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IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems

IEEE Standards Coordinating Committee 21

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

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IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems

Sponsor

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

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Abstract: Alternative approaches and good practices for the design, operation, and integration of distributed resource (DR) island systems with electric power systems (EPS) are provided. This includes the ability to separate from and reconnect to part of the area EPS while providing power to the islanded EPSs. This guide includes the DRs, interconnection systems, and participating EPSs.
Keywords: circuit island, distributed resources, DR island systems, electric power systems, IEEE 1547.4, intentional island, interconnection, lateral island, microgrid, secondary island, substation bus island

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Introduction

This introduction is not part of IEEE Std 1547.4-2011, IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems.

IEEE Std 1547.4 is part of the IEEE 1547™ series of standards. The IEEE 1547 series of standards was created to develop a national consensus on using distributed resources (DR) in electric power systems (EPSs). IEEE Std 1547.4 was specifically developed to address the lack of information included in IEEE Std 1547-2003 regarding intentional islands.[a] This document covers intentional islands in electric power systems (EPSs) that contain DRs. IEEE created a new term *DR island systems* to generically refer to all intentional island systems that could include local and/or area EPS. The term DR island systems, sometimes referred to as *microgrids,* is used for these intentional islands. DR island systems are EPSs that: (1) have DR and load, (2) have the ability to disconnect from and parallel with the area EPS, (3) include the local EPS and may include portions of the area EPS, and (4) are intentionally planned. DR island systems can be either local EPS islands or area EPS islands.

DR island systems offer many potential benefits. They can:

— Improve reliability by providing the islanded portion of the EPS power during an area EPS outage or disturbance.

— Relieve area EPS overload problems by allowing a part of the EPS to intentionally island and removing load from the rest of the area EPS. The benefit is for both island and normal parallel operation.

— Isolate from area EPS power quality issues (voltage distortion, voltage sag, flicker, lightning transients, etc.) while in island mode operation.

— Resolve power-quality issues by reducing total harmonic distortion (THD) at the loads.

— Allow for maintenance on the area EPS while allowing intentionally islanded customers to remain powered.

This document contains several clauses that address various aspects of DR island systems. Clause 3 gives a list of definitions and acronyms used in the document. Clause 4 gives an overview of the general considerations for design and operation of DR island systems and describes the various types of DR island systems. This clause also discusses the modes of operation of the DR island systems, including normal parallel mode, transition-to-island mode, island mode, and reconnection mode. Clause 5 explains the planning and engineering of DR island systems with detailed discussions about the considerations and solutions. Clause 6 describes the operations of the DR island system.

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1. Overview

This document covers intentional islands in electric power systems (EPSs) that contain distributed resources (DRs). The term *DR island systems,* sometimes referred to as *microgrids,* is used for these intentional islands. DR island systems are EPSs that: (1) have DR and load, (2) have the ability to disconnect from and parallel with the area EPS, (3) include the local EPS and may include portions of the area EPS, and (4) are intentionally planned. DR island systems can be either local EPS islands or area EPS islands. This document addresses issues associated with DR island systems on both local and area islanded EPSs. It provides an introduction and overview and addresses engineering concerns related to DR island systems.

1.1 Scope

This document provides alternative approaches and good practices for the design, operation, and integration of DR island systems with EPS. This includes the ability to separate from and reconnect to part of the area EPS while providing power to the islanded EPSs. This guide includes the DRs, interconnection systems, and participating EPSs.

1.2 Purpose

This guide is intended to be used by EPS designers, operators, system integrators, and equipment manufacturers. The document is intended to provide an introductory overview and address engineering concerns of DR island systems. It is relevant to the design, operation, and integration of DR island systems. Implementation of this guide will expand the benefits of using DR by targeting improved reliability and build upon the interconnection requirements of IEEE Std 1547™-2008.[1]

1.3 Limitations

This document also has the following limitation to its use:

- This guide does not establish DR reserve levels for a specific planned island.
- This guide does not address DR island systems on distribution secondary networks.
- The aggregate generating capacity within the DR island system is not restricted by this document.
- Each individual point of common coupling (PCC) is limited to 10 MVA of generation (per IEEE Std 1547-2003).
- This guide does not presume that an area EPS operator desires to establish planned islands on any portion of the area EPS that is normally connected to the balance of the area EPS.
- This guide does not presume that all DR located within an area EPS operator's planned island are participating.
- This guide does not presume that all load located within an area EPS operator's planned island are participating.
- This guide does not provide operational procedures for establishing and operating a planned island.
- This guide does not cover all possible contingencies (e.g., loss of control communications back to the area EPS) that may result in the cessation of planned island operations.
- This guide does not address physical security or cybersecurity.
- This guide does not cover contractual or regulatory considerations.
- This guide does not cover metering, which may be a contractual or regulatory consideration.

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.

ANSI/NEMA C84.1-2006, American National Standard for Electric Power Systems and Equipment—Voltage Ratings (60 Hertz).[2, 3]

ANSI/NEMA MG 1-2006, Motors and Generators.

[1] Information on references can be found in Clause 2.
[2] ANSI publications are available from the Customer Service Department, American National Standards Institute, 25 W. 43rd Street, 4th Floor, New York, NY 10036, USA (http://www.ansi.org/).
[3] NEMA publications are available from Global Engineering Documents, 15 Inverness Way East, Englewood, Colorado 80112, USA (http://global.ihs.com/).

IEEE Std 399™-1997, IEEE Recommended Practice for Industrial and Commercial Power Systems Analysis *(IEEE Brown Book™)*. [4, 5]

IEEE Std 446™, IEEE Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications *(IEEE Orange Book™)*.

IEEE Std 519™, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.

IEEE Std 1100™, IEEE Recommended Practice for Powering and Grounding Electronic Equipment *(IEEE Emerald Book™)*.

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

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

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

3. Definitions, acronyms, and abbreviations

3.1 Definitions

For the purposes of this document, the following terms and definitions apply. *The IEEE Standards Dictionary: Glossary of Terms & Definitions* should be referenced for terms not defined in this clause.[6]

black start: The ability to start local generation with no external source of power.

distributed resources (DR): Sources of electric power that are not directly connected to a bulk power transmission system. DR includes both generators and energy storage technologies.

distributed resources (DR) island system: DR island systems are parts of electric power systems (EPSs) that have DR and load, have the ability to disconnect from and parallel with the EPS, include the local EPS and may include portions of the area EPS, and are intentional and planned.

NOTE—Types of DR island systems include: local EPS island (facility island); circuit lateral island; distribution circuit island; substation bus island; substation island; adjacent circuit island.[7]

distribution system: That portion of an electric system that delivers electric energy from transformation points on the transmission or bulk power system to consumers.

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[6] *The IEEE Standards Dictionary: Glossary of Terms & Definitions* is available at http://shop.ieee.org/.
[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.

island interconnection device (IID): A device that allows separation of a distributed resources (DR) island system from the electric power system (EPS). This device may provide the function of a normal paralleling device to reconnect the DR island system with the Area EPS.

non-participating distributed resources (DR): Distributed resources that are in the DR island system but are not under control of DR island system operations.

paralleling device: A device (e.g., a circuit breaker or switch) that operates under the control of a synchronizing function (manual or automatic) to electrically connect two energized power sources.

participating distributed resources (DR): DR that are in the DR island system and are under control of DR island system operations.

point of distributed resources connection (point of DR connection): The point at which a DR unit is electrically connected in an electric power system (EPS).

scheduled transitions: Intentional events for which the time and duration of the planned island are agreed upon by all parties involved.

3.2 Acronyms and abbreviations

ac	alternating current
ANSI	American National Standards Institute
CT	current transformer
dc	direct current
DR	distributed resources
EPS	electric power system
IEEE	Institute of Electrical and Electronics Engineers
FERC	Federal Energy Regulatory Commission
IA	interconnection agreements
IID	island interconnection device
LGIP	Large Generator Interconnection Procedure
LVRT	low-voltage ride-through
MIC	monitoring, information exchange, and control
NEMA	National Electric Manufacturers Association
NERC	North America Electric Reliability Corporation
PCC	point of common coupling
PID	proportional, integral, derivative
SCADA	supervisory control and data acquisition
SLTG	single line to ground
SGIP	Small Generator Interconnection Procedure
var	volt-ampere reactive

4. DR island systems overview

This clause gives an overview of the general considerations for design and operation of DR island systems and describes the various types of DR island systems. This clause also discusses the modes of operation of the DR island systems, including normal parallel mode, transition-to-island mode, island mode, and reconnection mode.

4.1 General DR island system considerations

When designing a DR island system that can provide power to parts of the EPS during an area EPS outage, reliable DR units and careful coordination with the area EPS sectionalizing and protection equipment are necessary. This clause lists issues that are of particular interest when considering implementation of a DR island system. These are further discussed in Clause 5. In order to provide appropriate planning, it is important to understand the general considerations, types of islands, and planned operating conditions.

Important considerations include the following:

- Changes in power-flow magnitude and direction
- Proper control of voltage, frequency, and power quality
- Whether there is a single PCC or multiple PCCs
- Protection schemes and modifications
- Monitoring, information exchange, and control (MIC)
- Load requirements of the area or local EPS that will be islanded
- Characteristics and functionality of the DRs
- Steady-state and transient conditions
- Interactions between electrical energy sources
- Reserve margins, load shedding, and demand response
- Cold-load pickup

The operation of a DR island system also brings up concerns. These include the following:

- A risk of out-of-phase reconnection at all open points not designated and designed for synchronized connection
- Possible damage to equipment due to voltage and frequency aberrations
- Adequate and reliable DR
- Reduced area EPS reliability due to increased system complexity
- Safety for general public, emergency personnel, and operators
- Possible reduction in power quality
- Significant changes in fault duty between normal and island modes
- System protection coordination
- Coordination with load-shedding schemes
- Voltage and frequency regulation

- Load (phase) imbalance
- Load and generation matching
- Consequences of the potential deferral of area EPS improvements due to presence of DR island system

An important note on transformer configurations is that area EPS grounding configurations need to be maintained under all operating conditions. More information on this topic is provided in Clause 5.

4.2 Specific considerations for DR island systems that include a portion of the area EPS

Specific considerations need to be taken into account when the DR island system includes any portion of the area EPS. The following criteria and requirements are applicable to the DR and the portion of the area EPS that is to be incorporated into a planned island. These criteria may not be applicable to DR island systems that include only local EPSs:

- There is an agreement with the area EPS operator to operate the DR island system.
- The participating and non-participating DR need to be identified.
- Prior to formation of the planned island, each DR that is in parallel with the area EPS shall meet the requirements of IEEE Std 1547-2003.
- During transition to and operation of the planned island, one or more of the participating DR may be allowed to operate according to a predefined set of requirements outside of IEEE Std 1547-2003.
- System studies should be performed to support the establishment of the planned island.
- The area EPS is modified to operate in the planned island mode.
- At the initiation of the planned island, it should be determined that sufficient DR generation capacity is available to meet the capacity needs of the island.
- DR in the planned island that are non-participating or have not established the necessary business relationships for planned island operation with the area EPS may be permitted to continue operations in compliance with IEEE Std 1547-2003 or as a local EPS island. It may be necessary to conduct load-flow and stability studies to identify any risks that operation of the non-participating DR may be compromised or may compromise the DR island system.
- The planned DR island system should maintain voltage and frequency for the entire island system including the non-participating DR systems and loads.
- In a planned island, consideration should be given to achieving generation and load balance for each phase.

4.3 DR island system configurations

There are a variety of operating configurations for intentional islands that incorporate DR. Figure 1 shows examples of seven planned island configurations in the area EPS. There may be additional DR island system circuit topologies other than the ones pictured. The planned DR island systems in the figure include: local EPS island (facility island), secondary island, lateral island, circuit island, substation bus island, substation island, and an adjacent circuit island. These terms describe the majority of DR island systems covered in this guide.

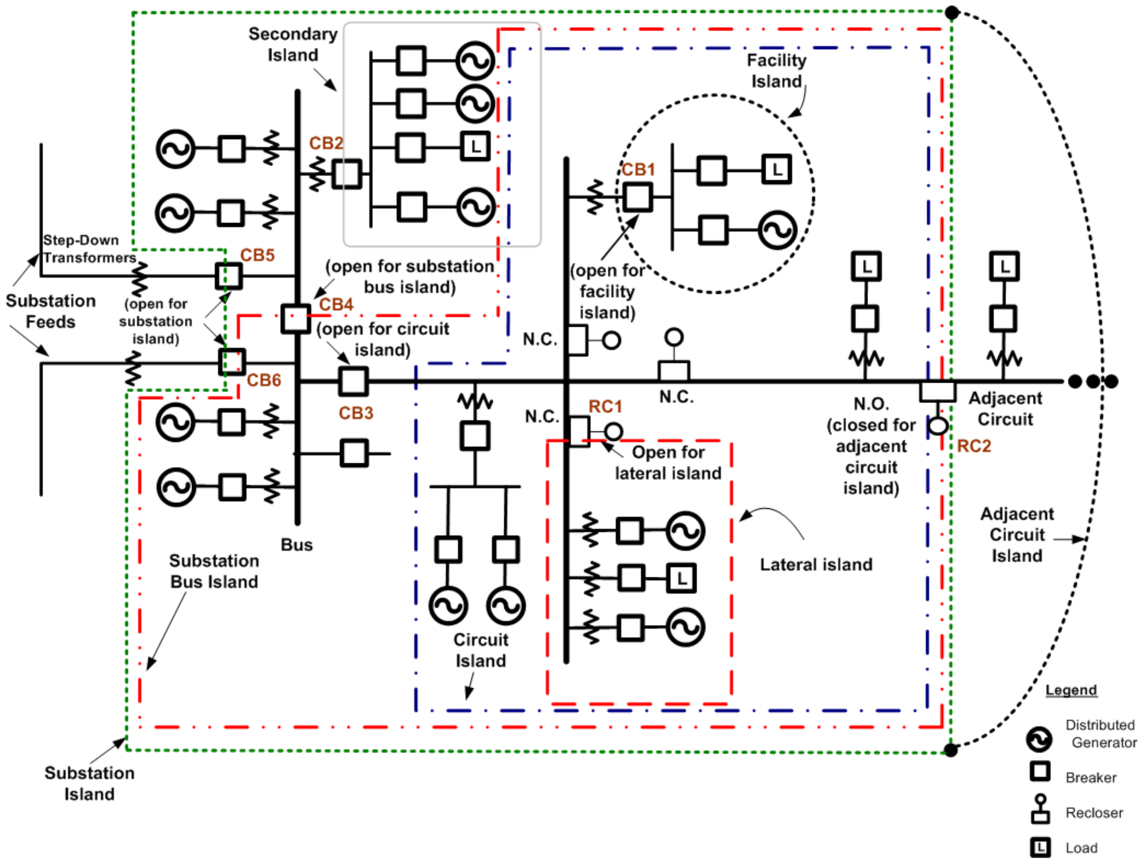

Figure 1—Examples of DR island systems

4.3.1 Local EPS island (facility island)

In a local EPS island (Figure 2), the DR island system is formed from generation and load normally served within a customer facility. This is also called a *facility island.* This DR island system has only one PCC (CB1) with the area EPS. Facility DR can be operated to serve the load of the facility when there is a loss of the area EPS.

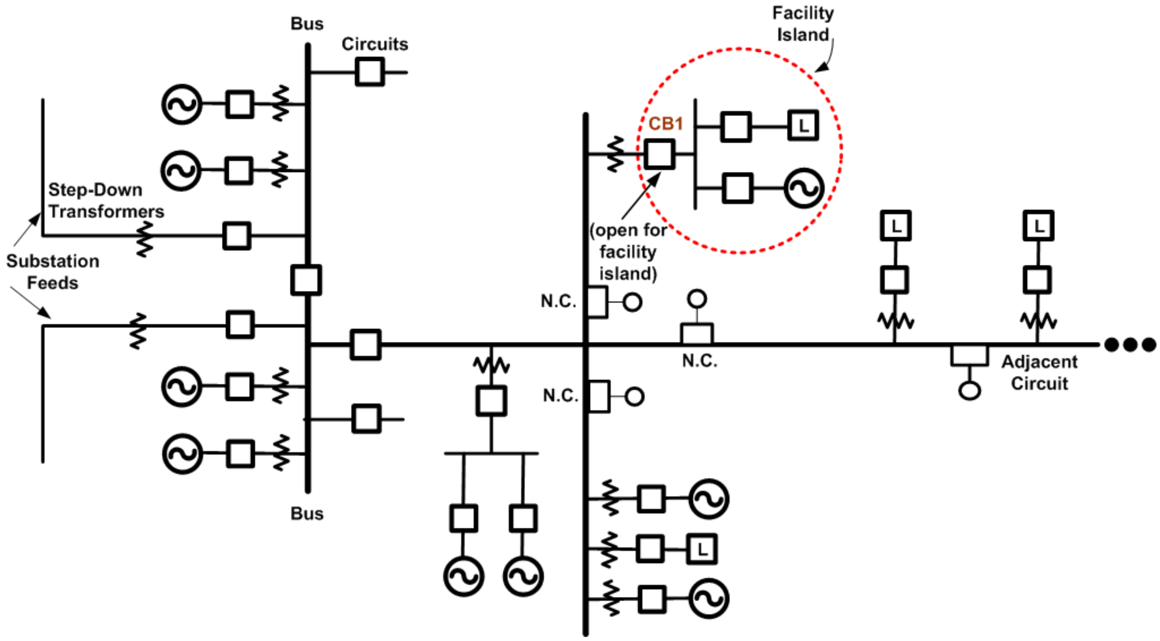

Figure 2—Local EPS island (facility island)

If the DR and local EPS decide to create an intentional island, the area EPS operator needs to be made aware of this method of operation. For a fault condition external to the planned island, the area EPS operator will expect the DR generation to be disconnected from the area EPS system. Figure 3 shows that, in the case of intentional island operation, the "tie" breaker (B1) will open for the fault shown before generator breaker (B2). This will leave the generation operating with the local load. To have maximum benefit from this type of operation, the DR island system should parallel the area EPS system *without* the need to shut down the DR. This will require the capability to parallel with using a *different* breaker (B1) than the breaker that was used to normally parallel the generation (B2).

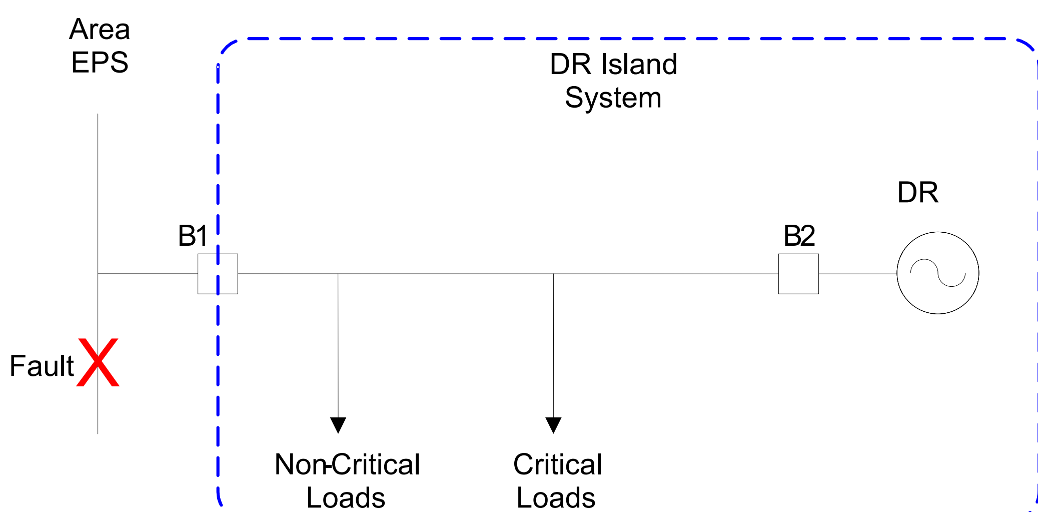

Figure 3—DR island system connected to EPS through "tie" breaker

The area EPS and the local EPS operators will need to discuss the required interlocks and the method of operation for paralleling the intentional island. A synchronization check at B1 is necessary to ensure proper reconnection.

4.3.2 Secondary island

A secondary island (Figure 4) is one or more DR and multiple customers connected to the secondary side of one distribution transformer. There may be multiple secondary islands on a single distribution lateral. For example, community energy storage units can be deployed in secondary islands. In these systems, an area EPS-owned storage device is connected on the secondary side of the distribution transformer with multiple customers connected to the secondary. Other forms of DR may be installed on the secondary island along with community energy storage.

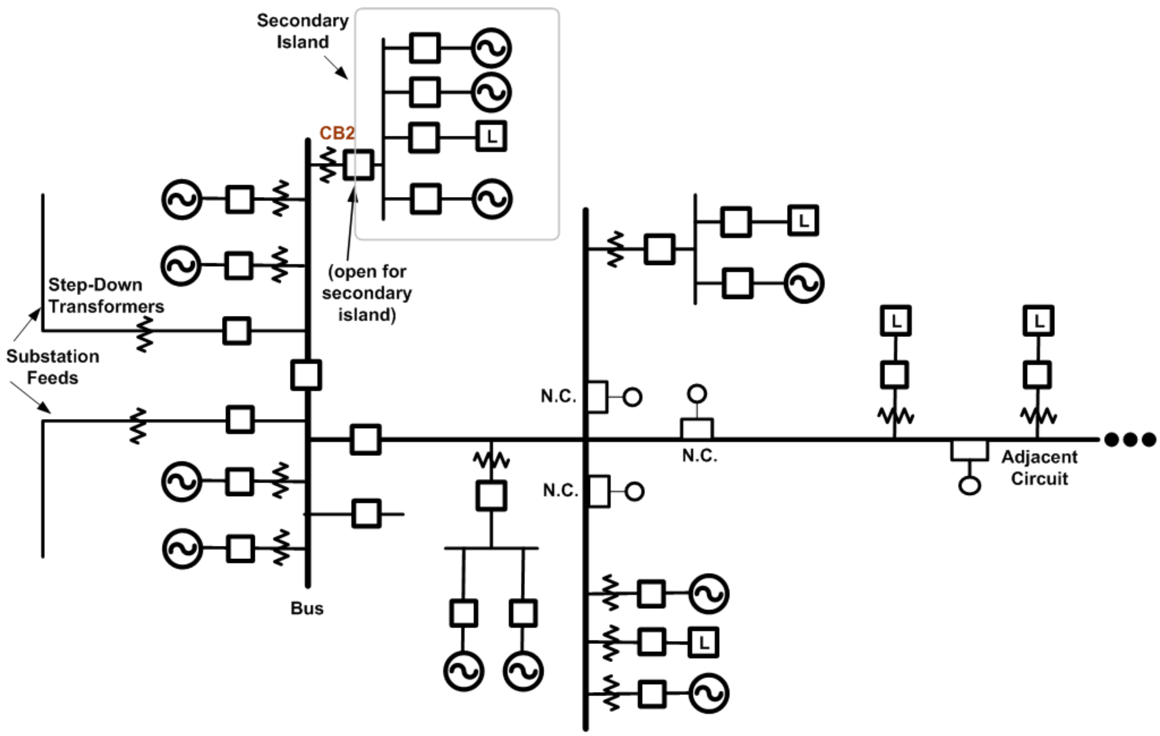

Figure 4—Secondary island

4.3.3 Lateral island

In the lateral island (Figure 5), an island is formed from load normally served from a lateral on a distribution circuit. The generation can be operated to serve the load of the island when the lateral switching device (e.g., the breaker, recloser, or sectionalizer) opens (RC1).

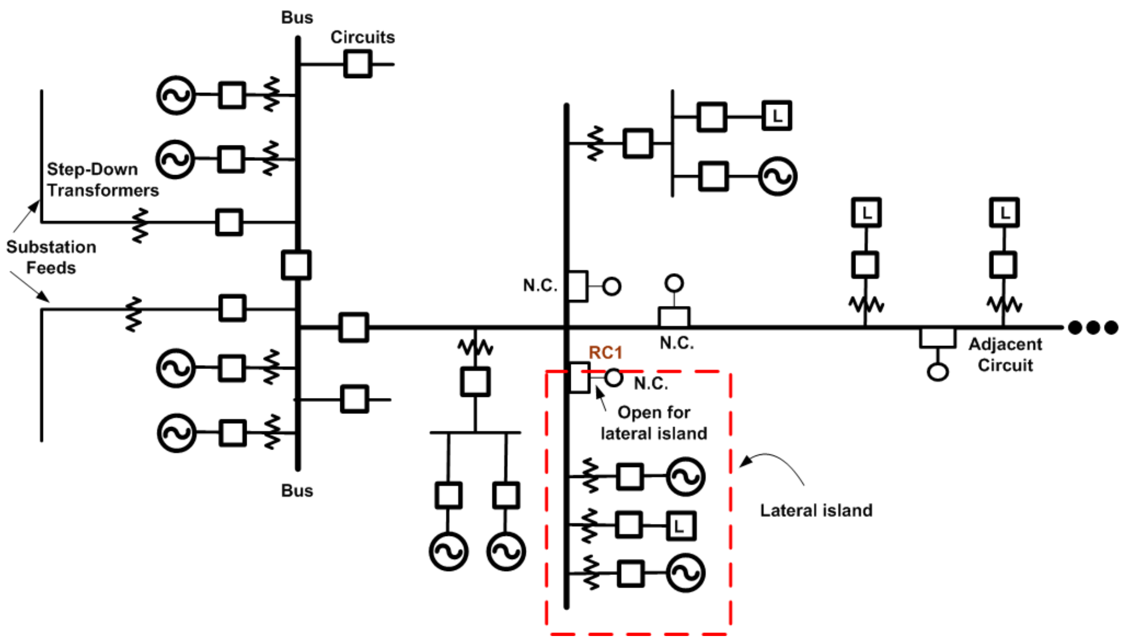

Figure 5—Lateral island

4.3.4 Circuit island

In a circuit island (Figure 6), an island is formed from load normally served from a single distribution circuit. For loss of the substation feed, transformer, or bus, DR can be operated to serve the load of the circuit by opening CB2.

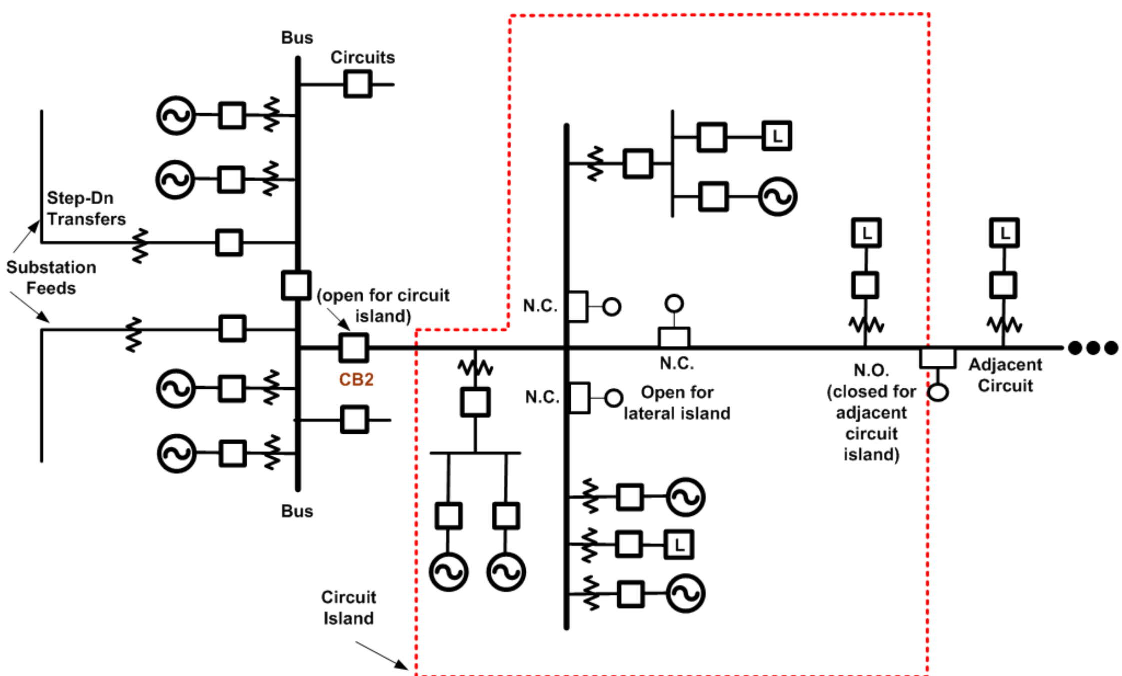

Figure 6—Circuit island

4.3.5 Substation bus island

In the substation bus island (Figure 7), an island is formed from load normally served from a single bus within a substation, though multiple buses may be used to serve loads from the substation. The DR on a specific bus can be operated if there is a loss of a substation feed or substation transformer. This operation entails opening the transformer secondary (low-voltage side) breaker (CB5) on the lost feed or transformer and operating the section breaker (CB3) either opened or closed.

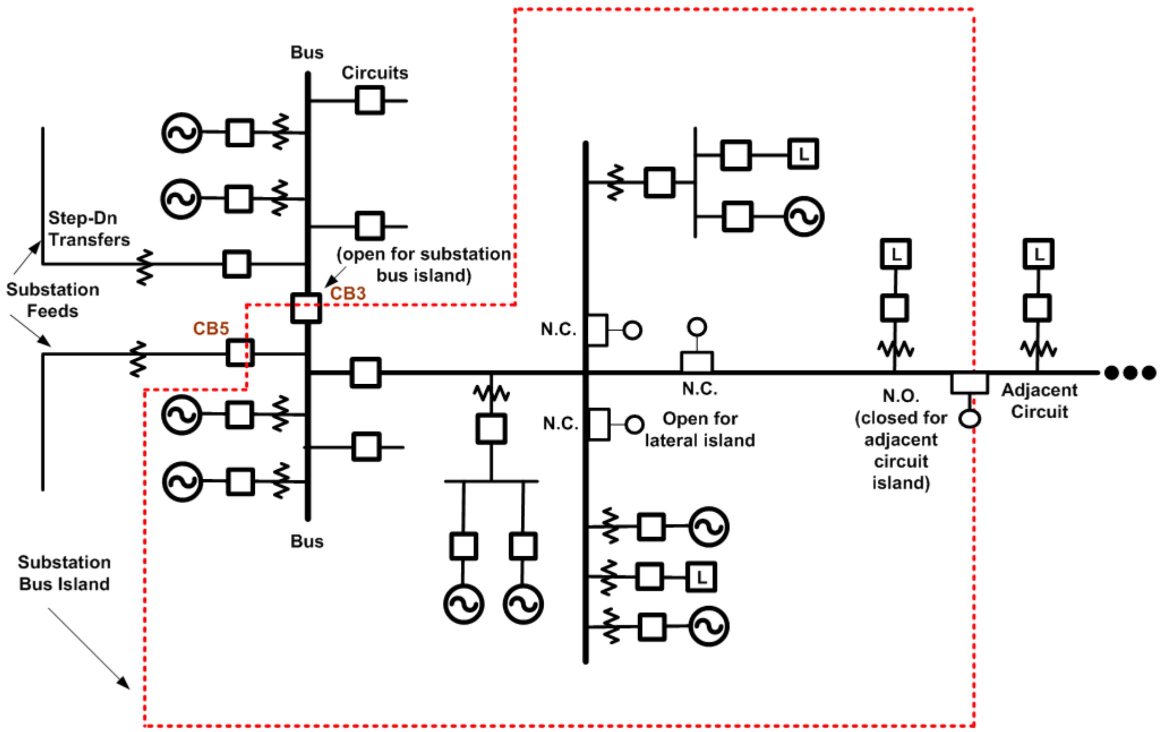

Figure 7—Substation bus island

4.3.6 Substation island

In the substation island (Figure 8), an island is formed from load normally served from a single substation. This island may be used when the distribution substation is out of service or when one transformer is out of service and the remaining transformer is not capable of supplying the entire substation load. This island can be used to alleviate a thermal (overload) or voltage problem on the substation feeds or an overload problem on the step-down transformers. Running the DR on both buses reduces the loading on these feeds and transformers and may improve voltage levels. The substation transformer secondary (lower-voltage side) breakers (CB4 and CB5) are open to create the DR island system.

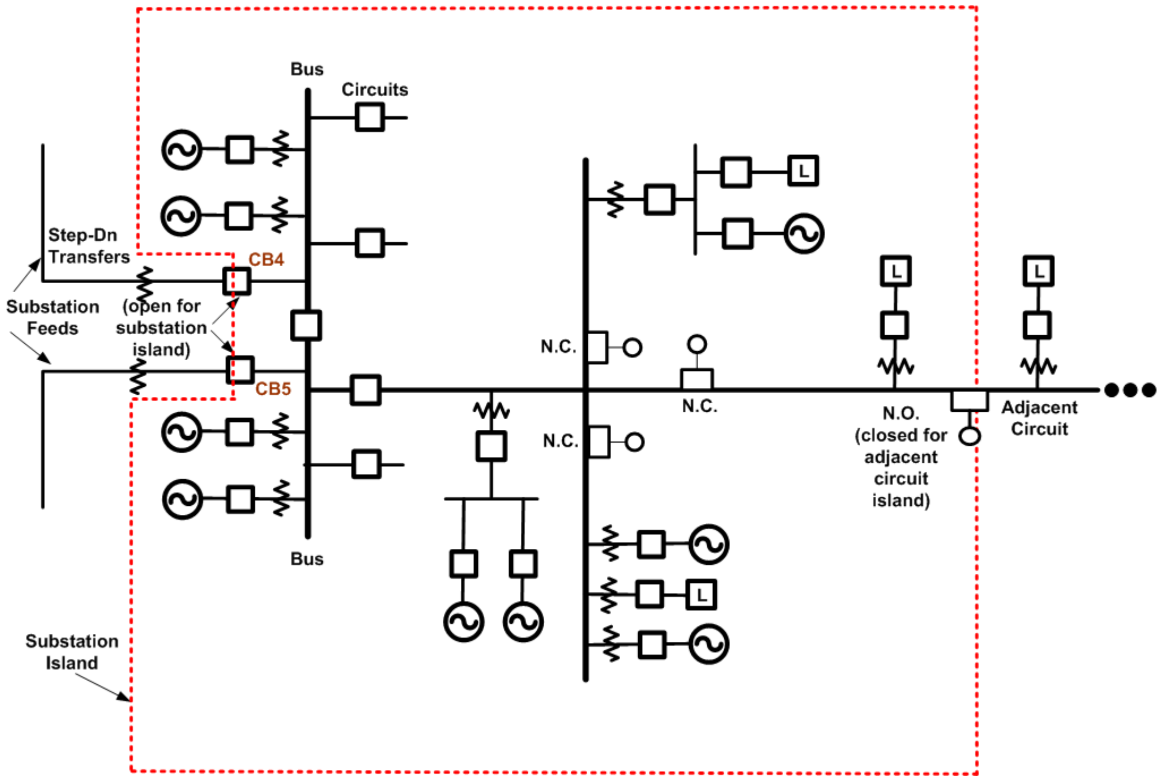

Figure 8—Substation island

4.3.7 Adjacent circuit island

In the adjacent circuit island (Figure 9), load from an adjacent circuit can be served from the islanded portion of the circuit. This provides service in the event of the loss of the adjacent circuit feed and the loss of the main substation feeds. Here, the DR on the substation bus, and on the circuit, could be run, including the facility DR by opening CB4 and CB5 and closing RC2.

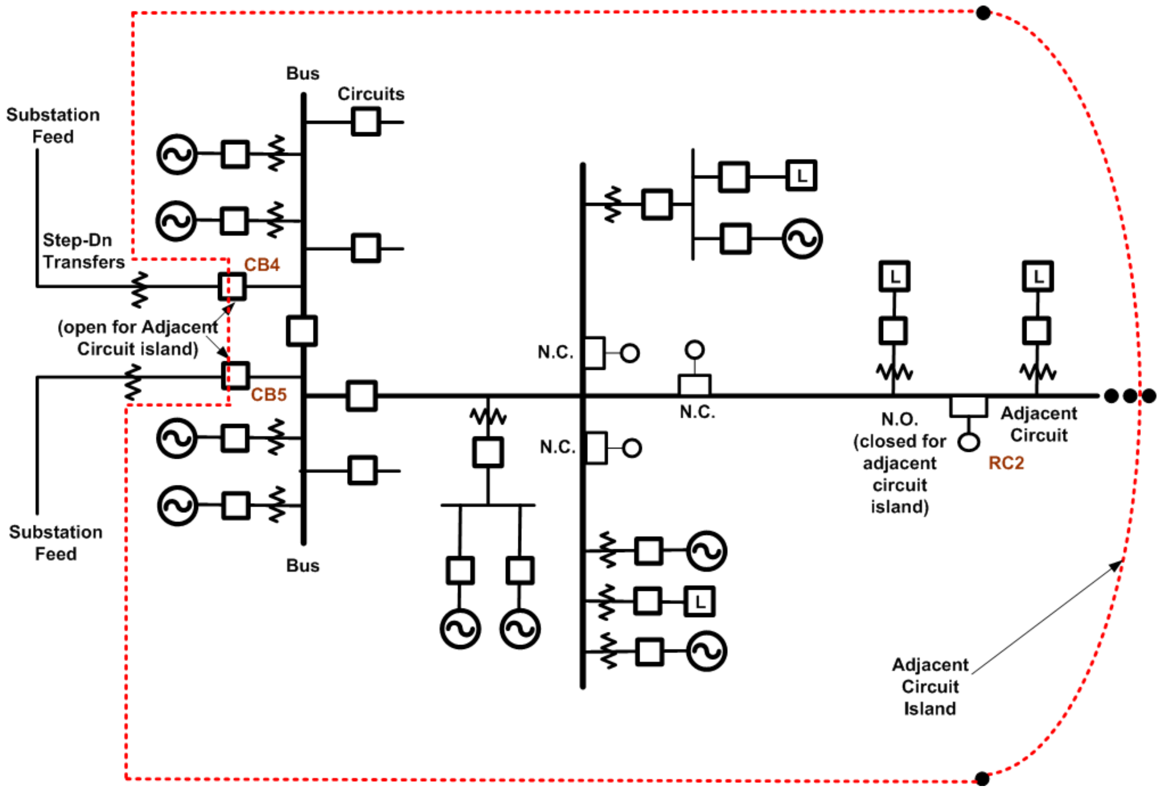

Figure 9—Adjacent circuit island

4.4 Functionality of the DR island system

This subclause explains the normal operating modes of the DR island system. Under most cases, this guide should be followed for strategies to maintain desirable operation of the system under normal parallel and island modes of operation. Some type of monitoring (voltage, frequency, etc.) and control equipment would be needed to control island operation and to implement the transition from normal mode to island mode and return. Depending on the degree of monitoring and control features needed, this controller may need to be very sophisticated.

4.4.1 Area EPS-connected mode (normal parallel operation)

During normal parallel operation with the area EPS, all of the DR on the planned island system shall operate in accordance with IEEE Std 1547-2003 unless agreed upon by the area EPS operator.

The MIC equipment required for island operation needs to be in operation during parallel mode. It is necessary to make this information available to the island control scheme such that a transition can be planned in advance. This should include information about the protective device status, generation levels, load levels, and system voltages.

4.4.2 Transition-to-island mode

A transition-to-island mode can be a result of scheduled or unscheduled events. Scheduled transitions are intentional events for which the time and duration of the planned island are agreed upon by all parties involved. Unscheduled transitions are inadvertent events that are typically initiated by loss of area EPS or equipment failure, and the DR island system may be automatically sectionalized from the area EPS by protective equipment.

Knowledge of the operating conditions of the system prior to islanding and control of those operating conditions will facilitate smooth transfer to an intentional island, particularly in response to abnormal events and when the area EPS is included in the island.

During a transition-to-island, enough DR, and DR of the correct type (e.g., DR conforming to all of IEEE Std 1547.4, including planned, designed, installed, and maintained) needs to be available to support the system voltage and frequency during the system disturbance or scheduled event that caused the island, for whatever time the island interconnection device (IID) and protective relaying takes to operate, to effect a successful transition. Additional equipment may be added to supplement the DR functionality. This DR or additional equipment should also be sufficient to dampen any transients produced in the island by this transition quickly enough to prevent protective relaying in the island from tripping-off islanded DR. If sufficient DR, or DR of the correct type, is not available, then black start capability needs to be provided inside the island.

4.4.3 Island mode

The DR island system needs to be designed to provide the real and reactive power requirements of the loads within the island and serve the range of load operating conditions. The DR island system should be able to actively regulate voltage and frequency within the agreed upon ranges (e.g., as specified in ANSI/NEMA C84.1-2006 for DR island systems that include the area EPS). Voltage regulation equipment within the DR island system may need to be modified to meet the needs of the DR island system. One or more participating DR will need to operate outside the IEEE 1547 voltage regulation requirement to assure DR island system voltage and frequency stability. Non-participating DR operations may also be affected by operating in island mode.

There also should be an adequate reserve margin that is a function of the load factor, the magnitude of the load, the load shape, reliability requirements of the load, and the availability of DR. To balance the load and generation within the island, various techniques (e.g., load-following, load management, and load shedding) can be used. In island mode, there is a need to provide dynamic response from the DR that may have not been necessary in normal parallel operation. The DR sources should have adequate real and reactive power capability and response characteristics. For example, if a motor start requires a large amount of reactive power, there should be sufficient reactive power capacity to correctly maintain voltage and frequency stability or current limiting equipment may need to be installed.

During the island mode condition, transient stability should be maintained for load steps, DR unit outage, and island faults. Protective device coordination should be maintained in both area EPS-connected and islanded operation. All potential faults within the island should be detected and cleared during island mode if they were able to be detected and cleared when in area EPS-connected mode. Adaptive relaying may be implemented to provide adequate protection for a variety of system operating modes.

There should be sufficient monitoring to operate and understand the status of the island. If there are multiple DR units in the DR island system, their operation should be managed and coordinated to effectively meet the needs of the island.

Clause 5 gives more details on planning the DR island system.

4.4.4 Reconnection mode

For reconnection of the DR island system to the EPS, monitoring should indicate that the proper conditions exist for synchronizing the island with the EPS. After an area EPS disturbance, no reconnection shall take place until the area EPS voltage is within Range B of ANSI/NEMA C84.1-2006, Table 1, the frequency range is between 59.3 Hz to 60.5 Hz, and phase rotation is correct. The voltage, frequency, and phase angle between the two systems should be within acceptable limits (i.e., as specified in IEEE Std 1547-2003, Table 5) in order to initiate a reconnection.

The island interconnection device may delay reconnection for up to five minutes after the area EPS steady-state voltage and frequency are restored to the ranges identified above. If an unscheduled event triggered the disconnection from the area EPS, the time before reconnection may be extended to ensure the area EPS is stable. If multiple islands exist, a strategy may be adopted to intentionally stagger the return of the islands.

There are several ways to reconnect the DR island system back to the EPS:

- In active synchronization, there is a control mechanism that can be used to match the voltage, frequency, and phase angle of the DR island system to the area EPS before initiating a reconnection. This technique requires sensing of the area EPS and DR island system conditions and that this information is communicated to the control mechanism.
- Passive synchronization employs a synchronization check for the DR island system paralleling device, which only reconnects the systems within acceptable limits. This device will only reconnect if the synchronization requirements for voltage, frequency, and phase angle are within a certain range to ensure minimal disturbance. This technique also requires sensing of the area EPS and DR island systems conditions and may take longer to reconnect than the active synchronization.
- Open-transition transfer of the DR island system to the area EPS would entail an interruption of the loads served within the DR island system. In this reconnection strategy, the load and DR are de-energized before reconnection to the EPS. DR island system synchronization sensors are not required for this reconnection.

Once the DR island system is paralleled to the area EPS, all DR shall return to IEEE 1547 compliance within area EPS time requirements.

5. Planning and engineering of DR island systems

When a DR island system is planned, the following information needs to be collected or defined:

- A site survey (including an inventory of loads, EPS components, and DR)
- Location, size, and configuration of capacitor banks, voltage regulation equipment, reactors, protective and sectionalizing equipment, and transformers
- Load characteristics and requirements for proper operation
- DR characteristics, fuel source, and black start capability
- DR island system, black start, abnormal voltage, and frequency ride-through capabilities
- Area and local EPS system parameters (e.g., system grounding, fault levels source impedance, impedance model, voltage regulation, protection scheme, and automation schemes)
- Acceptable voltage, frequency, and harmonic range (normal and transient)
- MIC systems and requirements

— The maximum acceptable rate of change of frequency for supplied power
— The acceptable imbalance of voltage at a specific point in the system
— The acceptable dynamic stability limits
— Ratings and types of switching devices
— A means to confirm the intended DR island system is still substantially the same as the previously studied planned DR island system
— Protection equipment and settings
— Provisions for future expansion

This information should be sufficient for developing an engineering model to understand how much power production capacity is needed to meet the island load. If there is not sufficient DR in the planned island to cover the full load, then a load-shedding scheme needs to be developed. This includes determining critical and non-critical loads. A DR installation with an emergency generator and an automatic transfer switch can be sized to support critical loads and would be considered a form of load shedding.

DR island systems operating outside normal utility parameters may cause equipment performance problems because of equipment operating ranges, safety concerns, or customer needs; however, DR island systems may operate outside normal utility parameters if acceptable to all interested parties.

Area EPS operators have an obligation to serve load, and DR availability and reliability needs to be taken into consideration if the DR is not under area EPS control. Planning considerations should be made to serve the load on an area EPS circuit without relying on the DR island system.

5.1 Load requirements and planning

This subclause discusses the characteristics of loads as they pertain to DR island systems. Issues with loads related to how they should be operated in island mode are discussed. Other documents that provide guidance on loads include IEEE Std 446™ *(IEEE Orange Book™),* IEEE Std 1100™ *(IEEE Emerald Book™),* and ANSI/NEMA MG 1-2006.

The DR island system needs to meet the load requirements. There are several considerations dealing with the loads in an island system. The load control scheme should manage all participating loads. This functionality includes load shedding when the DR cannot serve all connected loads. The DR needs to be able to maintain acceptable voltage and frequency throughout the DR island system during all expected load and DR changes.

Loads can have a variety of issues, including active and reactive demand profiles, step loads, motor starts, voltage imbalance, current imbalance, and power factor. On a DR island system, the loads may cause more issues than on an area EPS because area EPSs have a stronger source (i.e., higher fault levels), are larger, and aggregate more loads, which can have a balancing effect.

5.1.1 Load considerations

Load analysis should be completed for DR island systems that includes three-phase detail, historical demand profiles, customer composition, large spot loads such as motors, and a realistic profile of the instantaneous loads (both real and reactive).

When planning a DR island system, load imbalance within the island should be given careful attention. One issue with loads in a DR island system is that the loads may be extremely imbalanced. The individual phase currents of the loads may have considerable imbalance even though the phase-to-neutral voltages or phase-to-phase voltages may be reasonably balanced. Therefore, the load configuration needs to be studied and may need to be modified to facilitate an island configuration.

Single-phase loads may vary significantly during different times of the day or week, or season. Operation of a single-phase protective device (e.g., fuse) may cause a significant amount of load to be lost and substantially increase system imbalance. Large voltage imbalance (>3%) can cause problems to three-phase inverter-based DR by placing high ripple currents on the dc bus. These ripple currents may have an adverse affect on the inverter and energy source (e.g., battery and fuel cell). Most rotating equipment, specifically generators, is designed to operate with no more than as specified current imbalance (ANSI/NEMA MG 1-2006).

Imbalances in the distribution system or load imbalance can cause negative sequence currents that might damage equipment. Three-phase DR and motors have limited negative sequence capability and may be damaged by imbalanced load conditions. Use of a negative sequence current relay can mitigate damage to three-phase rotating machinery. DR island system customers may need to make modifications to protect their equipment for an intentional island.

Cold load pickup is the sudden surge in load on a distribution feeder after service restoration in which some loss of diversity among thermostatic controlled loads and motor starts has occurred. The DR island system needs to have sufficient capacity to pick up the load or have other means to manage the load such as sectionalizing the load into segments and soft-start motors, which will allow the system to start in staged steps. If multiple islands exist, a strategy may be adopted to intentionally stagger the return of the islands.

5.1.2 Reactive power considerations

The reactive power requirements of the DR island system during the island condition are important to consider. DR should be able to support real and reactive load requirements at an acceptable voltage level. The reactive power requirements of the load during island conditions needs to be understood in relation to the real power requirements of the load and the DR island reactive power resources. Particularly, reactive power resources need to be sufficient not only to address steady-state reactive power demands, but also to address dynamic reactive power demands, such as those related to motor starting within the DR island system. There are possible interactions between the customer's and area EPS's power factor correction equipment and synchronous motors and DR. There needs to be sufficient reactive power resources available when operating induction or some inverter-based DR.

Synchronous generators typically have the capability to provide rated power at 0.8 lagging power factor. This is to accommodate loads that consume reactive power. When designing the DR island system it is important to understand that if the load's reactive requirements are far greater than the rating (e.g., 0.7 lagging power factor) then the DR may not be able to provide the full-rated real power and that the generator's operation may be degraded without additional reactive power support (e.g., capacitors).

5.1.3 Transformers

There may be a variety of transformers located within the DR island system. The electrical and mechanical construction of some dry-type lighting transformers and isolation transformers is such that very high magnetizing inrush currents frequently occur when the transformer is re-energized during a transfer operation. The inrush currents may be as high as 20 to 25 times the rated current and may cause nuisance tripping of the overcurrent protective device. The amount of magnetic flux in a transformer is determined by the conditions that existed when the circuit was last interrupted and is unpredictable. The phenomenon exists regardless of whether the secondary is connected. Solutions for overcoming nuisance tripping depend on the manufacturer of the transformers. Sometimes, series reactance, impedance starting, and special overcurrent devices are considered as solutions. A robust solution(s) addressing system study results is necessary because other interruptions, such as momentary outages on the utility supply, can cause a similar problem.

5.1.4 Motors

DR island systems need to be capable of starting and maintaining motor operations. Motor-starting inrush current can exacerbate voltage drops in the DR island system. This voltage drop may result in a degraded ability to start the motor or cause loss of generation. Extended motor acceleration times may cause excess heating, which may reduce motor life and may cause motor overcurrent protective devices to operate. Soft-start controllers or reduced voltage starters on large motors can reduce inrush currents and thus minimize their impacts.

Upon loss of voltage in one phase, polyphase motors will single phase, which may lead to burnout of the motor. Although the motor is normally protected by the overload relays in the controller, additional motor protection schemes may be required. Differential voltage relays, negative sequence voltage, negative sequence current relays, or other detection methods with a close adjustment of 2% for dropout and pickup values will aid in the detection of phase outages and help provide protection when single-phasing occurs.

Because a DR will typically have a Thevenin impedance considerably larger than the area EPS source, large motor starts on the island may also produce much larger voltage sags when started from an island DR than when started from the area EPS system. Special motor-starting techniques can reduce inrush current in the starting of large motors. Excessive modulation of the voltage can produce pulsing and speed variations in motors and can introduce additional ripple in the output of ac/dc power supplies.

Motors and related equipment can be damaged when they are switched between two live power sources. During routine testing of the DR island system, or during retransfer from the alternate power source back to the normal power source, both power sources are at full voltage. Experience has shown that motors, especially three-phase motors of 50 hp or more, when transferred from one energized power source to another energized power source, can be subjected to abnormal inrush currents. This, in turn, can lead to damage of motor windings, insulation, couplings, and in some cases, the driven load. The motor overcurrent device may also trip out because of abnormal inrush current and require resetting. The abnormal currents are caused by the motor's residual voltage being out of phase with the voltage source to which it is being transferred.

5.1.5 Lighting

Lighting loads are used for a variety of service conditions, including evacuation, perimeter and security, warning, and task lighting. If the lighting loads are for emergencies, the power source selected should be capable of supplying emergency power throughout the duration of the longest anticipated power outage.

If the DR island system transition causes a momentary outage, then special consideration should be given if mercury or other high-voltage discharge lighting is used because the total time required for full illumination after a momentary power interruption can range from one minute for high-pressure sodium lights to twenty minutes for metal halide and mercury vapor lights. In these cases, it may be useful to have auxiliary lamps, such as incandescent or fluorescent lamps. Some high-voltage discharge lamps also require a cooling period before they re-strike the arc and a warm-up period before they attain full brilliance. Consideration should also be given when fluorescent ballast lights are used. Their power supplies can cause harmonics, which may be more noticeable when in islanded operation than when paralleled to the utility grid.

5.1.6 Sensitive loads

Electronic computer equipment, used in data processing and process control, typically have special needs to ensure continuous flow of energy, including short-time switching interruptions, voltage surges, dips, and frequency excursions. Often, the suppression of transient disturbances and the need for emergency or standby power can be satisfied through a single installation of supplementary or auxiliary equipment. These transient disturbances have been a part of the electric power supply in the past, but they caused few problems until electronic equipment came into extensive use. In some instances, the solid-state power control equipment has caused problems—particularly on small, independent power systems. Further information on these issues can be found in IEEE Std 1100 *(IEEE Emerald Book).* Computers and peripheral units that draw less than 1.5 kVA are often single-phase. Those that draw more than 10 kVA often require three-phase power. In most cases, single-phase loads can be connected to three-phase sources if load imbalance at maximum load is not excessive.

5.1.7 Load power quality

The DR island system should meet IEEE Std 519. After transferring to the intentional island mode, the DR island system will have a higher Thevenin source impedance, resulting in increased voltage distortion, and therefore may adversely affect power quality. Harmonic loads operating in islanded systems may have a larger negative impact on the DR island system than they would have when served from the area EPS. For example, harmonic loads may reduce transformer capability and life or cause problems with neighboring loads. Options for mitigating harmonics include reduction of the harmonic loads, adding filtering, or selecting a different transformer. Interaction between DR technologies may change during islanded operations.

Significant power line harmonics are being caused by many small, widely dispersed customer loads, such as rectifiers and solid-state controls for adjustable-speed motors. At the same time, an increasing number of other customers are using sensitive equipment such as computers—the operation of which may be adversely affected by harmonics. Excessive harmonic content can cause heating in magnetic (iron) devices such as transformers, motors, and inductors. The harmonic distortion will also appear as additional ripple in the output of some ac/dc power supplies and cause threshold limits to vary in peak and average sensing circuits. It should be noted that elements of the load may introduce considerable distortion or noise into the power source. This reflected noise, although not in the source, may require suppression through filtering to avoid interference with other loads also connected to the system.

Load imbalance may run from 5% to 30% (phase-to-phase) steady state and up to 100% dynamic, as in start-up. The effect of load imbalance is to produce imbalanced phase voltages. Excessive phase voltage imbalance can cause excessive heating to three-phase devices such as motors. Similarly, relays and other electromechanical devices may be damaged because of continuous operation at high (or low) voltage. In addition, high ripple may be observed in some three-phase ac/dc power supplies if the voltage imbalance to the supply is high. High operating voltages can cause the creation of excessive harmonics in transformers because of saturation. The power requirements of step loads can be high, and a DR island system should be designed to accommodate this. Pulsing loads can cause problems and occur when a number of devices that have power peaks, which are coincident and repetitive, are connected to the same power source.

5.2 EPS requirements and planning

If the area EPS allows an intentional island, then a variety of studies need to be conducted (see 5.4) to ensure that the DR island system can properly operate and is coordinated with the EPS. In addition, the adequacy of equipment, configurations, and operations needs to be identified.

The participating DR needs to be compatible with the planned island system and all operating configurations. Non participating DR that operate satisfactorily in parallel with the area EPS may not operate satisfactorily as an island.

5.2.1 Compatibility of grounding among the DR, transformer, and EPS

The area EPS grounding scheme (i.e., ungrounded, effectively grounded, or impedance grounded) needs to be maintained on the DR island system. To maintain the grounding scheme, it may be necessary to switch ground sources. An effectively grounded distribution system needs to maintain an adequate ground source at all times. An adequate ground source takes into consideration the short-circuit contribution of all generation sources. Creation of the island should not change the effectiveness of the grounding system.

An important note on transformer configurations is that area EPS grounding configurations need to be maintained under all operating conditions.

In normal parallel operation, a DR that uses a delta connection on the area EPS side of the isolation transformer may operate satisfactorily with a wye-connected, multi-grounded system. In island mode, a delta-connected DR, by itself without a ground source, shall not serve a multi-grounded islanded system.

There is a specific concern where an area EPS maintains a four-wire multi-grounded neutral system and DR transformers are connected using a delta connection on the high side. In this case, the DR may form an island that includes a faulted portion of a primary feeder that is temporarily separated from the substation circuit breaker while the system protection is attempting to clear a phase-to-ground fault. If the DR can supply the separated load while a phase is faulted to ground, the phase-to-neutral voltage on the separated feeder primary can suddenly rise to the level of phase-to-phase voltage. Thus, a damaging overvoltage condition, typically exceeding 173% is created. Therefore, this connection needs to be avoided, or equipment (e.g., ground bank with relay) shall be installed to stabilize the neutral connection.

This concern is not present for four-wire multi-grounded neutral system supplied by an effectively grounded DR generator through a transformer with windings that are grounded wye on both sides or delta connected on the side with the DR generator. A grounded wye connection on the high side of a four-wire multi-grounded neutral system with a delta low-side connection is commonly used for interconnecting DR with this type of primary distribution circuit.

Transformer connections providing a low-impedance ground source are subject to large circulating currents due to imbalances of ground faults in the area EPS may cause overheating in the transformer or operation of transformer fuses. To counter this potential problem, when a grounded-wye/delta transformer is used, a grounding impedance can be placed in the high-side wye neutral connection to ground to limit excessive circulating currents but still maintain effective grounding of the DR system.

Connecting multiple ground sources on the feeder pose the risk of desensitizing upstream protection devices and causing coordination problems during ground faults. The ground source transformer banks can create a sink for some of the imbalanced ground-fault currents to disappear into and never reach the upstream ground-fault protective relaying. This case needs to be studied to determine the impact on the existing protection and coordination. The DR island system may contain other types of transformer configurations—including T-connection, open-delta, and autotransformers—that may need to be considered. More information on this topic is included in IEEE Std 1547.2.

5.2.2 Voltage regulation

The voltage control scheme of the EPS and the DR island system should be coordinated in island mode and should not adversely interact. Detailed reviews of voltage profiles, voltage schedules, voltage control, and circuit element loading should be conducted. The voltage regulation equipment should be sized to handle the load conditions under parallel and island modes. Voltage regulation on the EPS distribution systems can be done with voltage regulators, shunt capacitors, load tap changers, static/dynamic var compensators (including inverters), static synchronous compensators (STATCOM), and synchronous condensers. In the planning stage, identify and account for all capacitors that will be tied into the DR island system. Capacitors contribute to the reactive power generation of the DR island system. The amount of reactive power of the DR island system should be balanced. Additional reactive power requirements may be provided by the DR.

When in island mode, one of the DR will need to regulate voltage. DR voltage control will need to be coordinated with other regulating devices in the system. This will require some type of control that will coordinate the set points of different DR units and those of capacitor banks and voltage regulators to maintain the desired voltage profiles. This may require that the DR operate outside of certain IEEE 1547 requirements. Line voltage regulators, within the island, may now have power flow reversed from the original planned direction. If the regulator control does not respond appropriately during reverse power-flow conditions then damaging voltage levels may be produced. Line voltage regulator controls need to regulate the weaker of the two sides to which they connect. If the stronger side is assigned as the controlled bus, the regulator will go to tap limits due to positive feedback, and can result in very high or very low system voltages. Line voltage regulator operation in an islanded area EPS needs to be carefully studied, as the stiff and weak sides may be very situational dependent. Also, many line voltage regulator controls have power-flow sensing, which assigns the controlled side depending on the direction of power flow. With DR in a system, either islanded or interconnected, the direction of power flow and the stiff/weak sides are generally uncorrelated, resulting in these power-flow-based controls adding another complication to be considered. Displaced load may also cause the voltage regulator to misoperate if it uses line-drop compensation. The settings on voltage regulators and load tap changers may need to be adjusted. The voltage impact of the shunt capacitor may also be affected by the amount of short-circuit duty in islanded mode versus parallel connection. Loss of load, when in island mode, may cause sudden voltage changes and needs to be evaluated and addressed if necessary.

Exchange of reactive power between the DR island system and the DR may be required in certain cases, depending on the location of the DR, its capacity, and the presence of other voltage-regulating devices within the DR island system.

There may be additional requirements for the development of the planned island. Specific voltage levels may be required at the substation or selected buses to facilitate smooth transfer to island mode, which will likely depend on the reactive resources within the island, load levels, and settings of regulating devices.

When considering inverter technologies, voltage source mode may be preferred to current source mode for a system planned for islanding. In this mode, the operation of the inverter more closely emulates that of a synchronous machine and may contribute to improved power quality by active harmonic suppression and voltage regulation. These issues are considered in IEEE Std 1547.2 in some detail, but the ability of this mode of operation to smooth the transition to island mode needs to be evaluated. Inverters are typically operated in voltage source mode when planned to control voltage in an island.

5.2.3 Frequency regulation

When planning DR island systems, it is important to consider the method of frequency regulation of the DR device and the frequency sensitivities of the loads. A DR island system may not be able to control frequency to the same bandwidth as the normal source of supply. The frequency deviation of a DR island system needs to be acceptable to all associated parties. For example, the North America power system normally operates at 60 Hz with a tight frequency band ± 0.05 Hz.

Considerations for the DR island system control strategy are the capability of a primary DR to operate in isochronous control mode (i.e., as a swing or slack generator), participating DR that operate in real power sharing mode, local speed droop control (i.e., can operate without communications between DRs, and depends on fuel availability, governor, and fast exciter), dispatch capability for rebalancing contribution of participating DRs, and load characteristics. The capability of the DR island system to maintain a tight frequency range will dictate the ability for load following.

Rotating ac loads are sensitive to system voltage and frequency. Therefore, they depend on the system power quality or the voltage and frequency stability. Some equipment may not operate correctly if frequencies deviate significantly from nominal (e.g., ac-powered clocks). Some DR have problems recovering from low frequencies and may not be able to support an island at this frequency. DR designed to meet IEEE Std 1547-2003 will also have specific frequency trip limits that may need to be adjusted to operate in an island mode.

Once in an island mode, the participating DR in the DR island system may need to change its control philosophy from anti-islanding schemes to integrate with underfrequency load shedding within the island.

Most turbine generators need to have frequency regulation to prevent mechanical resonance. In most cases, the turbine generator mechanical resonance frequencies are designed to be at frequencies far away from the intended electrical operating frequency. Therefore, unless the frequency deviation is greater than 5% of nominal, the mechanical resonance frequency may not be a concern.

The other issue related to frequency is the volt-per-hertz limits. The DR island system needs to operate within the volt-to-hertz ratio specified by any relevant equipment manufacturers. The heat loss in the generators, motors, and transformers is proportional to the volt-per-hertz ratio. Generators and transformers that operate at substantial deviation from the equipment designed frequency or outside the volt-per-hertz ratio boundary may be damaged.

5.2.4 Island interconnection device

An IID is used to create the intentional island. Existing sectionalizing devices that may be considered for the IID, and installed on the area EPS, need to be rated for use as an IID or may need to be upgraded for such use.

If the DR island system is planned to operate in a mode that parallels with the area EPS when it reconnects, then the IID is a paralleling device that shall be capable of withstanding 220% of the interconnection system rated voltage and needs to have a synchronization check function.

5.2.5 EPS power quality

When operating in the planned island mode, power quality may be negatively affected. Since the DR island system will have higher Thevenin source impedance, voltage flicker and harmonics may become an issue when operating in island mode. Capacitors used for power factor correction or voltage regulation that are within the DR island system may cause a harmonics sink, and a reactor may be required. The addition of capacitors with a high-impedance system may result in a ferroresonance condition.

5.2.6 Protection coordination

In an island mode, the DR island system needs to be able to detect area EPS faults. This will require that adequate protection equipment be installed, set and maintained in the DR island system. This includes sensitivity and time coordination changes (directional where applicable). Area EPS modifications may be necessary to accommodate planned islanding, in light of decreased fault-current contributions. Reclosing practices also need to be examined when planning the DR island system. There are many distribution system configurations and fault-clearing practices, and philosophies differ among utilities. Distribution systems are primarily radial from an area EPS substation and are generally not designed for parallel operation with downstream generation. Often, the utility uses three-phase as well as single-phase protective devices (e.g., fuses and single-phase reclosers). Often, multiple reclosing is attempted before a device is locked open. The reclosing can be instantaneous (i.e., no intentional time delay) or range from several seconds to longer.

Single-phase protective devices can become a problem between the substation and one or more DR within an island. DR fault-current contribution affects the sensitivity of area EPS protection and desensitizes all protection between the area EPS source and the DR. In addition, operating in this mode can increase the sensitivity of devices beyond the DR and on laterals during normal operation. If there are laterals connected between the normal source (area EPS) supply to the load downstream from the DR PCC, the area EPS supply protection electrical coverage is reduced for that portion of the radial circuit beyond the PCC. If there are laterals with overcurrent protection connected to the feeder between the point of EPS supply upstream of the PCC, the normal overcurrent protection electrical reach at the source to the feeder will be reduced, but the electrical reach of the lateral's protection will be increased.

DR can also interfere with fuse-saving schemes and change fault-current distribution for lateral fuse applications. Ground-fault detection depends on the type of ground protection and the type of grounding on the EPS side of the interconnecting transformer. Overvoltage effects also depend greatly on transformer connections.

Coordination problems may exist between the area source EPS protection and the DR protection associated with the area EPS because an island energized solely by DR is likely to have substantially reduced fault current available, and this may significantly impact the application and coordination of protective relays. Additional protection equipment, or modified schemes and settings, may be necessary to detect and clear all faults meant to be detected and cleared by the area EPS protection system.

The DR has fault-clearing practices that need to be integrated and coordinated with the area EPS. The DR fault-clearing practices are governed by the authority having jurisdiction. Fuse-saving schemes are very common on overhead distribution. In fuse-saving schemes, a recloser (or breaker) is designed to operate quickly and clear a temporary fault before a fuse is damaged. If the fault persists, the fuse will clear the fault.

The short-circuit current contribution from the DR needs to be identified. Inverter-based DR typically produces less fault current on a per-unit basis than the typical synchronous generators used to supply fault current. This needs to be considered in the system protection coordination studies. If an inverter-based DR that has a fault-current limit near 1 or 1.2 times the EPS's load-carrying capability or less is used, it is unlikely that selectivity (coordination of protective devices) can be established because sectionalizing fuses blow or other devices trip at approximately 2 times their respective load rating. If selectivity is required and inverter-based DR is being used, the overcurrent rating of the DR can provide appropriate fault-current contributions. If the inverter-based DR cannot supply this level of fault current, then a different protection scheme should be evaluated. System fault studies will indicate if the inverter system is capable of providing enough fault current to satisfactorily operate existing protective devices. Traditional distribution protective methods such as time-overcurrent may not be adequate for detecting and clearing faults within the island system.

All standard checks should be made to determine if faults will be cleared consistent with the applicable local policy. These checks include determining if all types of faults *anywhere* on the island system will be cleared. Sensitive relay settings at the generator may be necessary to accomplish this. Because the DR will typically serve considerably less load than the total circuit, it may be possible to use a relatively low overcurrent setting to sense faults on remote portions of the circuit. Sensing and clearing faults may be easier to accomplish than establishing conventional selective protective device operation. Protective devices already installed on the circuit may be set to trip at values far above the fault current supplied by the DR. Because the island condition is likely to be temporary, it may not be feasible to replace or reset protective devices to establish selective tripping for the entire island or even a portion of it.

5.2.7 Distribution automation schemes

Many area EPSs are implementing distribution automation schemes, which can dynamically change the configuration of area EPS lines. These schemes can automatically switch circuit load, reclosers, sectionalizers, and circuit breaker positions to limit the amount of the area EPS system that is overloaded or faulted. The goal of distribution automation systems is to increase the reliability of service to area EPS customers.

The proposed DR island system should consider the impact of existing EPS distribution automation schemes, and should also consider distribution automation schemes to match the DR island load with the available DR. The proposed DR island system should consider all possible arrangements of area EPS lines to determine the effect on the intentional island. If the DR island system was intended to include part of the area EPS line, then the reconfiguration will probably have a major effect on the operation of the island. If the intentional island is a lateral tap off the area EPS line, the impact may be much less. In either case, additional coordination studies will likely be required.

The above considerations are also applicable to local EPSs that use distribution automation schemes.

5.2.8 Monitoring, information exchange, and control

IEEE Std 1547.3-2007 provides guidance on information modeling, use case approaches, and pro forma information exchange templates. This information is applicable to the extended DR operating scenarios addressed by IEEE Std 1547.4 that include (1) DR in grid connected operation, (2) DR in intentional islanded operation, and (3) transition states between these two.

Information to support specific design and implementation of a communication system is beyond the scope of both IEEE Std 1547.3-2007 and IEEE Std 1547.4-2011. This guide identifies the need to incorporate MIC in the planning of an intentional island and points to recommended references.

As an introduction to the communication concepts underlying IEEE Std 1547.3-2007, two key figures from that guideline are reproduced below as Figure 10 and Figure 11. The reference diagram for information exchange shown in Figure 10 is Figure 1 in IEEE Std 1547.3-2007.

Figure 11 is from IEEE Std 1547.3-2007 Figure 2.

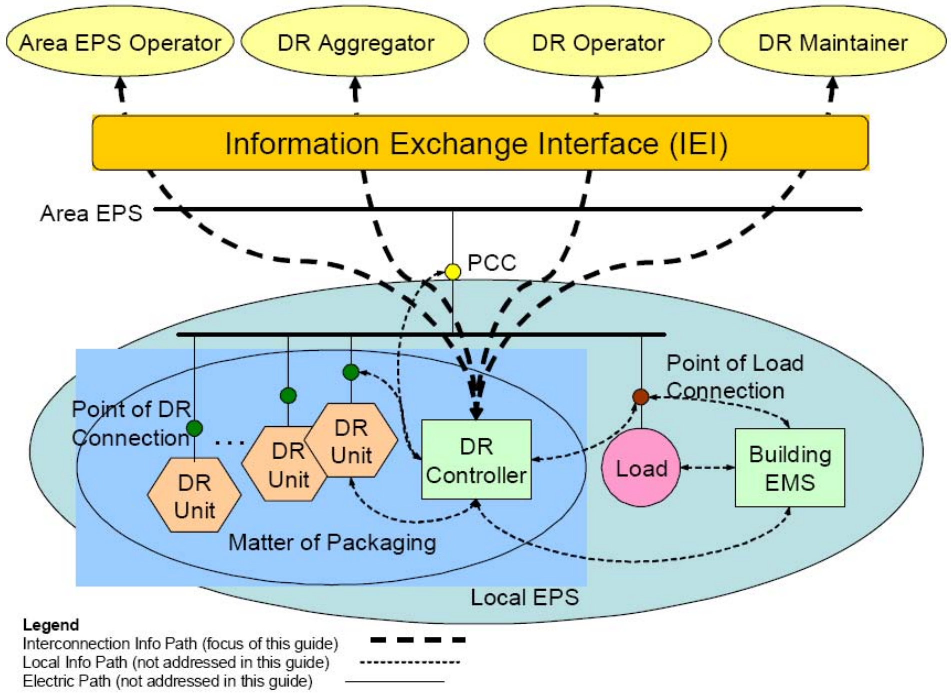

Figure 10 —Reference diagram for information exchange

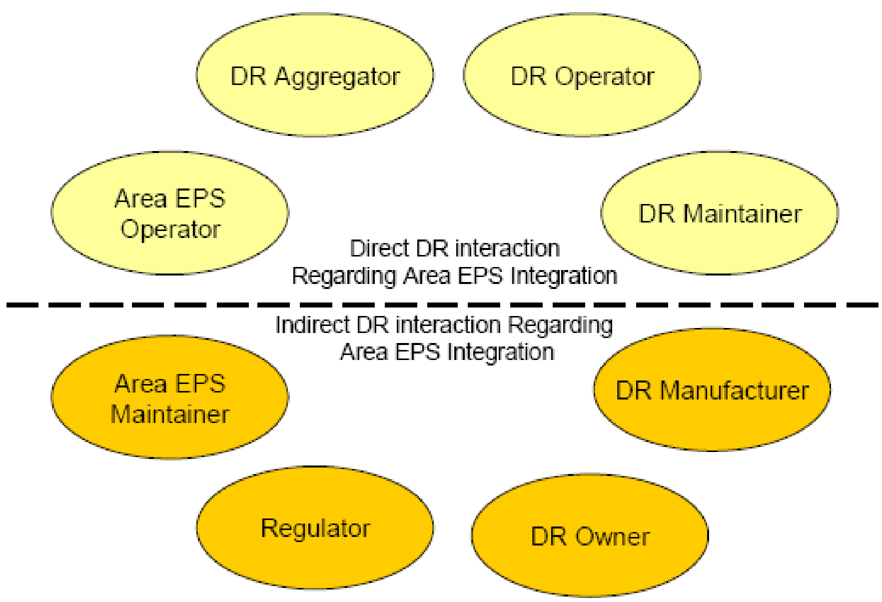

Figure 11 —Stakeholder roles relevant to DR interconnection

The basic stakeholders and communication pathways shown in Figure 10 and Figure 11 are relevant to an intentional islanding capable system. Clause 1 of IEEE Std 1547.3-2007 provides an explanation of these diagrams and key terms.

There are additional aspects unique to intentionally islanding systems that warrant consideration in the planning and operations of its communication system. While each islanding system may be unique, general consideration should always be given in planning any communication system that can be exposed to the additional challenges introduced, or aggravated, by a system that can be isolated and operate independently from the EPS.

There may be additional MIC requirements for DR island systems (typically increasing requirements for larger DR island systems), with specific monitoring, control and protection requirements for reconnection mode, coordinated frequency regulation, coordinated voltage regulation, communications assisted protection (when local protection was not planned for the intended island mode), and distribution automation schemes. These additional MIC requirements will warrant additional consideration in the planning and operations of the communication system to support the DR island systems.

A few communication topics for consideration during planning of an intentional island include the following:

— Mitigating communication system interference from increased electrical noise due to increased harmonics from operation of generators and loads on a relatively high-impedance isolated system.[8]
— Mitigating loss of communication systems dependent on energization from the EPS. The threat of loss of communication systems due to isolation from and/or loss of the EPS may require redundant communication systems. The time delays in the communication system should be considered if the system is used for protective signals.

When operating in an island mode, communication alternative arrangements may need to be made. For example, a power line carrier may not operate properly without provisions for the island condition.

5.3 DR requirements and planning

5.3.1 Planning for DR operation

Details of the characteristics of DR can be found in the annexes of IEEE Std 1547.2.

When a DR island system is connected to the EPS, then IEEE 1547 requirements apply at the PCC. In order to form an intentional island, the DR island system should recognize that certain conditions exist on the EPS. DR controls can be programmed to operate in different modes (base-load, load power dispatch, etc.) under normal grid paralleled conditions. When forming a DR island system, it may be necessary to switch from one such control mode to another when separating from a larger EPS. The DR may have to transition voltage control and switch from a passive control that follows the system voltage (per IEEE 1547 requirements) to an active control that maintains the voltage of the DR island system.

In a base-load mode, for example, an inverter-based DR can deliver a commanded level of power to the grid at a constant power factor. In this mode the inverter-based DR simply tracks the frequency and phase of the prevailing grid voltage, which is controlled by a local “swing” generator or by the aggregate effect of a connected larger utility grid.

[8] A recommended reference is Chapter 23, Coordination of Power and Communication Systems of the *Electrical Transmission and Distribution Reference Book,* ABB T&D Power Company, 2007.

Alternative power generation, either fueled or using renewable energy sources, often produces dc or variable frequency electrical power, requiring the use of an electronic power converter (inverter) for coupling to the ac grid. Viewed from the grid, an inverter-based DR is essentially an actively controlled voltage source connected through impedance (e.g., a passive low-pass filter network and coupling transformer). The controlled voltage response is usually extremely fast (<<1 ms), allowing the control system to produce a variety of possible operating characteristics. The intent and design of the voltage control system mainly determines the transient and the dynamic behavior of the equipment.

5.3.2 Aggregation of multiple DR

Although individual units can be controlled independently, the operation of participating DR in the island needs to be coordinated. Their operation will need to complement that of other DR as well as other components of the distribution network to ensure the required voltage levels, reserve requirements, and reactive power capabilities are met. In some respects, aggregating the DR units located within the proposed island can help identify whether these requirements are maintained during normal operation—particularly those related to power export/import and reserve margin. It is also useful to note that there may be non-participating DR within the island. The non-participating DR will operate as if they were connected to a larger EPS and still need to follow IEEE 1547 requirements. Intentional island operation may require greater knowledge of the voltage levels at specific locations within the island to help evaluate power balance.

Different DR have different capabilities and load-sharing needs to be coordinated according to their ratings and control capabilities. It will be important to make sure the aggregated DR can satisfy the load conditions of the island. It is also useful to plan for DR outage within the island to make sure there is enough generation to support the planned load or develop a load shedding scheme.

5.3.3 Adjustments to DR settings

When operating in a DR island system, it is usually necessary to adjust several control settings of the DR. Anti-island, undervoltage, and underfrequency settings may interfere with island operation. If the DR is using an active undervoltage and underfrequency island detection system consistent with IEEE 1547 limits, operation as an island may produce undesirable generator tripping. Faults electrically close to the DR are likely to reduce the voltage at the DR to less than 50% of nominal. The present requirements in IEEE Std 1547-2003 for undervoltage tripping time are 0.16 s for voltage less than 50% and 2 s for voltages less than 88%. Operation for these undervoltage conditions during fault conditions will trip the generator, which will result in an entire island outage if the island is served from a DR at a single PCC. This is likely to disrupt any selective operation of the protective devices on the island.

It may be desirable to turn off or modify undervoltage tripping that will trip the generator during the voltage sag caused by a fault. A review of relay settings within the island should be conducted.

In a DR island system, it may be necessary for inverter-based DR to "ride-through" voltage disturbances resulting from faults or sudden load changes. Low-voltage ride-through (LVRT) capability may be especially important during the brief period while separation from a faulted larger grid is being affected. LVRT capability is actually a deviation from prevailing standard practice for DR, but it is something that can readily be achieved with inverter-based DR.

5.3.4 DR voltage and frequency control and DR load-sharing

This subclause discusses various methods to control DR voltage and frequency when in island mode. These are important considerations, because when the DR island system is operating as an intentional island, one or more of the DR need to maintain proper voltage and frequency conditions. This subclause is applicable to both rotating and inverter-based DR systems.

5.3.4.1 Voltage regulation

When a DR is operating isolated from an infinite source such as the grid, voltage regulation can be achieved by either voltage droop or reactive power sharing. Voltage droop will probably be dependent on the island formed, while reactive power sharing will probably require a high-speed communication system and some form of central control.

5.3.4.1.1 Voltage droop

Voltage droop is a reduction of the voltage set point as the reactive load increases. The amount of reactive load on the generator is measured by what is typically referred to as a droop current transformer (CT). Control algorithms, implemented via electronic hardware or software, are used to change the droop setting as the reactive load changes. As an example, a 3% voltage droop setting is where the voltage setting and actual terminal voltage will reduce (droop) 3% at full reactive load compared to the voltage at zero reactive load. No communication or signals between generators other than the generator connection to the common bus are required for droop operation.

Droop operation requires periodic rebalancing of the droop control circuit to evenly balance the reactive load between generators, and the open loop control design can lead to inequitable reactive load sharing. One method of applying some simple feedback is by a system of relays connecting cross-current compensation CT currents to the generators that are currently connected in droop on the same bus.

5.3.4.1.2 Reactive power sharing

Reactive power sharing operates under the following control method. The system reactive load level is provided to all of the generators operating on the common isolated bus. Each generator adjusts its individual reactive power output to match the system-average reactive load. This is a closed-loop control method that is usually implemented with a proportional, integral, derivative (PID) algorithm, which results in more even control with less required readjustment to maintain satisfactory results. Unlike droop control, voltage control of the islanded system can be maintained by a control algorithm that corrects for low or high system voltage. The voltage-correction feedback is applied to all of the generators to maintain the desired system voltage.

Reactive power sharing requires that the system reactive power average be communicated to all generators. This is commonly achieved using an analog control signal or digital control communication. In this approach, specifics of the equipment, interfaces, and available communications protocols may present challenges.

5.3.4.1.3 Frequency control

When a DR is operating isolated from an infinite source such as the grid, frequency control can be achieved by either speed droop or real power sharing. Normally, the DR connects in parallel with an EPS that is a "strong source" (an infinite bus in most cases). The EPS source is the system swing generator, and the DR operates as the base-load unit. Therefore, if there is load swing because a block of load is added or removed from the system, there is little effect on the power system. When the DR and selected load are operating as an island from the EPS, the DR has to be able to regulate its voltage and frequency as well as system voltage and frequency within an acceptable band. In this islanding mode, the operating frequency band may not have to be as tight as that regulated by the North America Electric Reliability Corporation (NERC) or the area EPS operator. The quality of voltage and frequency of the intended island can be predetermined and accepted by the part of the area EPS that is islanding with the DR. This voltage and frequency band depends on the type and characteristic of the connected load in the island. However, for the DR generator to have the capability to respond to the frequency change (drop or rise) because of block loading or unloading, the generator governor control system needs to include a speed-droop control and operate just below its maximum rating (i.e., the turbine and generator need to be sized to be larger than the anticipated load of the intended island). To prevent equipment in the island from damage because of off-nominal frequency, the DR governor should automatically and quickly act to restore the system frequency if it deviates more than a prescribed amount.

Typically an inverter-based DR acts as a controlled current source. However it could be designed and controlled to act as the static equivalent of a hypothetical rotating synchronous generator having an extremely fast field exciter, very low circuit impedance under normal operating conditions, active current-limiting output under fault conditions, and a governor providing instantaneous control of frequency and phase angle, regardless of load.

If an inverter-based DR incorporates a controllable source of real power, it can act as the swing generator for an intentionally islanded grid, accurately establishing the absolute frequency and phase of the ac bus voltage at its point of connection (with negligible steady state or transient deviation). In this mode the inverter-based DR exchanges real and reactive power with the grid as needed to maintain the balance between generation and load.

A system-stability study should be performed for the islanding system under its maximum anticipated block load drop or block added load to ensure the system voltage and frequency can be recovered within a predetermined time and maintained within the predetermined and acceptable bands for all possible system swing conditions. The ramping rate of the generator should be determined when it is operating in islanding mode.

5.3.4.1.4 Speed droop

Speed droop (or a master-slave configuration) is defined as the reduction of the speed set point as the load on the generator is increased. For example, a 5% speed droop setting is where the speed setting on the governor is reduced (drooped) 5% at full real power load compared to the real power load at no load. No communication or signals between generators other than the generator connection to the common bus are required for droop operation.

Droop operation requires periodic rebalancing of the droop control circuits, and the speed setting is periodically required to evenly balance the real load between generators; the open-loop control design can lead to inequitable real load sharing. Active synchronization is usually required to match the frequency of the drooped system back to utility frequency to meet phasing and slip requirements before the reconnection can be made.

5.3.4.1.5 Real power sharing

In real power sharing, the system real load level is provided to all of the generators operating on the common isolated bus. Each generator controls its individual real power generated to constantly adjust its output to match the system real load. This is a closed-loop control method, which is usually implemented with a PID algorithm, that results in more even control with less required readjustment to maintain satisfactory results. Unlike droop control, the system remains very close to the nominal frequency, and time error correction is easily applied.

The disadvantage of real power sharing is that the system real power average needs to be communicated to all generators. This is commonly achieved using an analog control signal (e.g., load share signal), which is applied to an analog load bridge circuit on each generator control, or by a digital control communication.

5.3.4.1.6 Isochronous control

One variation on the droop method of control is to have a single generator, typically referred to as the *swing machine,* operating in isochronous mode. Other generators may be operated in droop against this swing machine and, by means of adjusting their speed set point, operated at a constant real power setting. The isochronous machine needs to be able to handle load rejection and acceptance to maintain the steady-state frequency.

Another variation of the isochronous load-sharing system is to put one or more of the generators in a base-load mode of operation. As opposed to droop, the individually base-loaded generators have a closed-loop feedback algorithm to maintain the desired base-load set point. The remaining units in isochronous load share need to be able to handle load rejection and acceptance to maintain the steady-state frequency.

5.4 System studies

When planning a DR island system, system studies need to be conducted in each operating mode that include detailed reviews of voltage profiles, circuit element loading, fault clearing, protective device operation, and system stability. System studies help ensure a satisfactory quality of service to customers served from the DR island system. This document provides a description of the studies that should be considered to evaluate the operation of the DR island system.

Conventional power system planning studies include load-flow studies (entirely steady state representation of the generator) and dynamic stability studies (sequential load-flow calculations in 5 ms to 20 ms time-step, capturing slow dynamics such as synchronous generator phase angle and excitation changes). In some instances, transient studies including detailed circuit and control models (1 µs timeframe) may be needed.

IEEE Std 399™-1997 *(IEEE Brown Book™)* provides a good reference for conducting several of the types of system studies.

5.4.1 Generation capability planning

A study should be conducted to examine the available generation of the DR island system and compare it with the load. Different DR have different real and reactive power capabilities and capabilities to change output to follow load variations. Load-sharing needs to be coordinated according to the DR ratings and control capabilities. Load requirements that have been identified should be addressed. The characteristics of the DR used in the island should be examined to see if they are compatible with the loads. The method of generation control should be defined when operating in both EPS-connected mode and island mode.

While paralleled to the area EPS, DR equipment needs to meet the power-quality requirements of IEEE Std 1547-2003. When in DR island mode, the power quality needs to be acceptable to all parties.

The island may also be required to provide black start capability. Black start capability then needs to be planned, including that it be considered as part of an operational procedure. Black start capability is the ability of the DR to restart itself without power from the area EPS.

After an outage that affects the loads in the island, cold-load pickup issues should be considered. This condition results in higher loading than originally expected due to high starting loads (motors and transformers) and should be accounted for with added capacity or a load-shedding scheme. Cold-load pickup needs to be designed into the system.

5.4.2 Load-flow studies

A load-flow or power-flow study of the island needs to be completed in order to evaluate the match between generation and load. It should be in addition to any studies done with the DR operating in parallel with the system. The load-flow study needs to include a voltage profile for all significant load conditions. The first concern includes heavy load conditions to detect low-voltage conditions. But the study should also provide voltage profiles for lightly loaded conditions. Motor-starting studies should also be performed if known large motors will be started during island operation.

All capacitors and regulators should be included in the model. As mentioned previously, caution should be taken to ensure no voltage regulators are online in the island that would have power flow reversed from the normal direction unless the voltage regulator is capable.

The island may have load that is imbalanced. A positive sequence (balanced) power-flow study may not produce indications of high imbalance. If the model is incapable of modeling imbalanced load, or if the database for the model is out of date or only indicates total three-phase values, consideration should be given to taking actual readings on the circuit. The values actually monitored should then be placed directly into the model or taken into consideration when determining imbalance loading of the generator. During the design phase, it may be necessary to first transfer load between phases to balance the load prior to implementation of the island to avoid unnecessary tripping of the generator because of highly imbalanced load producing high negative-sequence current in the generator.

The steady-state voltage profile on the system is one of the most important portions of the load-flow study. Voltage-regulation capability of the DR needs to be considered to ensure that voltages of the DR system are within the agreed upon ranges (e.g., as specified in ANSI/NEMA C84.1-2006 for DR island systems that include parts of the area EPS). The person performing the load-flow analysis should maintain an awareness that unexpected interactions with voltage control devices may exist. For example, a capacitor that turns on based only on time of day may cause high voltage if the DR is connected nearby and the capacitor is regulating to a 1.05 system voltage, but is monitoring the voltage only on the generator side of an interconnection transformer.

5.4.3 Short-circuit and protection coordination studies

Short-circuit studies should be performed for the island for all foreseeable configurations to ensure clearing of faulted conditions. The studies should be performed for the parallel case and the island case. Normally, this is done with all the generation connected and on (i.e., maximum DR generation) and with minimum generation on. Protection needs to be sensitive enough to protect for short circuits in the islanded area with reduced fault-current capability. Typically, the existing overcurrent protection may not work because the setting values were sized based on the fault-current contribution from the area EPS and not the DR of the DR island system. A coordination study needs to be completed on the protection devices. The transformer connection will also affect protection coordination and should be identified. The identification of the ground source is extremely important for ground-fault protection coordination. Many devices, such as thermal or magnetic circuit breakers, may exhibit delayed clearing (or not clear at all) due to the very limited fault current. This may lead to additional damage to the faulted device.

The short-circuit study should provide the maximum short-circuit duty at the location of major customer loads, each DR, and each voltage-control device. It should be noted that fault currents can be in different directions when the mode of operation is changed. There is a significant difference between utility contribution and DR contribution to provide fault current. The short-circuit current capability from the DR needs to be identified. In protection coordination, distance relays based on impedance could become inaccurate when the mode of operation of the DR island system is changed from paralleled to island mode.

When a short-circuit analysis is performed, the following items are recommended; a protection engineer should:

— Determine if existing protective devices will be desensitized beyond permissible limits; recommend protective device modifications as required.
— Determine if the additional fault-current contribution from the DR subjects any devices to fault-current duty beyond their capability (i.e., interrupting, momentary, and fault closing ratings).
— Determine if reclosing or momentary faults are likely to cause loss of synchronism by the DR.
— Determine if any protective devices will become overloaded because of the DR operation; recommend protective device modifications as required.

Inverter-based DR are usually current-limited, through rapid control action, in order to stay within the turn-off capability of their semiconductor switches. Consequently the fault-current contribution from an inverter-based DR are usually small by comparison to machine-based DR.

Ideally, the inverter-based DR would continue to output balanced sinusoidal current, less than or equal to the limit, while the EPS voltage deviates within specified allowable ranges. Clearly, the actual performance under these conditions may vary from one particular piece of equipment to another, depending on the design of the associated control system.

The limited fault-current contribution from inverter-based DR should be taken into account when designing the coordinated protection for an islanded grid. Furthermore, it is important to note that inverter-based DR do not generally provide any significant overload capability. In an islanded grid supplied by inverter-based DR, current surges due to motor starting, for example, need to be accommodated within the normal rating of the inverter-based DR equipment.

5.4.4 Stability of a DR island system

Traditionally, stability is determined by considering only the inherent mechanical and electromagnetic characteristics of the synchronous machines and the impedance of the circuits connecting them. Small-signal stability analysis takes automatic voltage regulator and governor system responses into account. If adequate modeling information is not available, testing may be required to determine an accurate response characteristic for the DR.

Stability studies require detailed knowledge of the equipment control system and electronic self-protection action. Because of the fast response of an inverter-based DR control system, the simplified dynamic equations and long time-steps (5 ms to 20 ms) normally used in stability studies may not be suitable. Instead, a detailed transient model of the inverter-based DR and its controls may be needed. Such detailed models are specific to each particular equipment design so generic parameterized models may not be adequate.

In the case of a islanded grid, the transient model for the inverter-based DR can be part of a detailed transient analysis of the entire grid or, through a suitable sampling interface, can represent the inverter-based DR accurately in a hybrid dynamic stability study (i.e., a dynamic stability study incorporating detailed transient models of some equipment).

In a DR island system, it may be necessary for inverter-based DR to ride-through voltage disturbances resulting from faults or sudden load changes. LVRT capability may be especially important during the brief period while separation from a faulted larger grid is being affected.

Under an intentional island scenario, stability should be evaluated and understood at the planning stage of a proposed intentional island. In large part, this requirement is to assess stability of the DR island system when in islanded versus parallel operation. This is due to the fact that prior connection to a high-capacity (dynamically stiff) utility system is no longer present under islanded conditions. Under DR island operations, the island needs to remain dynamically stable.

Once a DR island system is formed, it lacks connection to a system of much greater relative magnitude (megavolt-ampere capability) than any single machine within the intentional island. The lack of a substantial system with large aggregate inertia will, in general, lead to a much different stability response after operating conditions change from DR operating in parallel with a large area EPS to islanded operation with one or more DR. The one constant between these two scenarios is the impedance shared by the interconnected DR that comprises the islanded system.

When paralleled with a relatively large-capacity system, the stability of the overall system is not usually at risk because of the response of any one source. And in general, system-stability studies are not required for interconnection and parallel operation of smaller DR with a utility system. For example, the Federal Energy Regulatory Commission (FERC) pro forma tariff *Small Generator Interconnection Procedure* (SGIP) does not specify a stability study as part of the interconnection process for small generators (20 MW or less), but FERC *Large Generator Interconnection Procedure* (LGIP) does.

The intent and design of the voltage control system can help shape the transient and dynamic voltage behavior of the system. However, at the time of separating from an area EPS and forming the island, also present will be the influence of voltage effects due to the redistribution of energy stored in the inductive and capacitive circuit elements at the PCC. Additionally, if large inertia machines might exist in the island, similar transient and dynamic voltage effects can arise from sudden changes in stored energy.

Another reason for performing stability studies on an islanded system is to determine critical clearing times for protective relays, based on any identified dynamic stability limits revealed through a stability study. Many of these systems may not have backup or breaker-failure protection, which tends to reduce stability of the DR island system.

System studies for proposed intentional islands need to be minimally adequate to demonstrate and meet the reliability requirements of the connected area EPS. These studies should include the level of detail appropriate to make such a determination. Subclauses 8.6.3, 8.6.4, 8.6.5, and 8.6.6 in IEEE Std 399-1997 *(IEEE Brown Book)* provide general guidance on accepted industry standards for performing stability studies to determine if a proposed system will meet a criteria of remaining dynamically stable under credible operating conditions. But the requirements for each unique system should be determined and communicated to the proponents of a proposed intentional DR island system.

5.4.4.1 Transient stability studies

At least three electrical characteristics of a power system affect stability. They are as follows:

- Internal voltage of the generator(s)
- Reactance(s) of the machines
- Internal voltage of the motor(s), if any

This subclause addresses conducting stability studies under an intentional island mode. Some details in this clause are from IEEE Std 399-1997 *(IEEE Brown Book)*, and it should be used as a reference. The need for a stability study in parallel mode is addressed by IEEE Std 1547.2. Depending on the size of the DR island system and the relative size and location of the DR, a stability study may not be necessary.

A system is stable, under a specified set of conditions, if, when subjected to one or more bounded disturbances (less than infinite magnitude), the resulting system responses are bounded. After a disturbance, a stable system could be described by variables that show continuous oscillations of finite magnitude (e.g., ac voltages and currents) or by constants or both. In practice, engineers familiar with stability studies expect that oscillations of DR within the island should be damped to an acceptable level within 6 s following a major disturbance.

Figure 12 and Figure 13 are the time-domain simulation results of a system before and after the connection of a co-generation plant from the stability chapter of IEEE Std 399-1997 *(IEEE Brown Book)*. The increased magnitude and decreased damping of machine rotor oscillations shown in these figures indicate that the system dynamic stability performance has deteriorated after the connection. This requires joint studies between utility and co-generation systems to identify the source of the problem and develop possible mitigation measures. It may be possible to see similar results when evaluating the operation of DR island systems.

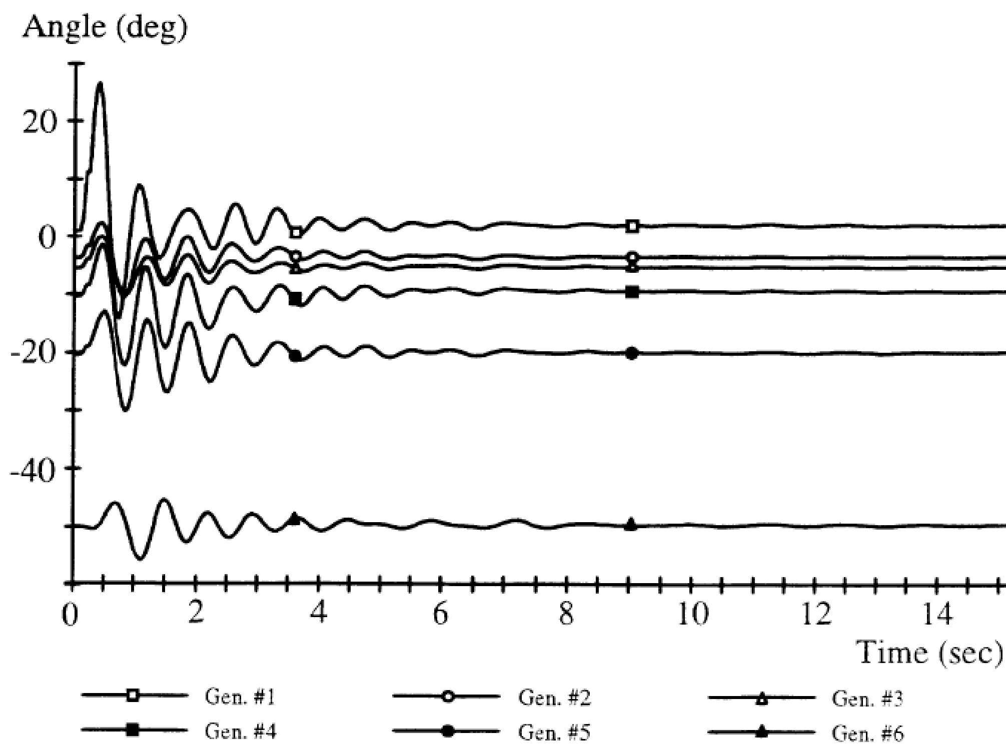

Figure 12 —System response to disturbance with no co-generation plant

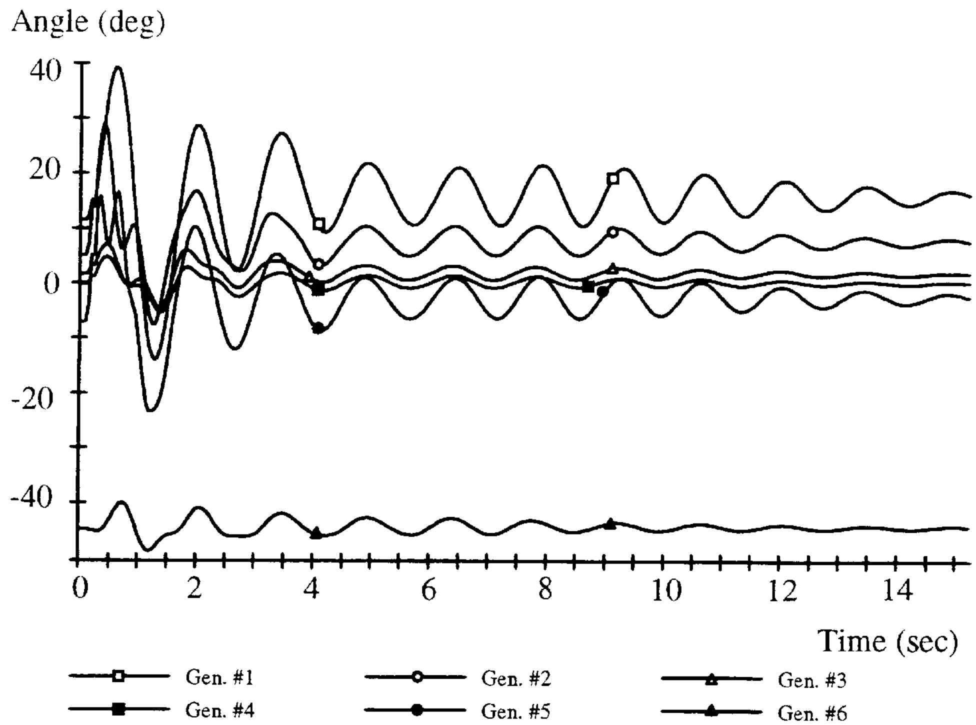

Figure 13 —System response to disturbance with co-generation plant

It is important to realize that a system that is stable by definition can still have stability problems from an operational point of view. (Oscillations may take too long to decay to zero, for example).

5.4.4.2 Small-signal stability

Traditionally, stability is determined by considering only the inherent mechanical and electromagnetic characteristics of the synchronous machines and the impedance of the circuits connecting them. Small-signal stability analysis takes automatic voltage regulator and governor system responses into account. If adequate modeling information is not available, testing may be required to determine an accurate response characteristic for the DR.

Stability studies require detailed knowledge of the equipment control system and electronic self-protection action. Because of the fast response of an inverter-based DR control system, the simplified dynamic equations and long time-steps (5 ms to 20 ms) normally used in stability studies may not be suitable. Instead, a detailed transient model of the inverter-based DR and its controls may be needed. Such detailed models are specific to each particular equipment design so generic parameterized models may not be adequate.

In the case of a islanded grid, the transient model for the inverter-based DR can be part of a detailed transient analysis of the entire grid or, through a suitable sampling interface, can represent the inverter-based DR accurately in a hybrid dynamic stability study (i.e., a dynamic stability study incorporating detailed transient models of some equipment).

In a DR island system, it may be necessary for inverter-based DR to ride-through voltage disturbances resulting from faults or sudden load changes. LVRT capability may be especially important during the brief period while separation from a faulted larger grid is being affected.

5.5 Motor starting studies

DR island systems need to be capable of starting and maintaining motor operations. Starting large motors, especially across-the-line, can cause severe disturbances to the motor and any locally connected load, and also to buses electrically remote from the point of motor starting. Because a DR will typically have a Thevenin impedance considerably larger than the utility source, large motor-starting on the island may also produce much larger voltage sags when sourced from an island DR than when sourced from the utility system. A study should be considered whenever the motor-starting horsepower exceeds 10% of the generator kVA rating, depending on actual generator characteristics.

5.6 Additional planning considerations

Arc flash considerations should be evaluated for the DR island system in all operating modes because potential hazards may differ.

Operations and contingency planning should be considered as part of the design of the DR island system. This planning should consider each of normal parallel operation mode, transition-to-island mode, island mode, and reconnection mode. This would include a study of reliability and availability issues within the island.

5.7 Testing and commissioning

Testing of DR island system components should be done to applicable standards for each of normal parallel operation, transition-to-island mode, island mode, and reconnection mode. Commissioning tests of the DR island system confirm engineering and design of the DR island system. There are potential risks of damage if the DR island system is not properly designed and tested.

6. Operation of DR island systems

6.1 DR island system management

When operating a DR island system, there are several important issues that need to be addressed, as follows:

- The DR island system needs to monitor and control generation output to ensure power is balanced in real time so that acceptable frequency and voltage are maintained. Load-shedding schemes may be implemented to ensure this.
- During island operations, it is desired to operate in accordance with ANSI/NEMA C84.1-2006. If the DR island system includes the area EPS, system performance is expected to meet ANSI/NEMA C84.1-2006.
- Frequency during island operations is desired to be stable and within the frequency range planned for the island system.
- During operations the participating DR (DR that are under control of the DR island system operations) should be identified. There may also be non-participating DR (DR that are in the DR island system but are not under control of the DR island system operations). The non-participating DR will be operating in accordance with IEEE Std 1547-2003.

— The DR island system operations should not cause non-participating utility customers to experience lower levels of reliability than would be considered normal.

— Additions and changes to significant loads and generation capacity should be evaluated and periodically reviewed. Forecasted load growth should be planned into the system design and verified annually. New generation in a planned island system may mask actual load growth.

— If an island mode exists for an extended duration, time correction may be an issue due to accumulated effects of off-nominal frequency operation.

— Confirm that the condition that caused the island has been studied. If not, then the integrity of the system may need to be confirmed.

— Training for all personnel involved with DR island system operations and maintenance.

6.2 DR island system transitions

Transitions need to be intentional by design and established at the planning stage of a DR island system. Establishing intentional islanding capability can be driven by a variety of reasons. For example, the participants may want economic savings or reliability improvement. But regardless of the intended result, the transition schemes will fall generally into the following categories with their unique implementation requirements:

a) Event-triggered operator/manual transition
    1) Economic
        i) Energy pricing prompts operator decision for self-generation
    2) Reliability
        i) Preventive islanding due to weather threat
        ii) Preventive islanding due to forecast system overload/stress
b) Event-triggered automatic transition
    1) Economic
        i) Energy pricing triggers energy management system (EMS) decision to use self-generation
        ii) Interruptible load called on through a load management program or market sale of DR capacity
    2) Reliability
        i) Loss of upstream power/voltage due to area EPS outage
c) Scheduled manual transition or automatic transition
    1) Economic
        i) Day-ahead or recurring scheduled self-generation for energy cost savings or DR revenue
    2) Reliability
        i) Peak load season planned recurring load shed

Operator/manual transitions occur when an EPS operator sends a specific signal to the interconnection device to create the DR island system. Automatic transitions occur by sensing that specific predetermined conditions have occurred.

6.3 Control strategies of DR island systems

The operation of the DR island system needs to be controlled by a strategy consistent with the planned operation of the island. There are at least three alternative control strategies, as follows:

- *Centralized control.* The central control system provides commands to the entire system in what is effectively a master-slave configuration between the central system and distributed devices.
- *Distributed control.* Control is accomplished with independent controls communicating with one another. This strategy uses intelligent devices that are strategically located to detect the conditions and initiate the required actions.
- *Autonomous control.* Control is accomplished with independent controls without communication with other devices.

6.4 Restoration after disturbances

The restoration crews need to be aware of the restoration plan and follow it.

6.5 Safety considerations

To ensure safe maintenance practices and avoid unintentional operations, deliberate de-energization procedures are followed by applicable entities. Having islanded system sources adds additional sources that personnel need to consider to adequately de-energize a system.

Arc flash considerations should be recognized and appropriate precautions taken for the system configuration. With islanded sections, the lower available fault current and likely longer clearing times with conventional protective devices may compromise the arc flash requirements due to increased exposure time when doing live line work.

Reclosing procedures should be evaluated for DR island systems. During operations, the states of the reclosers and switches in the system need to be identified. Coordination should be evaluated because the available fault current of the system may change when in island mode.

6.6 Periodic review, maintenance, and testing

Maintenance should be planned considering both islanded and non-islanded modes. Periodic testing of the island transition system should be performed as well.

Testing protocols should be established to ensure the system is actually ready to operate when islanding conditions are called for. Testing may be complicated when both the area EPS and local EPS are involved in the island.

As part of periodic testing and maintenance, the island system design should also be re-evaluated to ensure proper capabilities as far as load/generation.

Confirm the planned assets and equipment are still connected and operational.

6.7 Protection consideration

If selectivity (coordination) is allowed to be compromised for short-term island conditions, operating practices should be established to alert field crews of any abnormal selectivity concerns. For example, if the DR is likely to trip and outage the whole island for faults beyond an existing protective device such as an overhead sectionalizing fuse, system operators and field crews need to be made aware of this to aid in fault location and restoration. The restoration crews need to be aware of any grounded-wye, delta-connected DR in terms of ground-fault locating.

Operationally, when establishing the island, there may be protection system changes that have been designed that require implementation. Examples of such include distance relays for clearing of ground faults, reclosing changes, reconfiguring DR to non-IEEE-1547 settings, and relay settings changes.

For any high-side wye-connected DR, in terms of ground-fault locating, with the wye-side high connection with a single line to ground (SLTG) fault, fault will go in different directions for the different phases.

6.8 Monitoring, information exchange, and control

IEEE Std 1547.3-2007 provides guidance on MIC for DR.

For DR island systems that include part of the area EPS, MIC from the DR to the area EPS operator is likely to be required.

DR island systems with multiple DR may require communications among the DR. Load monitoring and control may be employed to manage the island systems.

6.9 Power quality

While paralleled to the area EPS, DR equipment needs to meet the power-quality requirements of IEEE Std 1547-2003. When in DR island mode, the power quality needs to be acceptable to all parties.

Harmonics may need more careful monitoring during islanded conditions.

Annex A

(informative)

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[11] The IEEE standards or products referred to in Annex A are trademarks owned by the Institute of Electrical and Electronics Engineers, Incorporated.
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Annex B

(informative)

Contractual and regulatory considerations that need to be addressed for DR island systems

In most cases, DR operating in parallel with area EPS systems do so under legal agreements known as interconnection agreements (IAs). In addition to many other requirements and understandings, the IA references the technical interconnection criteria under which the DR is permitted to operate in parallel with the area EPS system. These technical requirements usually reference IEEE Std 1547-2003 as the basis for parallel operation. If IEEE Std 1547-2003 is not referenced, then either local area EPS guidelines or statewide interconnection requirements are referenced or attached as an appendix to the IA.

The IA does not establish the level or quality of service that the DR can expect to receive from the area EPS system. These requirements are found in tariff documents of the individual utility or within regulatory agency orders establishing power-quality requirements. It is expected that when a DR is operating in parallel with a utility system, the power quality of the area EPS as seen by all other customers connected to the same portion of the area EPS will not be diminished.

The majority of older vintage IAs does not establish an obligation for the DR to serve area EPS loads beyond the PCC. These DR systems were installed to meet the needs of the host customer, and the area EPS was expected to remain the provider of last resort in the event of DR outages. The IAs will need to be amended to reflect the area EPS's dependence on the DR to support the needs of the planned intentional island. Each party to such an amended agreement will likely seek remedies for non-performance by the other party that are not adequately addressed in the existing IA language. Utility tariffs will need to be established to identify the financial parameters under which these agreements will operate.

Area EPSs do not have the right to unilaterally modify the level of power quality delivered to customers. Modifications to the level of power quality are generally permitted only in cases of pending emergency such as planned voltage reductions to avoid loss of supply to an entire region. It should be expected that in cases in which an area EPS operator contemplates the establishment of a planned intentional island on a portion of its system with one or more DR sources that the area EPS operator will desire to provide the same level of power quality as mandated either by tariff or regulatory guidelines.

The agency having jurisdiction over issues of power quality may have to provide modified guidelines to support the establishment and operation of planned intentional islands. Issues pertaining to liability connected with non-standard power quality may also need to be addressed. If the planned intentional island incorporates a population of customers who are not DR operators or hosts, they may need to be consulted and their approval granted to the establishment of the island if normal power quality cannot be assured.

Annex C

(informative)

Glossary

area electric power systems (area EPS): An EPS that serves local EPSs.

electric power system (EPS): Facilities that deliver electric power to a load.

intentional island: A planned island.

local electric power system (local EPS): An EPS contained entirely within a single premises or group of premises.

multi-grounded neutral system (power and distribution transformers): A distribution system of the four-wire type in which all transformer neutrals are grounded and neutral conductors are directly grounded at frequent points along the circuit.