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लिए मार्गदर्शिका

**Guide for Conducting Distribution
Impact Studies for Distributed
Resource Interconnection**

ICS 29.140.01

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NATIONAL FOREWORD



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IEEE Std 1547™ IEEE standard for interconnecting distributed resources with electric power systems	IS 18968 : 2024/IEEE Std 1547-2018 Interconnection and interoperability of distributed energy resources with associated electric power systems interfaces	Modified 
IEEE Std 1547.1™ IEEE standard for equipment interconnecting distributed resources with electric power systems	IS 18969 : 2024/IEEE Std 1547.1-2020 Conformance test procedures for equipment interconnecting distributed energy resources with electric power systems and associated interfaces	Modified

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IEEE Std 1547.2™	IEEE application guide for IEEE Std 1547, IEEE standard for interconnecting distributed resources with electric power systems.

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Indian Standard

GUIDE FOR CONDUCTING DISTRIBUTION IMPACT STUDIES FOR DISTRIBUTED RESOURCE INTERCONNECTION

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

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

IEEE Std 1547.2™, 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 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.

5.2.2.1 Operating status

Operating status signals (on or off) are sent from the DR to the feeder relay. This information may be used to adapt feeder relay protection settings, as a permissive signal for closing the feeder breaker, as a permissive signal for automatic reclosing, or for annunciation of DR status for system operators.

5.2.3 EPS equipment rating

The addition of DR to a feeder can result in equipment being subjected to faults beyond their short-circuit current ratings including increased fault duty potentially leading to damage or failure. In some cases, this can lead to unsafe conditions. DR that does not trip under fault or open substation breaker conditions can result in equipment damage if reclosing is applied without a synchronism check in place. For certain types and sizes of DR with delta high side transformer connections, backfeed on unfaulted phases under fault conditions can result in overvoltages that damage equipment such as surge arresters, affecting both the Area EPS and other customers in the vicinity of the DR. These conditions can result in unsafe conditions for Area EPS operator and customer operating personnel.

If a sustained island is created, there is danger to Area EPS operator personnel who may not know that the system is islanded and attempt to close a tie switch to an adjacent energized feeder.

5.2.4 System stiffness or weakness at the PCC

System stiffness or weakness refers to the ability of the Area EPS to resist voltage deviations from a DR. System stiffness or weakness is specific to a particular point of interconnection and PCC within the Area EPS. System stiffness or system weakness at a particular point within the Area EPS is indicated by the total impedance of the Area EPS between the primary or strong source and that point. Any individual DR will have some electrical impact on an Area EPS. Everything else equal, a given DR interconnected at a point in the Area EPS where the total impedance is high (e.g., a weak or non-stiff location) will cause greater voltage deviations in the Area EPS. Accordingly, there is greater potential for voltage-related impacts from the DR in the Area EPS such as flicker, voltage fluctuations, or changes in steady state voltage.

The concept of electrical proximity is related to system stiffness or strength. A DR interconnected at a point in the Area EPS where there is little cumulative impedance from the primary source at the substation may be referred to as electrically close to the substation. A DR connected at such a location is likely to have less voltage-related impacts on the Area EPS.

If the DR is small relative to the system stiffness (strength) at the PCC location in the Area EPS, then the potential for Area EPS voltage deviations at the PCC is less. Numerically, a comparison of the power (kVA) rating of the DR with the Area EPS short-circuit kVA at the PCC provides guidance to the DR voltage potential impact on the Area EPS—the higher DR MVA capacity versus Area EPS short-circuit MVA, the weaker the location, and the greater the potential of the DR to impact Area EPS voltage. A simple ratio of the Area EPS short-circuit kVA divided by the kVA rating of the DR may provide a basis for comparison to identify interconnections in weak (non-stiff) locations with the potential for greater voltage-related impacts.

IEEE Std 1547.2™ defines the stiffness ratio as the relative strength of the Area EPS at the PCC compared with the DR, expressed in terms of the short-circuit kVA of the two systems. The stiffness ratio is calculated at the PCC unless 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. See Equation (1) in 4.4.4.

Short-circuit studies and power flow studies can document the potential of the DR to impact the Area EPS's voltage, regardless of the weakness or stiffness of the Area EPS at the PCC.

5.2.5 Protection

The introduction of DR in a circuit can affect operating and fault current levels. Since the system operating parameters may have changed significantly due to the addition of the DR, the existing protection scheme of the Area EPS and its associated settings may not work as originally designed and should be evaluated under these revised parameters.

The presence of a large DR on a feeder also has an effect on fault location practices. DR that have a large contribution to short-circuit currents may cause an unexpected operation of fault indicators that are used to locate fault position. In this situation, directional fault indicators can be used to help the Area EPS operator better locate the fault.

Area EPS distribution systems are typically designed as radial systems with a single source feeding distribution load. While system conditions may result in variable circuit configurations, distribution systems and their associated protection systems are designed for one-way current flow and fault sensing. In the case of a typical distribution feeder protective system, when a fault occurs, the various protective relays sense the associated increase in fault current and trip a circuit breaker to de-energize the system, thus clearing the fault. Reclosing may be present to restore service in the case of temporary faults, but for permanent faults, the feeder will lock out and stay de-energized until the source of the fault can be identified and repaired. In this way, protective systems assure the safety of the general public that may come into contact with energized or faulted distribution system equipment as well as the safety of Area EPS operator personnel responsible for the identification, switching, and repair of the system.

Proper application and setting of interconnection protection is meant to assure that the DR trips and separates from the distribution system for fault conditions. Improper device application or settings can result in the DR not sensing the faulted circuit conditions. In cases where large DR are applied, short-circuit studies need to be completed to assure that backfeed from the DR source does not result in the desensitizing of feeder relays or create sympathetic tripping due to reverse current flow through feeder protection for faults on adjacent circuits. In some operating cases, such as a substation breaker being opened manually, the DR generation could match the system load and not trip the DR. Each of these scenarios of improper device application or settings compromises the safe operation of the distribution system.

Area EPS personnel may be accustomed to assuming that in a radial system, if an upstream switching or protective device has operated, then the circuit is de-energized and therefore safe. If the interconnection system protection functions fail and the circuit remains energized by the DR, an unsafe condition (unintentional island) is created. While operating and safety procedures are normally required to verify that a circuit is de-energized prior to beginning line-work, extra caution should be taken in cases where DR are present. Visual inspection of the DR interconnection to assure that it has separated from the Area EPS system should be considered. Many Area EPSs require an isolation device between the area EPS and the DR that includes a readily accessible, lockable visible-break device operable by Area EPS operator personnel.

Some Area EPS protection schemes may use transfer tripping features for a DR main breaker. This can be motivated by the islanding risk within the Area EPS or temporary overvoltage risks within the Area EPS.

5.2.6 Voltage regulation on circuit

The Area EPS is designed to operate within set ranges of voltage. Most customers depend on their voltage to be maintained within their applicable voltage limits to protect their equipment from excessive voltage or overheating. Voltage regulation throughout the Area EPS may be accomplished in various ways, such as using bus capacitors and load tap changers at substations and with line capacitor banks and voltage regulators installed on the distribution circuits.

Capacitor banks are used to offset reactive currents along the feeder and through the substation transformers, which also reduces the voltage drop. These devices are typically operated two to four times per day.

Load tap changers on the substation transformers operate more frequently, maintaining the bus voltage at the substation within the allowed tolerance as the substation load increases and decreases throughout the day.

Voltage regulators are located in the circuit so that the voltage can be maintained above the lower design limit at peak load levels. Long or heavily loaded circuits may employ multiple sets of voltage regulators to maintain voltage within the design range throughout the circuit. Voltage regulators may be set to operate at 30 second to one minute intervals. If there are multiple regulators, their response time needs to be coordinated. Load tap changers and voltage regulators operate mechanically; therefore, voltage fluctuations may also lead to increased operation of the regulating equipment, which could lead to increased maintenance or premature failure. The voltage fluctuations caused by some types of DR may occur faster than some voltage regulating equipment can react.

Some voltage regulator controls are designed based on the direction of power flow only coming from the source substation. For this type of control, when the power is flowing from the DR through the voltage regulator toward the substation, this control algorithm will misidentify the source side and cause the tap changer to operate in the wrong direction. However, other control algorithms have been designed such that they review the voltage after a tap change and modify the operation based on the actual voltage effect observed. Some voltage regulator controls may need to be replaced with a unit to use these latter types of algorithms.

5.2.7 Automatic restoration

Many radial systems include interrupting devices that are designed to trip and clear a fault and automatically restore load. Many of these devices have settings that call for fault clearing and reclosing with no intentional time delay. When DR is located beyond the interrupting device and the device attempts to restore the connection before the DR has separated from the circuit, that DR is in violation of IEEE Std 1547™ reclosing coordination requirement. In that case, the device may reclose the Area EPS with the DR unsynchronized with voltage, frequency, and/or phase angle. This unsynchronized reclosing may damage switchgear, power generation equipment, and customer equipment. Because of the potential damage to equipment, the Area EPS operator may choose to increase the recloser delay to allow more time for the DR to detect the recloser interruption and trip the DR. Some Area EPSs use a recloser delay of up to 10 seconds when a DR is connected on a feeder. In some applications, this delay may not be sufficient to avoid unsynchronized reclosing. Furthermore, a voltage block function may be installed on the recloser to prevent reclosing if the DR fails to detect an island. As a last resort, the Area EPS operator may decide to disable the recloser on the feeder.

5.2.8 Single-phase interconnection on a three-phase service

The addition of single-phase DR at a three-phase service may cause a voltage and phase imbalance. This may lead to overheating of three-phase equipment and the neutral wire where these effects have not been included in the design.

5.2.9 Shared secondary interconnection

DR connections into the Area EPS through secondary cable and distribution transformers cause a rise in the secondary voltage when the generation exceeds the Local EPS load. Where the impedance of the secondary circuit is high, or the primary voltage at the terminal of the distribution transformer is near the upper limit

of the operating voltage, an overvoltage condition may occur at the PCC. Where secondaries are shared by multiple customers, DR located at one or more PCCs may cause the overvoltage conditions to be experienced by several customers, including customers that may not have installed DR. Because the secondary is often not modeled, potential for impacts from DR interconnection may be difficult to predict. These effects may not be apparent under peak load conditions but may occur under off-peak conditions.

5.2.10 Area EPS topology

5.2.10.1 Radial primary topology

Radial primary distribution systems are designed so that the circuit is connected from a substation bus while load is supplied along the circuit. This radial design has lower reliability than looped primary topologies. The substations in radial designs are typically a single transformer and single bus section. A short-circuit or open circuit anywhere upstream of the DR or load location will result in loss of power. Installation of DR on radial circuits may result in reverse power flow along sections of the feeder.

5.2.10.2 Looped primary network topology

Distribution looped primary networks are designed so that the circuits are connected between the buses of two substations while load is supplied along the circuit. This design provides a continuous supply to customer load upon the loss of one substation supply, transformer, or bus section. The substations in this design are typically a single transformer and single bus section. Upon loss of a substation transformer or supply feeder, the substation bus is designed to remain energized through the backflow of power from the network circuits supplied from other substation(s). Installation of DR on these types of circuits may affect the flow of power through the network, which could cause overloads on some sections of the network under various outage contingencies.

5.2.10.3 Secondary network topology

The distribution secondary networks are designed so that the multiple primary circuits are connected through transformers and network protectors to secondary buses serving a single customer in spot networks or to secondary circuits that serve multiple customers in secondary grid networks. Network protectors are designed for automatically disconnecting a transformer from a secondary network in response to predetermined electrical conditions on the primary feeder or transformer and for connecting a transformer to a secondary network through manual or automatic control responsive to predetermined electrical conditions on the feeder and the secondary network. These devices may not be monitored by telemetry, which can lead to uncertainty of a single protector's status. When DR is operating in excess of the connected customers' load, all connected network protectors may open, which would cause an island condition. IEEE Std 1547.6™ addresses distribution secondary networks.

5.2.11 Concurrent tripping of multiple DRs

DRs on substations that experience a fault close to the substation may experience voltage sags sufficient to initiate the protective relays and cause the DR to separate from the Area EPS. Substations that have significant contributions from multiple DRs may find a marked increase in loading when a single event causes multiple DRs to separate from the Area EPS. This condition may lead to the substation operating at a reduced voltage until that voltage regulating equipment can compensate for the net loss of generation. Concurrent restoration of the generation, if not designed to be staged, could lead to high voltage.

A transmission fault could also cause concurrent tripping of DR across a wide region of the Area EPS. In portions of the Area EPS that contain a significant penetration of DR, the effects of the original fault could be exacerbated by the loss of DR throughout the region.

Systems with a large penetration of motor loads may cause large voltage deviations during faults and some other conditions (e.g., open circuit). DR may trip due to that voltage deviation. This tripping can be mitigated with LVRT.

5.2.12 Existing DR on Area EPS

Existing DR already interconnected within the Area EPS may affect the impacts of a given interconnection. 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. Under loss of load conditions, this aggregate generation could result in overloads of upstream equipment. DR as inverters together with synchronous machines within a circuit may increase the chances for an unintended, sustained island. Groups of DR may exhibit coincident behavior, multiplying their impacts on voltage and power quality; one example is PV under partly cloudy conditions. The fault current contribution of a given DR may become a concern when aggregated with the fault current contribution of existing DR on the circuit.

6. System impact example methodology

The example impact methodology is one approach for using this guide. The example methodology portrays how to determine whether impact studies need to be performed, and if so, which ones and how to consider the results.

The example methodology for using this guide includes the following steps:

- Read the entire document. Each clause in this document provides information that is helpful in effectively using this guide.
- Review general considerations (Clause 4) and operational and configuration considerations (Clause 5) that may have an impact on the DR and Area EPS under consideration.
- Review preliminary review criteria identified in Clause 7. Each of the criteria and relevant sub-criteria will determine whether conventional or special study efforts are needed. Additional study efforts may include conventional distribution studies (Clause 8) or special system impact studies (Clause 9).
- Acquire pertinent data identified in the data requirements section of this guide (Clause 10).
- Perform conventional studies (Clause 8) that are needed as determined by the preliminary review. The results of conventional studies may lead to technical approval of the DR installation, the need for mitigation techniques, or the need for additional conventional or special system impact study efforts. If additional studies are needed, data beyond that originally collected will most likely be needed.
- Perform special impact studies (Clause 9) as determined by the results of the preliminary review and conventional studies. The result of the special impact studies may lead to additional impact studies, additional conventional studies, the need for mitigation techniques, or technical approval of the DR installation.
- Determine any impact mitigation that is needed. Clause 11 provides an overview of impact mitigation.

The example approach may involve several iterations. In many cases, the result of preliminary reviews and impact studies may result in the need for additional studies. There may also be several alternative approaches to impact mitigation. These approaches may also prompt the need for additional study efforts.

7. Preliminary review criteria and sub-criteria

7.1 Introduction

A preliminary review is done by examining the items listed in this clause to determine if the DR has the potential to cause adverse effects to the operation, safety, and reliability of the Area EPS and to determine if potential further studies need to be considered. A preliminary review of a proposed DR interconnection should consider the impacts of the DR on the Area EPS for each of the criteria identified in Table 1. This clause describes individual preliminary review criteria and sub-criteria related to each of these areas that should be used to evaluate the DR in question. Each of the criteria and applicable sub-criteria should be evaluated. Applicable sub-criteria may differ depending on the DR's interconnecting technology, primary energy source, or other factors.

The preliminary review checks are designed to see if the addition of the DR will cause existing distribution equipment ratings and settings to operate outside their original design parameters. If the DR does not cause the existing equipment to operate outside their original design parameters, there are minimal impacts, and preliminary review may be sufficient. Please note it is likely that the existing distribution system is designed to operate in the radial direction, from the substation to load, and the DR may cause the current to reverse and may cause the existing protection and control equipment, including but not limited to voltage regulators, capacitor controls, and sectionalizers, to operate improperly. Under fault conditions, the DR will contribute fault current, and the protective equipment ratings and settings may need to be checked. The intent of the preliminary review is to allow the small units at low penetrations to be reviewed in a timely manner to determine if higher level assessment studies may be needed.

Interconnecting power generation to the distribution portion of an EPS has potential impacts on the Area EPS in the following general technical areas:

- Potential for unintended islands upon separation from the Area EPS. The power produced by the DR relative to the nearby load served and ability of the DR to reliably separate from the EPS should be considered.
- Impact on EPS equipment loading under all steady state conditions. This includes pure loads placed on the EPS by the DR and DR at one customer location impacting other customers on a shared secondary.
- Impacts on protection design, coordination, and fault ratings. This includes impacts on a variety of protection schemes, the affect faults have on the protection schemes, short-circuit current withstand limits, minimum fault coverage, and arc flash energy limits.
- Impacts on voltage regulation and reactive power management within the EPS under steady state conditions, including both the voltage impacts of changes in DR output and the cumulative impacts of multiple DRs on the voltage control range of the EPS.
- Impacts on EPS power quality, including flicker, sags and swells, and harmonics.

The impacts of the interconnection of a particular DR to a particular EPS at a particular location depend on the generation energy source, generation technology, modes of interconnection, modes of synchronization, modes of DR operation, and the EPS itself. For particular types of DR technologies, such as inverter-based PV or synchronous generation, there are technology-specific considerations that may mitigate or exacerbate the ways in which the DR may impact the EPS. Whether the proposed interconnection is at three-phase or single-phase and/or on a shared secondary may also mitigate or exacerbate the ways in which the DR may

impact the EPS. Efficient evaluation of these impacts in a preliminary review necessitates a firm understanding of the type of DR under consideration, its characteristics under normal and off-normal conditions, the details of the interconnection facilities, the level of control of the DR that will be available to the EPS operator, and the extent of monitoring.

The impacts noted above may arise at any level of penetration of DR relative to the load served by the EPS. However, in systems with small amounts of DR relative to load, the combined impacts of these DRs on the EPS may be insignificant. As the DR production relative to load increases, the potential impact of each DR addition on the EPS may be of increasing concern and require careful consideration.

These potential impacts are present for DR interconnections in any EPS. However, strong interconnected systems with significant generation sources are less susceptible to DR impacts. Evaluation of the potential impacts of a particular DR on an Area EPS requires a firm understanding of the details of the EPS itself, including existing DR units already operating or approved for connection.

A preliminary review is done by examining the items listed in this clause to determine if the DR has the potential to cause adverse effects to the operation, safety, and reliability of the Area EPS and to determine if potential further studies need to be considered.

Table 1 identifies the preliminary review criteria and sub-criteria that need to be considered to properly identify the studies that may need to be performed. A detailed description for each of the criteria and sub-criteria can be found in the identified subclause in this clause of the document.

All of the criteria and applicable sub-criteria listed in Table 1 need to be considered. Each of these criteria needs to be evaluated on an individual basis. When evaluating each of the criteria, applicable sub-criteria need to be evaluated. If the criterion is met, no further study pertaining to that criterion is needed. If the criterion is not met, additional study efforts may be needed. Additional study efforts may also be needed due to other sub-criteria. If all the criteria identified in Table 1 are satisfied, a more detailed impact study may not be needed.

Table 1—Preliminary review criteria checklist

Criteria ID	Clause	Preliminary Review Criteria & Sub-Criteria	Criteria Met?	Issues?
P1	7.2	Use of certified DR equipment		
P2	7.3	Potential for unintended islands		
P2.1	7.3.1	DR does not export power to area EPS at the PCC		
P2.2	7.3.2	DR production relative to served load (penetration) is small		
P2.3	7.3.3	DR interconnection incorporates acceptable anti-islanding protective features		
P3	7.4	Impact on EPS equipment loading under all steady state conditions		
P3.1	7.4.1	Gross kVA rating of aggregate DR is no greater than the kVA rating of the EPS transformer serving the facility on a per phase basis.		
P3.2	7.4.2	Gross kVA rating of aggregate DR on a particular feeder or substation is no greater than the feeder or substation rating.		
P4	7.5	Impacts on system protection, fault conditions, and arc flash rating		
P4.1	7.5.1	DR cannot cause any protective device or circuit component to exceed 85% to 90% of the short circuit interrupting capability		
P4.2	7.5.2	Aggregate DR on circuit does not contribute more than 10% of the circuit's maximum fault current at the primary voltage point nearest the PCC.		
P4.3	7.5.3	DR will interconnect with an Area EPS having radial topology		
P4.4	7.5.4	DR will not cause temporary overvoltages during a phase to ground fault		
P4.5	7.5.5	Existing protection schemes are configured to allow for DR connected to the Area EPS		
P5	7.6	Impacts on voltage regulation within the EPS under steady state conditions		
P5.1	7.6.1	DR PCC is relatively strong or stiff location within the Area EPS		
P5.2	7.6.2	DR would not be anticipated to result in voltage rising above specified limits in the Area EPS .		
P5.3	7.6.3	Loss of DR or variation in output of DR would not be anticipated to result in voltage in the Area EPS falling below specified limits		
P5.4	7.6.4	Variation in output of DR would not be anticipated to necessitate changes of settings of Area EPS voltage regulating devices.		
P5.5	7.6.5	DR is not expected to result in high voltage on shared secondary.		
P6	7.7	Impacts on EPS power quality		
P6.1	7.7.1	DR operation will not cause flicker exceeding limits at the PCC.		
P6.2	7.7.2	Real and reactive power flow from DR will not cause Area EPS voltage sags and swells		
P6.3	7.7.3	DR operation will not cause harmonics at the PCC to exceed allowed limits		

7.1.1 Additional studies

Potential study needs are typically conventional distribution studies while some special impact studies may be identified from the criteria. The results of conventional distribution studies may identify special impact studies or mitigation techniques that may need to be considered.

A preliminary review is performed by the Area EPS representatives to evaluate the attributes of a particular proposed DR to be interconnected, the particular Area EPS, and the specific location and nature of the interconnection. This preliminary review will determine if system impacts are likely to occur. If system impacts are likely, then conventional distribution studies or special system impact studies should be considered. The designation of “C#” refers to the conventional distribution study number, and “S#” refers to the special system impact study number.

Conventional distribution studies (described in more detail in Clause 8) include:

- Steady state simulation (C1)
- System protection studies (C2)
- Short-circuit analysis (C2.1)

- Protective device coordination (C2.2)
- Automatic restoration coordination (C2.3)
- Area EPS power system grounding (C2.4)
- Synchronization (C2.5)
- Unintentional islanding (C2.6)
- Arc flash hazard study (C2.7)
- Operational characteristics— loading, load shedding, etc. (C3)

Special system impact studies (described in more detail in Clause 9) include:

- Quasi-static simulation (S1)
- Dynamic simulation (S2)
- Electromagnetic transient simulation (S3)
- Ferroresonance (S3.1)
- Interaction of different types of DR (S3.2)
- Temporary overvoltage (S3.3)
- System grounding (S3.4)
- DC injection (S3.5)
- Harmonics and flicker (S4)
- Harmonic analysis (S4.1)
- Harmonic problems (S4.2)
- Harmonic resonance (S4.3)
- Flicker (S4.4)

7.2 Criteria ID P1—Use of certified DR equipment

DR, determined in a preliminary review, to be using certified (also known as pre-certified or listed) interconnection equipment appropriate for the given application exhibits predictable behavior under normal and abnormal operating conditions. If the DR equipment is not certified, full testing may be required to assure proper operation of the equipment.

While the definition of what constitutes “certified” varies, typical certification criteria are:

- The DR has been tested in accordance with IEEE Std 1547.1™ (and as applicable, also in compliance with other appropriate codes and standards) by an accredited testing laboratory—a laboratory that is recognized by the appropriate regulatory body (nationally recognized by the United States Occupational Safety and Health Administration in the U.S.). The DR has been labeled and is publicly listed by the NRTL.
- The accredited testing laboratory makes readily available for verification all test standards and procedures it utilized in performing such DR equipment certification labeling and listing.
- The intended use of the DR falls within the use or uses for which the DR was labeled and listed by the accredited testing laboratory.

- If the DR is an integrated equipment package such as an inverter, then the generator or other electric source being utilized is compatible with the interconnection equipment and is consistent with the testing and listing specified for this type of interconnection equipment.
- If the DR includes only interface components (switchgear, multi-function relays, or other interface devices), then generator or other electric source being utilized is compatible with the interconnection equipment and is consistent with the testing and listing specified for this type of interconnection equipment.

7.2.1 Technical basis for criteria

If the DR is certified for the application (e.g., an inverter that has been UL 1741 certified), then the Area EPS operator has assurance that the DR will separate in a reasonable period of time and behave in other predictable ways. If the interconnection equipment is UL 1741 certified, then the Area EPS operator can be assured that the equipment has been tested to include the following:

- Maximum-voltage measurements
- Temperature range
- Dielectric voltage-withstand
- Output power characteristics
- Output ratings
- Input range
- Harmonic distortion
- Utility compatibility
- Output overload
- Short-circuit
- DC input mis-wiring
- Ventilation
- Component short- and open-circuit
- Load transfer
- Loss of control circuit
- Grounding impedance
- Overcurrent protection calibration
- Strain relief
- Reduced spacing on printed wiring boards
- Dielectric voltage-withstand
- Shorted trace
- Bonding conductor
- Voltage surge
- Calibration
- Overvoltage

- Current withstand
- Capacitor voltage determination
- Stability
- Static load
- Compression
- Rain and sprinkler

7.2.2 Applicability

This criterion applies to all DR interconnections.

7.2.3 Area EPS-specific considerations

None

7.2.4 Technology-specific considerations—inverters

A utility-interactive or grid-connected inverter is a current-controlled voltage source that cannot sustain a voltage signal without a grid reference. This type of inverter uses the grid voltage as reference voltage, generally is certified, and has minimal system impact.

When utility-interactive inverters are required to comply with IEEE Std 1547™ and IEEE Std 1547.1™ test procedures, the interconnection system equipment (over a size limit stated in IEEE Std 1547™) are required to have field adjustable trip limits and trip times for voltage and frequency.

Stand-alone inverters are voltage-controlled voltage sources and can generate power when grid reference is not present. In parallel with the EPS, the fault current may be higher in the voltage source inverter but not high enough for the distribution operator to rely on the voltage source inverter to reliably trip line devices.

7.2.5 Potential further studies

If DR equipment fails to meet this P1 criterion, then technical issues identified in Clause 8 and Clause 9 should be considered. Upon P1 criterion failure, at a minimum, system protection studies (C2) will need to be performed to determine if the DR meets protection considerations.

7.3 Criteria ID P2—Potential for unintended islands

DR may inadvertently continue to energize a portion of the Area EPS following separation from the greater Area EPS due to a system fault or opening of an isolation device. This is particularly likely to happen if DR production is large relative to nearby load and/or if the fault or islanding is undetected. This criterion is met if sub-criterion P2.1, P2.2, or P2.3 is satisfied.

7.3.1 Sub-criteria ID P2.1—DR does not export power to area EPS at the PCC

If a preliminary review determines that the DR interconnection is designed such that power cannot be exported to the EPS across the PCC, then this sub-criterion is satisfied. Under some scenarios, such as

multiple types of DRs on a feeder, additional study may be needed. Intermittent DR may affect the Area EPS voltage as discussed in sub-criterion P6.1.

7.3.1.1 Technical basis for sub-criterion

If the DR or its interconnection cannot export power across the PCC, then the customer appears to the Area EPS as a traditional customer where power flows from the Area EPS to the customer in accordance with how the Area EPS was designed.

7.3.1.2 Applicability

DR interconnections designed to export power across the PCC may be excluded from this criterion. These interconnections may be addressed by sub-criteria P2.2 and P2.3.

7.3.1.3 Area EPS-specific considerations

In some jurisdictions, reverse power protection may be required. When the Area EPS has a fast automatic restoration scheme and the DR is not of the inverter type, then the chance may be increased for an attempted reclose into an out-of-sync, energized island, compared to an inverter based DR.

7.3.1.4 Potential further studies

If the DR will or may export power to the EPS across the PCC, the potential for the DR to inadvertently continue to energize the EPS following a fault may be addressed by sub-criteria P2.2 and P2.3.

7.3.2 Sub-criteria ID P2.2—DR production relative to served load (penetration) is small

If a preliminary review determines that the aggregate DR production in a circuit of a radial distribution system is less than 33% of the measured minimum line section load when the DR is in operation, an unintended island cannot be sustained and this sub-criterion is satisfied.

This evaluation should consider the likely match or mismatch of generation and load within the line section at any given time by taking into account the expected minimum load and maximum generation within the line section at times the DR is expected to be in operation. The likely match or mismatch of generation and load includes various considerations such as time of day, day of the week (e.g., weekday vs. weekend), and seasonal variations in load or generation.

Load data for each line section may be readily available or reliably estimated from data available. The quality of the estimate and the degree of accuracy needed will be important in determining whether additional studies are needed to assess this criterion. The accuracy needed is dependent on the amount of aggregated DR as a percentage of the minimum load. The lower the percentage of DR, the lower the accuracy need.

These criteria apply for the time period the energy source of the DR is available. For solar PV DR, applicable time period is daytime hours when sunlight is available. For all other energy sources (e.g., wind, natural gas, coal, methane gas, etc.), applicable time is all hours of the day.

The effects of DR penetration on the steady state voltage should also be considered as identified in criteria P5 and P6.

7.3.2.1 Technical basis for sub-criterion

For fuel-based DR and wind generation that may operate at any time, it is appropriate to evaluate the potential for an unintended island relative to the line section minimum load. For PV DR that operates only during the day, line section load data to indicate the minimum load during the period the DR is operating may not be available but may be estimated from line section peak load or minimum load values.

For inductive and synchronous DR, IEEE Std 1547.2™ refers to findings of an IEEE paper titled “Ferroresonance and Loading Relationships for DSG Installations” [B5] based on simulations and field tests of induction and synchronous generation islanded with various amounts of power factor-correcting capacitive kVAr. It was shown that as the pre-island loading approached three times the generation, no excitation condition could exist to support the continued power generation.

If all DRs in a circuit of a distribution system are solar PV, aggregate solar PV DR production less than loads cannot support creation of an unintended island. Therefore, for solar PV DR, 100% of the minimum daytime load can be considered if all other DRs in a circuit are solar PV systems.

7.3.2.2 Applicability

This sub-criterion applies to DR interconnections designed to export power across the PCC. For inverter-based DR interconnections designed to export power across the PCC, sub-criterion P2.3 also applies.

7.3.2.3 Exceptions to sub-criterion

This sub-criterion does not apply for DR island systems that are intentionally planned. For details on planning and creating intentional islands, see IEEE Std 1547.4™.

7.3.2.4 Area EPS-specific considerations

Where the Area EPS is operated with an automatic restoration scheme, this sub-criterion should be evaluated at the line section. Where there is synchronous DR and inverter-based DR within the same Area EPS line section they may interact in a way to extend the duration of a potential unintended island.

7.3.2.5 Technology-specific consideration—PV generation

PV generation only operates during daytime hours, during which, if a fault occurs, the line section is unlikely to be experiencing its minimum loads. Accordingly, it may be appropriate to apply this sub-criterion using line section minimum daytime loads.

7.3.2.6 Potential further studies

If this sub-criterion cannot be met, then consideration should be given to applying the mitigation techniques such as those identified in 11.1.1 and 11.1.2.

Minimum load studies may need to be conducted for every line section between the DR and the Area EPS source substation including the power transformer at the source substation. This analysis involves researching the most recent annual historical minimum load data for each line section. If this data is not available, a load flow study may be considered to determine the load in each line section.

Detailed impact studies may be needed where the aggregate DR capacity exceeds this criterion at any automatic restoration device. Additional study efforts may be needed if the DR is synchronous generation and an automatic restoration device is present.

Steady state simulation study (C1) and system protection studies (C2) may need to be performed if this sub-criterion is not met. These studies may potentially lead to special impact studies including quasi-static simulation (S1), dynamic simulation (S2), and electromagnetic transient simulation (S3).

Technical issues to be considered, if this sub-criterion is not met, include: protective device coordination (C2.2), automatic restoration coordination (C2.3), operational characteristics (C3), and system stability (S2.2).

7.3.3 Sub-criteria ID P2.3—DR interconnection incorporates acceptable anti-islanding protective features

If a preliminary review determines that an interconnection for DR incorporates acceptable anti-islanding protective functions, irrespective of DR production relative to load or expected export across the PCC, this sub-criterion is satisfied.

7.3.3.1 Technical basis for sub-criterion

Guidance on acceptable anti-islanding protective features is stated in footnote 12 of IEEE Std 1547™.

7.3.3.2 Applicability

This sub-criterion applies to DR interconnections designed to export power across the PCC. The DR anti-islanding protection requirement needs to be met at the PCC. For DR with integral isolation delta-wye or wye-delta transformers, this requirement applies at the Area EPS side of the transformer.

7.3.3.3 Area EPS-specific considerations

Where the Area EPS has a fast automatic restoration scheme, the DR may increase the chance of an attempted reclose into an out-of-sync, energized island. IEEE Std 1547™ specifies that the DR shall detect an island within two seconds. Some Area EPS operating practices may specify reclosing times faster than two seconds. The DR shall cease to energize the Area EPS circuit to which it is connected prior to reclosure by the Area EPS.

Where there are synchronous machines and inverter-based DR within the same Area EPS line section, this may introduce further risk of an unintended island even with anti-islanding features in place.

In some jurisdictions the DR may be required to trip for all faults.

7.3.3.4 Technology-specific considerations

None identified at this time.

7.3.3.5 Potential further studies

If this sub-criterion cannot be met, then consideration should be given to applying the mitigation techniques such as those identified in 11.1.1 and 11.1.2.

There is a variety of fault and system conditions under which inverter-based generation may continue to apply voltage to the Area EPS without non-islanding protective functions. Inverter-based DR interconnections incorporating delta-wye or wye-delta transformers may not detect ground faults within the Area EPS. Further, inverter-based generation on a single-phase interconnection may fail to detect EPS faults on another phase. Also, PV, as one class of inverter-based DR, may often export to the Area EPS at the PCC.

A steady state simulation study (C1) and system protection studies (C2) may need to be performed if this sub-criterion is not met. These studies may potentially lead to special impact studies including quasi-static simulation (S1), dynamic simulation (S2), and transient simulation (S3).

Technical issues to be considered, if this sub-criterion is not met, include protective device coordination (C2.2), automatic restoration coordination (C2.3), operational characteristics (C3), and system stability (S2.2).

7.4 Criteria ID P3—Impact on EPS equipment loading under all steady state conditions

Normal output from the proposed and existing DR interconnection may introduce operating currents affecting EPS equipment loading and voltage regulation operation. Sub-criterion P3.1 and P3.2 need to be met for this criterion to be met.

7.4.1 Sub-criteria ID P3.1—Gross kVA rating of aggregate DR is no greater than the kVA rating of the EPS transformer serving the facility on a per phase basis

If a preliminary review determines that for a single-phase DR and single-phase EPS transformer serving the facility, the gross kVA rating of the aggregated DR will not exceed the single-phase kVA rating of the EPS transformer serving the facility, it is likely that the DR will not exceed the capability of the EPS transformer and nearby EPS equipment even in the event of a loss of onsite load and this sub-criterion is satisfied. For DR connected to three-phase EPS transformers, the aggregated DR per phase kVA shall not exceed the equivalent per phase transformer kVA. This sub-criterion generally applies to DR interconnected to an existing transformer. These transformers may not be rated for reverse power applications. Note that if the transformer is not specifically rated for reverse power flow, the kVA capability of the transformer for reverse power flow may be less than the transformer rating. The reverse power flow rating may be available for some transformers.

7.4.1.1 Technical basis for sub-criterion

Under a loss of onsite load condition (with no system fault) the entire output of the proposed DR will be delivered to the Area EPS. Where this sub-criterion is met it is unlikely that this will result in an overload of any Area EPS equipment upstream unless there is substantial aggregated DR on the transformer.

Typically, the smallest single-phase distribution pad-mount transformer is rated at 25 kVA. The smallest single-phase distribution overhead transformer is typically rated at 5 kVA-10 kVA. Based on the loading limit of the transformer, most small DR (less than 10 kW) would be within the acceptable loading range of the transformer across all climate zones.

7.4.1.2 Applicability

This sub-criterion applies primarily to DR interconnections intended to serve local loads on the customer side of the PCC.

7.4.1.3 Area EPS-specific considerations

Where Area EPS design incorporates different equipment and line ratings for the same nominal voltage level and phase, the kVA rating of equipment on individual upstream line segments may be more limiting than the kVA rating of the circuit or the substation.

Single-phase DR creates a potential for imbalanced phase currents. Single-phase DR creates zero and negative sequence currents which may potentially cause voltage imbalances that may adversely impact other equipment and protective schemes. When applying multiple single-phase DR units on any line section, Area EPS operators should attempt to balance the DR to limit the phase imbalance. Further study may be necessary if the imbalance is greater than normal load imbalance found on the line section.

7.4.1.4 Technology-specific consideration

DR does not cause unacceptable phase imbalance.

7.4.1.5 Potential further studies

If the gross nameplate rating of the DR will exceed the nameplate rating of the EPS transformer serving the facility, or if single-phase DR creates an excessive voltage imbalance, then further study should be considered to determine if the DR interconnection could exceed the capability of nearby EPS equipment in the event of a loss of onsite load and could create excessive voltage imbalance for three-phase equipment.

Steady state simulation power flow study (C1) may need to be performed if this sub-criterion is not met.

Technical issues to be considered if this sub-criterion is not met include: equipment ratings as identified by steady state simulation study (C1), short-circuit analysis (C2.1), and system protection settings (C2).

7.4.2 Sub-criteria ID P3.2—Gross kVA rating of aggregate DR on a particular feeder or substation is no greater than the feeder or substation rating

If a preliminary review determines that additional DR exists on the feeder to the subject DR and the gross kVA rating of the aggregated DR on the feeder does not exceed the kVA rating of equipment on that feeder, this sub-criterion is satisfied. Likewise, if a preliminary review determines that additional DR exists on the substation that the subject DR is fed from and the gross kVA rating of the aggregated DR on the substation does not exceed the kVA rating of the substation, this sub-criterion is satisfied.

7.4.2.1 Technical basis for sub-criterion

If aggregated DR on a feeder is less than the rated equipment on the feeder, under no load conditions the DR is unlikely to exceed the rating of the equipment. Likewise, if aggregated DR on a substation is less than the substation rating, the DR is unlikely to exceed the rating of the substation equipment.

7.4.2.2 Applicability

This sub-criterion applies to all DR interconnections where more than one DR is connected to the feeder or substation.

7.4.2.3 Area EPS-specific considerations

Where Area EPS design incorporates different conductor ratings for the same nominal voltage level and phase, the kVA rating of individual upstream line segments may be more limiting than the kVA rating of the circuit or the substation.

7.4.2.4 Technology-specific consideration

None identified at this time.

7.4.2.5 Potential further studies

If the kVA ratings of the aggregated DR exceed the ratings of the feeder or substation, further study should be considered to determine if the DR interconnection could exceed the rating of the feeder or substation equipment.

A steady state simulation study (C1) may need to be performed if this criterion is not met.

Technical issues to be considered if this sub-criterion is not met include: equipment ratings as identified by steady state simulation study (C1), short-circuit analysis (C2.1), and system protection settings (C2).

7.5 Criteria ID P4—Impacts on system protection, fault conditions, and arc flash rating

The addition of DR to the existing system may necessitate changes in protection setting, protection schemes, and protection equipment. In addition, DR may introduce additional sources of short-circuit currents affecting the short-circuit duty on EPS equipment, protection settings, and alter the arc flash rating of the EPS network. DR output may also mask fault currents, interfering with the operation of protective devices. This criterion is met if all four sub-criteria (P4.1, P4.2, P4.3, and P4.4) are met.

Short-circuit current data may be readily available or reliably estimated from data available. The quality of the estimate and the degree of accuracy needed will be important in determining whether additional studies are needed to assess this criterion. The accuracy needed is dependent on the amount of short-circuit current contributed by the aggregate DR as compared to the short-circuit current contributed by the Area EPS and the level of Area EPS short-circuit current compared to existing equipment ratings.

7.5.1 Sub-criteria ID P4.1—DR cannot cause any protective device or circuit component to exceed 85% to 90% of the short-circuit interrupting capability

If a preliminary review determines that the DR will not cause any protective device or circuit component to exceed 85% to 90% of its short-circuit interrupting capability, it can be expected that the DR will have no significant impact on Area EPS protection and this sub-criterion is satisfied.

7.5.1.1 Technical basis for sub-criterion

If the resulting fault current with the DR at each protective device and circuit component remains sufficiently below the device's interrupting capability, it can be expected that the DR will have no significant impact on Area EPS short-circuit duty, fault detection sensitivity, relay coordination, or fuse saving schemes. Area EPS operators often establish as a fault duty threshold a share of each device's interrupting capability; once a system change results in fault current that exceeds that threshold, a circuit or component upgrade is a potential mitigation technique. The fault duty threshold applied by an Area EPS to DR interconnections should be the same as the threshold applied to other distribution upgrades.

7.5.1.2 Applicability

This sub-criterion applies to all DR. DR interconnections of 11 kVA and below typically have a minimal impact on fault current levels and may be excluded from this sub-criterion.

7.5.1.3 Area EPS-specific considerations

Since the circuit with which the DR normally operates in parallel has normal open ties with neighboring circuits, this sub-criterion needs to be evaluated for those system configurations in which DR could be served from the neighboring circuits. Also, this sub-criterion needs to be evaluated for adjacent circuits that are supplied from the source substation low side bus as the circuit to which the DR is normally interconnected.

7.5.1.4 Technology-specific considerations

Inverter-based DRs are current limited under fault conditions and have relatively low fault current contribution compared to rotating machines.

7.5.1.5 Potential further studies

If a preliminary review indicates that the DR interconnection's fault current contribution may cause one or more protective devices or circuit components to exceed 85% to 90% of their short-circuit interrupting capability (or the percentage used by the Area EPS operator for distribution upgrades if different), additional protection studies specific to the proposed interconnection and short-circuit studies should be considered.

A short-circuit study (C2.1) and system protection studies (C2) may need to be performed if this sub-criterion is not met.

Technical issues to be considered if this sub-criterion is not met include: equipment ratings as identified by steady state simulation (C1), short-circuit analysis (C2.1), system protection settings (C2), and arc flash hazard study (C2.7).

7.5.2 Sub-criteria ID P4.2—Aggregate DR on circuit does not contribute more than 10% of the circuit's maximum fault current at the primary voltage point nearest the PCC

If a preliminary review determines that the DR project when considered with other generation on the circuit does not contribute more than 10% of the circuit's maximum fault current at the primary voltage point nearest the PCC, there is little chance of the DR interfering with protection coordination and this sub-criterion is satisfied.

7.5.2.1 Technical basis for criterion

The DR unit may contribute current to system faults. Depending on the transformer connection configuration, it may reduce Area EPS system fault contributions to faults and cause mis-coordination such as failure of fuse saving schemes. This can result in some customer outages that would not occur with the DR disconnected or may create circumstances where EPS protective equipment does not clear the fault in a timely manner.

It is generally agreed that there is little chance of increasing Area EPS outages if the proposed DR, in aggregation with other generation on the distribution circuit, does not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high-voltage (primary) level nearest the PCC. This criterion addresses the issues of fault current from the DR not desensitizing protection equipment on the Area EPS. It also addresses the issue that voltage disturbances that may occur because of normal or abnormal operation of the DR are not likely to have a significant effect on voltage supplied to other customers (criteria P4).

The ratio of the DR's fault current to the circuit's maximum fault current for a three-phase fault at the primary voltage point nearest the PCC is sometimes referred to as the short-circuit current contribution ratio (SCCR).

7.5.2.2 Applicability

This sub-criterion applies to all DR. DR interconnections at 11 kVA and below will have a minimal impact on fault current levels and may be excluded from this sub-criterion.

7.5.2.3 Technology-specific considerations

Typically, inverter-based DRs are unlikely to cause problems related to short-circuit contribution due to their low fault duty capabilities. For larger three-phase rotating generators requiring more detailed impact studies, the SCCR also needs to be reviewed.

7.5.2.4 Area EPS-specific considerations

None identified at this time.

7.5.2.5 Potential further studies

If a preliminary review determines that the DR project, when considered with other generation on the circuit, contributes more than 10% of the circuit's maximum fault current at the primary voltage point nearest the PCC, then the DR may interfere with protection coordination and additional protection studies may be necessary.

A short-circuit study (C2.1) and system protection studies (C2) may need to be performed if this sub-criterion is not met.

Technical issues to be considered if this sub-criterion is not met include steady state simulation (C1), short-circuit analysis (C2.1), protection settings (C2), and arc flash hazard study (C2.7).

7.5.3 Sub-criteria ID P4.3—DR will interconnect with an Area EPS having radial topology

If a preliminary review determines that the DR will interconnect with an Area EPS having radial topology, this sub-criterion is satisfied.

7.5.3.1 Technical basis for sub-criterion

Networked EPS systems are inherently more complex systems than traditional radial systems. Networked secondary systems are designed to provide maximum reliability. There are typically more protective relaying devices (network protectors) that a proposed DR interconnection will need to coordinate with. This is usually not a trivial process.

7.5.3.2 Applicability

This sub-criterion applies to any DR interconnection. DR interconnections of 11 kVA and below will have a minimal impact on fault current levels and may be excluded from this sub-criterion.

7.5.3.3 Technology-specific considerations

None identified at this time.

7.5.3.4 Area EPS-specific considerations

Area EPSs that have tight margins on protection coordination may require some preliminary review of potential protection coordination issues.

7.5.3.5 Potential further studies

If the DR interconnection is in a distribution secondary network, then detailed protection studies should be considered. As networked secondary systems are designed to provide maximum reliability, there are typically more protective relaying devices with which a proposed DR interconnection will need to coordinate. This is usually not a trivial process and therefore more in-depth protection coordination studies should be considered.

System protection studies (C2) may need to be performed if this sub-criterion is not met.

Technical issues to be considered if this sub-criterion is not met include: automatic restoration coordination (C2.3), protective device coordination (C2.2), operational characteristics (C3), and system protection (C2).

7.5.4 Sub-criteria ID P4.4—DR will not cause temporary overvoltages during a phase-to-ground fault

If a preliminary review determines that there is no risk of temporary overvoltages to the Area EPS and other customers due to loss of system neutral grounding, this sub-criterion is satisfied. For the risk of temporary overvoltages due to loss of system neutral grounding to be null, one of the following grounding configurations need to be implemented:

- The DR is connected using a three-phase, three-wire configuration.
- The DR is connected on a single-phase distribution transformer and connected line-to-neutral.

- The DR is connected to a three-phase, four-wire system and is effectively grounded, or DR peak power is less than 10% of minimum load of smallest Area EPS section.

Based on the type of interconnection to be used for the DR, the Area EPS operator will determine from Table 2 if the proposed DR passes the sub-criterion after identifying the primary distribution line configuration that will serve the DR.

Table 2—Primary distribution interconnection sub-criterion

Primary distribution	Type of interconnection	Results/Criteria
1-phase, line-to-neutral	Any type	Pass sub-criterion
3-phase, 3-wire	Any type	Pass sub-criterion
3-phase, 4-wire	Effectively grounded	Pass sub-criterion
3-phase, 4-wire	Floating and DR facility peak power is less than 10% of minimum load of smallest Area EPS section.	Pass sub-criterion
3-phase, 4-wire	Floating and DR facility peak power is greater than 10% of minimum load of smallest Area EPS section.	Fail sub-criterion
NOTE—If distribution system is a 3-phase, 3-wire section of a 3-phase, 4-wire circuit, the pertinent table entry for 3-phase, 4-wire primary distribution should be used.		

7.5.4.1 Technical basis for sub-criterion

When a DR is connected using 3 phases and 4 wires in an effectively grounded manner, the ratio of the zero sequence reactance to positive sequence reactance ($X0/X1$ ratio) needs to be considered so temporary overvoltages will not be caused by phase-to-ground faults. Additional guidance on grounding may be found in IEEE Std C62.92.1™ [B10]. For floating connections, temporary overvoltages are an issue. When the DR is very small (e.g., when its peak production is less than 10% of the minimum load), the load will be large enough to limit temporary overvoltages.

7.5.4.2 Applicability

This sub-criterion applies to all DRs including inverter-based DR interconnections incorporating anti-islanding protective features.

DR interconnections of 11 kVA and below will have a minimal impact on any potential line overvoltages from loss of system neutral grounding and may be excluded from this sub-criterion.

7.5.4.3 Technology-specific considerations

If this sub-criterion cannot be met, then consideration should be given to applying the mitigation techniques such as those identified in 11.4.1.4.

DR interconnections with anti-islanding protection and without direct sensing of Area EPS faults in locations of the Area EPS with system neutral grounding may, in the event of a loss of system neutral grounding, fail to separate quickly enough to avoid an overvoltage condition. These overvoltage conditions may persist until after the faults are detected and isolated by Area EPS protective devices.

7.5.4.4 Area EPS-specific considerations

None identified at this time.

7.5.4.5 Potential further studies

If the DR interconnection does not pass this sub-criterion, more detailed impact studies should be considered to assess the risk of post-fault overvoltage or an unintended island due to the DR or to identify additional measures for post-fault separation.

A system protection study (C2) may need to be performed if this sub-criterion is not met.

Technical issues to be considered if this sub-criterion is not met include: automatic restoration coordination (C2.3), protective device coordination (C2.2), system protection (C2), and system grounding (S3.4).

7.5.5 Sub-criteria ID P4.5—Existing protection schemes are configured to allow for DR connected to the Area EPS

This sub-criterion is satisfied if a preliminary review determines that existing protection schemes allow for the addition of DR of the size and type similar to the proposed project(s), existing settings are unaffected by the addition of DR, and other preliminary review sub-criterion do not state that additional protection studies should be considered.

This may be the case when DR is already connected to the feeder for new DR and the new DR is not substantially larger than the existing DR. If special equipment was required to communicate with the existing DR for purposes of protection, similar equipment may be needed for the new DR.

7.5.5.1 Technical basis for sub-criterion

Sometimes changes to protection schemes are needed with the addition of DR. A quick review of protection schemes in use on the Area EPS will often determine whether any of these schemes conflict with changes to Area EPS operation due to changes in power flow, fault contribution, ground fault sources, and Area EPS standard practices. If DR already exists on the Area EPS and the DR being added is not substantially larger, the existing protection schemes are often sufficient. If DR does not presently exist on the feeder, but simple protection schemes are in use, and the DR has sufficient anti-islanding capability, further analysis of the protection schemes is usually not needed.

7.5.5.2 Applicability

This sub-criterion applies to all DR interconnections incorporating all DR technologies.

7.5.5.3 Technology-specific considerations

None identified at this time.

7.5.5.4 Area EPS-specific considerations

Existing protection systems that have been designed with future DR applications in mind have a high likelihood of allowing the addition of DR, with appropriate anti-islanding schemes, with only a preliminary review of the protection systems. Likewise, simple protection systems (i.e., overcurrent only) with the addition of DR with anti-islanding protection systems will have a high likelihood of only a preliminary review of protection systems. However, more in-depth protection studies should be considered for more complex protection systems (i.e., transfer trip schemes, multi-layered setting, automatic restoration, multi-ground point protection).

7.5.5.5 Potential further studies

If the DR interconnection does not pass this sub-criterion, more detailed impact studies should be considered to determine the appropriate protection schemes and settings.

A system protection study (C2) may need to be performed if this sub-criterion is not met.

Technical issues to be considered if this sub-criterion is not met include: circuit automatic restoration coordination (C2.3), protective device coordination (C2.2), and system protection (C2).

7.6 Criteria ID P5—Impacts on voltage regulation within the EPS under steady state conditions

DR may create circumstances where voltage regulation requirements are violated. This sub-criterion is met if each of the sub-criteria P5.1, P5.2, P5.3, and P5.4 are met and criterion P5.5 is met if applicable.

7.6.1 Sub-criteria ID P5.1—DR PCC is relatively strong or stiff location within the Area EPS

If a preliminary review indicates that the PCC of the DR is a relatively strong or stiff location within the Area EPS, the Area EPS has the ability to resist voltage deviations caused by the DR, and the DR will not adversely affect Area EPS voltage for other Area EPS customers and this sub-criterion is satisfied.

7.6.1.1 Technical basis for sub-criterion

System stiffness or weakness refers to the ability of the Area EPS at a particular point to resist voltage deviations from a DR connected at that point. Where this sub-criterion is met, the Area EPS is capable of resisting voltage deviations from the DR such that other customers are not adversely affected. System stiffness or weakness at a particular point within the Area EPS is indicated by the total impedance of the Area EPS between the primary or strong source (e.g., a substation) and that point. A given DR interconnected at a point in the Area EPS where the total impedance is high (e.g., a weak or non-stiff location) will cause greater voltage deviations in the Area EPS, and there is greater potential for voltage-related impacts from the DR in the Area EPS such as flicker, voltage fluctuations, or changes in steady state voltage. As explained in Clause 5, there are several ways to measure and compare system weakness or stiffness at the PCC of a DR. Any measure of system stiffness or weakness should be based on the total system impedance between the primary source and the proposed PCC of the DR. Ideally the measure should also consider the size of the DR as well. Numerical values for locations that are sufficiently stiff or strong to meet this sub-criterion will depend on the computational method used and may vary from Area EPS to Area EPS.

7.6.1.2 Applicability

This sub-criterion applies to any DR interconnection designed to export power to the Area EPS over the PCC.

7.6.1.3 Area EPS-specific considerations

The effective weakness or stiffness of the Area EPS will vary from point to point; accordingly, this criterion should be applied at the specific location within the Area EPS where the DR is proposed for interconnection. Interconnections near the end of long radial circuits or in weak island systems are classic

examples of weak or non-stiff DR interconnections having elevated potential for voltage-related impacts. Where the Area EPS incorporates voltage regulation features such as load tap changers, line voltage regulators, or capacitors capable of responding to voltage variation, the Area EPS may be more capable of interconnecting a particular DR without voltage concerns and without detailed studies. However, the settings of these voltage regulation controls need to be adjusted to take into account the effects of DR. The operation of the DR should not cause the Area EPS voltage regulation devices to operate excessively, potentially causing a shortened life for these devices.

7.6.1.4 Technology-specific consideration

Where stiffness is evaluated using the short-circuit contribution of the DR, as in a stiffness ratio as defined in IEEE Std 1547.2™, this may distort comparisons of stiffness or weakness between DRs with high short-circuit contribution such as synchronous generators and DRs with relatively low short-circuit contribution such as inverter-based generation.

7.6.1.5 Potential further studies

If, based on a preliminary review, the DR interconnection is in a weak or non-stiff location within the Area EPS, additional studies should be considered to directly assess the Area EPS voltage impacts of the DR.

A steady state simulation (C1) study should be considered if this sub-criterion is not met. These studies may potentially lead to special impact studies including quasi-static simulation (S1), dynamic simulation (S2), and electromagnetic transient simulation (S3).

Technical issues to be considered if this sub-criterion is not met include: operational characteristics (C3) and considerations such as voltage imbalance, voltage regulation, temporary overvoltage, voltage fluctuations, and voltage sags and swells (C1).

7.6.2 Sub-criteria ID P5.2—DR would not be anticipated to result in voltage rising above specified limits in the Area EPS

If a preliminary review predicts that the aggregated DR production will not directly cause voltages in the EPS to rise above specified limits, it is likely the DR will not adversely affect power quality (delivery voltage) for other Area EPS customers, and this sub-criterion is satisfied.

7.6.2.1 Technical basis for sub-criterion

Injection of active power from DR into the distribution system within the Area EPS under normal operating conditions offsets factors that normally contribute to voltage drop along a radial. This sub-criterion addresses the capability of the voltage control mechanisms within the Area EPS, along with any voltage regulation features of the DR, to compensate for this effect. Where this sub-criterion is met, the impact of the DR lies within the voltage control range of the Area EPS.

7.6.2.2 Applicability

This sub-criterion applies to any DR interconnection designed to export power to the Area EPS over the PCC.

7.6.2.3 Area EPS-specific considerations

Where the Area EPS incorporates voltage regulation features such as load tap changers, line voltage regulators, or capacitors capable of responding to voltage variation, the Area EPS may be more capable of interconnecting a particular DR without voltage concerns and without detailed studies. However, the settings of these voltage regulation controls need to be adjusted to take into account the effects of DR. The operation of the DR should not cause the Area EPS voltage regulation devices to operate excessively, potentially causing a shortened life for these devices. Also, for bus regulated substations with multiple feeders, the voltage regulation impact on the non-DR feeder(s) needs to be considered.

7.6.2.4 Technology-specific consideration

Some inverter-based generation may be limited to operation at a unity power factor and thus may lack the ability to compensate for its voltage rise impact. This may limit the amount of aggregate inverter-based DR that can interconnect with an Area EPS while meeting this sub-criterion.

7.6.2.5 Potential further studies

If, based on a preliminary review the DR, interconnection is expected to cause normal condition or steady-state voltage rise in the Area EPS that results in EPS voltage above normal specifications, additional studies should be considered to augment or reconfigure Area EPS voltage regulation features to compensate.

A steady state simulation (C1) study should be considered if this sub-criterion is not met. These studies may potentially lead to special impact studies including quasi-static simulation (S1), dynamic simulation (S2), and electromagnetic transient simulation (S3).

Technical issues to be considered if this sub-criterion is not met include: operational characteristics (C3) and considerations such as voltage imbalance, voltage regulation, temporary overvoltage, voltage fluctuations, and voltage sags and swells (C1).

7.6.3 Sub-criteria ID P5.3—Loss of DR or variation in output of DR would not be anticipated to result in voltage in the Area EPS falling below specified limits

If a preliminary review predicts that the loss of, or variation in, DR production will not directly cause voltages in the EPS to fall below specified limits, it is likely the DR will not adversely affect power quality (delivery voltage) for other Area EPS customers, and this sub-criterion is satisfied.

7.6.3.1 Technical basis for sub-criterion

The loss of or reduction in active power injection from DR into the distribution system within the Area EPS contributes to factors that normally result in voltage drop along a radial line. DR production may be lost to the Area EPS due to dispatch decisions, DR outages, or changes in conditions affecting the capability of the DR. This sub-criterion addresses the capability of the voltage control mechanisms within the Area EPS, along with any voltage regulation features of the DR, to compensate for this effect. Where this sub-criterion is met, the impact of the DR lies within the voltage control range of the Area EPS.

7.6.3.2 Applicability

This sub-criterion applies to any DR interconnection designed to export to the Area EPS over the PCC. This sub-criterion is particularly applicable to DR: a) whose output may be expected to vary under normal

operating conditions, such as DR with solar or wind primary energy sources, and b) using interconnection technology with a fixed power factor.

Dispatchable DR such as synchronous or inductive generation or storage that is not subject to continuously varying output or that has voltage compensation features may be excluded from this sub-criterion.

7.6.3.3 Area EPS-specific considerations

Where the Area EPS incorporates voltage regulation features such as load tap changers, line voltage regulators, or capacitors capable of responding to voltage variation, the Area EPS may be capable of compensating for the loss of the DR without voltage concerns and without detailed studies. However, the settings of these voltage regulation controls need to be adjusted to take into account the effects of DR. The operation of the DR should not cause the Area EPS voltage regulation devices to operate excessively, potentially causing a shortened life for these devices.

7.6.3.4 Technology-specific consideration

Generation with a solar primary energy source, for example PV, is subject to unpredictable, relatively rapid output changes due to changes in solar radiation. More importantly, multiple PV projects may simultaneously experience output reductions due to a common factor such as a cloud passing or a system voltage deviation event. Studies of PV output variability for individual large-scale PV projects indicate short-duration output transients over one minute of 39% or less of ac nameplate output for 90% of days, and a maximum observed of 50% of output over one minute for all days. Sustained transients such as at sunrise and sunset were observed at 10% to 13% of output over 15 minutes. [B5]

Accordingly, the application of this sub-criterion should consider not only the steady state impact of the loss of an individual DR, but the aggregate impacts of nearby PV projects, and the quasi-dynamic phenomena such as the rate at which voltage regulating devices such as voltage regulators can respond to voltage changes. In addition, PV generation as inverter-based may be limited to operation at a unity power factor, and thus may lack the ability to compensate for its voltage reduction impact. These attributes of PV generation may limit the amount of aggregate PV that can interconnect with an Area EPS while meeting this sub-criterion.

7.6.3.5 Potential further studies

If this sub-criterion cannot be met, then consideration should be given to applying the mitigation techniques such as those identified in 11.4.1.1 and 11.4.1.2.

If, based on a preliminary review, loss of or expected variation in the output of the proposed DR interconnection is expected to cause voltage drop in the Area EPS that results in EPS voltage below normal specifications, additional studies should be considered to augment or reconfigure Area EPS voltage regulation features to compensate.

For projects with a solar primary energy source, the presence of additional nearby solar DR interconnections having the potential to respond simultaneously to an external factor, such as a cloud passing, may necessitate additional study. Similarly, for projects with wind as a primary energy source, the presence of additional nearby wind turbine interconnections that have the potential to respond almost simultaneously to large changes in wind speed may necessitate additional study.

A steady state simulation (C1) study should be considered if this sub-criterion is not met. These studies may potentially lead to special impact studies including quasi-static simulation (S1), dynamic simulation (S2), and electromagnetic transient simulation (S3).

Technical issues to be considered if this sub-criterion is not met include: operational characteristics (C3), and voltage considerations such as voltage imbalance, voltage regulation, temporary overvoltage, voltage fluctuations, and voltage sags and swells (C1).

7.6.4 Sub-criteria ID P5.4—Variation in output of DR would not be anticipated to necessitate changes of settings of Area EPS voltage regulating devices

If a preliminary review determines that the maximum voltage change at voltage regulating devices (e.g., voltage regulators, tap changers, and automatic switched capacitors) caused by the DR production is less than the regulating device dead band, and the DR cannot cause reverse power flow at the voltage regulation device, this sub-criterion is satisfied. Reversing regulation may have unanticipated results when the DR is weak relative to the system.

Setting changes may be necessary due to larger magnitude of voltage changes sensed or direction of power flow through voltage regulation equipment. In some instances, consideration of bidirectional capability of voltage regulation equipment may necessitate equipment modification or replacement.

7.6.4.1 Technical basis for sub-criterion

Variable injection of active power from DR into the distribution system within the Area EPS variably offsets or contributes to factors that normally contribute to voltage drop along a radial feeder. This sub-criterion addresses the increased duty placed upon the voltage control mechanisms within the Area EPS, along with any voltage regulation features of the DR, to compensate for any unpredictable output variation of the DR. Area EPS operators often set desired operations-per-day limits on voltage-regulating devices to reduce the chances of premature failure, which in turn affects power quality for all customers of the Area EPS. Where this sub-criterion is met, the impact of the DR is small enough that a change in its output alone does not directly trigger a change in Area EPS voltage controls, thus the DR cannot incrementally contribute to premature failure of Area EPS voltage control elements.

7.6.4.2 Applicability

This sub-criterion applies to any DR interconnection designed to export power to the Area EPS over the PCC. This sub-criterion is particularly applicable to DR whose output may be expected to vary under normal operating conditions, such as DR with solar or wind primary energy sources, and using interconnection technology with a fixed power factor.

Dispatchable DR such as synchronous or inductive generation or storage that is not subject to continuously varying output or has voltage compensation features may be excluded from this sub-criterion.

7.6.4.3 Area EPS-specific considerations

None identified at this time.

7.6.4.4 Technology-specific considerations

PV generation is subject to unpredictable, relatively large output changes due to changes in solar radiation. Further, under partly-cloudy conditions PV output may fluctuate repeatedly over an extended period of time, contributing to a much less stable operating environment for voltage control equipment than may have been intended. In addition, PV generation may be limited to operation at a unity power factor, and may therefore lack the ability to compensate for its voltage variation impact. These attributes of PV

generation may limit the amount of aggregate PV that can interconnect with an Area EPS while meeting this sub-criterion.

If the DR has the potential to cause reverse power flow through voltage regulators with line drop compensation, additional study efforts may be needed. Reverse power flow through this type of voltage regulator may create worse voltage profiles than those found from voltage regulators without line drop compensation.

7.6.4.5 Potential further studies

If this sub-criterion cannot be met, then consideration should be given to applying the mitigation techniques such as those identified in 11.4.1.1 and 11.4.1.2.

If a preliminary review indicates that the expected variation in production of a proposed DR has a sufficient voltage impact to directly result in changes in the settings of Area EPS voltage regulating devices, additional studies should be considered to augment or reconfigure Area EPS voltage regulation features to compensate.

A steady state simulation (C1) study should be considered if this sub-criterion is not met. These studies may potentially lead to special impact studies including quasi-static simulation (S1), dynamic simulation (S2), and electromagnetic transient simulation (S3).

Technical issues to be considered if this sub-criterion is not met include: operational characteristics (C3) and voltage considerations such as voltage imbalance, voltage regulation, temporary overvoltage, voltage fluctuations, and voltage sags and swells (C1).

7.6.5 Sub-criteria ID P5.5—DR is not expected to result in high voltage on shared secondary

If a preliminary review determines that the output of the DR or the aggregate output of DR on the shared secondary will not directly result in voltage exceeding acceptable service limits, further studies and voltage management on the secondary may not be needed.

7.6.5.1 Technical basis for sub-criterion

Service transformers typically operate with secondary voltage at a fixed ratio relative to the Area EPS primary voltage seen by the transformer, that is, without any active management of secondary voltage. The output of DR within the secondary, particularly DR with a fixed, unity power factor such as inverter-based PV, may increase secondary voltage if low load within the secondary coincides with high DR output. Under these circumstances customers within the secondary other than the DR host may experience delivery voltage outside of accepted specifications.

7.6.5.2 Applicability

This sub-criterion applies only to DR interconnections on shared secondaries where the DR also lacks voltage regulation or compensation features, such as inverter-based DR with a fixed unity power factor.

7.6.5.3 Area EPS-specific considerations

None identified at this time.

7.6.5.4 Technology-specific consideration

Single-phase PV DR on shared secondaries where the DR is non-dispatchable, inverter-based operating at a fixed unity power factor has essentially no features to provide compensation for voltage variation within the secondary. Multiple PV projects within a single secondary with common operating profiles may exacerbate voltage variability or out-of-specification delivery voltages within the secondary.

7.6.5.5 Potential further studies

If a preliminary review indicates that the output of the DR or the aggregate output of all DR on the secondary will result in voltage within the secondary exceeding acceptable limits, further studies should be considered.

A steady state simulation (C1) study should be considered if this sub-criterion is not met. These studies may potentially lead to special impact studies including quasi-static simulation (S1), dynamic simulation (S2), and electromagnetic transient simulation (S3).

Technical issues to be considered if this sub-criterion is not met include: operational characteristics (C3) and voltage considerations such as voltage imbalance, voltage regulation, temporary overvoltage, voltage fluctuations, and voltage sags and swells (C1).

If this sub-criterion is not met, then consideration could also be given to mitigation techniques such as those identified in Clause 11.

7.7 Criteria ID P6—Impacts on EPS power quality

Rapid fluctuation or loss of output from the proposed DR interconnection may cause voltage sag/swell or flicker. DR may introduce unacceptable harmonic distortion. This sub-criterion is met if each of the sub-criteria P6.1, P6.2, and P6.3 are met.

7.7.1 Sub-criteria ID P6.1—DR operation will not cause flicker exceeding limits at the PCC

If a preliminary review determines that the DR will not cause the Pst (short term flicker value) to exceed 0.9 when starting and during normal operation at the PCC, it is likely that the DR will not result in objectionable flicker for other Area EPS customers and this sub-criterion is satisfied.

7.7.1.1 Technical basis for sub-criterion

The DR shall not create objectionable flicker for other customers on the Area EPS (see 4.3.2 of IEEE Std 1547™). For example, flicker at the PCC caused by the generating facility should not exceed the limits defined by IEEE Std 1453™ and IEEE Std 1453.1™. This approach provides guidance toward meeting the requirements in 4.3.2 of IEEE Std 1547™.

7.7.1.2 Applicability

This sub-criterion applies to any DR interconnection.

7.7.1.3 Area EPS-specific considerations

None identified at this time.

7.7.1.4 Technology-specific considerations

Synchronous generators may be connected and brought up to synchronous speed (as an induction motor) resulting in starting voltage drop. This is permissible provided flicker limits are not exceeded.

Starting voltage drop is typically not a concern when the DR is inverter-based. However, a high number of changes in levels of energy produced in a short period of time may create voltage changes that violate flicker sub-criterion. Both solar and wind turbines have the potential to have quick changes in output energy. For example, for PV generation an output change of 40% to 50% within 30 seconds is possible [B5]. If the generation is connected at an EPS location where such an output change results in an EPS voltage change of 1.7% or more, flicker could be a concern. The susceptibility of the energy-producing technology to these types of quick energy level changes needs to be considered.

7.7.1.5 Potential further studies

If a preliminary review determines that the starting voltage drop of a DR at the PCC may exceed the limits defined by maximum borderline of irritation curve, the DR may result in objectionable flicker for other Area EPS customers and additional study should be considered.

Steady state simulation (C1) and short-circuit analysis studies (C2.1) should be considered if this sub-criterion is not met. These studies may potentially lead to special impact studies including dynamic simulation (S2) or electromagnetic transient simulation (S3).

Technical issues to be considered if this sub-criterion is not met include: voltage regulation, flicker, temporary overvoltage, and voltage fluctuations (C1), as well as voltage flicker (S4.4).

7.7.2 Sub-criteria ID P6.2—Real and reactive power flow from DR will not cause Area EPS voltage sags and swells

If a preliminary review determines that the voltage sags and swells due to the real and reactive power flow from the DR independent of line voltage regulating equipment will not exceed acceptable Area EPS distribution level variations, further analysis of power quality voltage variations may not be necessary.

7.7.2.1 Technical basis for sub-criterion

IEEE Std 1159™-2009 [B7] defines a voltage sag or swell as, respectively, a short-duration decrease in root-mean-square (rms) voltage to between 0.90 per unit (PU) and 0.10 PU, or a short-duration increase in rms voltage to between 1.10 PU and 1.80 PU.

Variable injection of active and reactive power from DR into the distribution system within the Area EPS variably offsets or contributes to factors that normally contribute to voltage drop along a radial. This sub-criterion addresses the potential for voltages exceeding normal voltage ranges. Where the expected output variation of the DR will not result in voltage changes, the impact of the DR is small enough to not directly cause sags and swells. Alternatively, if expected variation in the output of the DR may result in large enough voltage changes to cause sags or swells (e.g., a voltage change of 0.10 PU or more), further studies should be considered so the circuit does not experience voltage sags or swells due to the DR.

7.7.2.2 Applicability

This sub-criterion applies to DR interconnections designed to export power to the Area EPS over the PCC. This sub-criterion is particularly applicable to DR: a) whose output may be expected to vary under normal operating conditions, such as DR with solar or wind primary energy sources, and b) using interconnection technology with a fixed power factor.

Dispatchable DR such as synchronous or inductive generation or storage that is not subject to continuously varying output or has voltage compensation features may be excluded from this sub-criterion.

7.7.2.3 Technology-specific considerations

None identified at this time.

7.7.2.4 Area EPS-specific considerations

None identified at this time.

7.7.2.5 Potential further studies

If a preliminary review indicates that the expected variation in production of a proposed DR has a sufficient voltage impact to directly result in changes in the settings of Area EPS voltage regulating devices, additional studies should be considered.

A steady state simulation (C1) study should be considered if this sub-criterion is not met. These studies may potentially lead to special impact studies including quasi-static simulation (S1), dynamic simulation (S2), and electromagnetic transient simulation (S3).

Technical issues to be considered if this sub-criterion is not met include: operational characteristics (Study C3) and voltage considerations such as voltage imbalance, voltage regulation, temporary overvoltage, voltage fluctuations, and voltage sags and swells (C1).

If this sub-criterion is not met, then consideration should also be given to mitigation techniques such as those identified in 11.4.1.1 and 11.4.1.2.

7.7.3 Sub-criteria ID P6.3—DR operation will not cause harmonics at the PCC to exceed allowed limits

This sub-criterion is satisfied if a preliminary review determines that the harmonic generation from the DR meets IEEE Std 1547™ requirements and the harmonic levels and SCCR at the PCC are low; thus it is unlikely that the addition of DR will create harmonics in excess of the levels identified in IEEE Std 1547™.

7.7.3.1 Technical basis for sub-criterion

At the PCC, the harmonic levels are due to the harmonics from the system plus the harmonics injected by the DR. If the injected harmonics are low, changes to the harmonic levels will be low. The capacity of the DR to impact harmonic voltage levels at the PCC also depends on the SCCR. If the Area EPS is strong relative to the DR size (low SCCR), the DR will have little impact on the voltage harmonics at the PCC. IEEE Std 1547™, not IEEE Std 519™, establishes harmonic limits for DR interconnection.

7.7.3.2 Applicability

This sub-criterion applies to any DR interconnection with standard transformer connections and system grounding. DR connected to systems with large amounts of power factor correction capacitors should be considered for study for potential resonances if the amount of harmonics injected by the DR approaches the limits identified in IEEE Std 1547™.

7.7.3.3 Technology-specific considerations

None identified at this time.

7.7.3.4 Area EPS-specific considerations

Capacitive reactance, inductive reactance, and background harmonic levels will have an effect on the level of harmonics produced when harmonic-producing DR is connected. The net level of harmonics is exacerbated by resonances throughout the distribution system. Resonances created by capacitance and impedances should be considered if background harmonics are high and the DR produces substantial (in terms of percentage of current harmonic levels) harmonics.

7.7.3.5 Potential further studies

If the proposed DR interconnection is at a location with large background harmonic levels and the proposed DR may produce substantial levels of harmonics, a harmonic analysis (S4.1), harmonic problems (S4.2), or harmonic resonance (S4.3) should be considered.

8. Conventional distribution studies

8.1 Introduction

In general, a large DR or a large number of small DR may cause the Area EPS to experience voltage excursions, overload, equipment misoperations, protection and coordination issues, and power quality issues. When the proposed DR interconnection exceeds preliminary review criteria limits, the DR may be examined using conventional study methods discussed in this clause. The tools used in these studies are generally familiar to Area EPS operating and planning personnel.

Results of these studies may show that the impact of the DR on the Area EPS is acceptable, they may indicate that mitigations should be considered for the Area EPS to approve the installation of the DR, or they may indicate that more complex, special studies should be considered. Table 3 shows the different conventional system impact studies and their relationship to potential system impacts on the Area EPS, along with a clause number reference.

Table 3—Type of study vs potential impact on the EPS

Impact study type	Study ID	Clause	Un-intentional islanding	Area EPS equipment duty and operating ratings	Protection design, coordination and fault rating	Voltage regulation and reactive power management	Power quality
Steady state simulation	C1	8.2		X	X	X	
System protection studies	C2	8.3	X	X	X		X
Short-circuit analysis	C2.1	8.3.1	X	X	X		X
Protective device coordination	C2.2	8.3.2	X	X	X		X
Automatic restoration coordination	C2.3	8.3.3	X		X		X
Area EPS power system grounding	C2.4	8.3.4			X		X
Synchronization	C2.5	8.3.5			X		X
Unintentional islanding	C2.6	8.3.6	X		X		
Arc flash hazard study	C2.7	8.3.7			X		
Operational characteristics—loading, load shedding, etc.	C3	8.4	X	X	X	X	

8.2 Study ID C1—Steady state simulation

8.2.1 Technical basis for the study

A conventional steady state simulation may be performed when the preliminary review indicates that the proposed DR interconnection has the potential to cause the Area EPS to experience equipment overloads, sustained overvoltage conditions, excessive voltage fluctuations, or equipment control problems. Steady state simulations are also the basis for short-circuit studies and other protection studies.

8.2.2 Study methodology

A steady state simulation tool, generally referred to as a power flow simulation, solves a snapshot of an EPS model using an EPS model at the nominal EPS frequency. In their most basic form, these tools solve voltages, currents, and real and reactive power flows and losses throughout the Area EPS at a single point in time. Some steady state simulation tools solve only Area EPS models limited to one power source in a radial configuration. These tools are therefore not appropriate for DR studies. To study the impact of DR on the Area EPS, the steady state simulation tools used need to support multiple power sources and Area EPS architectures other than radial.

Most Area EPS operators have a topological model of their respective system that includes the distribution circuit of the proposed interconnection and substation source. Since it takes time and effort to model the system and keep them up to date, some Area EPS operators may not have their entire system modeled. The power flows are done on an as-needed basis. Ideally, the scope of the model should be sufficient to assess possible impacts beyond the individual distribution feeder, including neighboring circuits, the substation, and the Area EPS serving the substation. But some programs are designed to simulate individual circuits only. When procuring a new tool to accommodate distributed generation, the model should include capacitor control settings and tap changer control settings to assess the impact of DR on system voltage

with and without voltage regulating devices. The model should incorporate loads expected for periods in which the DR would be operating. Existing programs may not have these capabilities. The Area EPS operator with older tools may need to assess the cost and benefits of replacing the tool. Note that previously approved DR should be included in the Area EPS model.

A variety of commercial and open source steady state simulation tools are available. Many of these tools provide toolboxes and analysis packages designed to facilitate commonly performed studies. When selecting a steady state simulation tool for DR impact analysis to supplement or replace an existing load flow program some functions that may be useful are:

- Unbalanced solution
- Availability of DR models
- Distribution transformer and secondary models
- Ability to solve loops and meshed networks
- Availability of additional types of load models (constant current, constant kVA, etc.)

For the purposes of a power flow study, a DR installation can be represented, as appropriate, by one of the following:

- A fixed source of real and reactive power. Preferred for conventional studies.
- A fixed source of real power with a fixed power factor. A possible solution if large voltage fluctuations are found.
- A fixed source of real power, providing ac bus voltage control to a set level (subject to limits on reactive power output). A DR designed to operate in this manner would generally not be approved in a conventional study.
- A swing generator in a stand-alone power system, providing control of ac bus voltage, frequency, and phase angle (subject to limits on real and reactive power output). This type of model would generally be used to model a microgrid in which the DR would be designed to provide service to select loads on the Area EPS as discussed in IEEE Std 1547.4™, which is beyond the scope of this document.

The information needed to model a DR installation in a power flow study is contained in the basic equipment rating and the description of the available operating modes. Parameterized models of conventional synchronous generators are commonly available in the libraries of leading power flow analysis programs. These models can readily be adapted to represent other types of DR installation if the libraries do not include specific models for these particular types.

In these studies, several types of concerns may arise as follows:

- Excessive voltage rise. The installation of DR on the circuits of the Area EPS may prove to be acceptable under peak loading conditions, but the reverse flow of power may cause a rise in the voltage that exceeds acceptable limits under light loading conditions. Modeling both peak and light load conditions protects against this contingency. Note that the operating schedule of the DR may affect the minimum conditions to be studied. Solar DR units, for instance, would be studied under the lowest daylight loading conditions. The scope of the power flow study should include the low-voltage equivalents to determine the impacts on the power quality at the equivalent customer terminals and to be capable of analyzing the performance of the DR connected to the low-voltage circuits. Where the service transformers and the low-voltage secondary service cables are not modeled, the studies may fail to detect overvoltages at the Local EPS caused by the impedance of the low-voltage circuit. Overvoltages are most likely to occur when the DR is injecting into the Area EPS. Overvoltage may also occur when the Area EPS is operating near the voltage limit prior to the DR operation and the DR may push the voltage over the limit.

- Excessive voltage fluctuations. The installation of intermittent types of DR, such as PV and wind units, may cause voltage fluctuations that become noticeable or irritating to other customers in the Area EPS. Circuit voltage is controlled with mechanical equipment, voltage regulators, and capacitor banks that may experience increased numbers of operations, causing increased maintenance or premature failure. The DR output may fluctuate more rapidly than the Area EPS control equipment can operate. To model this in the power flow simulation, the voltage regulating equipment can be locked and the generation can be removed from the case to model the Area EPS before the voltage regulating equipment can react to the system change.
- Improper operations. The installation of DR on circuits may create reverse flow conditions that cause some types of equipment to operate incorrectly. Some voltage regulating equipment may be designed to operate as though power flows from the direction of the line side (source of stable voltage). Where DR causes a reversal of power flow through this equipment, the equipment may adjust the voltage improperly. This condition may not be present under peak load conditions but may occur under light load conditions. Many manufacturers have developed control schemes for their equipment that operate correctly under reverse power flow conditions. Capacitor controls may also be affected by the installation of DR on the circuits.
- Incorrect situational awareness. When significant amounts of DR are installed on a circuit, circuit metering should be examined to determine whether reverse power flow would be identified in readings provided to the system operators. This condition may not be present under peak load conditions but may occur under light load conditions. The metering equipment may need to be replaced or modified to capture bi-directional flow. Additionally, DR can mask the true load on a circuit by reducing the amount of forward power flow as seen by system operators.
- Equipment overloads. The installation of DR that is significantly larger than the local load in the Area EPS may cause equipment overloads. These overloads may occur at times other than the peak load conditions.
- Unbalanced operation. The installation of DR at a location in the Area EPS with significant phase imbalances may cause voltage imbalances on the generator terminals. Installation of single-phase DR may increase the imbalances, which may adversely impact other devices connected to the Area EPS circuits. Modeling single-phase DR or three-phase DR on unbalanced circuits using a three-phase power flow analysis tool (capable of unbalanced calculations) may identify complications that arise on the circuit.

For violations of the above, mitigation techniques should be considered along with results that may arise from the power flow, protection, and the short-circuit studies.

8.2.3 Potential further studies

If the conventional steady state simulation (“power flow” study) shows indications of equipment overloads, sustained overvoltage conditions, excessive voltage fluctuations, or equipment control problems, a quasi-static simulation (S1), as described in the Special Studies section, should be considered to confirm the steady state results or to analyze corrective measures. Operating strategies of the DR may also lead to special studies.

8.3 Study ID C2—System protection studies

The purpose of system protection studies is to assure that the integrity of the electrical system and the effectiveness of protection devices is maintained despite changes to the distribution system due to the addition of DR. The system protection study attempts to meet that purpose by portraying the appropriate protective devices and device settings to properly protect the Area EPS during fault conditions.

The DR type and characteristics are important considerations when performing protection studies. The knowledge of energy sources (e.g., engine, wind, solar, etc.) and interface to the power system (e.g., synchronous machine, induction machine, inverter, etc.) as well as the knowledge of grounding characteristics and interconnection transformer configuration are critical to perform the protection study. The DR's normal operating characteristics (e.g., generation levels and variability) as well as fault or open circuit characteristics are an important part of the protection study. When multiple DRs are located on the same feeder or area the protection study needs to consider the multitude of possibilities from the various combinations of DR operations.

Protective devices such as circuit breakers and fuses are located throughout the electrical power system for reliable and safe operation. Various types of protection issues may occur in an electrical power system. Many of these protection issues can be handled by a single protective device or several protective devices operating in alliance with each other. Because of the large amount of damage that may occur due to the failure of a protective device to operate properly, most protective devices need to be backed up by other protective devices.

Protection studies require a variety of other types of studies as prerequisites. System protection studies start with power flow and short-circuit studies of the relevant portion of the area electrical power system. These studies provide the basic information for analyzing the reaction under differing fault considerations and pre-fault (load) conditions.

A system protection study looks at the entire protection scheme including several categories of studies that are covered below.

8.3.1 Study ID C2.1—Short-circuit analysis

8.3.1.1 Technical basis for the study

DR may substantially increase fault current levels at nearby substations as well as at other locations in the distribution system. Increased fault currents may exceed existing equipment ratings, interrupting ratings, and/or through fault ratings as well as cause potential mis-coordination of existing protective devices. Hence the DR needs to be modeled in a fault study computer program along with the existing distribution circuit models and different fault simulations performed in order to determine the fault current levels for proper protection coordination and relay settings.

8.3.1.2 Study methodology

Short-circuit analysis utilizes a fault study program and studies the effect of three-phase, line-to-ground, line-to-line, and line-to-line-to-ground faults on electrical distribution systems. The short-circuit study typically calculates the total short-circuit currents as well as the contributions of individual motors, generators, and Area EPS ties in the system. These short-circuit current values are important for rating circuit breakers and designing properly coordinated protection schemes. The short-circuit study feeds into the protective device coordination and arc flash hazard studies.

For DR impact studies, it is important that the DR short-circuit contribution be properly represented. Some DR technologies do not behave like classical synchronous generators or induction machines, which most commercial short-circuit analysis packages can handle. The voltages during short-circuit conditions can be used to estimate voltage sag magnitudes experienced by other customers, including any effects of the DR.

Consideration has to be given, in the case of a synchronous generator, to the fault current decrement related to the transitions from the subtransient state to the transient state and should include synchronous impedance, excitation response, and the dc offset in the fault current as this impacts upon the coordination

of the fault protection equipment. The classical method for short-circuit analysis uses the Thevenin equivalent of the power system while modeling different fault locations. For unbalanced faults, symmetrical components are used to obtain a solution. This involves the derivation of equivalent impedance networks for positive, negative, and zero sequence currents respectively. The associated Thevenin voltages are obtained from the voltage at the fault location prior to the fault. The three equivalent sequence networks are interconnected differently for each of the four fault types and solved to obtain the respective fault currents.

The equivalent impedance networks used for short-circuit analysis are generally obtained by utilizing the respective equivalent equipment impedances in the system and neglecting shunt-connected capacitors and static loads.

The solution method is based on constant-frequency steady-state circuit analysis, so dc offset effect is not represented. Correction factors need to be applied to obtain asymmetrical fault currents.

In the case of synchronous machine-based generators, the study can be repeated using sub-transient, transient, and synchronous impedances respectively to obtain the fault current during different time intervals after the onset of the fault, depending on whether the analysis is to be used for equipment overstress assessment or instantaneous and time overcurrent relay coordination. During the modeling of the DG for the short-circuit analysis, the existing power system model is kept as is. Only the DG generator impedances are changed for the different conditions. So, the system generator models are still using subtransient impedances even though the DG impedances are being changed for the various conditions. The implicit assumption is that the system is almost an infinite bus relative to the DG and the system generator impedance values will not change by any significant amount during the distribution fault.

The short-circuit current from inverter-based DR installations is generally limited to slightly more than nominal rated current. This is done using active control methods in order to protect the semi-conductor switching devices in the inverter. Some short-circuit programs now have inverter models, which better represent inverter-based DR. Short-circuit simulation of inverter-based DR can also be done with a time-domain model, but this is usually not necessary or practical for protection studies. In the absence of adequate inverter models, a classical synchronous source is often used with equivalent impedance to simulate the short-circuit contribution from the inverter.

8.3.2 Study ID C2.2—Protective device coordination

8.3.2.1 Technical basis for the study

The existing protection system was coordinated to ensure that the device closest to the fault isolates the fault and that the least amount of customers will be impacted for a fault on the system. Adding DR on the feeder changes the fault current distribution, and the existing protection coordination needs to be checked to verify that the coordination is still satisfactory. In the event mis-coordination exists, new settings/devices need to be identified.

8.3.2.2 Study methodology

The operating times under different fault conditions for all devices need to be checked. Sufficient time margin between the devices needs to be present to ensure that the appropriate device, typically the device closest to the fault, operates first.

Protective device coordination studies assure that different protective devices are coordinated in such a way to assure the best trade-off between high speed protection, reliable operation, and selectivity of the protective relays. In order to provide optimum protection, each protective device needs to be coordinated

with other protective devices to assure that the maximum safety, reliability, and selectivity is achieved. In this way, a minimum number of end customers will be affected by problems in the electrical power systems, and safety will be maximized.

The fundamental protective device used on the distribution system is non-directional overcurrent protection. Overcurrent protection at the substation and DR are typically devices that sense a proportion of the current flowing through the circuit and typically will trip a breaker. These devices will sense phase current as well as a derived or actually measured ground current. Fuses are single-phase protective devices that will open a phase of the circuit when the current exceeds clearing characteristics. Some Area EPS operators use fuse-saving schemes where an upstream automatic restoration device will attempt to trip and clear temporary faults before the fuse melts. If not done properly, fuse saving schemes may lead to damaged fuses and the fuse blowing on load later.

The protective overcurrent settings and fuse application needs to take into account maximum and minimum short-circuit levels, full load, nominal load, low load, equipment short-circuit capabilities, system configuration, dc offsets during faults, decay time of fault, automatic restoration schemes, large motors connected, and generation connected.

Overcurrent protective devices, including circuit breakers, are typically connected on the distribution system at the substation while fuses, sectionalizers, and reclosers are typically located along the distribution lines and at the customer feeds. Many types of DR will have overcurrent protection as part of the DR protection package. Voltage restrained overcurrent protection can be an alternative for detecting faults remote to the DR. This can be the case for DR with changing short-circuit contribution because of multiple generator sets, or DR with low short-circuit current such as inverter-based DR.

The objective of setting overcurrent protection is to determine settings that will clear the fault as quickly as possible while limiting the portion of the circuit that is de-energized to affect as few end customers as possible while avoiding false trips.

The use of time-current curves is the traditional methodology of determining the coordination among the protective devices. All protected equipment has a time-current damage characteristic, and each protective device has a time-current characteristic that will determine the time it takes to clear at a given current. By coordinating the different overcurrent protective devices at different levels of anticipated short-circuit currents, a well-designed overcurrent protection system can reliably protect lines and equipment in an electrical distribution system while minimizing the extent of outages.

Each of the overcurrent devices needs to be applied and set such that faults at customer loads are cleared by the customer protection or fuses on the Area EPS line feeding the customer. Normally, faults along the Area EPS feeder should be cleared by the closest upstream device. However, DR also may provide fault current in addition to that from the Area EPS and in some situations may cause the downstream protective device between the fault and the DR to trip due to the DR fault contribution. So, both upstream and downstream protective devices next to the fault may be tripped due to the presence of the DR. This can cause confusion for the system operator and may delay the restoration effort. So, the potential DR fault current needs to be taken into account when considering the protection impact of the DR on existing overcurrent protection. It may be necessary to use directional overcurrent or distance elements to avoid having a device trip for upstream faults. Directional fault indicators may also be helpful.

Excessive unbalance in phase currents can result in inadvertent operation of substation and distribution circuit ground fault protective equipment. Directional fault sensing can be confused when the positive sequence current flow is different than the negative and zero sequence current as could occur depending on the transformer configuration of the DR.

Ground fault protection can be set to detect a lower level of fault current than that of phase protection since normal operating ground current flow on four-wire circuits should be much lower than load current. On three-wire circuits, there are no normal ground current flows and the ground relay can be set very sensitive. For four-wire circuits, the feeder ground overcurrent protective device also needs to be set high enough to

avoid tripping on normal unbalanced load current flow through the device. Tripping of single-phase laterals may provide the highest levels of unbalanced current flow through upstream devices.

Sensitive DR ground fault settings may quickly remove the DR from the circuit, and thereby return the circuit to its pre-DR configuration. The protection coordination of the circuit without the presence of the DR should also be considered.

An important outcome of the protective device coordination study is to determine the appropriate protective device sensitivity. The sensitivity levels will need to be closely examined once the effects of the DR are incorporated. Typically, the minimum fault current contribution from the Area EPS decreases with increased DR, which reflects a loss of sensitivity. A properly applied protection scheme may allow a device to sense the lowest level fault while not false-tripping under non-fault situations. The application and setting of the protective devices are often a trade-off between setting to maximum sensitivity with a probability of some false trips or maximum reliability which will avoid false trips but may result in some faults not being cleared in a timely fashion.

Each type of fault has its own characteristics, and different types of DR technologies affect these characteristics. Bolted three-phase faults have high levels of fault current, which is limited only by the source impedances, and need to be cleared quickly to minimize the damage. Line-to-line and line-to-line-to-ground faults will generally have lower energy but need to be cleared quickly since the amount of energy is still substantial.

Line-to-ground faults are based on the positive, negative, and zero sequence impedance values. The DR grounding configuration, as well as the DR interface transformer winding and grounding configurations, will influence the ground fault detection sensitivity of existing ground fault relays. An interface transformer may be a source of zero sequence current, which will serve to reduce Area EPS sensitivity to line-to-ground faults. An interface transformer may also pass zero sequence current flow supplied by the DR, also resulting in reduced Area EPS sensitivity to line-to-ground faults. Neutral grounding impedances of either the DR or the DR interface transformer need to be considered to properly evaluate the impact on Area EPS line-to-ground fault contributions.

The relative amount of fault current provided to a fault is also characterized by the DR technology implemented. The fault levels contributed by synchronous generators can sometimes reach eight times to 10 times full load current for bolted three-phase faults. Induction generators can sometimes provide initial fault levels up to six times full load current, but the fault level will typically decay within a few cycles. Inverters typically provide fault levels slightly greater than their full load rating. Inverter fault levels can be maintained or can decay quickly depending on the inverter's controls and the energy source behind the inverter.

Some electrical power systems are grounded with solid grounds at the neutral of a transformer, generator, inverter, or other ground deriving device. In some cases, the ground is created through an impedance such as a grounding resistor or grounding reactor. These impedances have the effect of limiting the ground current. Some industrial systems utilize ungrounded delta connections with ground fault detection schemes.

Ground fault protective devices are typically set to detect the lowest level of ground fault current flow. When multiple grounding sources are on a circuit, or when DR creates an additional grounding source, the ground current flow at the point of grounding may, under some conditions, be lower than anticipated since the multiple grounding sources will be in parallel with each other feeding the grounding impedance. These devices, however, need to be set high enough in order to avoid a false trip due to ground current flows due to normal operation such as that due to normal neutral current flow through the ground and third harmonic current flow. Some protective devices are sensitive to third harmonic and other harmonic current flow which may cause them to false trip if these harmonics are not taken into consideration.

Bolted faults are the easiest to detect; however, high impedance and arcing faults can be difficult to detect. The contribution to faults from a DR can reduce the contribution through the Area EPS devices and may aggravate the situation. Arcing faults may be intermittent and have high current for several cycles followed

by low or no current flow. Arcing faults can occur due to downed conductors or some types of cable damage. If the system is a floating delta system, the arcing may create a transient overvoltage situation where the voltage-to-ground may reach many times rated phase-to-ground voltage until flashover occurs. Arcing faults are difficult to protect against. Ground fault protection provides some level of protection. But in many cases, the fault is not cleared until enough damage is done for the arcing fault to clear itself, escalate into a solid fault, or the Area EPS operator shuts down the circuit due to notice from a member of the public. Some types of relays are designed to sense when a conductor is down and provide appropriate protection.

DR often aggravates the issue of detecting arcing ground faults. Since an arcing ground fault and many other ground faults are high impedance faults, the current contribution of the DR in some cases decreases the current contribution from the substation. This means that the substation protective devices may need to be more sensitive with DR connected than if no DR were connected.

The addition of a DR may increase the chances of the Area EPS not being able to detect certain faults. In such cases, the Area EPS protection may need to be reconfigured to regain some of its sensitivity. Alternatively, by setting the DR protection very sensitive with a long time delay to detect and eventually trip for these faults, staggered tripping could be achieved when the DR disconnects and an increase in the fault current is then detected by the Area EPS allowing the Area EPS to eventually clear the fault as well. When setting the protection of the DR this low, it may pick up for adjacent feeder faults and, therefore, the time delay should be set sufficient to allow the adjacent feeder to clear first.

8.3.3 Study ID C2.3—Automatic restoration coordination

8.3.3.1 Technical basis for the study

Most Area EPS operators use automatic restoration as part of their distribution system fault restoration schemes. Faults on overhead circuits are often temporary in nature, therefore Area EPS operators have found that reclosing often restores service without further action.

Historically, radial distribution systems have only one source upstream of the automatic restoration device, and Area EPS automatic restoration devices are set up to automatically reclose after a preset time interval. The reclosing time delay may vary between 15 cycles to 30 seconds depending on the Area EPS practice. With the presence of a DR on the distribution feeder, there is a possibility that the feeder breaker recloser may close in on the DR out of phase and cause severe damage to the DR and transient overvoltage on the feeder. Hence, the feeder recloser operation needs to be checked so the breaker will not reclose while the DR is still energized and tied with the feeder at the time of reclose.

8.3.3.2 Study methodology

An automatic restoration coordination study looks at the DR impact on the Area EPS sectionalizing and automatic restoration scheme. Once the protective devices protect the system and separate the different portions of the electrical system, the automatic restoration devices may start to put the electrical system back together. Automatic restoration coordination becomes extra critical with distributed resources.

Reclosers typically use overcurrent protection to open the circuit and may automatically close back on the circuit either instantaneously or with a set time delay. In IEEE Std 1547™, it states the DR shall cease to energize the Area EPS circuit to which it is connected prior to reclosure by the Area EPS. Because the frequency and phase angle of the DR may differ from the EPS when the two are separated, the recloser should not reclose unless the DR is disconnected from the EPS or is within the allowable voltage and phase tolerance from the EPS on each phase. The disconnection may be by fault detection or by the DR anti-islanding protection scheme.

All of the factors below need to be taken into account when performing an automatic restoration coordination study, which should be done as a companion study to any short-circuit and protective coordination studies. The issue of automatic restoration could be very serious or not very serious at all, depending on these factors:

- Area EPS reclosing times, if applicable. Some underground feeders do not have reclosing.
- The nature of the DR generator (size and type).
- Maximum and minimum kW and kVAr load levels on the line section beyond the automatic restoration device(s) in question.
- Possible reclose blocking capabilities of the automatic restoration device(s) in question.
- Nature of the interconnection protection equipment and its ability to clear the DR generator offline prior to upstream device reclosure.
- Large motor loads on the line section up to the automatic restoration device.
- Likelihood of the DR to stay on-line longer than the reclosing interval.

8.3.4 Study ID C2.4—Area EPS power system grounding

8.3.4.1 Technical basis for the study

Incompatible grounding systems may cause overvoltages and floating neutrals when the feeder breaker is opened. The study should confirm the DR will not cause phase overvoltages if the feeder is disconnected from the rest of the distribution system and the DR circuit is isolated from the ground reference. During single-phase faults, unfaulted phases will experience overvoltages for the duration of the fault due to a shift in the neutral point of the line-to-ground voltage vectors. The degree of overvoltage depends on the effectiveness of the overall grounding system. If the DR interconnection is not equally effectively grounded, the overvoltages on unfaulted phases can increase substantially when the DR is isolated with the circuit during a line-to-ground fault.

8.3.4.2 Study methodology

A grounding study looks at the impacts of DR on the integrity of the Area EPS grounding scheme. The study should consider the Area EPS configuration (i.e., delta, grounded-wye, etc.), DR interconnection configuration and equipment, and existing and proposed ground fault protection equipment. At a minimum, the study should evaluate temporary overvoltages on the unfaulted phases when the DR backfeeds a ground fault on the Area EPS. It should also consider the DR contribution to ground fault currents, and the possible miscoordination with overcurrent protection devices on the Area EPS. If the study recommends neutral grounding impedance or grounding transformers, the voltage and thermal ratings of such equipment should be specified [B11].

8.3.5 Study ID C2.5—Synchronization

8.3.5.1 Technical basis for the study

The DR needs to be running within its phase, frequency, and voltage tolerances with the grid at the moment of the breaker closing to avoid voltage and current transients which may cause severe generator damage and damage to adjacent customers' equipment.

8.3.5.2 Study methodology

The synchronization study will check the relay and/or inverter control settings to assure that generation cannot connect to the electric power system out of phase tolerance, out of voltage tolerance, or out of frequency tolerance.

8.3.6 Study ID C2.6—Unintentional islanding

8.3.6.1 Technical basis for the study

The voltage and frequency on an unintentional island are not controlled by the Area EPS and may be well outside the allowable limits.

8.3.6.2 Study methodology

An unintentional islanding study looks at the potential for single or aggregate DR and load to form islands when connection to the Area EPS is interrupted. The study should analyze the potential to island under varying expected Area EPS topologies and loading conditions and should include the effects of existing and planned load shedding schemes and DR ride-through capabilities. The study should also consider DR voltage, frequency, power, and reactive power control modes and capabilities.

8.3.7 Study ID C2.7—Arc flash hazard study

8.3.7.1 Technical basis for the study

Changes to the National Electrical Safety Code®^{8,9} have focused attention on the dangers of arc flash hazards when persons are working near energized electrical equipment. These changes have prompted Area EPS operators to initiate projects to calculate incident arc flash energy on circuits to determine potential exposure. The addition of DR may increase the fault duty and the associated arc flash hazards; therefore, an arc flash hazard evaluation may be needed as part of the overall interconnection review.

8.3.7.2 Study methodology

Arc flash hazard studies are an extension of the short-circuit analysis described earlier in this clause. System and DR information required for short-circuit and protective device analyses are also required for these studies.

Arc flash hazard studies determine the amount of incident energy available at the work location, the minimum personal protective equipment (PPE), and the alterations to existing protection schemes and work practices to meet the maximum fault energy limitations.

The arc flash hazard is proportional to the voltage, current, and duration of the arcing event. The incident energy is calculated from the fault current, arc duration time, and the work distance and is expressed in either cal/cm² or Joules/cm². The fault contribution is a summation of fault currents from all sources. Each source of fault current has a clearing time associated with its protective equipment that determines the

⁸ National Electrical Safety Code and NESC are both registered trademarks and service marks of The Institute of Electrical and Electronics Engineers, Inc.

⁹ The NESC is available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, NJ 08854, USA (<http://standards.ieee.org/>).

duration of the arcing event. The calculated incident energy value is then used to determine the PPE to provide adequate protection and to determine the arc flash boundary distances.

The addition of DR may increase the arc flash magnitudes. The magnitude will largely depend on characteristics and settings of the protective devices clearing the fault. Possibly, multiple scenarios should be analyzed for the worst case incident energy at each location. The arc flash calculations may reveal that the present level of PPE is exceeded by the additional fault energy provided by the DR. If the incident energy increases due to DR installation, a higher level of PPE may be used to reduce the impact of increased arc flashover. However, individual Area EPS operator work practices may not permit the DR to exceed present arc flash levels or may not allow an increase to the level of PPE that may cause restrictive work methods. Too much PPE may cause heat stress, poor visibility, and restrict body movement. In these cases, if changes to the protection schemes are not sufficient to mitigate the arc flash energy, and if the risk is too great to allow safe working conditions, the DR may not be allowed to interconnect or may be required to disconnect from the grid while work is performed on energized equipment. In some cases, fault current limiters may be a potential solution.

Arc flash hazard studies calculate the highest energy level at the work location. The worst case arc flash energy values are usually near the substation. This is due to the high source fault current and the long clearing time of the breakers. However, the energy feeding the arc is a function of fault current and duration, so the slower clearing faults at locations remote from the substation can deliver more energy even with a lower current. Also, as DR penetration increases, calculations should be done at various locations on the circuit to determine the worst case scenario. It is recommended that sub-transient impedances of the synchronous DRs be used in arc flash calculations. Fault contributions from induction and inverter-based generation should be included in the calculations given that both contribute fault current to the location.

8.4 Study ID C3—Operational characteristics—loading, load shedding, etc.

8.4.1 Technical basis for the studies

Unless an adequate capacity allowance is maintained on the circuit that supplies DR, circuit capacity limits may be exceeded if the DR is not operated under high load conditions. Calculation of the capacity allowance for DR on the circuit may need to be based on an estimate of the power injected by DR without interval monitoring. Underfrequency load shedding relaying should be coordinated such that on dropping frequency, load is shed before generation is shed; on overfrequency, generation is shed first. The coordination would be to not compound a bad situation (i.e., falling frequency) by shedding generation before, or at the same time as, load. There may be a need to alter the location or operation of existing load shed schemes so that feeders with large DR or high penetration of DR are not connected to the load shedding schemes.

8.4.2 Study methodology

The operational procedures and policies for the Area EPS should be reviewed with the introduction of DR and as additional DR is installed. Where the overall penetration of DR is low compared to the load on the Area EPS, loss of generation would not be expected to cause adverse effects to the circuit loading. As the effects of the increased penetration of DR in the Area EPS become more pronounced, special studies should be considered to analyze the impacts of normal and dynamic operation.

The operational procedures and policies may need to be reviewed for the impact of variation in DR output that is typical of some types of DR. Equipment may need to be reset or replaced if the control algorithms are not capable of reacting properly to the DR impacts. Equipment inspection policies may need to be reviewed since some types of DR may cause increased operation of the voltage regulating devices.

When circuits in the Area EPS are subjected to load shedding, the DR anti-islanding protection would be expected to operate correctly, as in any other islanding event. Load shedding schemes may need to be revised to account for the circuit generation available to support the system. Schemes that use static peak load values for circuits may not provide the expected load reductions if the DR is not properly included in the database. If there is a high penetration of DR in the Area EPS, anti-islanding protection may cause excessive sensitivity to voltage dips or frequency fluctuations. Special studies should be considered to analyze the impacts of a large scale separation of DR from the Area EPS, which could possibly cause a system stability problem.

Areas with large penetrations of solar and wind DR are subject to generation production changes due to the changing magnitude of the solar or wind resource. These production changes can be large, and special studies should be considered to analyze the impacts of large scale reductions and increases.

In cases when automatic restoration can transfer a DR to another feeder, the impact study needs also to be done on that feeder. If the study determines that the DR cannot be transferred, the automatic restoration scheme needs to be modified accordingly. Furthermore, if automatic restoration devices can transfer load from neighboring feeders to the DR feeder, the impact study also needs to consider these loads. This is especially important for the criteria of minimum fault coverage in the protection study.

9. Special system impact studies

9.1 Introduction

There is no definite division line between conventional and special system impact studies. Different EPS may have different guidelines on this matter. In most cases, special studies will not be necessary. However, a need could arise to perform special studies even after the DR has been interconnected. For example, technical issues experienced after the DR interconnection, customer complaints, or a new DR application on the feeder might trigger some of these special studies.

Table 4 shows the different special system impact studies and their relationship to potential system impacts on the Area EPS, along with a study ID for reference and a clause number reference.

Table 4—Type of study vs potential impact on the EPS

Impact Study type	Study ID	Clause	Un-intentional islanding	Area EPS equipment duty and operating ratings	Protection design, coordination and fault rating	Voltage regulation and reactive power management	Power quality
Quasi-static simulation	S1	9.4	X	X	X	X	
Dynamic simulation	S2	9.5	X		X	X	
Dynamic stability	S2.1	9.5.1	X		X	X	
System stability	S2.2	9.5.2	X		X	X	
Stability analysis interpretation	S2.3	9.5.3	X		X	X	
Voltage and frequency ride-through	S2.4	9.5.4		X	X	X	
Electromagnetic transient simulation	S3	9.6			X		X
Ferroresonance	S3.1	9.6.1			X		
Interaction of different types of DR	S3.2	9.6.2	X	X	X	X	X
Temporary overvoltage	S3.3	9.6.3		X	X	X	X
System grounding	S3.4	9.6.3		X	X		X
DC injection	S3.5	9.6.4					X
Harmonics and flicker	S4	9.7		X			X
Harmonic analysis	S4.1	9.7.1		X			X
Harmonic problems	S4.2	9.7.2		X			X
Harmonic resonance	S4.3	9.7.3		X			X
Flicker	S4.4	9.7.4					X

9.2 Technical basis for the studies

9.2.1 Under special conditions

Special studies may need to be conducted for the following conditions: when conventional impact studies performed yield marginal results, when impacts may be anticipated under conditions that are not conventionally studied, or where special conditions have been observed in the Area EPS near the DR location that may cause improper operating conditions. These impacts could be power quality problems, such as harmonic resonance; voltage flicker or temporary overvoltage; control operation, such as interaction of multiple DR or interaction between DR and Area EPS equipment; or excessive operations of mechanical equipment.

9.2.2 Load levels

Special studies may need to be conducted when an adverse impact is anticipated for the DR under various load levels or conditions on the Area EPS. Traditional Area EPS studies of the Area EPS have tended to focus on peak load conditions because radial distribution overloads and voltage deficiencies generally occur under these conditions rather than under off-peak conditions. Some Area EPS have also required study at minimum load to determine if overvoltages occur. The injection of power into the Area EPS by DR may cause overvoltages to the Area EPS under reduced load conditions where the injected real and/or reactive power flow exceeds the Area EPS power flow at some point on the circuit. Since some types of

DR will not operate under certain conditions, such as PV after dark, identifying the actual load conditions that could lead to overvoltages on the Area EPS may require a large number of conventional power flow studies, which may become impractical. In these cases, a quasi-static simulation tool may be used to identify load and injected power levels that cause problems on the Area EPS.

Many Area EPS operators have not modeled distribution secondary transformers and secondary cable in their conventional model. The size of the transformer and the cables to the customer meter are typically sized for the anticipated Local EPS load and the distance from the transformer to the PCC. When reverse power flow occurs in this section of the Area EPS, special studies may be considered to confirm that the voltage remains in the proper range under all load levels. Where several Local EPSs share the transformer and/or the secondary main, overvoltage conditions may exist for both the DR owner as well as nearby customers. A quasi-static simulation tool may identify adverse conditions caused by DR at the service voltage level if the transformer and secondary can be properly modeled.

9.2.3 Multiple DR or control algorithms

Special studies may need to be conducted when an adverse impact is anticipated between multiple DR or between DR and Area EPS control algorithms on the Area EPS. When adverse impacts are anticipated between the DR and locally controlled equipment in the Area EPS or between operations of multiple DR on the Area EPS, a special study may be prepared to analyze the interactions. For these studies, typical conditions, such as cloud shear for PV, may be studied over a minute-to-minute basis to model the interaction between the control algorithms of the various DR and Area EPS equipment. These devices can include voltage regulators, field capacitor banks, transformer load tap changers, and bus capacitors. Area EPS operators use a wide variety of control techniques for their field equipment, including several types of local control and various centralized control algorithms using telecommunication devices to convey system information and control responses. Control algorithms for DR, including techniques for mitigating voltage fluctuations that may be caused by variable power output, may need to be adjusted for specific conditions in the Area EPS. Multiple DR connected near each other in the Area EPS may lead to adverse impacts because of their control interactions.

Where Area EPS operators make use of automated transfer schemes to reconfigure the Area EPS, special studies may be used to analyze the interaction between these schemes and the DR affected by the transfers. These schemes are often initiated by a fault and are used to isolate the faulted segment of the circuit so that the rest of the circuit can be restored. The control algorithm may initiate a transfer assuming DR within the scheme is operating when it would have disconnected from the Area EPS because of the fault. This could lead to an overloaded circuit until the DR reestablishes connection with the Area EPS. When DR located within the scheme is significantly large, the Area EPS operator may enhance the control algorithm to account for the temporary loss of the DR. The DR output may be telemetered to the Area EPS operator, or an assumed output could be calculated for the DR where the actual output is unavailable.

9.2.4 DR operations

Special studies may need to be conducted when the DR operations may impact EPS resilience to bulk EPS emergencies. Large DR or large aggregations of DR may change the outcome of EPS angle, voltage, and frequency instability situations. The behavior of the DR in response to swings in voltage, frequency, and angle in the EPS depends on the setup of DR protection and controls. These parameters can be optimized based on the analyses of the EPS emergency situations with integration of the interconnected DR. For example, if in an under-frequency situation some generation is lost due to disconnection of DR, the frequency may further drop, which may lead to a significantly more severe development of the contingency. Studies of such situations may assist in determining the recommended setups of the DR protection and control to provide secure ride-through behavior of DR.

9.3 Study methodologies

Considering the potential issues that can be studied under a special study category, four study types and tools are presented below:

- S1: Quasi-static simulation
- S2: Dynamic studies
- S3: Electromagnetic transient simulation
- S4: Harmonics and flicker studies

Before discussing these four methodologies, general background on models is given.

9.3.1 Adequacy of Area EPS and DR models

For the production of high fidelity and faithful results from any system study involving DR, use of accurate models of DR and Area EPS is of paramount importance and can be considered as the foundation of the study. Use of an accurate model for both DR and the Area EPS is quite challenging, especially in a situation when validated models are not available for fast and continuously evolving DR technologies. Moreover, different models are used to perform different kinds of studies, and each of these studies focuses on different issues of interest which use a particular type of model to represent the Area EPS and the DR.

At present, models of some DR technologies are available in the literature to a limited scale. Many of these models are not validated and hence, remain questionable. In addition, many models of DR are not the models of individual units but rather an aggregated version. These aggregated models do not show the interaction between different DR units. The models also suffer from some inaccuracy, especially in the case of large PV or wind plants, because solar irradiance and wind velocity vary over geographic dispersions of the plants. However, for studying the impact of large DR technologies, the use of aggregated models is unavoidable in some cases. In such cases, accuracy of aggregated models could be improved through further research. In the course of time, the situation is expected to improve. Adequate and validated models would be developed to perform these studies.

Among various studies used for understanding the impact of DR, power flow study is the simplest, and the information needed to model DR installation and Area EPS in a power flow study is mostly contained in the basic equipment rating. However, dynamic and transient study models are not easily available for each type of DR technology. For example, dynamic stability models (generic) for synchronous machine-based generators of various types of DR installations are typically available in the libraries provided with leading power-system-analysis programs. These usually include a selection of dynamic models for synchronous machine generators, which can be combined with a variety of models for exciters and prime mover systems. Using these models, there is usually no difficulty representing this traditional type of DR in a dynamic stability study. However, models for proprietary equipment, especially related to the exciter or governor system, may not be available. In that case, a generic model would be a good approximation to go ahead with the impact study. Similarly, for dynamic stability models for inverter-based DR, there is a rapidly growing class of DR that is electronically coupled to the ac bus by means of various types of power frequency converters or inverters. At present, this class of DR includes practically every type of generation based on renewable or alternative energy sources where the electricity produced at the source is either dc or variable frequency ac. Generic dynamic stability models representing the behavior of certain types of inverter-based DR are usually included in analysis program libraries. However, accurate models of specific commercial inverter-based DR equipment are often viewed as proprietary property and are not yet as freely available as those for synchronous machine-based generators. This may be expected to change as dynamic stability studies involving new DR installations become more common.

The detailed behavior characteristics of inverter-based DR are determined by the design of their respective control systems; but, in general, the ac output control can be dramatically faster than in the case of a

synchronous machine-based generator. They have the capability to control output current, power, or voltage virtually instantaneously as they are not subject to the field-exciter response time and slow rotational dynamics of machine-based generators. For purposes of dynamic stability analysis, the dynamic response of inverter-based DR is usually so fast that it can be assumed to be instantaneous, and the equipment can be modeled as an ideal, current-limited, variable-power source. The value of the associated output power at each time step may be obtained from a separate model of the power source. For example, in the case of a solar PV power source, the modeled DR power level may be derived directly from a time-varying irradiance input.

Although the dynamic response time may be neglected in formulating the dynamic stability model of an inverter-based DR installation, it is important that the built-in protective features and various modes of operation of the DR installation should be properly represented. Depending on the operating modes selected, the equipment may allow externally supplied commands to change the power factor, maximum power, reactive power, or other operational parameters. Similarly, the model should allow the appropriate mode selection inputs and should provide operational parameter inputs that can be changed from one time step to the next. Typical protective features that should be modeled include the limiting of output current and automatic disconnection from the power system when the local bus voltage is outside specified tolerance limits, or when a remote trip input (originating from protective relaying) is active.

Dynamic stability analysis was rarely applied to the analysis of distribution systems in the past, possibly due to the fact that most synchronous machine generators connected to distribution feeders are typically too small to cause power oscillation or instability in the grid. However, the prospect of increasing DR penetration into the grid with considerable aggregate rating has made dynamic stability studies more relevant for distribution systems, and they are now being mandated, in some cases, for large DR installations. For example, large solar plants could lose their generation within a few seconds due to the cloud cover. This might have significant impact on the system stability, which can be understood only through a dynamic analysis. Therefore, these studies are helpful for verifying the behavior of the system and its protective relaying during specified contingency conditions.

For transient study, generic transient models (e.g., differential equations) for the various types of DR (e.g., synchronous machine, inverter-based) can be defined, assuming textbook power circuits and controls with parameters selected to provide reasonable performance. The model equations for the generic system can then be solved in transient system studies to calculate typical waveforms for voltage, current, etc., under specified conditions. Unfortunately, accurate transient models for specific commercial DR equipment often contain sensitive proprietary design information and are not freely available. This is particularly true in the case of inverter-based DR where the transient performance is entirely determined by the design and implementation of the inverter control system. Generic transient models may be useful for research, but they may not be particularly meaningful for use in impact studies. Consequently, transient studies often benefit from the participation of the equipment manufacturer. An equipment manufacturer may be willing to provide executable encoded transient models of their equipment for use in broader system studies without having to reveal the source of the model code. Once verified, such models can be used in transient studies in much the same way as the actual equipment is used in a real system without revealing proprietary design information.

Modeling the Area EPS for all types of studies is less challenging as compared to the modeling of the DR. The Area EPS, which consists of only conventional technology, can be modeled using the existing models from the program library. The Area EPS operator also owns the Area EPS data, which enables model development. However, an Area EPS with newer DR technologies and other advanced system reconfiguration capability might need to address similar challenges discussed above. Network reconfiguration, distribution automation, and smart grid features might bring newer challenges in the future for modeling Area EPS.

The interaction of DR with the Area EPS can become more challenging when the Area EPS is in an abnormal condition, which can be caused by substation outages, storm damage, or high level transmission contingencies. Analysis of abnormal conditions is difficult since the nature of the precipitating event can be highly varied. Typically, the addition of generation in periods of stress on the Area EPS is positive;

however, the uncertainty of the DR reaction to the stress on the Area EPS may lead to a wide range of possible outcomes.

DR connected to the Area EPS where the Area EPS operator has implemented distribution automation schemes to enhance system reliability should be studied in alternative system configurations for proper operation. Similarly, other emergency conditions should be modeled assuming the DR is anticipated to continue operation. For example, in distribution automation schemes that use section loads prior to an outage to develop a switching plan, loss of DR precipitated by the outage may lead to significantly larger section loads than would have been expected based on the loads prior to the outage. Large DR may be monitored and specifically added back in the switching plan. Large numbers of small DR, however, may be estimated from the known total maximum output of the individual units. The maximum output of the small DR may reduce before adding back to the switching plan in accordance with the expected output based on the weather in the area.

9.4 Study ID S1—Quasi-static simulation

Quasi-static simulation refers to a sequence of steady-state power flow conducted at a time step of no less than 1 second but that can use a time step of up to one hour. Discrete controls, such as capacitor switch controllers, transformer tap changers, automatic switches, and relays may change their state from one step to the next. However, there is no numerical integration of differential equations between time steps. A simple quasi-static simulator can be implemented with existing power flow or short-circuit programs under supervisory control. Open-source quasi-static simulators are also available.

One application is to perform energy and loss evaluations over actual profiles of load and generation. Some commercial programs perform this function by simulating the power flow over load duration curves. These studies are useful in determining the economic value of DR.

For variable power sources, such as wind and solar, a quasi-static simulation can reveal voltage fluctuation impacts or changes in Area EPS voltage due to variable DR output that occur before discrete voltage controls can respond. A quasi-static simulation can also show the impact on voltage controls, such as capacitor switches and tap changers. It can also simulate impacts on overcurrent protection. Quasi-static simulation can also address integrated volt/var control and other automation schemes. These modeling features are often only available in programs tailored to distribution systems.

The power flow tool should be capable of simulating the behavior of controllable devices in accordance with the control settings and constraints, such as band centers, time delays, bandwidths, line drop compensation, overrides, number of operations, etc. Quasi-static simulations can show the impact of the voltage fluctuations on system equipment and customers. Separate flicker studies, described below, analyze the effects of voltage fluctuations on customer lighting systems located near the DR.

9.5 Study ID S2—Dynamic simulation

Dynamic simulation refers to analysis intended to model the Area EPS voltage magnitude and frequency response to major events, such as the loss of large generators, the loss of heavily loaded transmission circuits, and faults that are not cleared from the Area EPS for a significant period of time. These simulations would predict, based on protective settings of the relays and breakers in the Area EPS, cascading outages that might follow a major event. The response of the Area EPS to a major event may show the same characteristics at the PCC of DR as a local disturbance that would initiate a trip of anti-islanding protection. Where DR serves a significant percentage of load in Area EPS, a transmission level event that caused a high percentage of DR to disconnect could seriously exacerbate the stability of the system. These effects have been experienced in small Area EPSs, generally on physical islands that are not connected to the mainland Area EPS. The effects that are anticipated include local voltage magnitude dips

and surges, frequency excursions, and current surges that result from changes in system configuration during a serious transmission level event. Under certain circumstances, an event on a distribution circuit could cause a loss of DR on neighboring circuits that would lead to reduced voltages at the distribution substation level.

Dynamic simulation models use an initial system load pattern developed in a standard power flow model; however, where the frequency is assumed to remain unchanged in a power flow, the dynamic characteristics of the system are modeled so that frequency changes caused by faults, separation of heavily loaded paths, and loss of large generators can be evaluated. Differential equations are used to model the changes in generator output from one time step to the next due to rotational dynamics and the action of field exciters and engine governors. Appropriate time steps are used (e.g., 5 ms to 20 ms), and the steady state power flow solution at each time step is based on balanced impedance calculations at the nominal power system frequency. Dynamic models of electromechanical generators are mature and mirror actual performance of the generators under actual conditions. Models of inverter and generator combinations may not have reached that level of maturity.

9.5.1 Study ID S2.1—Dynamic stability

A dynamic stability study looks at the DR impact on the ability of the Area EPS to return to a suitable operating point after a dynamic response to a disturbance. The study should consider the Area EPS configuration, DR interconnection configuration and equipment, and Area EPS protection and coordination schemes, DR characteristics, and expected DR generation levels as well as DR voltage, power, and reactive power control capabilities. The study should also reflect the impact of DR under varying expected topologies and loading conditions.

Dynamic stability studies are appropriate for capturing certain kinds of time-varying conditions in a power system. These variations may be due to the (relatively slow) dynamic characteristics of synchronous machine generators, the operation of protection systems, or other conditional changes in circuit elements or loads as a function of changing power flow, bus voltage, or time.

Dynamic stability analysis is commonly used to study power oscillation in transmission systems but is rarely applied to the analysis of distribution systems that are part of a major grid. This is possibly due to the fact that most synchronous machine generators connected to distribution feeders are typically too small to cause power oscillation or instability in the grid. However, the prospect of increasing DR penetration into the grid, with considerable aggregate rating, has made dynamic stability studies more relevant for distribution systems, and they are now being mandated, in some cases, for large DR installations. These studies are helpful for verifying the behavior of the system and its protective relaying during specified contingency conditions.

Many of the existing electrical distribution systems have quickly changing loads and generation. Quickly changing loads are characteristic of customers' usage of electricity. Quickly changing generation is often due to quickly changing intermittent energy sources, such as wind and solar. Dynamic analysis takes the power flow study one step further by analyzing the effects these quickly changing parts of the electrical distribution system have on each other and the system operations. In particular, quickly changing load and generation can create large voltage swings and changes in power flows that may threaten the integrity of the integrated power distribution system. This may result in excessive operation of some equipment (e.g., tap changers, voltage regulators, capacitor banks, etc.) or may, in the extreme, result in loss of synchronization between different parts of the system.

9.5.2 Study ID S2.2—System stability

DR integration might lead to some stability-related issues, especially if a large DR is connected to a weak system in a high-penetration scenario. Area EPS system planners will need to determine the test cases used

for analysis of the dynamic model without the DR (benchmark case) and with the DR (test case). The benchmark case is used to determine the response of the system to steady state conditions and to disturbances to verify that the system is able to meet the criteria set by the system planner prior to the addition of the DR as well as verify that there are no errors in the benchmark model.

A simulation of the benchmark case without disturbances, if initialized properly, should show no transient or dynamic oscillations. If oscillations are found, a model error in the dynamic data may be out of limits or may not have initialized properly, and the system planner will need to fix the problem prior to any stability analysis of the DR installation.

A simulation of the benchmark case with disturbances should show damping of oscillations and should meet all stability criteria developed by the system planner prior to any stability analysis of the DR installation.

Once a valid benchmark model is obtained for the system, the DR installation may be added to the model and stability analysis performed. Similar to the benchmark case, the DR test case should not develop any system oscillations prior to a disturbance on the system. If oscillations occur, the system planner will need to verify that they have a valid stability model for the DR installation and that initialization of the model is acceptable.

Once a valid DR test model is developed, the system planner will need to investigate transient and/or dynamic responses of the DR to disturbances on the system. The system planner will need to develop the types and duration of specific disturbances. A list of typical disturbances that may be investigated during stability analysis is as follows:

- Motor starting
- Capacitor switching
- Voltage regulator and/or transformer LTC action
- Under-frequency load shedding
- Fault responses
- Fault and reclose
- Fault and clear
- Fault and intentional island of DR

9.5.3 Study ID S2.3—Stability analysis interpretation

After results of the stability analysis are obtained, they will need to be interpreted. Interpretation of the results will include analysis by the system planner to verify that the DR installation meets the stability criteria. If the DR installation does not meet the criteria, the system planner may need to develop solutions that will provide a means for the DR installation to meet the criteria.

System mitigation options for stability concerns may include facility additions, modification of protective equipment, recalibration of capacitor/regulator/LTC controls, or other modifications to the system including remedial action schemes or special protection systems. The system planner may need to determine critical clearing times to clear faults or isolate devices, provide location and size for capacitors/regulators, or provide distribution system modifications.

Options at the DR installation may include changing the DR inertia, adjusting exciter or governor controls, adding voltage compensating devices, or instituting special protective systems including isolation of the DR during fault conditions.

9.5.4 Study ID S2.4—Voltage and frequency ride-through

As DR reaches higher penetration levels, disturbances may lead to a significant number of DR units tripping, with an impact on bulk system reliability. NERC's Task Force on Integrating Variable Generation found that DR at high penetration levels will significantly impact the bulk power system, and high penetration levels need to be included in the planning process [B17]. In particular, this NERC Task Force recommended response to abnormal grid conditions in IEEE Std 1547™ to be reconciled with bulk power system ride-through requirements. There have been additional requests for ride-through capabilities from other organizations.

FERC Order 661-A specifies a 9-cycle, zero-voltage ride-through capability for any possible post-fault recovery voltage. The NERC and WECC proposals add some constraints on the recovery voltage.

Some grid frequency ride-through requirements used or proposed for the U.S. distribution grid versus transmission grid are different from each other. In IEEE Std 1547™, for DR over 30 kW in size, the default set points shall be field adjustable with the DR set point trip value at 0.16 seconds when the frequency exceeds 60.5 Hz. This is different than the WECC and NERC requirements. The other default set point values in IEEE Std 1547™ are also different than the WECC and NERC set points.

In IEEE Std 1547™, for DR equal to or less than 30 kW in size, the default set points and clearing times shall be either fixed or field adjustable. For DR equal to or less than 30 kW in size, the IEEE Std 1547™ default clearing times are different than the WECC and NERC requirements. For a large number of small DR units interconnected on the Area EPS, if they all have the same fixed clearing time, then a relatively large amount of generation could be cleared at the same time in response to a certain abnormal condition. This could result in a destabilizing condition.

Some system operators allow broader ride-through requirements than IEEE Std 1547™. Distribution ride-through capability would be even more important to those operators.

Ride-through analyses need a dynamic or transient program for these studies. Appropriate models are needed. Alternative islanding detection methods could be employed. The Area EPS operator might redesign the feeder to accommodate islanding and ride-through or may encourage the DR owner to provide ride-through capability. These are all possible focus points of a ride-through study.

9.6 Study ID S3—Electromagnetic transient simulation

Electromagnetic transient (EMT) simulation addresses time-varying phenomena up to a frequency range that is practically limited only by the simulation time-step. This type of simulation addresses unbalanced conditions and solves for instantaneous voltage, current, etc. This type of simulation is done with electromagnetic transients programs (EMTPs). EMTPs use the detailed differential equations describing the circuits and the equipment, including any associated controls. These circuit equations are solved by numerical integration, using relatively short time steps (e.g., 1 μ s-50 μ s), with the assistance of circuit-analysis and simulation programs.

An EMT simulation is appropriate when the objective is to investigate instantaneous system behavior in detail. In addition to the steady-state system response in the time-domain, a transient analysis study might also determine the transient voltage and current waveforms that occur during a variety of fault conditions, or following circuit switching related to breaker operation, capacitor switching, or load rejection, etc. For example, the objective could be to ascertain the transient overvoltage that will not reach the threshold for surge arresters to conduct, or the transient current that will not exceed breaker interrupt capability, or adversely affect the operation of protective relays.

A transient analysis of DR might be done to verify control and protection systems of the DR or to verify DR impacts on EPS control and protection systems. Transient simulation may be considered for the

analysis of temporary overvoltages and ferroresonance. Practically all of these studies need a detailed and proprietary DR model, which means the DR vendor may be responsible for supplying the DR-related data. A partial exception might be a ferroresonance study that is dominated by the interconnection transformer model instead of the DR model. The transient analysis can be exempted by evaluating the design studies, statements of assurance, or hardware test results by the vendor.

In practice, the use of transient analysis is often restricted by the lack of accurate detailed transient models, inadequate data for transient models, and by the large amount of computing power needed to solve larger networks. However, transient analysis is an excellent methodology for determining the effect proposed DR might have on power quality. Transient analysis is the best tool for a system where the distribution system is complicated and/or DR operation results in very quickly changing currents and voltages. The results of the transient analysis can result in a full determination of levels of harmonics, voltages, and currents that may result from the proposed DR. This information should be used to determine the appropriateness of existing electrical distribution system equipment and the need for changes in equipment.

The following issues and concerns can be investigated using an EMT type study when an open-conductor condition may occur.

- Open-phase (single-phasing) conditions may occur on the Area EPS due to blown fuses, damaged conductors, connector failure, bad splices, etc.
- Backfeed from the generator can produce excessive overvoltages on the open phase, depending on where the open occurs.
- An open-conductor study looks at the potential for the DR to produce overvoltages or unstable load voltages on the isolated section.

The study should consider the Area EPS configuration, DR interconnection configuration and equipment, and Area EPS protection and coordination schemes. The study should also reflect the impact of DR under varying expected topologies and loading conditions.

The determination of an open-phase fault impact on the electrical distribution system is a specialized study using a time-domain and/or dynamics type analysis.

9.6.1 Study ID S3.1—Ferroresonance

A ferroresonance study looks at the potential for the DR to excite or facilitate the excitation of oscillations between a capacitance and a non-linear inductance such as a saturable iron core transformer. The study should consider the Area EPS configuration, DR interconnection configuration and equipment, and Area EPS protection and coordination schemes. The study should also reflect the impact of DR under varying expected topologies and loading conditions.

The determination of ferroresonance in an electrical distribution system is a specialized study that analyzes the details of equipment implementation. Ferroresonance studies should be considered wherever the electrical system is ungrounded or where it is effectively ungrounded due to high ground impedances.

9.6.2 Study ID S3.2—Interaction of different types of DR

When different types of DR are interconnected to the distribution system, the voltage profile of the system might have some impact due to the operation of neighboring DR. A temporary overvoltage situation in a DR can even trip/disconnect the nearby DR which is located in the close vicinity. In addition, the protection coordination and relay settings might need some readjustments as it was observed that the presence of neighboring DR in some cases reduces the critical fault clearing time of another DR plant [B18]. It has been found that stability of a wind farm is reduced when generating at a higher output level. However, if another wind farm is added in the feeder and they both operate simultaneously, critical fault clearing times

of both wind farms are reduced further. Therefore, the addition of distributed generation complicates protection schemes and associated control equipment to such extent that if not properly handled, lower reliability and even a reduction in power quality can result [B14]. In addition, there might exist a resonance condition due to the presence of distributed shunt capacitance, series reactance, transformer winding capacitance, inverter EMI filter capacitance, and capacitance-to-ground between the neighboring DR. Transient simulation through proper modeling of all the DR and Area EPS in the close vicinity can accurately reflect all these interactions due to the fault or any abnormal operation of the neighboring DR.

9.6.3 Study ID S3.3—Temporary overvoltage

Temporary overvoltages (TOVs) are generally defined as ac overvoltage with a significant duration and amplitude that appear in a system following a switching or fault condition, either resulting from normal system operation or from fault conditions. The most common causes of TOV in a DR connected line could be the faults and their clearing (including reclosing), sudden load rejection, transformer energizing, capacitor switching, momentary reverse power flow, etc. Other special conditions such as ferroresonance, uneven breaker pole operation, and faulty grounding can also cause overvoltage. The duration of the TOVs are in the range of a few cycles to seconds, and the magnitude generally falls in the range of 1.0 p.u. to 1.6 p.u. (but sometimes 2.0 p.u. is used), which depends on system configurations, protection methods, and operating equipment characteristics.

TOV is an abnormal event that is extremely difficult to prevent. However, in the planning and design process it can be studied using transient simulation programs. Possible scenarios could be simulated to estimate the impact of TOV in the ac line caused by various malfunction situations of DR as stated above. Possible TOV mitigation techniques include the following:

- Use an interconnection transformer winding configuration that provides a ground source. However, this can upset ground fault coordination of protective devices and increase the neutral unbalance currents.
- Have the protection system disconnect DR before the Area EPS clears a fault.
- In the case of ferroresonance-producing TOV, three-pole switching and certain transformer types have been less susceptible.

Normally, surge arresters in the Area EPS are the first to fail during high TOV events. However, the TOV limits should not be increased by upsizing surge arresters in the Area EPS because that may leave customer equipment vulnerable to the un-mitigated TOV.

Customer equipment may be more vulnerable to TOV than Area EPS surge arresters. For example, the ITIC (CBEMA-2000) curve¹⁰ indicates that equipment damage may occur when the voltage is above 120% for times ranging from 3 ms to 500 ms, and when the voltage is above 110% for longer periods. An Area EPS that is effectively grounded can meet TOV limits, but ground faults cannot be allowed for any length of time if the Area EPS becomes ungrounded. This means ungrounded DR should trip before the Area EPS device on such systems.

9.6.4 Study ID S3.4—System grounding

The system grounding study is a more in-depth analysis than C2.4. The system grounding study may be needed when the DR interface and control systems produce significant ground fault currents and associated

¹⁰ The ITI (CBEMA) Curve, included within this Application Note, is published by Technical Committee 3 (TC3) of the Information Technology Industry Council (ITI, formerly known as the Computer & Business Equipment Manufacturers Association). It is available at <http://www.itic.org/technical/iticurv.pdf>.

voltages under certain open circuit or short-circuit fault scenarios. An EMT simulation is an example method for analysis of this type of system grounding study.

9.6.5 Study ID S3.5—DC injection

Inverters connected directly, without isolation transformers, to the Area EPS are the main concerns for dc injection to the Area EPS. DC current injections can cause saturation in the transformers and other magnetic elements and can also cause torque ripple in adjacent machine loads [B3]. There is also a potential threat of continuous dc voltage being applied to the grid under internal DR power converter faults. The control and protection of the system has to be designed to cease to energize the inverter from the grid in such conditions. DC current injection limits should be preset and the control should typically cease to energize DR distributed generation from the grid if the limit is exceeded. The dc injection study should be performed to assure that the level of dc injection is below the allowable maximum limits. A transient analysis of the network around PCC can detect the presence of dc currents through the Fourier analysis of instantaneous currents and voltages.

9.7 Study ID S4—Harmonics and flicker

A harmonic study looks at the potential for the DR to supply or contribute to distortion in the Area EPS electrical power wave form. The study should consider the Area EPS configuration, DR interconnection configuration and equipment, and DR characteristics. The study should also reflect the impact of DR under varying expected topologies and loading conditions.

9.7.1 Study ID S4.1—Harmonic analysis

Harmonic analysis should be considered if a DR installation is a possible source of significant harmonic (or other non-fundamental frequency) currents. Additionally, pre-existing voltage harmonics at the point of connection could adversely affect the operation of the DR installation. In either case, corrective action could include the installation of power circuit filters.

Generating equipment used in DR installations is often pre-certified by various authorities as conforming to standard harmonic specifications. In such cases, harmonic studies treating the equipment as a harmonic source may be unnecessary.

If the existing electrical distribution system has harmonic-related power quality issues and/or the proposed equipment is a source of harmonics, a harmonic analysis needs to be considered. Harmonic-related power quality issues may be the effect of ambient power system voltage harmonics on the DR equipment and the effect of residual current harmonics from the DR on the power system. Harmonic analysis takes into account any possible resonance problems that may occur through interaction of the DR equipment and the power system.

In some cases, the data for a harmonic study needs to include field measurements so that an accurate model of the existing system can be made. Several study methodologies can be used to determine harmonic levels. These include frequency domain studies, simulation of harmonic flows, transient analysis, and resonance studies. The data that is required for these studies varies depending on the type of study. The level of data available often determines the type of study that can be performed. The level of data available and the type of study will often determine the level of detail in the results.

The result of the harmonic studies is to determine if a potential power quality threatening level of harmonics may exist. There are several methods for mitigating harmonics. These methods may include filtering, changes in the electrical distribution system (e.g., changing circuits, changing capacitor banks), and/or changes in customer equipment. Changes in customer equipment may include that of proposed and

existing DR as well as existing nonlinear load equipment. The following issues and concerns can be investigated using harmonic analysis.

9.7.2 Study ID S4.2—Harmonic problems

Any DR technology may inject harmonic currents into the EPS within limits established in IEEE Std 519™. In IEEE Std 519™-1992, these limits appear in row one of Table 9-3 for any size DR connected at medium voltage. The developer should provide harmonic injection data within these limits. The first step in evaluation of harmonic problems is to conduct a frequency scan from the point of interconnection. If a series or parallel resonance appears near one of the injection frequencies, then an estimate of voltage distortion may be made based on the DR under study. Total voltage distortion can be estimated with a harmonic power flow program, considering all other DR and harmonic-producing loads on the EPS. As with transient programs, a harmonic power flow program should include unbalanced load and source models.

However, comprehensive data on background sources and loads are usually not available, so harmonic measurements would be recommended. Measurements should include both magnitude and angle of harmonic current injections and the resulting harmonic voltage components. The monitoring period should cover at least one week prior to DR commissioning and one week after. At relatively little expense, the measurements help to calibrate the study model and establish whether DR contributes to harmonic distortion problems. Measurements can be represented with either time-varying profiles or probability distributions. The limits in IEEE Std 519™ are to be exceeded no more than 1 hour in 24 hours, or about 4% of the time.

Some harmonic issues are not yet covered in IEEE Std 519™, including inter-harmonics and possible interference with ripple control frequencies. These problems are less common, but the study engineer should be cognizant of them.

9.7.3 Study ID S4.3—Harmonics resonance

Some DR may cause harmonic distortion problems on an electric power system if resonances in the system align with the harmonic frequencies produced by the DR. If capacitors are located on the distribution feeder as shown in Figure 1, both parallel and series resonant circuits are formed with the system reactances. A resonance occurs whenever the equivalent capacitive reactance equals the equivalent inductive reactance in a current loop.

One harmonic resonance problem of particular interest occurs when a switching inverter is installed in a system that is resonant at frequencies produced by the inverter switching process. The capacitance involved in the resonance can be cable capacitance if the inverter is connected to an underground cable [B2].

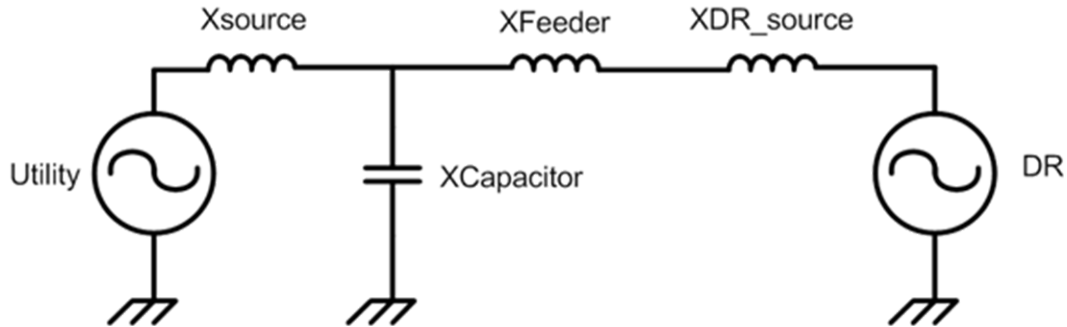


Figure 1—Typical DR installation where harmonic resonance may exist between system reactances and the DR

Some induction generators are designed to be self-exciting using capacitors. While such generators are not generally a significant source of harmonic currents, the added capacitance for excitation could cause harmonic resonance problems if the system resonant frequency is near one of the harmonics that is generated by a harmonic source near the induction machine interconnect. For the example in Figure 2, a parallel resonance path is created with the equivalent source reactance. The resonance occurs at the frequency where the impedances of the capacitor and the system are equal.

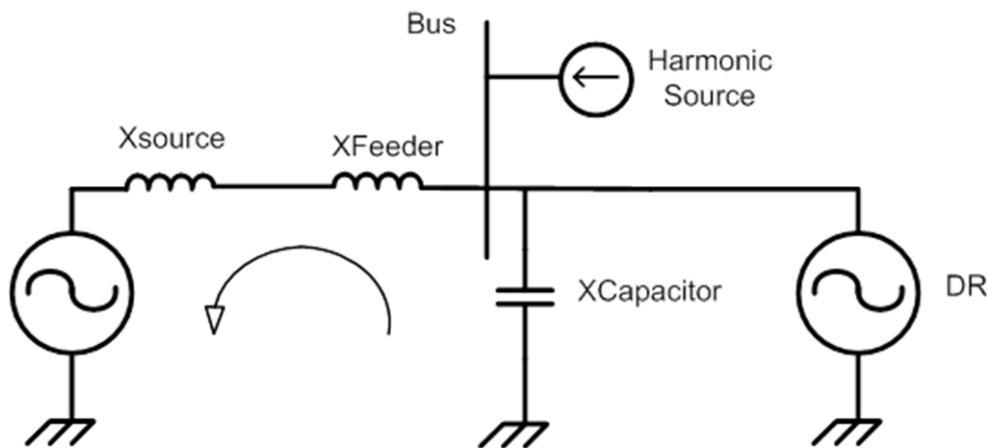


Figure 2—Parallel resonance created by local capacitance

Under this condition, the resonance harmonic, n , is:

$$n = \sqrt{\frac{X_{\text{CAPACITOR}}}{X_{\text{SOURCE}} + X_{\text{FEEDER}}}}$$

Where n is the harmonic number.

For instance, if $n=5$, the frequency is 300 Hz on a 60 Hz system. This is usually an undesirable frequency to have a resonance because it is near one of the most common harmonics that is generated by power system harmonic sources. An amplification of harmonics at that frequency is likely to occur, resulting in noticeable harmonic distortion.

To fully evaluate complex harmonic cases, a harmonics simulation program is often used. The data needed includes the harmonic output characteristics of the DR and DR site. Measurements may also be needed to characterize the problem or determine the solution [B15].

9.7.4 Study ID S4.4—Flicker

A flicker study looks at the potential for DR to produce noticeable changes in output from incandescent lighting caused by voltage fluctuations on the Area EPS. The study should consider the Area EPS configuration, DR interconnection configuration and equipment, and Area EPS protection and coordination schemes. The study should also reflect the impact of DR under varying expected topologies and loading conditions.

Flicker caused by DR could occur on any radial distribution system. The risk of flicker should be evaluated for any type of distribution system. It can be the result of starting a machine (e.g., an induction generator) or of changes in DR output that produce significant voltage change on the feeder. Any type of DR can produce voltage fluctuations on the electric power system. For example, PV power output can drop from 100% to 20% of nameplate in less than one minute, and wind power output of a single turbine can vary between 50% and 100% of nameplate in less than one minute. Conventional generation may also switch on or off at any time, but less frequently. If a generator starts or its output fluctuates frequently enough, flicker of lighting loads may be noticeable to customers. The analysis is more complicated if there are other flicker sources which may have some degree of correlation. It is also possible for DR output variation to influence voltage regulators or switched capacitors on the feeder, and for control system “hunting” to exacerbate the flicker. Flicker studies would focus on the power quality impact of voltage fluctuations for customers near the DR, including the DR itself.

The impacts may be quantified using different metrics:

- Light flicker, P_{st} and P_{lt} coefficients
- Maximum step voltage change in percent for infrequent events
- Increased number of regulator tap change operations in a period
- Increased number of capacitor switching operations in a period
- Comparison to the ITIC (CBEMA-2000) or other equipment curves

Evaluation of the percentage steady state voltage change, between full-on and full-off generation, may be done with basic circuit analyses Equation (2) and Equation (3):

$$V_{drop} = \frac{100}{U_n^2} (R_1 + jX_1)(P_n - jQ_n) \quad (2)$$

$$\frac{dV}{U_n} = \sqrt{(100 + \text{Re}V_{drop})^2 + (\text{Im}V_{drop})^2} - 100 \quad (3)$$

where

R_1 and X_1 are the positive sequence impedances in ohms between the Area EPS equivalent voltage source and the PCC

P_n and Q_n are the real and reactive generation in MW or MVA

U_n is the nominal line-to-line voltage in kV

This provides a quick way of screening for potential flicker problems, and for voltage changes over the 5% limit specified in IEEE Std 1547™. When Q_n is negative, the DR absorbs reactive power and the step voltage change is minimized.

IEEE Std 519™-1992 and IEEE Std 141™-1993 present curves that show acceptable flicker limits for incandescent lights used by a large number of Area EPS operators. The frequency content is extremely important to determine whether flicker levels are observable (or objectionable). The typical frequency

range of observable flicker is from 0.5 Hz to 30.0 Hz, with observable voltage change magnitudes starting at less than 1%. The most sensitive frequency range for flicker is approximately 5 Hz to 10 Hz. In essence, this means that the human eye is more susceptible to voltage fluctuations in the range of 5 Hz to 10 Hz. As the frequency of flicker increases or decreases, the human eye generally becomes more tolerant to luminance fluctuations.

Historically, voltage fluctuations that caused flicker were measured with fast-time-constant rms meters, load duty cycles, and a strip chart or similar recorder. This simple method works only for single frequencies of flicker. IEEE Std 1453™-2004 adopted the flicker evaluation and measurement methods in IEC 61000-3-3, IEC 61000-3-5, IEC 61000-3-7, and IEC 61000-4-15. IEC 61000-4-15, the flicker meter specification, was adopted as a normative annex of IEEE Std 1453™-2004. The IEC flicker meter contains five functional blocks, which can be implemented in hardware for an instrument or in software for processing of simulation results. These blocks are as follows:

- Input voltage scaling interface and calibration circuit
- Demodulator; squares the scaled input voltage, simulating behavior of a lamp
- Two cascaded filters; the first one eliminates the dc offset and second harmonic voltage, and the second one simulates the borderline flicker perception curve for a 60 W incandescent lamp
- Squaring and smoothing filters
- Statistical processing of the output levels to produce a single output, P_{st}

The IEC flicker meter measures voltage fluctuations, weighted as a function of frequency to produce one output value, but it also embeds the characteristics of incandescent lamps. Newer lamp types, and other load types, should probably weigh the voltage fluctuations differently to evaluate the impact. The P_{st} output is defined for a 10 minute period. A long-term flicker severity, P_{lt} , is defined over a two hour period by the cubic geometric mean of 12 consecutive P_{st} samples. This method produces an output for any voltage fluctuation within the previous two hours, albeit weighted for incandescent lamps.

The IEC flicker meter performance test specifies that the P_{st} output should range from 0.95 p.u. to 1.05 p.u. during any of the regular rectangular voltage changes listed in Table 5, for a 60 Hz system.

Table 5—Some voltage fluctuations producing $P_{ST} = 1.0$

Events per minute	% Voltage change
1	3.166
2	2.568
7	1.695
39	1.044
110	0.841
1620	0.547

Each rectangular fluctuation period produces two changes, one up and one down. The magnitude $\Delta V/V$ is the min-to-max variation, divided by the average voltage, such that $\Delta V/V$ of 20% means a variation from -10% to +10% of the average.

IEEE Std 1453™-2004 superseded most of IEEE Std 141™-1993 and the flicker sections of IEEE Std 519™-1992. The main body of IEEE Std 1453™-2004 stated that limitations from IEEE Std 141™-1993 were still useful for infrequent events because the IEC flicker meter works best for periods of 1 hour or less. An informative annex gives the percent voltage dip from IEEE Std 141™-1993 as 2.7% for perception and 6% for irritation, at 1 dip per hour. In IEC terms, these would be equivalent to 5.4% and 12%, respectively, at 0.017 changes per minute.

The main body of IEEE Std 1453™-2004 adopted flicker compatibility limits and planning levels. The compatibility limit is the severity level at which customer complaints are likely to occur. The planning level

is used to set limits on new loads (or DR), which have to be coordinated with fluctuating loads on the system. These levels are shown in Table 6.

Table 6—Acceptable flicker severity levels

Flicker severity level	Compatibility level	Planning—MV	Planning—HV and EHV
P_{st} [10-min]	1.0	0.9	0.8
P_{lt} [120-min]	0.8	0.7	0.6

For DR applied on medium-voltage systems, the applicable planning limits would be $P_{st} = 0.9$ and $P_{lt} = 0.7$. These should be exceeded no more than 1% of the time. Higher flicker levels may be allowed at the discretion of the Area EPS operator.

On low-voltage systems, the compatibility limits may be allowed, $P_{st} = 1.0$ and $P_{lt} = 0.8$. These should be exceeded no more than 5% of the time and should not propagate to other customer loads connected to the Area EPS.

DR units will meet the flicker planning level if the single-frequency power variation from the unit (ΔS) compared with the available short-circuit capacity (SSC) of the Area EPS at the PCC is within the limits described in Table 7.

Table 7—Acceptable voltage changes as a function of $(\Delta S/SSC)_{max}$

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

If the DR power does not vary at a single frequency, then a simple curve or table evaluation does not apply. In particular, vendor test reports provide for a complete flicker evaluation of wind turbines. The applicable standard is IEC 61400-21 on power quality characteristics of grid-connected wind turbines. IEEE Std 1453.1™-2012 provides guidance on applying IEEE Std 1453™-2011.

10. Data requirements

This clause summarizes the DR and Area EPS data requirements to conduct three main types of impact studies: 1) preliminary studies, 2) conventional studies, and 3) special studies.

The data items are partitioned into lists, moving from simpler studies to more complicated studies. The DR data may be collected in the study stages (preliminary, conventional, and special) rather than for each individual study. This presents two opposing forces on the study engineer: first to request all needed DR data at one time, and second to avoid requesting details that will not or cannot be used in the study. Therefore, Clause 9 of this document should be reviewed before attempting to collect DR transient models or other data required by special studies.

Once the DR design is completed, the Area EPS operator could benefit from receiving final design specifications to help perform future impact studies of other DR.

The Area EPS data collection will be more efficient if supporting electronic databases and software tools already exist. This could mean that feeder electrical models are built and maintained for voltage drop and

overcurrent protection studies, a geographical information system (GIS) contains an up-to-date electrical model, feeder and customer load measurements are readily available, etc.

Table 8 provides a list of the various types of data that may be required for a complete study, including:

- Data for preliminary review studies
- Data for conventional studies
 - Data for power flow studies
 - Data for system protection studies
- Data for special studies
 - Data for quasi-static studies
 - Data for dynamic studies
 - Data for EMT simulation
 - Data for harmonics and flicker studies

The data for each of the listed study categories may need to be more detailed for conventional and special studies. The extent of data requirements for a DR preliminary study is also different with those of a DR conventional or special impact study as indicated in the following subclauses. Additionally, Annex B provides example data for impact studies. However, it is not an exhaustive list of data and should not be considered typical data.

Table 8—Overview of typical types of data for different studies

Data types	Preliminary review	Study category					
		Conventional		Special		Harmonics and flicker	
		Steady state simulation	System protection	Quasi-static	Dynamic		Special EMT simulation
One-line diagram of DR facility	✓	✓	✓	✓	✓	✓	
One-line diagram of Area EPS including protection devices	✓	✓	✓	✓	✓	✓	
Three-line diagram of Area EPS including protection devices		✓	✓	✓	✓	✓	
Relay and metering one- and three-line diagrams			✓	✓	✓		
Trip circuit diagrams			✓	✓	✓		
Schematic diagrams of protection, control, and monitoring for DR and Area EPS			✓	✓	✓	✓	
System operation and feeder configurations			✓	✓	✓		
Protective device functions, ratings, settings, and interrupting rating	✓		✓	✓	✓		
Operation characteristics—daily, seasonal, etc. ^a			✓	✓	✓		
Line section maximum and minimum load	✓		✓	✓	✓		
Feeder loads			✓	✓	✓	✓	
On-site load			✓	✓	✓	✓	
Metering capabilities of feeder and substation equipment			✓	✓	✓		
Total maximum generation on each line section	✓		✓	✓	✓		
Type of energy conversion technology	✓		✓	✓	✓	✓	
DR—rotating machine-based generation characteristics	✓		✓	✓	✓	✓	
DR—power electronic-based generation/storage characteristics	✓		✓	✓	✓	✓	
Inverter maximum current output	✓		✓	✓	✓	✓	
Main grid equivalent source			✓	✓	✓	✓	
Short-circuit model of Area EPS	✓		✓	✓	✓	✓	
Transient (electromagnetic transient type) DR model					✓		
Dynamic DR model					✓		
Power quality test report for DER, specifically wind turbines						✓	
Harmonic spectrum data and THD for DR and EPS	✓					✓	
Climate data—irradiance, wind speed, ambient temperature				✓	✓	✓	
Interconnection transformer	✓		✓	✓	✓	✓	
Substation transformers	✓		✓	✓	✓	✓	
Grounding configuration and locations (ground banks)	✓		✓	✓	✓	✓	
Sectionalizing and automatic switches			✓	✓	✓		
Automatic reconfiguration scheme information	✓		✓	✓	✓		
Feeder section (OH/UG)			✓	✓	✓	✓	
Cable and line data			✓	✓	✓	✓	
Voltage regulators and LTC	✓		✓	✓	✓	✓	
Capacitor bank and d-SVC/d-STATCOM	✓		✓	✓	✓	✓	
Surge arresters	✓		✓	✓	✓	✓	

^aNeeded for Study C3—Operational characteristics

10.1 Data requirements and modeling for preliminary review studies

An exchange of preliminary data can be very useful in the early stages of a DR interconnect evaluation. This exchange offers the Area EPS an opportunity to advise the DR applicant of particular interconnection requirements. It may also help the DR applicant choose the most advantageous DR sizes and/or PCC. The listed data will suffice for assessment of circuit ampacity, voltage fluctuation magnitudes, and potentials for reverse power flow or unintended islanding.

For the purpose of preliminary studies, the assumption is that a circuit model of the Area EPS is available or can be easily created. The model does not need to include DR model. In fact, preliminary studies are geared toward utilization of the existing information and knowledge regarding the system characteristics. The following data is needed to build an Area EPS model if it does not exist:

- EPS one-line diagram showing the equivalent source (substation), operating and nominal source voltages, line sections (downstream of equivalent source), and circuit equipment.
- The Area EPS source substation values for the Thevenin equivalent impedance of the source, base power and base voltage of the aforementioned impedance, three-phase and single-phase fault current values at the bus where the Thevenin equivalent impedance is established.
- Line section values for the length, the number of phases and size of each conductor including the neutral conductor, the phase and neutral spacing data (for calculation of the primitive impedance matrix of each line section, the positive and zero sequence impedance and susceptance of each line section).
- Information about major spot loads and load center for distributed loads.

Basic DR data for preliminary studies includes:

- DR type and interface specifications (e.g., nameplate rating)
- Primary energy source (e.g., fuel, prime mover, renewable source)
- Nameplate specifications of the overall DR plant
- Point of common coupling and/or point of DR connection
- DR certification and standard compliance
- General information about DR protection characteristics, grounding, and level of current contribution to fault
- Maximum/minimum of on-site load (station load)

10.1.1 Criteria ID P1—Use of certified DR equipment

Data to assess this criterion includes a certified test report or letter from the DR equipment manufacturer or supplier indicating the proposed DR equipment has been listed by an accredited test laboratory to meet the applicable standard(s) (e.g., UL 1741).

10.1.2 Criteria ID P2—Potential for unintended islands

There are three sub-criteria associated with the P2 criterion as described in 10.1.2.1 through 10.1.2.3.

10.1.2.1 Sub-criteria ID P2.1—DR does not export power to the Area EPS at the PCC

Data to assess this criterion includes the following DR facility drawings:

- EPS one-line diagram showing line section protective device and all DRs interconnected to the line section.
- Relay and metering one-line and three-line diagrams which show either a reverse power relay (32R) or a forward power relay (32F) at the point of common coupling; current and voltage circuits of these relays need to be wired correctly so that they sense power flow in the appropriate direction.
- Trip circuit diagram of the intertie breaker or switch which shows tripping of these devices by the 32R or 32F relay after a time delay deemed to be appropriate by the Area EPS operator.

10.1.2.2 Sub-criteria ID P2.2—DR production relative to served load (penetration is small)

Data to assess this criterion includes:

- Area EPS one-line diagram showing line section protective device and all DRs interconnected to the line section,
- The line section maximum or minimum load for the time period all line section DRs are expected to operate, and
- Total maximum generation capacity of all line section DRs.

10.1.2.3 Sub-criteria ID P2.3—DR interconnection incorporates acceptable anti-islanding protective features

Data to assess this criterion include the Area EPS one-line diagram showing:

- The line section protective device
- All DRs interconnected to the line section
- Area EPS one-line diagram and equivalent representation
- Energy conversion technology type of each DR (e.g., inverter, synchronous generator, or induction generator)
- Each DR type (e.g., single-phase or three-phase)
- DR anti-islanding test certificate and test condition description
- Type and winding configurations (e.g., delta, wye,) of transformer through which each DR is interconnected to the line section, and transformer neutral impedance, if used
- Total maximum generation capacity of all line section DRs

10.1.3 Criteria ID P3—Impacts on EPS equipment loading under all steady state conditions

There are two sub-criteria associated with the P3 criterion as described in 10.1.3.1 and 10.1.3.2.

10.1.3.1 Sub-criteria P3.1—Gross kVA rating of the DR is no greater than the kVA rating of the EPS transformer serving the facility on a per phase basis

Data to assess this criterion include the following:

- The aggregate rated kVA power output of all DR connected to the EPS transformer.

- The rated kVA power capability of the EPS transformer as determined by the EPS transformer owner. This may differ from nameplate rating established by the transformer manufacturer.

10.1.3.2 Sub-criteria ID P3.2—Gross kVA rating of the DR on a particular feeder or substation is no greater than the feeder or substation rating

Data to assess this criterion for a particular feeder include:

- The aggregate rated kVA output capability of all DR connected to the feeder
- The rated kVA power capability of the interconnecting feeder as determined by the Area EPS operator

10.1.4 Criteria ID P4—Impacts on system protection, fault conditions, and arc flash rating

There are four sub-criteria associated with the P4 criterion as described below.

10.1.4.1 Sub-criteria ID P4.1—DR can not cause any protective device or circuit component to exceed 85% to 90% of the short-circuit interrupting capability

Data to assess this criterion include the Area EPS one-line diagram showing:

- A short-circuit model of the Area EPS or data to develop a model
- All protective devices and interrupting rating of each
- All DRs interconnected to each line section
- Proposed location of the new DR facility
- Energy conversion technology type of each DR (e.g., inverter, synchronous generator, or induction generator)
- Each DR type (e.g., single-phase or three-phase)
- Type and winding configurations (e.g., delta, wye) of transformer through which each DR is interconnected to the line section
- For all synchronous machine DR, the direct axis sub-transient reactance value and X/R ratio
- For all induction machine DR, the short-circuit or locked rotor reactance and X/R ratio
- For all inverter-based DR, the maximum fault current output and duration
- For each transformer in each DR (single-phase or three-phase), the following nameplate values: power rating, impedance, X/R ratio, and power and voltage base of impedance

10.1.4.2 Sub-criteria ID P4.2—Aggregate DR on circuit does not contribute more than 10% of the circuit's maximum fault current at the primary voltage point nearest the PCC

Data to assess this sub-criterion is similar to data for criterion P4.1.

10.1.4.3 Sub-criteria ID P4.3—DR will interconnect with an Area EPS having radial topology

Data to assess this criterion is Area EPS one-line diagram showing proposed location of DR facility is served by radial distribution feeders.

10.1.4.4 Sub-criteria ID P4.4—DR will not cause temporary overvoltages during a phase-to-ground fault

This criterion is generally applicable when the primary distribution line serving the DR is of a three-wire configuration, or a four-wire configuration with effectively grounded three-phase interconnection, or a DR's distribution transformer is single-phase connected in a line-to-neutral configuration.

Data to assess this criterion includes:

- Area EPS one-line diagram showing line section protective device and all DRs interconnected to the line section
- Information about substation transformer winding configuration and neutral impedances
- The line section maximum and minimum load for the time period all line section DRs are expected to operate
- Total maximum generation capacity of all line section DRs

10.1.4.5 Sub-criteria ID P4.5—Existing protection schemes are configured to allow for DR connected to the Area EPS

Data to assess this criterion is similar to data for criterion P4.1 with the addition of data related to protective device settings.

10.1.5 Criteria ID P5—Impacts on voltage regulation within the EPS under steady state conditions

10.1.5.1 Sub-criteria ID P5.1—DR PCC is a relatively strong or stiff location within the Area EPS

Data to assess this criterion includes Area EPS one-line showing:

- Existing voltage regulators (including transformer load tap changers) and their settings
- Existing Area EPS capacitor banks (fixed and switched) and control settings of the switched capacitors
- Location of existing and proposed DRs, maximum output capability of each, and settings of the excitation control schemes
- Area EPS peak and valley loads at the substation, feeder electronic reclosers, and large spot loads

10.1.5.2 Sub-criteria ID P5.2—DR would not be anticipated to result in voltage rising above the specified limits in the Area EPS

Data to assess this criterion is similar to that of 10.1.5.1.

10.1.5.3 Sub-criteria ID P5.3—Loss of DR or variation in output of DR would not be anticipated to result in voltage in the Area EPS falling below specified limits

Data to assess this criterion is similar to that of 10.1.5.1.

10.1.5.4 Sub-criteria ID P5.4—Variation in output of DR would not be anticipated to necessitate changes in settings of Area EPS voltage regulating devices

Data to assess this criterion include a three-line diagram that shows the following:

- The single-phase transformer and the following attributes: power rating, impedance, X/R ratio, and nameplate voltage ratings
- All DRs served by the transformer and the following attributes of each: maximum output capability of each and settings of excitation control scheme
- Peak and valley load demands for the transformer for the time period all DRs are expected to be operational

10.1.5.5 Sub-criteria ID P5.5—DR is not expected to result in high voltage on shared secondary

Data to assess this criterion is similar to that of 10.1.5.4.

10.1.6 Criteria ID P6—Impacts on EPS power quality

10.1.6.1 Sub-criteria ID P6.1—DR operation will not cause flicker exceeding limits at the PCC

Frequent voltage variations (flicker) level at the PCC caused by DR should not exceed the limits identified in IEEE Std 1453™.

For evaluation of potential flicker issues during preliminary studies, generally the system equivalent impedance ($R + jX$) at the PCC is used along with information from the DR power quality test report (if available) and the DR size. If a power quality test report is not available and there seems to be potential for flicker issues, detailed routine studies and/or field monitoring (in two stages of pre and post commissioning) can be suggested. For DR under consideration, DR start up real and reactive power information is needed.

10.1.6.2 Sub-criteria ID P6.2—Real and reactive power flow from DR will not cause Area EPS voltage sags and swells

Data to assess this criterion is similar to that of 10.1.5.1.

10.1.6.3 Sub-criteria ID P6.3—DR operation will not cause harmonics at the PCC to exceed allowed limits

Data to assess this criterion is harmonic spectrum data for the DR (based on published DR data sheet) and total harmonic distortion (THD) of voltage for the grid. The intent at this stage is not to perform detailed harmonic analysis, and only to determine if additional study is needed.

10.2 Data requirements for conventional studies

The PCC is an important location to understand data related to the Area EPS and the DR. Typical conventional studies may include: power flow, short-circuit, protection coordination, and unintentional islanding studies.

10.2.1 DR data for conventional studies

The DR interconnect application should include one data submittal sufficient for power flow and short-circuit studies.

10.2.1.1 General DR data

General interface data from the customer includes the following:

- A legible one-line relay and metering diagram showing the configuration of all generating facility equipment, transformers, current and potential circuits, and protection and control schemes. The one-line diagram should be a separate diagram specific to the application and clearly illustrate the following items:
 - PCC to the Area EPS
 - Protective devices and relays need to indicate what they trip
 - Synchronizing or synch check relays or devices need to indicate which voltages are being used for synchronizing
 - Relay nomenclature and type
 - Relay device numbers (see IEEE Std C37.2™)
 - If the protective device is a fuse, provide the type, size, and manufacturer
 - All interrupting devices need to be uniquely identified and verifiable
 - Lockable line sectioning devices
 - Clear indication of where the DR unit will be electrically located
 - Other DR units at this facility and their interconnection
 - DR unit size, type, power factor, voltage, and grounding information
 - Transformer (if customer owned) size, winding configuration, grounding configuration, impedance, and any transformer protection
 - Power factor correction equipment data (kVAr steps, configuration, voltage)
 - Current sensing devices, class, ratio, and configuration
 - Voltage sensing devices, ratio, and configuration
 - Interlocking between tripping devices (if applicable)
 - Metering point

The one-line should not include:

- Test procedures
- Equipment grounding diagrams

- Logic diagrams
 - Riser diagrams
 - PLC code
 - System operating procedures
- Legible three-line ac diagram showing the current and potential circuits for protection and control schemes. This is referred to as an ac key elementary diagram. This diagram should include the following:
- Phase references
 - Relay test block locations
 - CT short-circuit switches
 - VT fuses
 - All CT and VT selection switches
 - CT and VT configuration connections
 - CT and VT ratios
 - Neutral grounding positions on secondary CT and VT circuits
 - Secondary circuit connections to relays and metering equipment
 - Interrupting devices

The ac elementary diagram should not include the following:

- Test procedures
 - Equipment grounding diagrams
 - Logic diagrams
 - Riser diagrams
 - PLC code
 - System operating procedures
- Site documentation that indicates the precise physical location of the proposed generating facility (e.g., USGS topographic map or other diagram or documentation)
- Documentation that describes and details the functions and operation of the protection and control schemes
- Proposed location of protective interface equipment on property (if different from interconnection customer's address)
- Copies of schematic drawings for all protection and control circuits, relay trip circuits, and alarm/monitoring circuits (if applicable). This is also referred to as a dc key elementary diagram.
- The dc elementary diagram needs to include the following:
- Trip circuits for interface breaker or switching devices
 - Close circuits for interface breaker or switching devices
 - Trip coil monitoring devices and breaker fail circuits
 - Loss of dc (fuse fail on trip circuit or relay power supply) and relay fail alarm circuits
 - DC fuses for trip coil, control circuits, etc., if used

- Site system operating procedure (SOP) documentation detailing all the different modes of operation and system configuration. The SOPs need to include the following:
 - All possible system configurations
 - Complete steps for transitioning from one configuration to all other possible configurations
 - References to the one-line diagram interrupting and switching devices
 - Changes to relaying or system control functions and generator control functions for the different configurations
- Relevant study data as detailed in Clause 10

10.2.1.2 C1—DR data for steady state simulation

The following power flow study data should be included with the DR application:

- Screening data, if not already provided:
 - Type of DR—primary energy source and interface (e.g., synchronous machine, induction machine, power electronic converter)
 - DR unit rating (rated voltage, rated power or MVA, rated frequency) and number of units.
 - Minimum and maximum real power limits
 - Minimum and maximum reactive power limits
- Numbers and sizes of power flow controllers such as capacitor banks, d-SVC, d-STATCOM, etc.
- Proposed load, including specific large motor sizes
- Customer existing interconnection type and size
- Maximum export capability requested (kW and kVAr)
- Interconnection transformer data:
 - Single-phase/three-phase
 - Size (kVA) including base rating and additional rating for fan cooling, etc.
 - Transformer impedance (%) on (kVA Base)
 - Primary and secondary voltage ratings (including tap settings)
 - Primary and secondary connection types (e.g., delta, wye, grounded, or ungrounded)
 - Neutral grounding impedance, if applicable
 - Special considerations (e.g., additional windings, cooling, special type, core construction, etc.)
 - Load loss watts values (typically estimated at 5% to 10% of nameplate impedance if load loss watts values are not specified)

10.2.1.3 C2—DR data for system protection studies

In addition to the data above, the following protection study data should be included with the DR application:

- Fault contribution from the DR, excluding transformer, specified by one of the following:

- For synchronous machines, the synchronous, transient, and sub-transient reactances and time constants.
- For induction machines, the equivalent fault reactance, which may be inferred from locked-rotor conditions in the absence of other information.
- For power electronic interfaces, the maximum level and time duration of current output into a terminal fault. More than one time interval may be specified to account for control and protection system operation.
- Length, type, and impedance of overhead line or cable segments connecting any DR units and interconnection transformers with the PCC
- Transformer fuse data (if applicable)
 - Copy of fuse manufacturer's minimum melt and total clearing time-current curves
 - Fuse manufacturer
 - Type
 - Size
 - Characteristic
- Interconnecting circuit breaker (if applicable, for each LV or MV breaker)
 - Manufacturer
 - Type
 - Load rating (amps)
 - Interrupting rating (amps)
 - Maximum fault current rating
 - Clearing time (cycles)
 - Close speed
- Sources of grounding at interface voltage
 - If wye-wye transformers are used, lower voltage grounding configuration data may be needed
- Recloser at the PCC (if applicable)
 - Manufacturer, type, load current rating, fault current rating
 - Trip curve selections for both phase and ground trip
- Interconnection protective relays (if applicable, for each relay)
 - All interface protection settings values
 - Manufacturer
 - Type
 - Style, catalog number
 - Proposed settings
 - Relay accuracy and settings ranges
 - Standards to which device is compliant
- Current transformer data (if applicable, for each transformer)

- Copy of manufacturer's excitation and ratio correction curves
- Manufacturer
- Type
- Accuracy class
- Proposed ratio connection
- Voltage transformer data (if applicable, for each transformer)
 - Manufacturer
 - VA rating
 - Type
 - Accuracy class
 - Proposed ratio connection

10.2.1.4 C3—DR data for operational characteristics studies

Operational characteristics of the DR are needed for this study. This includes (as a minimum):

- A one-line diagram including the location of the interconnection on the Area EPS
- Generation control schemes, if dispatchable, and any seasonal adjustment

10.2.2 Area EPS data for conventional studies

The data to study the interaction between the Area EPS and proposed DR will primarily be found in the power flow and short-circuit models maintained by the Area EPS operator. These models should include proposed and approved DR for proper coordination. Studies using these models should emulate the operating guidelines that have been developed. Revisions to the operating guidelines may be proposed as a result of these studies—to be followed by a careful review of the possible ramifications of the proposed change.

10.2.2.1 Data from the Area EPS operator

Data from the Area EPS operator includes the following:

- Existing and planned future (if known) circuit configurations
- Protection and control schemes applicable to the site
- Self-healing or auto restoration schemes applicable to the site
- Interconnection transformer ground source requirements
- Screening data, if not already provided:
 - Voltage level and number of phases
 - System strength and X/R ratios at the PCC, for both single-phase and three-phase faults, or positive sequence and negative sequence
 - Minimum and maximum load on the connected circuit
 - Minimum and maximum load on the smallest switched segment serving the PCC
 - Numbers and sizes of DR already connected to the circuit
 - Numbers and sizes of DR already on the smallest switched segment serving the PCC

10.2.2.2 C1—Area EPS data for steady state simulation

The Area EPS data to prepare power flow studies for proposed DR units includes:

- Area EPS voltage levels and limits
- Voltage regulator settings
 - Control mode (e.g., locked forward, reverse, co-gen, bidirectional, etc.)
 - Target voltage and bandwidth (at load center or regulator terminal)
 - VT and CT ratios if parameters are in per unit
 - Compensator R and X settings in forward and reverse directions
 - Permissible upper and lower voltage limits for the regulator terminal, as determined by R and X settings (example is protection limits for the device closest to the voltage regulator)
- Switched capacitor bank settings
 - Mode of automatic control (e.g., voltage, current, reactive power, temperature, time of day, manual, etc.)
 - Target voltage and bandwidth, or schedule of manual switching
 - VT and CT ratios if parameters are in per unit
 - Single-phase or three-phase control
 - Neutral grounding
- Area EPS connectivity information including the connection point for the proposed DR
- Positive sequence impedance data for the connected branches and equipment
- Positive sequence impedance equivalent circuit data looking from the pertinent portions of the distribution system to the Area EPS
- Work in progress that affects the connected circuit (anywhere from design to construction) for transmission and distribution
- Circuit demand load, nominal load, and low load conditions, or a load profile, or a load duration curve
- Customer loading on the Area EPS, either individual or aggregated
- Physical limitations (current carrying capacity, customer voltage limits) of the Area EPS system elements
- Predicted increases in area load caused by adding new customers and by increased usage of existing customers
- Existing aggregate generation and DR already on the EPS and predicted increases of DR in the distribution area
- Effects of customer energy usage patterns on daily and seasonal power flows on the Area EPS
- Season-specific operation practices
- Metering capabilities of field and substation equipment
- Utility generation and non-utility generation capacities and schedules
- Automatic restoration schemes or self-healing network configurations

10.2.2.3 C2—Area EPS data for system protection studies

In addition to power flow study data, the Area EPS data to prepare protection studies for proposed DR units includes:

- Negative and zero sequence impedance data for the connected branches and equipment, including the source equivalents
- Negative and zero sequence impedance data on equivalent circuits from alternate feeds
- Existing facility fault contribution
- Physical limitations (duty) of the Area EPS system elements
- Existing relay settings for protective devices in the Area EPS
- Injection points for utility generation, non-utility generation, large customer motors, and other sources of fault current
- Transfer trip or trip blocking capabilities between Area EPS and DR
- Automatic restoration schemes or self-healing network configurations and arc flash energy level requirements

10.2.2.4 C3—Area EPS data for operational characteristics studies

Operational characteristics of the Area EPS with respect to the location of the DR are needed for this study.

At minimum, this includes:

- A one-line diagram including the location of the interconnection on the Area EPS
- Load shedding schemes, as applicable to the Area EPS
- Minimum and maximum load for the Area EPS
- Acceptable voltage ranges for contingency operation
- Seasonally acceptable short-term and long-term thermal limits of the Area EPS

10.3 Data requirements for special studies

Special studies typically include detailed (comprehensive) modeling of DR and Area EPS to investigate impact on power quality (harmonics, flicker), system dynamics, and transients.

10.3.1 DR data required for special impact study: DR data for Study ID S1 quasi-static and Study ID S2 dynamic studies

DR data for quasi-static and dynamic studies should include the best available dynamic model for the DR (including the controls). For synchronous machines, induction generators, or wind turbines, the model may be provided in parameters for an IEEE-sponsored format (e.g., IEEE Std 421.5™, PSDP committee papers). These models are well-established for synchronous machines, including the excitation system, governor system, and mechanical inertia. Similar IEEE-sponsored generic models are under development for wind turbines. These established model structures have been implemented in many commercial software programs for transmission system analysis. Most of these models are positive sequence only and need to be used with a three-phase balanced Area EPS model.

The established models usually do not work with power electronic DR interfaces, nor do they work with a single-phase or unbalanced Area EPS model. In such cases, two possibilities are:

- Use a transient DR model to conduct the dynamic study in an electromagnetic transients program (EMTP type software tools).
- Obtain a “user” model of the DR. This has to be coded, compiled, and linked for the dynamic simulation program to be used in the study. The model developer and user may need matching versions of the dynamic simulation program.

Both of these options benefit from participation and support from the DR technology vendor.

10.3.2 DR data for Study ID S3 EMT simulation studies

There may be circumstances requiring a transient model of the DR and its interface. In the case of conventional synchronous generators, this poses little technical difficulty because the dynamic model can be readily translated for use in an EMTP. Control system block diagrams for the excitation system and governor can also be implemented in any available EMTP type software tools. For this kind of DR, the data for transient and dynamic studies are nearly the same and should include zero sequence and neutral impedance data.

For DR other than synchronous generators, a transient model is much more difficult to obtain. In practice, such models have to be obtained from the DR technology vendor and used with their permission. The model may only be available to use with one program. Other programs may have the technical capability of running the model, but the DR vendor may not be willing to invest the time in converting a model from one program to another.

Generic DR transient models need to be used with great caution because they do not include proprietary control and protection system details, which could be crucial in the transient phenomena under study. With access to all of the design details, a transient model could be developed from scratch. However, special expertise is needed, it usually takes too long for a DR impact study, and data is still needed to verify the model. These are reasons why only vendor-supplied DR transient models should be used for impact studies, except for the case of synchronous generators without a power electronic interface.

10.3.3 DR data for Study ID S4 harmonic and flicker studies

DR data for harmonic and flicker studies include the following:

- Maximum harmonic current injections according to IEEE Std 519™
- For wind turbines, a wind power quality test report according to IEC 61400-21
- Characteristics of perturbing loads at the DR facility

If harmonic studies are performed by Fourier analysis of time-domain waveforms, then a transient model of the DR is needed.

10.3.4 Area EPS data for special impact study

10.3.4.1 Area EPS data for Study ID S1 quasi-static and Study ID S2 dynamics studies

In addition to short-circuit study data, Area EPS data to prepare dynamic studies for proposed DR units includes:

- Dynamic model for existing generators represented in the Area EPS, including existing and approved DR units.

- Modeling characteristics of loads in the Area EPS (e.g., constant power, constant current, constant impedance, or combinations thereof).
- Dynamic models for existing power controllers such as d-SVC, d-STATCOM, UPFC, etc.
- Dynamic model of conventional voltage control devices such as under load tap changer (LTC), line voltage regulator (VR), and switched shunt capacitors. The model should include the control aspects and delays associated with tap changer operation or capacitor switching in/out.

A dynamic model for existing generators or flow controllers may fit a standard IEEE format. It should have been developed and tested for the dynamic simulation program that will be used in the study, including applicable control and protection systems (machine reactances and time constants, mechanical inertia, excitation system, governor system, voltage regulator, real or reactive power flow control, etc.).

10.3.4.2 Area EPS data for Study ID S3 EMT simulation studies

In addition to harmonics and dynamics study data, the following Area EPS data is needed if available (if not, need to estimate) to prepare transient studies of the proposed DR units:

- Physical overhead line and cable data (conductor, insulating material, spacing, layer thicknesses, and soil resistivity data). These may be processed through line and cable parameter calculation routines to derive transient models.
- Transformer data sheet information (MVA rating, voltage levels, impedance and loss test results, saturation characteristics, wye or delta connection, tap settings, grounding impedance, zero-sequence test results). This data may be processed through a specialized parameter calculation routine to derive transient models.
- Transient model of existing power flow controllers (STATCOM, UPFC, etc.). Use a dynamic model if the transient model is not available.
- Detailed model of conventional voltage control devices such as LTC, line VR, and switched shunt capacitors. The model should include the control aspects and delays associated with tap changer operation or capacitor switching in/out.
- Data for transient models of existing DR units. A dynamic model can be used if the transient model is not available.
- Surge arrester data.
- Instrument transformer capacitance—capacitance coupled voltage transformer (CCVT).

For synchronous machines, a dynamic model is convertible to a transient model, but this may not be true of other generator technologies or power electronic devices. An approximate or generic transient model may be acceptable if the device is not a direct subject of study.

10.3.4.3 Area EPS data for Study ID S4 harmonic and flicker studies

In addition to short-circuit study data, Area EPS data to prepare harmonic and flicker studies for proposed DR units includes:

- Cable and line charging values, both positive and zero sequence.
- Power factor correction capacitor values, configuration, and location in the circuit.
- Background levels of harmonic distortion, using measurements, earlier study results, or inferences from any previous customer complaints.
- Background level of flicker.

The harmonic study data can also be derived from a transient model of the Area EPS.

11. Impact mitigation overview

The results of the preliminary review, conventional distribution study, or special study may identify failure of the DR project, as it is proposed, to meet established criteria. After such a failure to meet criteria is identified, further study may help to better assess the situation. Further study may result in identifying the degree to which the criteria is violated. The degree of criteria violation will help to determine potential mitigation techniques and possibly determine if the project is feasible. The amount of study to assess potential mitigation techniques is a matter of judgment and experience. In some cases, mitigation techniques could be assessed based on preliminary criteria; but, in most cases, detailed studies need to be performed before identifying mitigation techniques. Mitigation techniques are a solution for failure to meet criteria of the pertinent conventional distribution studies (Clause 8) or special studies (Clause 9).

Mitigation techniques include changes needed to be made to the DR, changes to the Area EPS, or combinations of both of these. Often there is more than one mitigation technique to any set of criteria violations. Mitigation techniques may be as simple as changing equipment settings or upgrading some equipment. In some cases, mitigation techniques may be extensive including such items as replacing substations, reconductoring distribution lines, establishing new distribution lines, or upgrading the transmission system. In all cases, mitigation techniques are available to solve an issue identified in the impact study; but, in some cases, the mitigation resources may be too large to make installation of the DR practical.

Issues identified in impact studies can generally be classified in the following categories:

- Potential for unintended islands upon separation from the greater Area EPS
- Impact on EPS equipment loading under all steady state conditions
- Impacts on system protection and fault conditions
- Impacts on voltage regulation within the EPS under steady state conditions
- Impacts on power quality

The following subclauses identify a representative sample of some potential mitigation solutions to specific issues that may be identified in impact studies.

11.1 Potential solutions for unintended islands upon separation from the greater Area EPS

Once the potential for unintended islanding is identified, mitigation techniques are usually focused on anti-islanding protection. In some cases, a possible but a rarely used method is to mitigate the issue by transferring load.

11.1.1 Example methods for mitigating unintended islanding

11.1.1.1 Issue: Insufficient anti-islanding protection is built in the DR protection schemes

- Cause: Additional anti-islanding protection is needed due to Area EPS considerations and potentially due to equipment not meeting the requirements of IEEE Std 1547™.

- Potential solutions:
 - Use a DR that is certified to pass applicable non-islanding test. (See 8.4.1.3.2 of IEEE Std 1547.2™ on non-islanding inverter for details.)
 - Use reverse power protection if the DR is not intended to supply Area EPS load (See 8.4.1.3.3 of IEEE Std 1547.2™ for details.)
 - Provide tighter under voltage trip settings based on actual calculations for circumstances expected
 - Coordinate protection devices based on actual calculations for circumstances expected
 - Use power factor control of synchronous generator excitation system (See 8.4.1.3.6 of IEEE Std 1547.2™ for details.)
 - Employ direct transfer trip (DTT) of DR upon opening of Area EPS protective device; this applies to every device (See 8.4.1.3.7 of IEEE Std 1547.2™ for details.)

11.1.2 Issue: Out of synch reclosing

- Cause: Subsequent to fault and disconnection of the main source, if the first reclosing attempt of a feeder recloser occurs prior to a DR disconnection because of unintended islanding, the two systems may connect in an out-of-synch condition causing large in-rush current and a large voltage spike.
- Potential solutions:
 - Utilize secondary voltage supervision for a recloser to prevent reclosing on sensing of an energized feeder (dead-line reclosing).
 - Block reclosing on the feeder or line section that has DR connected.
 - On feeders with potential of close match between load and generation, use transfer trip schemes to trip DR prior to the first reclosing attempt.

11.1.3 Issue: Temporary overvoltage upon islanding of DR on line sections with generation in excess of load (cycles)

- Cause: Transient events are measured on the order of cycles. Certain power system events may create a high voltage transient.
- Potential solutions:
 - Utilization of instantaneous overvoltage protection settings on DR interconnection relay(s)
 - Specification of DR technology which uses control systems to limit temporary overvoltage in islanded conditions
 - Review surge arrester voltage rating. The surge arrester voltage ratings may need to be increased from normal levels, subject to maintaining adequate protective margins for the insulation
 - A change in transformer connection type
 - Supplemental grounding transformers
 - Install a transfer trip scheme
 - Use an interconnection transformer winding configuration that provides a ground source. However, this can upset ground fault coordination of protective devices and increase the neutral unbalance currents

- Having the protection system disconnect DR before the Area EPS clears a fault
- In the case of ferroresonance producing temporary overvoltage (TOV), three-pole switching and certain transformer types and configurations are less susceptible to ferroresonance problems

11.2 Potential solutions for impacts on EPS equipment loading under all steady state conditions in violation of requirements

When a preliminary review or conventional distribution study identifies that the DR introduces the potential for steady state operation of the Area EPS in excess of its ratings, mitigation techniques should be considered. Operation in excess of ratings usually results in equipment overloads.

- Criteria and identification. The potential for operation in excess of equipment ratings may occur when the preliminary review or conventional distribution study identifies the potential for increased current flow among line sections or through equipment due to the DR. The potential is often first identified in the preliminary review as discussed in preliminary review criteria P3. This can be further clarified by a steady state simulation study as shown in 8.2.
- General mitigation techniques. Once the potential for operation in excess of equipment ratings is identified, mitigation techniques are usually focused on upgrading affected equipment. In some cases, line section reconfiguration may provide acceptable mitigation.

11.2.1 Example method for mitigating operation in excess of equipment ratings

11.2.1.1 Issue: Substation transformer and/or line sections are overloaded due to DR

- Cause: DR causes line section and the substation transformer to be overloaded due to high penetration of DR.
- Potential solutions:
 - Upgrading substation transformers and reconductoring feeders to eliminate overloads
 - Move the DR closer to the substation source
 - Serve DR from a dedicated substation or dedicated feeder

11.3 Potential solutions for impacts on system protection and fault conditions in violation of requirements

When a preliminary review or conventional distribution study identifies the potential for changes in the system protection schemes or potential for the Area EPS to operate in excess of its fault ratings, mitigation techniques should be considered.

- Criteria and identification. Potential for changes in the system protection schemes are usually identified in the preliminary review or conventional distribution studies. Special impact studies may further identify changes needed to system protection schemes in order to mitigate particular conditions identified in the subject studies. Potential for operation in excess of its fault ratings may occur when a preliminary review or conventional distribution study identifies that the fault contribution of the DR is substantial and when combined with existing system fault contribution has the potential to exceed Area EPS equipment ratings. The potential may be first identified in the preliminary review as discussed in preliminary review criteria P4. It is usually further clarified by a short-circuit analysis as identified in 8.3.1.

- General mitigation techniques. Mitigation techniques for changes in system protection schemes can range from changes in settings to the installation of new protection equipment. Mitigation techniques for Area EPS equipment operating in excess of ratings due to faults is usually focused on upgrading equipment, limiting Area EPS fault current, limiting DR fault current, or reconfiguring lines. In rare cases where the interrupting current is the limiting factor on fast clearing protective devices, changes in protection settings may avoid the issue.

11.3.1 Example methods for mitigating Area EPS equipment operating in excess of ratings due to faults

The following five subclauses are examples of methods for mitigating Area EPS equipment operating in excess of ratings due to faults.

11.3.1.1 Issue: Aggregated DR contributes three phase fault current that results in momentary and interrupting fault current at the substation to be in excess of ratings

- Cause: Additional fault current contribution due to DR is added to area substation fault current to create a higher fault current at all circuit breakers in the substation and at downstream equipment.
- Potential solutions:
 - Replace affected equipment as needed at the substation and potentially on the downstream circuit. Affected equipment may include circuit breakers, substation buses, fuses, etc.
 - Decrease fault current levels by decreasing fault contribution from DR. This may be resolved by a different DR design, higher impedance DR transformers, or current limiting devices such as series reactors. In some cases, connecting the DR to a different line may mitigate the problem.
 - Decrease fault current levels by decreasing fault contribution from the Area EPS. This may be resolved by a higher impedance substation transformer, current limiting devices such as series reactors, or in rare cases connecting the substation to a different incoming line.

11.3.1.2 Issue: Recloser fuse mis-coordination for a fuse saving strategy during temporary faults

- Cause: Additional fault contribution from a DR located downstream of a faulted branch on backbone feeder and/or de-sensitizing a recloser when DR is located after recloser but upstream of faulted branch.
- Potential solutions:
 - Re-coordinate the recloser-fuse taking into account the maximum DR fault contribution
 - Change the protection strategy to a fuse burning method
 - Replace fuse with a recloser to clear fault locally

11.3.1.3 Issue: Loss of system stability

- Cause: Violation of stability criteria caused by a fault, motor starting, generation connection, capacitor switching, voltage regulator action, transformer load tap changer (LTC) action, or under frequency load shedding event.
- Potential solutions. Mitigation options for stability concerns may include:
 - Facility additions.

- Modification of protective equipment.
- Resetting of capacitor/regulator/LTC controls.
- DTT to allow the system operators to manually or automatically separate the DR during de-stabilizing events (e.g., when a large motor is about to start).
- Other modifications to the system including remedial action schemes or special protection systems. The system planner may need to determine critical clearing times to clear faults or isolate devices, provide location and size for capacitors/regulators, or provide distribution system modifications.
- Options at the DR installation may include changing the DR inertia, adjusting exciter or governor controls, adding voltage compensating devices, or instituting special protective systems including isolation of the DR during fault conditions.

11.3.1.4 Issue: Mis-operation of a protection device due to upstream faults and/or fault on adjacent feeders

- Cause: Reverse power flow and fault back-feeding of a DR may cause tripping of a protection device for faults not in the protection zone or may not trip for certain faults within the protection zone.
- Potential solutions:
 - Use directional protection schemes
 - Direct transfer trip from the substation to the DR is added
 - Automatic line reclosers are used to replace intermediate circuit fuses between the DR and the source substation
 - Protective device settings and/or device protective functions are changed
 - Changes in operating practice of the DR to minimize potential for such issues, for example, operating in an exclusively import state

11.3.2 Issue: Nuisance tripping of DR

- Cause: Voltage fluctuations caused by large load changes and/or faults on adjacent feeders
- Potential solutions:
 - Re-design voltage protection schemes for DR by utilizing voltage polarization and unbalance detection supervision
 - Utilize fault ride-through capability of DRs

11.4 Potential solutions for impacts on voltage regulation within the EPS under steady state conditions in violation of requirements

When a preliminary review, conventional distribution study, or special impact system study identifies a potential for impacts on voltage regulation, mitigation techniques should be considered.

- Criteria and identification. Potential impacts on voltage regulation include the potential for steady state voltage violations and voltage imbalances. Causes of these potential impacts include the existing voltage regulation systems on the Area EPS, the effect of DR voltage regulation systems, as well as real and reactive power flow changes due to the DR.

The potential for violation of voltage regulation requirements may first be identified by preliminary review as identified in preliminary review criteria P5. Conventional distribution studies (Clause 8) that may further delineate this issue include steady state simulation (8.2), and protection (8.3). Special impact studies that may provide more detailed understanding of the impact on voltage regulation include quasi-static simulation (9.4) and dynamic simulation (9.5).

- General mitigation techniques. Mitigation techniques for violation of voltage requirements may be focused on re-assessing the performance of voltage regulation devices, defining the appropriate voltage regulation requirements of the DR, and improving the impedance of the distribution system.

11.4.1 Example methods for mitigating violation of requirements

11.4.1.1 Issue: Steady state high and low voltage (minutes or longer)

- Cause: High and low voltage conditions where DR and load are at a specified level representing a single snapshot in time. Typically, steady state analysis is applied to the conditions that place the most stress on the system. Because the DR injects power into the Area EPS, the worst case steady state conditions may or may not be during peak load demand.
- Potential solutions:
 - Install or upgrade line or bank LTCs
 - Change line or bank LTC settings
 - Install shunt capacitor banks
 - Change existing shunt capacitor switching bias points
 - Replace temperature or time-controlled capacitor switching with local voltage control, current control, reactive power control, or centralized capacitor dispatch
 - Modify voltage regulator settings or provide voltage regulators designed to operate properly with reverse power flow
 - Install shunt reactor banks
 - Change existing shunt reactor switching bias points
 - Operate the DR using an absorbing power factor
- Under the right conditions, it may be feasible to use DR to minimize the PCC voltage fluctuation due to the DR operation by absorbing reactive power. If a fixed power factor is used to absorb reactive power, it may still be compliant with IEEE Std 1547™. Please note that the absorbed reactive power will need to be made up elsewhere in order to keep the substation transformer high side power factor within requirements. Also, the magnitude of the resultant current will be higher due to the reactive component, as compared with unity power factor operation, which may lead to higher line losses. A load flow should be conducted to determine the amount of reactive power needed and assess whether the inverter is capable of supplying it. Also, the developer may need to provide a higher rated inverter to allow this mode of operation.

11.4.1.2 Issue: Quasi steady state high and low voltage (seconds to minutes)

- Cause: High- or low-voltage excursions that develop on the order of seconds. Typically mechanically switched capacitor or reactor banks or LTCs are designed to respond to steady state events which develop over minutes (or longer). Quasi steady state voltage excursions may be due to intermittent DR.

- Potential solutions:
 - Thyristor or insulated gate bipolar transistor (IGBT) switched capacitor or reactor banks
 - Static var compensator
 - STATCOM devices
 - Adjustment of reactive power generation or absorption by DR resources
 - Change existing shunt capacitor or reactor bias points to avoid nuisance switching
 - Energy storage systems
- Under the right conditions, it may be feasible to use DR to minimize the PCC voltage fluctuation due to the DR operation by absorbing reactive power. If a fixed power factor is used to absorb reactive power, it may still be compliant with IEEE Std 1547™. Please note that the absorbed reactive power will need to be made up elsewhere in order to keep the substation transformer high side power factor within requirements. Also, the magnitude of the resultant current will be higher due to the reactive component as compared with unity power factor operation, which may lead to higher line losses. A load flow study should be conducted to determine the amount of reactive power needed and assess whether the inverter is capable of supplying it. Also, the developer may need to provide a higher rated inverter to allow this mode of operation.

11.4.1.3 Issue: Voltage imbalance (minutes or longer)

- Cause: DR may be installed on single-phase services and may not be installed in a balanced manner
- Potential solutions:
 - Add DR resources to absorb or generate power on the affected phase(s)
 - Reconfigure single-phase customer connections

11.4.1.4 Issue: Temporary overvoltage during phase-to-ground faults

- Cause: Depending on system configuration, the single line-to-ground voltage may rise to as much as 173% of the nominal line-to-ground voltage during single line-to-ground fault.
- Potential solutions:
 - Interconnect DR to a different system configuration.
 - Insulate system to highest potential overvoltage level.
 - Install a ground bank on the area EPS primary system. A current transformer (CT) will be connected either to the ground bank neutral or to its secondary delta to provide current for protective relays. A ground bank may affect the distribution of ground fault current and be a sink for normal current unbalance. The neutral should be designed to carry these currents.

11.4.1.5 Issue: Temporary overvoltage on faulted feeders subsequent to a loss of grid condition

- Cause: Asymmetrical faults on weakly grounded or ungrounded systems and tripping of the main feeder CB or recloser prior to DR disconnection that leads to forming an ungrounded system
- Potential solutions: (Note that the following potential solutions trip off the DR once overvoltages are sensed. These solutions may require that system insulation requirements, including arresters, take into account these temporary overvoltages.)

- Use of a ground bank and neutral over current protection (50N) to disconnect DR intertie breaker
- Use of high side broken delta with neutral overvoltage protection disconnect DR intertie circuit breaker¹¹
- Use suitable ground fault detection method to disconnect DR
- Direct transfer trip to disconnect DR
- Control design to assure that DR is not providing overvoltages upon loss of grid

11.5 Potential solutions for impacts on power quality

When a preliminary review, conventional distribution study, or special impact system study identifies a potential for power quality concerns, mitigation techniques should be considered.

- Criteria and identification. Studies may identify several impacts on power quality including flicker, sags and swells, and harmonics.

The preliminary review may identify the potential for power quality concerns. A steady state simulation (see 8.2) defines the impedance and voltage parameters. The degree of impact of power quality concerns is further identified in special impact studies. Pertinent studies for power quality concerns include quasi-static simulation (see 9.4), dynamic simulation (see 9.5), transient simulation (see 9.6), and harmonics and flicker (see 9.7).

- General mitigation techniques. Power quality covers several different issues with differing mitigation techniques. Flicker as well as voltage sags and swells can be mitigated by improving the impedance of the system, changing grounding, and in some cases the voltage regulation system. Harmonic issues may be mitigated by filters, changing grounding, changing transformer configurations, changing the resonance characteristics of the distribution system by changing capacitance or inductive characteristics, or changing the source(s) of harmonics by replacing equipment or appropriate tuning.

11.5.1 Example methods for mitigating impacts on power quality

11.5.1.1 Issue: Excessive harmonics

- Cause: DR contributing harmonics to the system along with harmonics already on the system from other sources.
- Potential solutions:
 - Installation of filters
 - Different DR interface technology
 - Vendor tuning of the interface controls
 - Move other sources of harmonics to another line
 - Decrease SCCR by increasing substation transformer size

¹¹ See Basler Application note “The 59N and Broken Delta Applications” #PC-59N01, August, 2004.

11.5.1.2 Issue: Excessive flicker

- Cause: DR produces noticeable changes in output of incandescent lighting caused by voltage changes on the EPS.
- Potential solutions:
 - Reduce the system impedance at the PCC. This can be done with series capacitors, upgraded line conductors, upgraded feeder voltage level, or upgraded substation transformer size.
 - Alter the appropriate characteristics of the DR. For example, the number of on-and-off switching operations may be constrained, or operation may be allowed only under favorable conditions. A wind turbine vendor can sometimes make changes to the control system and reduce flicker levels.
 - Disperse the DR. The voltage fluctuation contributions of smaller DR units will not be perfectly correlated, even with wind and solar. Therefore, the total voltage fluctuation level should decrease.
 - Install a static var system (e.g., DSTATCOM) to counteract the DR switching operations and output variations. This is often done for large loads, and the application is well understood but relatively expensive.
 - Adjust the feeder voltage regulator and capacitor switch settings if those are contributing to the problem.
 - Operate at leading power factor (absorb reactive power).
 - Operate in closed-loop voltage control.

Annex A

(informative)

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Annex B

(informative)

Sample data for impact studies

Obtaining realistic and trustable data sources may be considered as one of the major challenges in performing comprehensive DR impact studies. While Area EPS operators and DR owners may have access to some design and nameplate type data of the equipment and system component, not all the detailed parameters of various elements may be available. In some cases, for missing data, some assumptions on sample parameters and range of values may help expedite the studies. This section describes parameter types and sample range of the parameters for each data type. The sample data provided can be found in many electric utility systems and DR applications. This data should be considered only as example data and is not an exhaustive list.

B.1 Main grid data

In a DR study, the main grid is normally represented by a voltage source at substation level or an equivalent voltage source and one or two step-down transformer(s) feeding a feeder or multiple feeders on a common bus. An example of generic main grid parameters for a distribution substation is shown in Table B.1.

Table B.1—Example main grid parameters for an example distribution substation

Parameters	Example data
Short-circuit capacity (MVA)	300
Base voltage (kV)	24.9
X/R ratio	15
Thevenin equivalent impedance (positive seq.)	0.2+j1.8
Thevenin equivalent impedance (negative seq.)	0.2+j1.8
Thevenin equivalent impedance (zero seq.)	0.6+j6.2
System fault current (TPH/SLG) -kA	14/12
Voltage THD	0.10%
Harmonic spectrum	1 st -1pu, 3 rd -0.1pu, 5 th -0.05pu

B.2 Substation transformer data

If the main grid source is represented at a high voltage level (e.g., 69 kV or 115 kV), substation transformer parameters are needed to model the low side voltage interface of the substation for the study. An example of the generic parameters of a substation transformer is given in Table B.2.

Table B.2—Example substation transformer data

Parameters	Example data
MVA	30
Frequency	60
Winding types	D-Yg
Impedance data	8%
X/R ratio	30
No load losses	0.10%
Copper losses	0.20%
Manual or LTC	LTC
Voltage ratio (kV)	69/12.47
Saturation data	N/A
Grounding impedance (ohms)	0
DETC (de-energized tap changer) setting	A, B, C, D, or E

B.3 Load tap changer and voltage regulator data

Load tap changers (LTC) and voltage regulators (VR) may be used on some distribution feeders to regulate and maintain the voltage of the feeders within a preferred range during daily and seasonal load variations. LTC is normally used at substation transformer regulating the bus voltage common to all feeders, while VRs may be found in several locations along a feeder depending on length and loading of the feeder. Sample LTC and VR parameters are given in Table B.3. The LTC and VR data may include number of taps, time delay, percent regulation, regulated voltage setting, and bandwidth.

Table B.3—Example load tap changer and voltage regulator data

Parameters	Example data	
	LTC	VR
Location	Substation	Along a feeder
Target and bandwidth	±2%	±2%
Time delays	30/45 sec	45/60 sec
Voltage control method	Terminal voltage	Load compensation
Load compensator settings—R/X (primary ohms)	N/A	0.1/0.3
Control scheme	Forward	Co-generation
Configuration	Single pole	Single pole

B.4 Circuit breaker and recloser data

Circuit breaker and recloser data is used for coordination studies to determine if the generator's protection settings coordinate with the EPS protection settings. The circuit breaker and recloser data may include operating voltage, short-circuit current interrupting capability, continuous current rating, and interrupting settings.

Table B.4—Example circuit breaker and recloser data

Parameters	Example data
Configuration (time current curves)	Various
Continuous current rating	800
Interrupt rating (kA)	32
Ground current pick up (amps)	360
Phase current pick up (amps)	600
Number of reclosing attempts	3
Reclosing intervals (seconds)	5, 10, 15
Reset time (seconds)	10

B.5 Capacitor bank data

Capacitor data is used to model EPS circuit reactive power management scheme. The capacitor bank data may include bank operating voltage, bank kVAr size, control mode, and bank switch settings.

Table B.5—Example capacitor bank data

Parameters	Example data
Voltage class (kV)	15
Size (kVAr)	900
Type—fixed, switched	Fixed
Control mode—current, voltage, time, kVAr, power factor, temperature	Current
On to Off time delay (seconds)	30
Sensing phase	A

B.6 Feeder protection equipment data

The protection equipment data may include protection device type, operation parameters, and device location. Protection equipment usually includes fuses, breakers, and reclosers and is discussed in B.4.

Table B.6—Example feeder protection equipment data

Parameters	Example data	
	Fused cutout	Sectionalizer
Continuous current (amps)	1-300	10-400
Ground min. actuating current (amps)	2-600	3.5-448
Phase min. actuating current (amps)	2-600	16-640
Rated voltage (kV)	4-38	4-38
Interrupting rating (sym. rms kA)	8-20	
Reset time (seconds)	N/A	15-180
Operations to lockout	1	1-3

B.7 Load data

The load data may include current, kVAr, and kW by phase and load allocation algorithm. Metered load data is not instantaneous load data but load data averaged over a given time period such as 15 minutes, 30 minutes, etc. Minimum load data is often estimated to be 1/3 of peak load data. Alternatively, minimum load may also be the minimum load data for the smallest circuit section served by the DR. Larger demand loads and their location may be known from specific customer metering and their use contributes to more accurate models.

Table B.7—Example load data

Parameters	Example data
Substation load	
Load components	kVA, kW, kVAr
Size (kVA)	2-30 MVA
Location	Metered at transformer bus
Connection type	Wye or delta
Load type	Commercial, industrial, residential
Feeder load	
Load components	kVA, kW, kVAr
Size (kVA)	2-30 MVA
Location	Metered at feeder breaker
Connection type	Wye or delta
Load type	Commercial, industrial, residential
Customer load	
Load components	kVA, kW, kVAr
Size (kVA)	0.5-30 MVA
Location	Metered at customer PCC
Connection type	Wye or delta
Load type	Commercial, industrial, residential

B.8 Feeder (sections) data

Feeder section data may include data within ranges provided in Table B.8 and Table B.9 as well as voltage regulators, capacitors, switches, fused cutouts, sectionalizers, reactors, and distribution transformers.

Table B.8—Example feeder section data

Overhead lines	Example data or ranges
Line length (feet or meters)	100-10 000
Conductor size and type	6-556 kCM, Al, AA, ACSR, or Cu
Conductor geometry	Horizontal, vertical, armless
Earth resistivity (ohms)	20-400
Phase spacing data (inches)	18-50
Nominal rating (amps)	165-730

Table B.9—Example feeder section data

Underground cables	Example data or ranges
Cable configuration	Multi-wire concentric neutral cable, shielded cable, unshielded
Cable length (feet)	100-5000
Rated voltage (kV)	5-35
Cable size	180-1000 kCM
Cable Z1 impedance (ohms/mile)	2.3+j0.7 to 0.2+j0.2
Cable Z0 impedance (ohms/mile)	2.3+j0.7 to 0.5+j0.1
Cable Z1 admittance (US/mile)	93-300
Cable Z0 admittance (US/mile)	93-300
Earth resistivity (ohms)	20-400
Phase spacing data (inches)	4-10
Insulation type	XLPE, EPR

B.9 DER data—rotating machine type

Distribution resource rotating machines include synchronous and induction machines. They are the most susceptible to severe mechanical forces due to loss of synchronization.

Table B.10—Example generator data

Equipment parameters	Synchronous	Induction
Rated power (kVA)	2500	1500
Rated voltage (kVLL)	13.2	13.2
Active generation (kW)	2000	1250
Power factor (%)	85	-85
Max. reactive power (kVAr)	1500	
Min. reactive power (kVAr)	-1500	
Steady state impedance (pu or ohms)	0.2+0.05	
Transient impedance (pu or ohms)	0.1+j0.13	
Subtransient impedance (pu or ohms)	0.1+j0.098	0.01+j0.05
Zero sequence impedance (pu or ohms)	0.1+0.023	
Machine grounding impedance (ohms)	25	
Winding configuration	Wye or delta	Wye or delta
Rated speed	1800	1850
Efficiency (%)		90

B.10 DR data—electronically coupled type

Many renewable power sources and energy storage devices produce dc output voltage (or variable frequency output voltage that is first rectified to dc). Such power sources are coupled to the EPS through electronic dc/ac inverters. Electronic control makes synchronization of inverter output with the EPS much easier than in the case of a rotating synchronous machine generator. The inverter acts as a controlled, current-limited, real and reactive power source. The inverter real power output varies with the source power output, while reactive power (leading or lagging) is generated by the inverter itself. Since the output power from the inverter can affect the voltage in the EPS, voltage regulation and transient portions of an impact study need to include a prediction of the expected variability of the generator output. Solar generator impact studies need to include a prediction of the expected variability of generator output as a function of expected sunlight variability. Wind generator impact studies need to include a prediction of the expected variability of generator output as a function of expected wind variability. The models of the inverters may include the power source (e.g., PV array or wind turbine) to provide convenience for the transient study. A general inverter model may include data shown in Table B.11. An inverter often uses a distribution transformer to step the voltage up to EPS voltage level for interconnection.

Table B.11—Example inverter data

Parameters	Example data
Rated power (kVA)	150
Rated voltage (kV)	0.69
Active generation (kW)	100
Power factor	100
Max. fault contribution (%)	107
Fault current duration (cycles)	10
Reactive power control range	±45% of rated MVA with Q priority control over ±10% voltage range from nominal
Power factor control range	0.9 lagging to 0.9 leading at nominal MW power, and 0.85 lag to 0.85 lead at reduced power

B.11 Solar PV inverters

Solar PV inverter models may include a prediction of the expected variability of generator output as a function of expected sunlight variability. In addition to inverter data shown in Table B.11, a solar PV panel model may include data shown in Table B.12. The PV panel characteristics, the number of series and parallel panels, and orientation of panels are used to determine the production and variations. The inverter will often use a distribution transformer to step the voltage up to EPS voltage level for interconnection.

Table B.12—Example additional PV panel data

Parameters	Example data
Maximum current (amps)	20
Maximum voltage (volts)	20
Short-circuit current (amps)	23
Open circuit voltage (volts)	23.5
Short-circuit current temperature coefficient (amp/ °C)	0.002
Open circuit voltage temperature coefficient (volt/ °C)	-0.08
Normal operating cell temperature (°C)	45
Reference ambient temperature (°C)	20
Standard test condition temperature (°C)	25
Standard test condition insolation (W/m ²)	1000

B.12 Wind turbine inverters

Wind turbine inverter models may include a prediction of the expected variability of generator output as a function of expected wind variability. In addition to inverter data shown in Table B.11, a wind turbine inverter model may include data shown in Table B.13. The inverter will often use a distribution transformer to step the voltage up to EPS voltage level for interconnection.

Table B.13—Example additional wind turbine inverter data

Parameters	Example data
Rated power (kVA)	1645
Rated maximum power (kW)	1645
Primary energy source	Example data
Rated wind speed (ft/sec)	36
Cut-in wind speed (ft/sec)	9.8
Cut-out wind speed (ft/sec)	42.6
Number of blades	3
Rotor radius (ft)	164
Rated rotor speed (rpm)	16.2
Minimum rotor speed (rpm)	9.75
Maximum rotor speed (rpm)	16.2
Turbine inertia (lb-ft ²)	16 325
Gearbox ratio	93.83
Spring constant (Nm/rad)	2700
Damping constant (Nm/rad)	5

Additional generator data that may be included is locked rotor data shown in Table B.14.

Table B.14—Example additional wind turbine generator data

Parameters	Example data
Stator (ohms)	0.0056+j0.0372
Magnetizing (ohm)	7.7+j1.54
Rotor #1 (ohm)	0.0098+j0.0745
Rotor #2 (ohm)	0.0098+j0.0745
Cage factor	0.8-j0.1
Generator inertia (MW*s/MVA)	0.55

B.13 Energy storage inverters

Energy storage inverters by design allow energy flow into and out of the EPS. The inverter will often use a distribution transformer to step the voltage up to EPS voltage level for interconnection.

Table B.15—Example additional energy storage inverter data

Parameters	Example data
Rated power (kVA)	2400
Rated voltage (kV)	0.48
Active generation (kW)	2400
Power factor (%)	100
Fault contribution (%)	200

Annex C

(informative)

Glossary

arc flash hazard: A dangerous condition associated with the release of energy caused by the electric arc (see IEEE Std 1584™-2002).

area electric power system (Area EPS): Facilities that deliver electric power to load (see IEEE Std 1547™-2003).

distributed resource (DR): Source of electric power that is not directly connected to a bulk power transmission system. DR includes both generators and energy storage technologies (see IEEE Std 1547™-2003).

impact study: A collection of electrical engineering studies addressing the effects of a DR interconnection with an electric power system.

inverter: A machine, device, or system that changes direct-current power to alternating-current power (see IEEE Std 1547™-2003).

local electric power system (Local EPS): An EPS contained entirely with a single premises or group of premises (see IEEE Std 1547™-2003).

stiffness: The ability of an area EPS to resist voltage deviations caused by DR or loading. *See:* **stiffness ratio** (see IEEE Std 1547.2™-2008).

stiffness ratio: The relative strength of the area EPS at the PCC compared with the DR, expressed in terms of the short-circuit kilovolt-amperes 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.

$$\text{Stiffness ratio} = \frac{\text{SC kVA (Area EPS)} + \text{SC kVA (DR)}}{\text{SC kVA (DR)}} = \frac{\text{SC kVA (Area EPS)}}{\text{SC kVA (DR)}} + 1 \quad (\text{C1})$$

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

(see IEEE Std 1547.2™-2008).

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This Indian Standard has been developed from Doc No.: ETD 46 (25627).

Amendments Issued Since Publication

Amend No.	Date of Issue	Text Affected

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