti-islanding protection

The DR may have (or be required to have) features to detect a loss of the primary Area EPS source and trip the DR in that event. Anti-islanding protection can rely on either sensing power system quantities locally, or on communication of remote intelligence from Area EPS protection. In the case of the former, the protective devices use local measured quantities to determine if the DR should be disconnected from the EPS. There may be events where the protection cannot distinguish between disturbances on the line section that the DR is connected to and those on adjacent line sections or feeders that ought to be isolated by Area EPS protection. This may cause the DR to disconnect from the EPS causing a nuisance tripping of the DR. In some circumstances, the anti-islanding protection may not be able to detect an island and therefore will not separate the DR from a portion of the EPS that should be de-energized. Active anti-islanding protection increases the probability of the DR disconnecting from the EPS during islanding events. However, nuisance tripping may still occur since all local protection relies on sensing whether or not certain key system parameters have violated specified limits to initiate tripping without accurate information on the response of the upstream protective devices.

The communication-based approach is usually less economical, but allows the operation of isolating devices at the DR facility and in the Area EPS to be coordinated such that the probability of an unintended island forming may be reduced. Communication schemes become highly complex when the Area EPS is subject to reconfiguration, particularly when reconfiguration is automated. When coordinated properly with other protective devices, it can reduce the probability of nuisance tripping.

Communication-based schemes can fail to detect islands. There can be faults in the communication scheme, or the island can be formed at a circuit point that is not monitored by the communication scheme, for example, at an unmonitored fuse. For a fail-safe communication scheme, a failure of the communication channel can cause a nuisance trip.

5.1.12 Low-voltage ride-through

The low-voltage ride-through (LVRT) approach for DR potentially supporting Area EPS voltage tends to impose conditions on DR controls that shall then need to be coordinated with the unintentional islanding required in IEEE Std 1547™-2003. Assessment studies involving LVRT capabilities are beyond the scope of this guide and IEEE Std 1547™.

The term low-voltage ride-through refers to an operational functionality for the DR to respond to an undervoltage condition in a prescribed manner differing from that stated in IEEE Std 1547™-2003. Instead of requiring that the DR cease to energize the Area EPS within a specified duration since the onset of the condition, this LVRT operating mode may state the DR should either provide voltage support to the Area EPS in a specified manner or switch to a mode whereby it ceases to energize output temporarily. The precise LVRT DR response characteristics should be defined as a function of the magnitude and duration of the area EPS undervoltage conditions. Furthermore, though IEEE Std 1547™-2003 states that the DR reconnection after an abnormal area EPS voltage condition may be delayed for up to five minutes after the Area EPS has returned to normal voltage, the LVRT operating mode is aimed at stating more prescriptively when the DR may resume operation; for example, immediately upon return of normal area EPS supply conditions (provided this occurs within the time period contemplated by the LVRT response capability).

5.1.13 DR var capability

DR that relies on a variable primary energy source interconnected into a weak portion of the Area EPS may cause voltage fluctuations. DR that are capable of providing volt amperes-reactive (var) support or are capable of absorbing vars may be able to mitigate these voltage fluctuations so that less intrusive solutions are possible. The voltage fluctuations caused by the fluctuations in power output of the DR would be counteracted by changing the var output of the DR to compensate. To provide this capability, the service transformer, the inverter, and/or the generator would need to be sized to support adequate var flow. A control methodology, such as a constant leading (absorbing) power factor would be selected to mitigate the voltage fluctuations caused by power fluctuations from the DR. Control methodologies that react to the power fluctuation of the DR may be considered to be compliant with IEEE Std 1547™. Control methodologies that adjust var output in response to monitored voltage at the PCC may be considered out of compliance with IEEE Std 1547™.

5.2 Area EPS attributes affecting interconnection

The location of a PCC within the Area EPS and the type of power system in that area have important effects on the interconnection requirements and impact studies. For example, direct transfer trip may be complicated and expensive for a DR on a radial circuit with many switches and alternate sources, but less so for a DR connected to a substation bus. Reverse power flow is a very important concern for DR connected to low-voltage secondary networks, but less so for other DR connections. Voltage control and voltage fluctuations are more important for interconnection points that are electrically distant from the substation bus or in weak locations within the Area EPS. A radial circuit with individual voltage controls may be better suited to manage variable DR output or reverse flow.

Systems that normally operate effectively grounded are usually more susceptible to temporary overvoltages than ungrounded systems. Effectively grounded systems are usually not rated to withstand the temporary overvoltage levels that may exist on ungrounded systems. When there is a choice, these factors can help determine more economical locations for interconnection. Existing DR in the Area EPS need to be considered as part of the Area EPS in impact studies for new interconnections.

5.2.1 EPS system configuration and grounding

The configuration of the Area EPS system grounding and the interface transformer associated with DR interconnection can impact both the Area EPS and the Local EPS ground fault current contribution and overvoltages during single-phase switching and faults on the Area EPS. There are many three-phase transformer connection configurations used in multi-grounded neutral distribution systems in North America. The first connection designation is that of the primary side which is connected to the Area EPS. The second connection designation is the connection of the winding serving the Local EPS. Example configurations include the following:

- a) Y-grounded/Y-grounded
- b) Y-grounded, Y-grounded/tertiary-delta
- c) Delta/Y-grounded
- d) Delta/Y-ungrounded (not common and not recommended)
- e) Open-delta/open-delta (for load only, not typically for generators)
- f) Delta/delta (not common)
- g) T-grounded/T-grounded (not common)
- h) Y-grounded/delta(i) Y-ungrounded/delta

On a four-wire multi-grounded neutral distribution system, the transformers are normally connected phase-to-neutral except for delta/Y-grounded configurations and Y-ungrounded/delta configurations. These configurations have the disadvantage of having some neutral current flow due to load unbalance, and it may be difficult to set the ground relay to be very sensitive. For DRs with delta/Y-grounded configuration, substantial overvoltages can occur after the loss of one phase of the area EPS (due to any of the following: single-phase primary switching, fuse blow, or single line-to-earth fault) and before the DR supply is isolated.

If the existing distribution transformers are connected wye grounded on the high side, the loss of substation ground reference may cause line-to-line voltage to be impressed on the distribution transformers that are only rated for line-to-neutral voltage under the ground fault condition with the DR backfeed.

A full discussion of this topic is complex and outside the scope of this guide. For further reading, see the IEEE Std C62.90™ series.

Primary grounding systems (typical) three-wire ungrounded at substation transformer neutral are commonly used in conjunction with delta-wye grounded distribution transformers. The advantage is that there is normally no zero sequence (residual) current flow, and the feeder ground relay can be set to be very sensitive for excellent ground fault protection. The grounded wye secondary configuration also provides good ground fault detection for the secondary system. This configuration works well on radial distribution systems. But when the feeder breaker opens due to a ground fault, the normal ground reference at the substation is disconnected and any DR connected through a delta high side transformer may not be able to detect the ground fault on the feeder. So, separate ground fault detection may be required.

The DR impact study should model the grounding resistance according to the Area EPS practice.

In general, the power system needs to be grounded for personnel safety.

Secondary grounding systems (typical) can be:

- Solidly grounded at the distribution transformer neutral for secondary Y configuration
- Center tap grounded for 120 V/240 V single-phase transformer
- Corner grounded for secondary delta configuration.

5.2.2 Information exchange for protection, control, and monitoring

Communication between distribution feeder relays and DR may have the following basic functions:

- Protection function to transmit a transfer trip signal from the Area EPS to the DR
- Protection function to transmit operating status (connected or disconnected) from the DR to the Area EPS
- Control
- Monitoring

An Area EPS operator may request the exchange of information for status and protection purposes if there is a significant possibility that the DR may inadvertently remain operating when the feeder breaker or automatic restoration device opens. In this case, status and control would be used to indicate the DR is online and allow the feeder protection and control systems to direct trip the DR breaker. For example, information exchange may be useful if the feeder breaker or automatic restoration device does not open, such as under a range of light load to heavier normal load conditions.