Supplemental Information for New York State Standardized Interconnection Requirements

Michael Ingram, David Narang, Barry Mather, and Benjamin Kroposki
National Renewable Energy Laboratory

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List of Acronyms

3V0	Zero-sequence voltage
CESIR	Coordinated Electric System Impact Review
DER	Distributed energy resources
DTT	Direct transfer trip
EPS	Electric power system
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent system operator
PCC	Point of common coupling
PV	Photovoltaic
SIR	Standardized Interconnection Requirements
VAR	Volt-ampere reactive

Executive Summary

This document is intended to aid in the understanding and application of the *New York State Standardized Interconnection Requirements* (SIR) and *Application Process for New Distributed Generators 5 MW or Less Connected in Parallel with Utility Distribution Systems*,[1] and it aims to provide supplemental information and discussion on selected topics relevant to the SIR. This guide focuses on technical issues that have to date resulted in the majority of utility findings within the context of interconnecting photovoltaic (PV) inverters. This guide provides background on the overall issue and related mitigation measures for selected topics, including substation backfeeding, anti-islanding and considerations for monitoring and controlling distributed energy resources (DER).

This guide is intended to be used by individuals participating in activities related to the SIR. We hope that those who seek greater understanding on requirements for DER interconnection and adverse utility findings related to these topics find this resource helpful.

Anti-Islanding Protection/Direct Transfer Trip

Unintentional islanding protection is specifically addressed in SIR Section II.G on special protection schemes for islanding and Section II.A.1 on common design requirements. These clauses describe requirements to ensure that unintentional islands do not occur for an extended period of time. A typical anti-islanding protection scheme is DTT, which uses a communications method to send a trip signal to the DER. PV inverters feature built-in anti-islanding protection methods that are required under standards such as Institute of Electrical and Electronics Engineers (IEEE) 1547/IEEE 1547.1: Standard for Interconnected Distributed Resources with Electric Power Systems and certified under UL 1741: Standard for Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources.

Utilities commonly use automatic reclosing to clear temporary faults to minimize the duration of interruptions to customers. DER must cease energizing an area electric power system before the first reclose to ensure that the fault completely clears; however, some utilities in New York use instantaneous reclosing, which typically operates within 15–20 cycles (IEEE 2008) after the fault. If the DER do not trip off prior to the reclose, the reclose attempt may be unsuccessful, and the duration of the interruption will increase. If the DER should island when the recloser opens, the islanded section is likely to drift out of synchronism with the area electric power system. When the reclose is attempted under such out-of-phase conditions, severe transient overvoltage surges might be created on the feeder, which can damage customer and utility equipment connected to the feeder. For these reasons, mitigation schemes, such as recloser blocking or DTT, are employed to avoid detrimental conditions.

Substation Transformer Backfeeding/Neutral Overvoltage Protection

Distribution substations contain power transformers connected in a delta-wye configuration that are radially fed or tapped from a single transmission source. Where backfeeding is expected,

[1] See the New York State Standardized Interconnection Requirements (SIR) at: http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/August%202017%20SIR%20-Final.pdf

special neutral overvoltage protection to reduce prolonged overvoltages from phase-to-ground faults on the delta-wye connected transformers may be required. Zero-sequence voltage protection, such as 3V0 or another high-speed detection method, on the primary side of the transformer might be needed to detect these overvoltage conditions and to protect delta-wye connected transformers under these conditions.

Monitoring and Controlling DER

The general requirements for monitoring and control have been developed by the Joint Utilities[2]. While the JU are currently focused on solar PV, the following monitoring and control general requirements may be applicable to other distributed energy resource (DER) technologies.

Monitoring

- Monitoring refers to near real-time telemetry as well as the reporting of data values, and is defined as the ability to observe the performance of various assets, including solar PV, on the distribution system at pre-determined intervals.
- The minimum required measurements taken at the PCC are per-phase voltage, per-phase current, three-phase real power, three-phase reactive power, and power factor. Additional monitoring points may be required per individual utility requirements.
- Monitoring may be required for PV systems that are less than 50 kW and shall be required for all systems that are 50 kW and more.
- Monitoring data shall be accessible remotely by the use of communications technology per the utility's protocols.

Controlling

- Control refers to the signaling of distribution assets and solar PV inverters to take actions to satisfy system operational needs in near real-time.
- *Basic* control refers to remotely changing status of a device (i.e. tripping or resetting of a disconnect device). *Advanced* control might include changing the protective relaying set points.
- Any solar PV system requiring control shall also require monitoring.
- Basic control may be required for PV systems that are rated 50 kW to 300 kW.
- PCC recloser shall be required for all systems that are 300 kW and more.
- Control may be required for future scenarios when distributed generation is required to help meet local distribution capacity under contingency conditions (Mather, et al. 2016)

[2] JU Draft Monitoring and Control Requirements for Solar Photovoltaic Projects in NY, 06-14-2017.

	< 50 kW	*50 kW to 300 kW (aggregated)*	*300 kW and greater*
Monitoring	Monitoring *may* be required	Monitoring *shall* be required	Monitoring *shall* be required
Control (PCC Recloser)	Not required	Not required	PCC recloser shall be required
Control (RTU)	Not required	Basic control *may* be required	Not required

Table 1. NY Joint Utilities-Proposed state-wide M&C requirements.

Distribution System Key Concepts

Requirements in the SIR directly relate to important utility practices for distribution planning, operation, and system protection. Distribution planning refers to activities undertaken by a utility to ensure reliable and adequate electric supply to meet customer demand and any repairs or upgrades related to those efforts. Distribution operation functions include load management, routine maintenance, and response to unplanned outages. Distribution system protection serves two primary functions: protection of plant (assets, equipment and stable delivery of electricity) and the public (including employees). Methods to effectively manage fault conditions, distribution circuit configurations (radial or network), and distribution voltage level are additional important considerations that govern certain SIR.

Photovoltaic System Key Concepts

In addition to meeting the requirements for energy production, basic power quality, and protective functions, modern "advanced" inverters can provide grid-support functions under both normal and abnormal grid conditions. Modern inverters are able to operate as a voltage or current source, and depending on specific design features, they might be configured to provide positive and negative real and reactive power. This capability allows inverters to provide many grid-support functions, such as active voltage and frequency regulation. These functions will become increasingly beneficial as the amount of variable generation on a circuit increases, and they might be used to increase the PV hosting capacity of a given circuit. Standards for new functions are being updated on a national level through IEEE 1547/IEEE 1547.1, and they have been implemented in some state interconnection standards such as in California and Hawaii.

Impacts of New York State's Reforming the Energy Vision

New York State's Reforming the Energy Vision initiative is based on the premise that New York must transition its electric energy industry to meet challenges triggered by technological innovation, increasing competitiveness of renewable energy resources, aging infrastructure, extreme weather events, and energy system security and resiliency needs. Adapting to these challenges will require significant changes in energy generation, distribution, management, and consumption. Some of these changes will include a dramatic increase in PV generation and a new distribution system platform to manage services based on these assets.

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1 Introduction

1.1 Scope and Purpose

This guide was developed to provide supplemental technical background information to support the New York State Standardized Interconnection Requirements (SIR) and Application Process for New Distributed Generators 5 MW or Less Connected in Parallel with Utility Distribution Systems.[3] This guide focuses on technical issues that have to date resulted in the majority of utility findings within the context of interconnecting photovoltaic (PV) inverters, including substation backfeeding,; anti-islanding,; and considerations for monitoring and controlling distributed energy resources (DER). Each of these concerns can be mitigated by various methods discussed below.

1.2 Intended Audience

This guide is intended to be used by individuals participating in activities related to the SIR. We hope that those who seek understanding on adverse utility findings related to these topics find this material helpful.

1.3 Limitations

- This guide presents information related to the SIR that might be beneficial for consideration, but it is not intended to provide detailed and comprehensive information on the topics listed.
- Discussions in this guide are not intended to address all topics that might be pertinent to interconnections. The topics herein were selected based on priority during discussions among the members of the New York State Interconnection Technical Working Group and as further selected by staff from the New York Department of Public Service and New York State Energy Research and Development Authority.
- This guide primarily focuses on inverter-based DER.
- This guide is meant to inform, but it does not intend to provide any additional guidelines related to the SIR.

[3] See the New York State Standardized Interconnection Requirements (SIR) at: http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/August%202017%20SIR%20-Final.pdf

2 Distribution System Key Concepts

Requirements in the SIR are directly related to important utility practices on distribution planning, operations and system protection.

2.1 Distribution Planning and Operations

Distribution planning refers to activities undertaken by a utility to ensure adequate electric supply to meet customer demand and any repairs or upgrades related to those efforts. Planning occurs on a relatively long time frame (months to years) and relies on well-placed and timely measurements of load and generation. Traditionally, measurements taken by an energy management system (EMS) at the feeder head (substation) and sometimes from other equipment on the feeder, such as voltage regulators and capacitor banks, have provided adequate information for this function. As the mix of distributed generation and controllable loads (current and forecasted) increases on feeders, however, additional measurements (augmented with modeled forecasts) interior to the feeder at key load and generation centers and at key times (such as during peak load and during minimum daytime load) become necessary.

Distribution operation functions include load management, routine maintenance, and response to unplanned outages. Utilities routinely perform certain actions to ensure that the distribution system is configured to provide reliable electric service to meet customer demand. Many circuits are designed to allow line sections to be connected to multiple sources of power. This capability allows utility load management specialists to “move” customers from one circuit to another in case of emergency or in cases when the demand on a particular section of the circuit exceeds the capability of the source supply or exceeds physical current-carrying or voltage capacity.

2.2 Distribution Power System Protection

Power system protection serves two primary functions: protection of plant (equipment and stable delivery of power) and protection of the public (including employees). At a basic level, protection seeks to disconnect equipment that experiences an overload or a short to ground. Thus, protection schemes must be applied with a pragmatic and conservative approach to clearing system faults. The devices that are used to protect the power system from faults are called protection devices.

Distribution protection settings for each protection device are calculated to provide adequate coordination under various fault conditions and are then programmed into each protection element to provide a coordinated response. The protection devices respond automatically based on grid conditions at the point of connection. Note that PV inverters and inverter-based systems also have automatic response to fault conditions. Under fault conditions, protective functions generally operate too quickly for any effective human intervention based on monitoring or control.

2.2.1 Overview

Protection devices consist of several elements that are arranged to test the system condition, make decisions regarding the normality of observed variables, and take action as required. These elements are depicted in Figure 1.

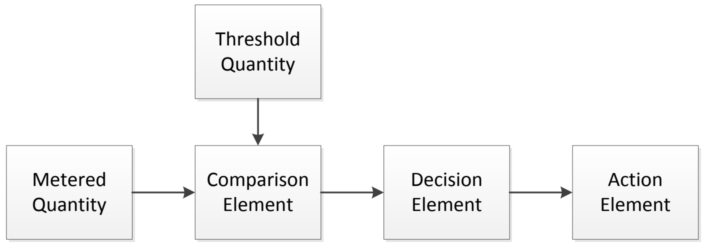

Figure 1. Protection functions (elements)

The protection system measures certain quantities, such as voltages and currents, and compares these quantities, or some combination of these quantities, against a threshold setting that is calculated by the protection engineer and set into the device. If a comparison indicates an alert condition, the decision function (element) is triggered. The decision may involve a timing element (delay) to determine the permanence of the condition or provide coordination among other elements on the system. Finally, if all checks are satisfied, an action element is released to operate—usually a circuit breaker is instructed to open and isolate a section of the network. Protection devices are installed with the aim of safeguarding the public, protecting assets, and ensuring the reliable supply of energy. (P. Anderson 1999)

2.2.2 Coordination

Protective device coordination is the process of determining the best-fit timing of fault interruption when abnormal electrical conditions occur. The goal is to minimize an outage to the greatest extent possible. (Mason 1967)

Protection coordination is typically accomplished through dividing the power system into protective zones (see Figure 6). If a fault were to occur in a given zone, necessary actions would be executed to isolate that zone from the entire system. A separate zone of protection is established around each system element. The significance of this is that any failure occurring within a given zone will "trip" (i.e., open) all circuit breakers within that zone—and only those breakers. Zone definitions account for generators, buses, transformers, feeders/lines, and motors. Overlapped regions are designed for redundancy to eliminate unprotected areas.

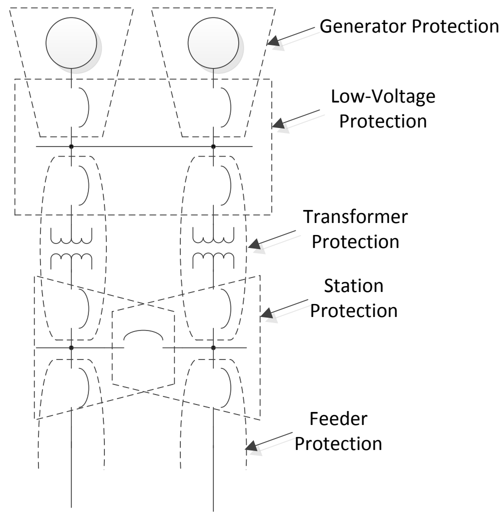

Figure 2. Zones of protective coordination, *Illustration from NREL*

As depicted above, circuit breakers are generally located so that each generator, transformer, bus, line/feeder/circuit, etc., can be completely disconnected from the rest of the system. Failures might occur in each zone, such as insulation failure, fallen or broken lines, incorrect operation of circuit breakers, short circuits, and open circuits.

It is helpful to note that switchgear consists of a combination of electrical disconnect switches, fuses, or circuit breakers that are used to control, protect, and isolate electrical equipment. *Switches are safe to open under normal load current; protective devices are safe to open under fault current.*

2.2.3 Abnormal Conditions

The function of protective relaying is to cause the prompt removal from service of any element of a power system when it suffers a short circuit or when it starts to operate in any abnormal manner that might cause damage or otherwise interfere with the effective operation of the rest of the system.

All relays used for protection operate by virtue of the current and/or voltage supplied to them by current and voltage transformers connected in various combinations to the system element that is to be protected. Through individual or relative changes in these quantities, failures signal their presence, type, and location to the protective relays. For every type and location of failure, some distinctive difference exists among these voltage and current quantities, and various types of protective-relays are available, each of which is designed to recognize a particular difference and to operate in response to it.

More possible differences exist in measured current and/or voltage than might be suspected. Differences are possible in one or more of the following:

- Magnitude
- Frequency
- Phase angle (synchronism)
- Duration
- Rate of change
- Direction or order of change
- Harmonics or wave shape.

2.2.4 Faults

Electrical power systems must be designed to serve a variety of loads safely and reliably. Effective control of short-circuit current—or fault current, as it is commonly called—is a major consideration when designing coordinated power system protection. To fully understand the nature of fault current as it is applied to electric power system design, it is necessary to distinguish among the various types of current available, normal and abnormal (Army Corps of Engineers 1991).

- Normal current (or load current) may be defined as the current specifically designed to be drawn by a load under normal, operating conditions.
- Overload current is greater in magnitude than the current under the maximum load and flows only in the normal circuit path. It is commonly caused by overloaded equipment, single-phasing, or low-line voltage, and thus it is considered to be an abnormal current.
- Ground-fault current consists of any current that flows outside the normal circuit path. A ground-fault condition results in current flow in the equipment grounding conductor for low-voltage systems.
- Short-circuit current might range upward of thousands of amperes. The maximum value is limited by the maximum short-circuit current available on the system at the fault point.

Short circuits on power systems are usually shunt disturbances of one of the following types:

- Three-phase short circuit
- Phase-to-phase short circuit
- Two-phase-to-ground short circuit
- Single-phase-to-ground short circuit.

The total current flowing to the fault depends on the type of fault and the location on the system where the fault occurs. The impedance looking back into the system varies with location, the amount of generation in service and the amount of load at the time, and the configuration of the network. All of these variations can be important in determining the range of available fault current (minimum and maximum) at a given place and time. Maximum values are necessary to determine the safe interrupting ratings of devices. Both the maximum and minimum values are important to ensure the correct operation of the protection system.

In some cases, it is important to recognize system configurations that are not short circuits but are still considered "faults." Single-line-open and two-line-open conditions present unbalanced current flow in the three-phase system and may require a protective response if the unbalance presents a threat to equipment.

2.3 Distribution Circuit Configuration

The circuit configuration has an effect on reliability. Longer radial circuits are exposed to more risks of faults than shorter circuits and therefore tend to have more interruptions (Short 2006). Grid and spot networks such as those in New York City offer the highest level of protection from sustained interruptions. Common circuit configurations are:

- Simple radial
- Primary auto-loop
- Underground residential
- Primary selective
- Secondary selective
- Spot network
- Grid network.

The most common of these are discussed in more detail below.

2.3.1 Simple Radial

The most common distribution system is a simple radial circuit that can be 100% overhead, 100% underground, or a combination of both (Behnke et al. 2005). The radial system is the simplest delivery system that can be used and has the lowest system investment. In absence of DER, a radial system has only one power source for a group of customers (see Figure 7). A power failure, planned outage, or an electrical fault may interrupt power on the entire line.

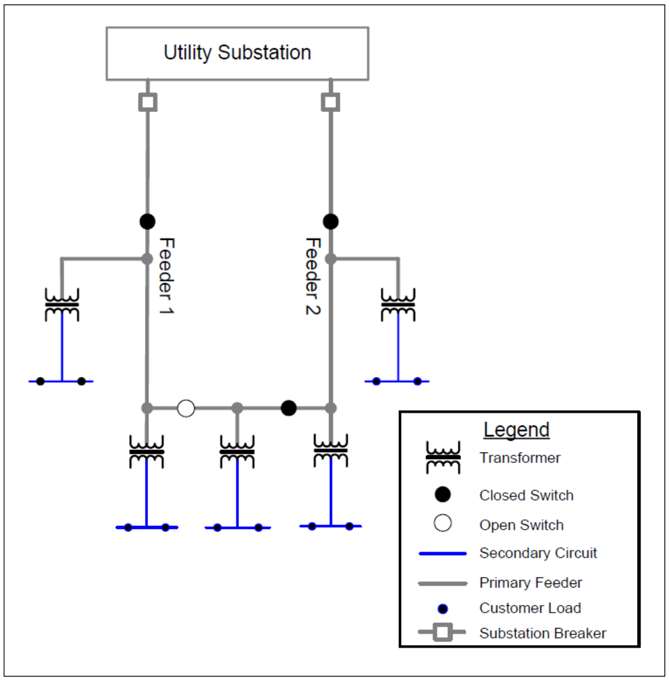

Figure 3. Radial system (Anderson, et al. 2009)

2.3.2 Spot and Grid Network

The SIR refers to networks in two clauses, as outlined below.

SIR Section 1.B on the application process steps for systems 50 kW or less, Exception 3, states:

> For all systems 50 kW or less, that are proposed to be installed in underground secondary network areas, the applicant should be aware that additional information and review time may be required by the utility (refer to Step 3). In some cases, interconnection may not be allowed or approved. DG systems interconnected to underground secondary network systems can cause unique design issues and overall reliability problems for the utilities. For this reason, additional review and analysis may be needed on a case by case basis.

SIR Section 1.C. on the application process steps for systems more than 50 kW up to 5 MW, Exception 1, states:

> For all systems 50 kW up to 5 MW that are proposed to be installed in underground secondary network areas, the applicant should be aware that a CESIR may be required by the utility, based on each utility's specific technical requirements and design considerations on a case-by-case basis. In some cases, interconnection may not be allowed or approved. DG systems interconnected to underground secondary network systems can cause unique design issues and overall reliability problems for the utilities.

Spot networks refer to a type of secondary network configuration that has two or more feeders and two or more transformers networked together to serve a single customer site. Customers served by spot networks are typically very large buildings with major electric loads (Anderson, et al. 2009). (See Figure 8.)

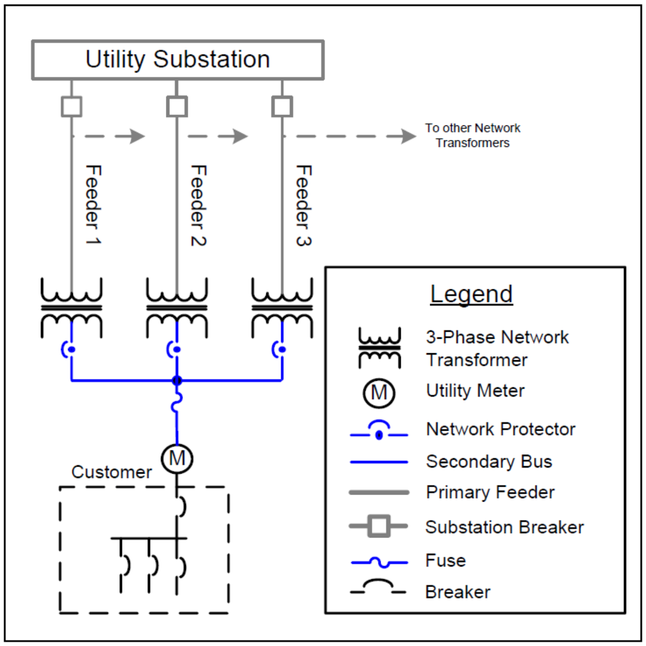

Figure 4. Spot network (Anderson, et al. 2009)*)*

Spot network systems are designed to provide highly reliable service. These systems are commonly applied in high-load-density areas, such as metropolitan and suburban business districts. In a network configuration, each customer is served through multiple parallel feeders and transformers. In the case of a loss of a single line or transformer, the redundant equipment continues to serve the customer without interruption to their power supply.

Area or grid networks are similar to spot networks in that there are multiple feeds, but area networks serve multiple customers.

Network systems use protection schemes and devices designed around one-way power flow: from the substation to customers (see Figure 9). In this type of system, power flow in the reverse direction is indicative of an upstream supply feeder fault. Network protectors are installed to sense reverse power flow and physically disconnect the faulted supply feeder. Once isolated, this prevents damage to equipment and allows personnel to make repairs and restore service. In the case of local generation sources such as PV, if the generation exceeds the local loads, the extra power is fed back into the network and causes network protectors to open unnecessarily because of the reverse power flow (Anderson, et al. 2009). After the fault has been cleared, network protectors will sense that power is flowing in the correct direction and reconnect the supply feeder. The PV generation might once again exceed the local load and cause the network protector to cycle.

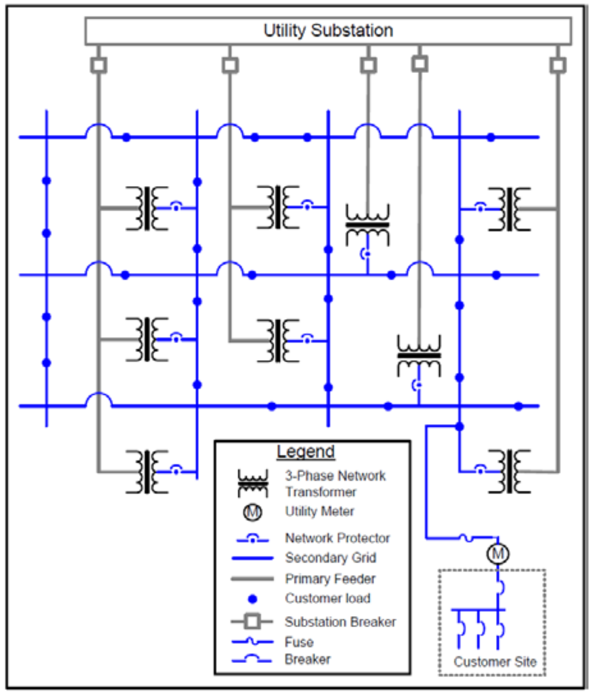

Figure 5. Area or grid network system (Anderson, et al. 2009)

2.3.3 Distribution Voltage Level

Common primary line voltages are 4 kV, 13 kV, 25 kV, and 34.5 kV. The voltage used for primary distribution depends on the amount of power required and the distance or length of the circuit. Higher voltage lines carry more power for given electrical current. Less current translates to lower losses and reduced voltage drop throughout longer distances.

Voltage class is a term applied to a set of distribution voltages and the equipment common to them and can be a source of confusion; it is not the actual system line voltage. As introduced above, higher voltages require higher classes of equipment and insulation.

3 Key Interconnection Topics

This section discusses key topics related to interconnection requests in New York.

3.1 Anti-Islanding Protection/Direct Transfer Trip

Unintentional islanding protection is addressed in several clauses of the SIR.

SIR Section II.G on special protection schemes for islanding states:

> Systems must be designed and operated so that islanding is not sustained on utility distribution circuits or on substation bus and transmission systems. The requirements listed in this document are designed and intended to prevent islanding. Special protection schemes and system modifications may be necessary based on the capacity of the proposed system and the configuration and existing loading on the subject circuit.

SIR Section II.A.1 on common design requirements states:

> The generator-owner shall provide appropriate protection and control equipment, including a protective device that utilizes an automatic disconnect device that will disconnect the generation in the event that the portion of the utility system that serves the generator is de-energized for any reason or for a fault in the generator-owner's system. The generator-owner's protection and control equipment shall be capable of automatically disconnecting the generation upon detection of an islanding condition and upon detection of a utility system fault.

3.1.1 Islanding

The Institute of Electrical and Electronics Engineers (IEEE 2003) defines an island as "a condition in which a portion of an Area EPS [electrical power system] is energized solely by one or more Local EPSs through the associated PCCs [point of common coupling] while that portion of the Area EPS is electrically separated from the rest of the Area EPS."(IEEE 2003) Figure 6 shows an example of an island (Kroposki 2016). Islands can be intentional (planned) or unintentional (unplanned).

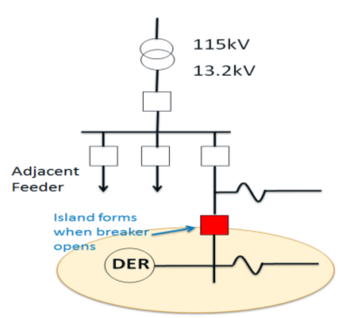

Figure 6. Example of an island (Kroposki 2016)

A planned island is designed to perform safely in all modes of operation—while it is transitioning to an island, reconnecting to the grid, and in island mode. An unplanned island, on the other hand, lacks design and operational elements to maintain safe and reliable electric supply to affected personnel and customers. Concerns related to unplanned islands include the following (IEEE 2008; Walling and Miller 2002; Barker and de Mello 2000; Stevens, Bonn, and Gonzalez 2000):

- Personnel safety. Unintentional islands can cause hazards for utility workers if they assume that downed lines are not energized during restoration.
- Overvoltages. Transient overvoltages caused by the rapid loss of load are possible. If an adequate ground source is not present in the island, a ground fault can result in voltages that exceed 173% of nominal on the unfaulted phases.
- Reconnection out of phase. Reconnections out of phase can result in large transient torques applied to motors connected to the islanded area electric power system and their mechanical systems (e.g., shafts, blowers, and pumps), which could result in damage or failure.
- Power quality. Unplanned island area electric power systems may not have suitable power quality for loads.
- Protection. Unintentional islands may not provide sufficient fault currents to operate fuses or overcurrent relay protection devices inside the island.

3.1.2 Anti-Islanding Protection

Anti-islanding protection is required for all inverters that are compliant with standards IEEE 1547: Standard for Interconnected Distributed Resources with Electric Power Systems and UL 1741: Standard for Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources. Specifically, according to IEEE 1547, a PV plant that energizes a portion of the grid through the interconnection point (unintentional island) shall detect the island and cease to energize the grid within 2 seconds of the formation of an island. A number of methods can be used to protect against unintentional islands, including DTT, reverse power detection, or minimum import/export relays (Kroposki 2016).

3.1.3 Direct Transfer Trip

DTT is one of several schemes used to avoid sustained unintentional islanding. DTT uses a communications signal from an area electric power system component, such as a feeder breaker or automatic line sectionalizing device, to command the DER to disconnect from the circuit. DTT might also be implemented with the addition of sync-check relaying or undervoltage-permissive relaying at the feeder breaker or automatic line sectionalizing devices to maintain coordination with protection schemes. DTT might require communications from not only the substation breaker but also any automatic line sectionalizing devices upstream from the DER.

Several options for DTT communications are available (Pacific Gas and Electric Company 2014), including:

- Direct fiber to substation with proper interface provisioning
- Licensed microwave with proper interface provisioning

- Class A DS0, four-wire, leased-line provisions by local exchange carrier
- Telecommunication options via Class B, T1 lease options.

DTT can also eliminate out-of-phase reclosing concerns because the recloser action can be coordinated with tripping schemes to ensure that no unintentional islands are formed. Even with DTT, depending on the latency of the trip signal, fast reclosing schemes might need to be reviewed and either slowed down to guarantee that the DER stop generation prior to the first reclose action (see Section 3.2 for more information on protection coordination) or otherwise modified to maintain protective coordination.

In addition to DTT, utility communication-based anti-islanding techniques include power line carrier and impedance insertion.

3.1.4 Photovoltaic Inverter-Based Active Anti-islanding Techniques

PV inverters feature built-in protection mechanisms that detect when a distribution grid is disconnected to cease generating power. These inverter anti-islanding functions use a variety of techniques to actively try to change the voltage and/or frequency of the grid. Because the grid is generally a more powerful source than the DER, if the grid changes, the inverter assumes that it is in an island. These techniques include[4]:

- Impedance measurement
    - An impedance measurement can be used as a mechanism to detect a failed grid. A grid impedance exceeding a preset threshold triggers a grid fault in the PV inverter.
- Impedance detection at a specific frequency
    - An intentional injection of a current harmonic at a specific frequency in order to detect a harmonic voltage when the utility is not present.
- Slip-mode frequency shift
    - Slip-mode frequency shift uses positive feedback to the phase of the voltage to destabilize the PV inverter when the utility is not present.
- Frequency bias/Sandia frequency shift
    - Frequency bias or active frequency drift uses a current injected into by the PV inverter that is slightly distorted so that there is a continuous trend to change the frequency.
- Sandia voltage shift
    - Sandia voltage shift applies positive feedback to the voltage amplitude to prevent islanding.
- Frequency jump

[4] PV inverter manufacturers often use proprietary techniques which may use other techniques or combinations of the techniques mentioned here. .

    - Frequency jump is a modification of the frequency bias method. It is conceptually similar to an impedance measurement.

- Mains monitoring units with allocated all-pole switching devices connected in series (MSD, also called ENS)
    - This is an automatic isolating capability consisting of two independent, parallel mains monitoring devices with allocated switching devices connected in series in the external and neutral conductor. In other words, the two switching devices in series are independently controlled. This method is currently required for interconnections in Germany and Austria, and the capability is beginning to appear in inverters imported into the United States.

3.1.5 UL 1741 Testing/Certification of Anti-Islanding Requirements

Note that SIR Section 1.B on the application process steps for systems 50 kW or less, Exception 1, states:

> For inverter based systems above 50 kW up to 300 kW, applicants may follow the expedited application process outlined in this section provided that the inverter based system has been certified and tested in accordance with the most recent revision of UL 1741 and the utility has approved the project accordingly.

PV inverters are rigorously tested to comply with anti-islanding requirements under UL 1741, which is used to certify that the inverter is constructed properly and can perform all of its functions in a safe manner. Certification covers many topics for inverters, including:

- General construction of frame and enclosure, protection of users and service personnel from electric shock, general wiring, equipment grounding, overcurrent protection of control circuit, and output AC power circuit
- Protection against risks of injury to persons
- Output power characteristics and utility compatibility, including compliance with limitations of harmonic voltage distortion and trip limits for voltage and frequency
- Performance requirements, including correct performance under maximum voltage and the ability of the inverter to maintain safe operating temperature under ambient and higher than ambient temperatures
- Output power characteristics, which show that the inverter can maintain output voltage and current within ±10% of its rated output voltage or current range and that it can maintain output frequency within ±1 Hz of rated output frequency
- Utility compatibility in the form of compliance with requirements in IEEE 1547 and IEEE 1547.1
- Risks under abnormal conditions, which show that the inverter does not become a risk of fire, electric shock, or injury to persons under abnormal conditions such as output overload, short circuit, DC input miswiring, malfunctioning ventilation, component short circuit and open

circuit, loss of control circuit, overcurrent, voltage surge, rain and sprinklers, and compression

- Ratings and markings.

3.1.6 UL 1741 Supplement A

In September 2016, UL 1741 was revised to provide additional requirements related to inverters capable of grid-support functions. Supplement A validates compliance with new functions related to low voltages, high voltages, and frequency ride-through and active and reactive power control (specified power factor, volt/volt-ampere reactive [VAR], and frequency-watt modes). Supplement A also prescribes additional anti-islanding testing with these functions enabled.[5]

3.1.7 Notes on Recloser Blocking

Most fault conditions on distribution systems are temporary in nature—such as wind causing tree branches to make contact with a live overhead line—and utilities often implement fast-reclosing schemes to decrease outage occurrences. Reclosers are fast-acting switches capable of breaking and making contact under load. Reclosing schemes often include “fast reclosing,” that is, reenergizing the distribution circuit within 1 second or less after a fault condition has been detected. Additionally, multiple reclosing actions may be programed to repeatedly test whether the fault condition has subsided. Reclosing functionality is most commonly implemented on the level of a whole circuit, but it can be implemented in a zoned approach, especially on long circuits, wherein multiple reclosers protect different sections of a single distribution circuit.

With the addition of DER on a distribution circuit, the potential for an unintentional island on a circuit or a section of a circuit after a recloser has opened, following the detection of a faulted condition, often raises the concern for a potential out-of-phase reclose. Under conditions when no unintentional island can be formed, the loads downstream of the recloser are effectively off, and the reclosing operation simply reenergizes the line. If an unintentional island persists after the recloser opened, it is possible that the phase relationship of the islanded grid could deviate from that of the bulk system, due to temporary or constant frequency differences, and the reclosing action could forcibly resynchronize the grids. The risk of this forced synchronization is potentially significant because customer equipment—motor loads, in particular—could be damaged by the possible sudden change in frequency and voltage phase. Effectively, the phase voltages experienced by the loads could jump instantaneously, stressing any machine that has a speed/position relationship to the grid frequency. Generally, the greater the phase difference between the islanded grid and the bulk system, the greater the risk of damage to these types of equipment.

To address the concerns of out-of-phase reclosing, three solutions are typically considered: recloser blocking, removing recloser functionality, and DTT. Recloser blocking is a functionality added to existing reclosers that delays fast reclosing until the circuit being reclosed is measured to be de-energized. This requires the addition of voltage sensors at the recloser position installed on the downstream side of the circuit. The voltage sensors determine if an unintentional island

[5] When the revised IEEE 1547.1 is published, UL 1741 will also need to be fully revised to reflect the new testing requirements specified in IEEE 1547 and IEEE 1547.1.

has formed. If an unintentional island has formed, the voltage of the downstream circuit segment does not collapse, and the reclosing action is not allowed (i.e., it is blocked) either permanently or until the island no longer persists. Another option is to simply remove the reclosing functionality of the protection equipment from a circuit. Removing the reclosing functionality might decrease the circuit's reliability because it might increase the duration of interruptions. These reliability impacts need to be considered when choosing a solution.

3.1.8 Reverse/Minimum Import/Export Relaying

Reverse power or minimum import/export relays are passive anti-islanding techniques. These methods add overvoltage/undervoltage and frequency trip settings implemented through relay functions (81o, 81u, 27, 59). These settings define an acceptable range of voltage and frequency limits. If the measured conditions are outside of this range, the DER trip offline.

This approach is often used in cases when DER are not expected to export power to the grid (e.g., when local loads are larger than the DER, and all generated power is consumed on-site). In these cases, an additional protective relay function (Function 32: reverse power) is added to the site relay scheme to disconnect the DER if the relay senses that they are exporting power (see Figure 7).

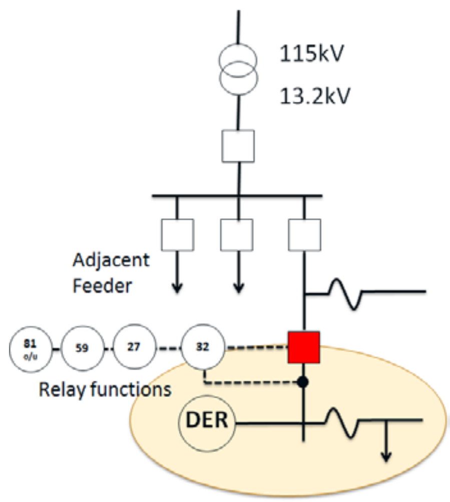

Figure 7. Relay functions (Kroposki 2016)

3.1.9 Other Solutions

Other passive anti-islanding techniques include measuring the rate of change of frequency, monitoring voltage or current harmonic distortion, or detecting if there has been a sudden jump in phase displacement between the inverter voltage and output current (i.e., a voltage phase jump; see Figure 8) (Bower and Ropp 2002).

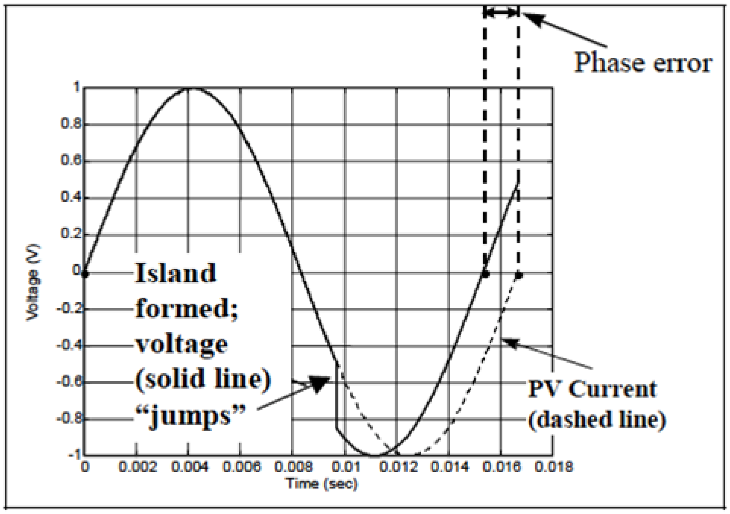

Figure 8. Voltage phase jump (Kroposki 2016)

3.2 Substation Transformer Backfeed/Neutral Overvoltage Protection

SIR Section II.G on special protection schemes for islanding states:

> *The need for zero-sequence voltage (3V0) and direct transfer trip (DTT) protection schemes shall be evaluated based on minimum loads on the associated feeder and substation bus, including certain fault conditions resulting from system installation to protect for an islanded condition.*

SIR Section II.A.1 on common design requirements for transformer connections states:

> The settings below are listed for single-phase and three-phase applications using wye grounded-wye grounded service transformers or wye grounded-wye grounded isolation transformers. For applications using other transformer connections, a site-specific review will be conducted by the utility and the revised settings identified in Step 6 of the Application Process.

3.2.1 Implications

In cases when "the PV is connected via a delta-wye transformer (or wye-wye transformer when the utility side of the transformer is ungrounded), ground faults upstream of the PV might result in high voltages on the unfaulted phases" (see Figure 9) (Mather et al. 2016).

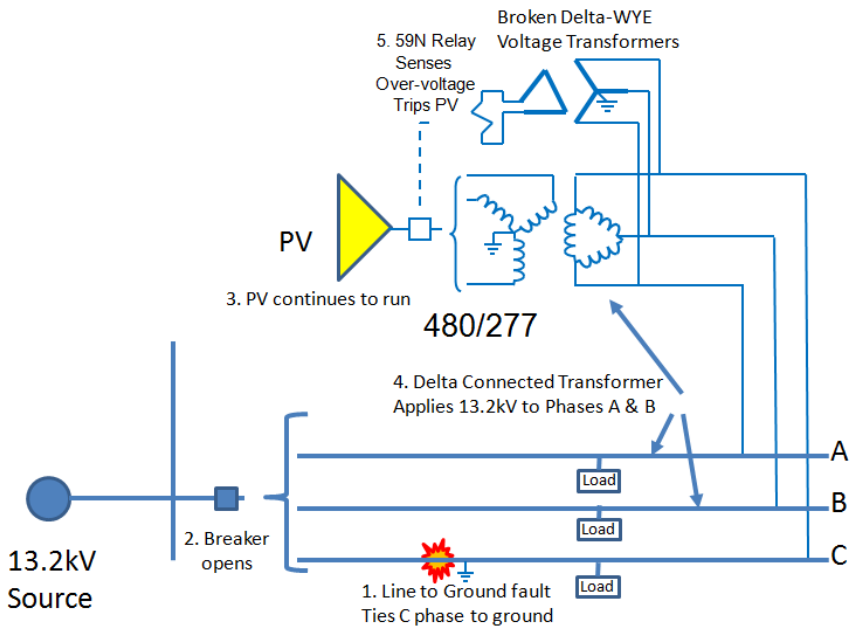

Figure 9. Example of line-to-ground overvoltage caused by PV (Mather, et al. 2016)

Distributed generation sources might cause reverse power flow through the substation power transformer if the generation exceeds the feeder load. Although backfeeding is currently allowed for all overhead radial systems in New York, modifying the substation transformer protection scheme might be required in certain cases. Yet, only the transformers sourcing (whether backfeeding by generation or by paralleled circuits) will need 3V0 protection because once they are tripped off the condition is mitigated.

Distribution substations that comprise power transformers connected in a delta-wye configuration that are radially fed or tapped from a single transmission source where backfeeding is expected require special neutral overvoltage protection to reduce prolonged overvoltage from phase-to-ground faults on the delta-wye connected transformers. If a phase-to-ground fault were to occur, it would cause an overvoltage condition on the high side of the distribution transformer. Upstream voltage-based detection will likely trip the delta-connected line, but it is also likely that no protection for such overvoltage events exists at the substation because previous assumptions of guaranteed one-way power flow would have sufficed, and clearing such faults with upstream devices would mitigate the fault. However, a significant amount of generation interconnected on the low side (wye-connected) of the substation makes detecting the fault difficult because no appreciable change in the voltage on the low side of the distribution transformer is realized. Additionally, no current flows through the fault on the high-side delta-connected line resulting in practically no perceptible change in load.[6]

[6] For more in-depth treatment of this subject, see *Assessment of Inverter-based Distributed Generation Induced Ground Fault Overvoltage on Delta-Wye Substation Transformers* (Report R149-16) by Pterra Consulting (January 3, 2016).

The ITWG Technical Guideline Matrix states that "these overvoltage conditions have the potential to exceed insulation levels (BIL) of the substation and transmission line equipment, and maximum continuous operating voltage of surge arresters[7] Additionally, the faulted delta-connected line remains energized until DER-based generation trip offline, creating a possible increased safety hazard to the public and utility crews.

3.2.2 Zero-Sequence Voltage

Zero-sequence voltage protection such as 3V0 (or another high-speed detection method) on the primary side of the transformer is needed to detect overvoltage conditions and to act to protect delta-wye connected transformers from zero-sequence voltage issues, such as overvoltage from a phase-to-ground fault, by disconnecting the generation from the substation transformer and stopping the DER and substation transformer from contributing to the transmission-side overvoltage condition (Bower and Ropp 2002).

3.2.2.1 Mitigation

Pterra Consulting (2016) made the following observations based on findings from simulations investigating the feasibility of measuring neutral point shift overvoltages at the DER location (i.e. on a wye-grounded circuit connected to a substation with a delta connected transmission feed):

- "While inverters can potentially cause overvoltage on the delta side of the substation transformer, some inverter designs can detect a single-line-to-ground fault condition and trip instantaneously. Time domain simulation is a potential tool for evaluating the fault detection capability of inverters for this purpose."
- "According to ANSI/IEEE C62.92, the GFOV [ground-fault overvoltage] for an effectively grounded system is to be limited to 138%. This value can also be used to limit the overvoltage for ungrounded systems. Simulation results indicate that overvoltage on the delta side of the study substation transformer peaks at 1.38 PU as the PV/load ratio approaches 65%. At penetration levels below 65%, no overvoltage is observed. Two important notes relate to this finding:
    - The calculation for the load should account for those connected to the transmission side as well as the distribution side of the isolated system.
    - Though this ratio seems close to the threshold proposed by National Grid (i.e., 67%), there is possibility of under counting the load if only the distribution side load is considered."
- "The 65% penetration limit (based on 1.38 PU overvoltage threshold) can be relaxed if:
    - Damage to equipment connected to delta side of the substation transformer is the reason for requiring 3V0 protection; and
    - Surge arresters connected to delta side of the substation transformer are taken into account."

[7] JU revised ITWG Tech Guideline Matrix - December 13, 2016

- “Simulations conducted in this study with station class surge arresters indicate that arresters can safely operate for penetration levels of up to 100%.”

3.2.2.2 Standards Guidance (Future)

Additional guidance and explanations of ground-fault overvoltage issues related to DER integration is being developed in IEEE PC62.92.6: Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part VI—Systems Supplied by Current-Regulated Sources. This is currently being balloted and likely to be approved and available for reference outside the developing working group within the next few months.

3.2.3 Joint Utilities Considerations of Transformer Backfeed

The New York Joint Utilities analyze the potential for overvoltage caused by substation transformer backfeeding from DER on a case-by-case basis by the New York Joint Utilities. The magnitude of the overvoltage depends on the ratio of the distributed generation to load within the (potential) island, which includes all loads downstream of the opened utility breaker. The peak generation during the minimum daytime loading time frame is calculated, and the minimum daytime load of the substation transformer during normal system conditions as well as during N-1 contingencies are also calculated (such as the loss of the feeder on the substation bus with all loads connected and the loss of a feeder connected to an adjacent substation that automatically transfers more “new” generation on the feeder under study).

Table 2. Time Frame for Minimum Daytime Load Measurement or Calculation

National Grid	Central Hudson	AVANGRID	Con Edison	Orange & Rockland
8:00 a.m.–8:00 p.m.	8:00 a.m.–6:00 p.m.	10:00 a.m.–6:00 p.m.	11:00 a.m.–2:00 p.m.	8:00 a.m.–6:00 p.m.

If the aggregate generation is equal to or greater than the minimum daytime load on the substation transformer, additional transformer protection is indicated. For National Grid, the threshold is currently 67% of seasonal peak load; for Central Hudson, the threshold is approximately 85% (this may vary based on system conditions).

Table 3. Default Values for Minimum Feeder Load (in Case of Missing or Unavailable Measurements)

National Grid	Central Hudson	AVANGRID	Con Edison	Orange & Rockland
25% of feeder seasonal peak load	25% of feeder peak load (needed for approx. 22% of feeders)	15% of system peak load (needed for the majority of feeders)	100% of circuits have measured values	99% of circuits have measured values

In the case of circuits for which data is unavailable at a sufficiently granular level, a default minimum loading level (15% at Avangrid; 25% at Central Hudson) of the substation (feeder) peak load is generally used. For substations with available data, the range for minimum load has been measured from 9%–30% less than the feeder peak; however, the value might be much less depending on the substation configuration and circuit/feeder topology.

3.2.4 Solutions

Common solutions to ground-fault overvoltage concerns generally revolve around adding sensing and protection of the high-voltage delta-connected line at the substation. These types of solutions are well known; many substations that are served by multiple high-voltage lines already employ such equipment for bidirectional protection. Such solutions, however, are expensive and generally cost $250,000–$450,000 per substation upgraded (Bower and Ropp 2002).

Table 4. Typical Range of Costs for Installing Neutral Overvoltage Protection

National Grid	Central Hudson	AVANGRID	Con Edison	Orange & Rockland
> 69 kV: $300,000–450,000 < 69 kV: $250,000–350,000	Approx. $250,000 (estimated)	None required to date	Already installed at all Con Edison substations	$350,000–$450,000 (estimated)

Alternative methods include the addition of utility-quality highly reliable communications among the breakers on either side of the delta-connected line. Functionality is added that trips both sides of the line at the same time, effectively utilizing existing sensors and protection at the upstream substation but transferring protection to the end-of-the-line substation. This solution is typically expensive because such high-quality communications links among substations fed by only one high-voltage line are not already in place, thus it is likely that the installation of fiber-optic cable would be required throughout a significant distance.

Additional research is currently being conducted on future protection methods that typically focus on detecting the overvoltage on the high side of the transformer via some means requiring actual measurements only on the low side (wye-connected side). Relaying based on the detection of negative-sequence current is currently the most evolved advanced detection technique, but concerns regarding its sensitivity and selectivity remain to be addressed.

Note that 3V0 is a protection scheme designed to reduce the duration of long-term overvoltage conditions, but it does not reduce the risk of the fault occurring (Bower and Ropp 2002).

3.3 Metering, Monitoring, and Controlling

Virtually all energy planning and distribution grid management functions require knowledge of basic electrical quantities such as real and reactive power, voltage, and frequency. The increase in intelligent grid-edge devices has also increased the need for interoperability or information exchanged among devices and systems. Traditional distribution functions such as planning, operation, and protection need these types of information, and they are critical for newer functions such as the provision of ancillary services and forecasting load and distributed generation.

3.3.1 Understanding Monitoring and Control

3.3.1.1 Metering

The most common measurement on the distribution network is metering. With respect to interconnected generation, metering is a means of determining the energy production (kWh) of DER throughout time (e.g., monthly meter reads or 15-minute advanced metering infrastructure data). Generally, these measurements are captured by a billing/production metering system (meter plus backhaul). The metering system is subject to program compliance (state, local, utility, etc.) because of the financial implications of the information developed. Even "basic" metering systems are capable of production performance assessments, such as peak generation and interval energy (typically 15-minute). Newer metering systems might provide the capability to measure additional parameters, such as voltage and reactive power. Higher-resolution metering provides an enhanced level of situational awareness and the ability to plan with higher levels of confidence and accuracy.

3.3.1.2 Monitoring

Monitoring refers to near real-time methods that communicate system status, output level (kW), etc., to the utility and possibly other stakeholders. Monitoring aids distribution planning departments in performing a variety of longer term functions, including asset management, capacity planning, and forecasting (e.g., transformer sizing, phase balancing, load planning, and protection review). By increasing the fidelity of and supporting off-line models, monitoring also improves future interconnection decisions (i.e., hosting capacity determinations). Within distribution operation departments, monitoring data is used for load management (e.g., native load determination, reconfiguration planning, fault restoration). Because the monitoring system's "four Vs" (veracity, velocity, volume, and variety) better match the complexity of the physical system, monitoring enables higher order applications. Advanced distribution management systems (ADMS) applications can inform the operation of other controllable equipment (i.e., volt/VAR optimization). High penetration levels of DER ultimately necessitate data to support resource planning at the level of the balancing authority or independent system operator because better state estimates are needed to forecast reserves, ramping, etc. Sub-transmission planning and operations might require monitoring for certain circuits affected by high penetration levels of DER.

3.3.1.3 Control

Control is defined here as direct utility control of a load-break element in line with DER grid connection (which might include utility-owned protection). Similar to monitoring, control serves a host of functions; the most important is safety. Generally, control ensures the safe practice of distribution maintenance functions—hot line tagging/arc flash mitigation, for example. Functions of distribution operations enabled by control include feeder reconfiguration and restoration. When coupled with possibly additional protection applied at the PCC control element, reductions in DER downtime are potentially achievable with certain control schemes.

New York utilities view control as potentially necessary to dispatch/curtail PV to ensure reliability, efficiency, and safety (especially as a means to ensure anti-islanding protection) in normal and alternate circuit configurations. Direct control of a PV system, with the ability to disconnect it, is considered a means to maintain system safety and reliability during abnormal system conditions. Enhanced control capability is a consideration to meet future New York Independent System Operator requirements for DER markets, volt/VAR, and frequency control[8]. For these distribution operation functions, it is advantageous to add real-time monitoring of additional locations along the feeder, generation, and load centers and connection status of key generators and loads.

Control has traditionally been achieved through supervisory control and data acquisition (SCADA) systems that monitor various parameters at key locations, beginning at the source substation and at various locations along the circuit. Control of assets such as part of lockout procedures during maintenance or other grid operations may also be required.

Potentially, under a high penetration level of DER, an ISO could use control to mitigate over generation (curtailment). In the future, grid-supportive inverter technology might provide additional ancillary services that may require control.

Note that PCC control is not necessarily a solution for islanding concerns of DER. Local protection, typically applied at the PCC, would disconnect the DER in case of faults on the distribution system or within the DER facility; but if matched islanding conditions exist, the PCC protection elements are unlikely to detect a fault and trip the DER offline. PCC control can be used as a slower version of DTT if the PCC control element is triggered automatically by a substation breaker/recloser opening.

Controlling the DER/plant directly by using externally derived set points to meet specific control objectives is considered advanced control. Examples of interoperable advanced control include the capability of DER to respond to inputs for distribution-level services, such as voltage regulation, VAR support, scheduling, controlled curtailment, and capacity management. Advanced control enables DER to be actively dispatched or participate in ISO-level services (e.g., providing reserves, following automatic generator control), potentially improving grid operations at high penetration levels

3.3.2 Applications of Monitoring, Information Exchange, and Control

Distribution planning and operations have different needs from distribution protection regarding monitoring, information exchange, and control.

Distribution planning functions, such as upgrades to equipment and infrastructure to meet increasing customer demand, require measurements at key points on the system and under specific conditions such as during peak load. Distribution operation functions such as load management, routine maintenance, and response to unplanned outages require robust real-time situational awareness to execute successfully. Some distribution system management techniques also require a certain degree of control, which may be manual or automated depending on the

[8] JU Monitoring and Control Discussion slides, ITWG meeting, 1/18/2017

equipment and need. In addition to providing information for distribution system operators, measurements can provide useful inputs for further modeling and simulation, especially related to planning for and integration of distributed generation.

Distribution planning, which considers a relatively long time frame (months to years) may be adequately addressed by well-placed and timed measurements of load and generation. Traditionally, measurements taken by an energy management system (EMS) at the feeder head (substation) and from other equipment, such as voltage regulators and capacitor banks on the feeder, have provided adequate information for this function. As the mix of distributed generation and controllable loads (current and forecasted) on feeders increases, however, additional measurements (augmented with modeled forecasts) interior to the feeder at key load and generation centers and at key times (such as during peak load and during minimum daytime load) become necessary. In future scenarios, timely information exchange among the distribution service provider and external entities, such as aggregators or regional planners, also becomes more important.

Distribution operation functions require robust real-time situational awareness to address concerns related to load management, routine maintenance, unplanned outages, fault restoration, and system reconfiguration or upgrades on the distribution line or at customer premises. For these functions, it is advantageous to add real-time monitoring of additional locations along the feeder, generation and load centers, and connection status of key generators and loads. Control of assets such as lockout during maintenance or for other grid operations may also be required. A special case might be communications requirements to update firmware for key assets. To avoid unnecessary expense for equipment, infrastructure, and staff, some consideration should be given to optimizing the monitoring strategy. Some information exchange might be necessary between the distribution service provider and external entities—for example, in cases of feeder boundary reconfiguration or notification of outages.

Distribution protection requirements for each protection element are planned to provide adequate coordination under various fault conditions and are then programmed into each protection element to provide a coordinated response. The protection devices respond automatically based on grid conditions at the point of connection. Note that inverter-based systems also have automatic response to fault conditions. Under fault conditions, protective functions generally operate too quickly for any effective human intervention based on monitoring or control.

Other considerations, such as power quality, might require measurements and/or monitoring at key locations and facilities. Power quality is a complex interaction of load, line, and, today, distributed generation. The seasonal nature of the solar resource, for example, coupled with short-term variability in load and generation contribute to making it difficult to pinpoint the root cause of power quality anomalies. It is advisable to augment field data with software modeling and simulation of these situations to determine the location and size threshold for required monitoring.

Generally, the requirements for DER monitoring and control are a function of the following:

- DER project size: Monitoring is applied first, and monitoring and control are applied at higher project levels.
- Voltage level and overall aggregate DER penetration of a circuit are taken into consideration.
- Market requirements often supersede interconnection monitoring and control requirements (i.e., participating in a wholesale market often requires visibility from the level of the independent system operator [ISO]).
- DER asset ownership might influence required monitoring and control (particularly control) because of safety concerns.

3.3.3 Interoperability, Modeling, and Simulation

Interoperability is "the capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively" (IEEE, 2011)

A core element of the New York's Reforming the Energy Vision is that in the future New York will have a system operator at the retail (distribution) level. This entity, the distribution system platform (DSP) provider, will be responsible for dispatching DER. Key to providing effective dispatch of DER, thoughtful consideration and balanced investment are required among adequate monitoring, control, and modeling and simulation of load and generation.

Integrating the monitoring and modeling platforms could help optimize the investment in equipment and resources needed for reliable, safe, resilient, and affordable electric service to meet the significant changes in generation, distribution, and management of energy in New York. This integration will depend on the extent to which diverse equipment and systems are interoperable.

Key elements to providing effective dispatch of DER at the distribution level will be adequate monitoring of load and generation, adequate and timely information exchange between the DSP provider and other energy services aggregators and providers, and adequate control of dispatchable assets. Another important consideration is the degree to which modeling and simulating load and generation could support the monitoring framework. Integrating the monitoring and modeling platforms could provide improved situational awareness in cases of communications failures of the monitoring system and might also decrease the number of measurements needed on the distribution system.

3.3.4 Joint Utilities General Requirements for Monitoring and Control

The general requirements for monitoring and control have been developed by the Joint Utilities[9]. While the JU are currently focused on solar PV, the following monitoring and control general requirements may be applicable to other distributed energy resource (DER) technologies.

[9] JU Draft Monitoring and Control Requirements for Solar Photovoltaic Projects in NY, 06-14-2017.

3.3.4.1 Monitoring

- Monitoring refers to near real-time telemetry as well as the reporting of data values, and is defined as the ability to observe the performance of various assets, including solar PV, on the distribution system at pre-determined intervals.
- The minimum required measurements taken at the PCC are per-phase voltage, per-phase current, three-phase real power, three-phase reactive power, and power factor. Additional monitoring points may be required per individual utility requirements.
- Monitoring may be required for PV systems that are less than 50 kW and shall be required for all systems that are 50 kW and more.
- Monitoring data shall be accessible remotely by the use of communications technology per the utility's protocols.

3.3.4.2 Control

- Control refers to the signaling of distribution assets and solar PV inverters to take actions to satisfy system operational needs in near real-time.
- *Basic* control refers to remotely changing status of a device (i.e. tripping or resetting of a disconnect device). *Advanced* control might include changing the protective relaying set points.
- Any solar PV system requiring control shall also require monitoring.
- Basic control may be required for PV systems that are rated 50 kW to 300 kW.
- PCC recloser shall be required for all systems that are 300 kW and more.

3.3.4.3 NY Joint Utilities-Proposed Requirements for Solar PV in New York State

	< 50 kW	***50 kW to 300 kW (aggregated)***	***300 kW and greater***
Monitoring	Monitoring *may* be required	Monitoring *shall* be required	Monitoring *shall* be required
Control (PCC Recloser)	Not required	Not required	PCC recloser shall be required
Control (RTU)	Not required	Basic control *may* be required	

Table 5. Proposed state-wide M&C requirements.

3.3.4.4 Recommended Screening Criteria for Monitoring and Control

When monitoring and/or control ***may*** be required, the Joint Utilities have proposed a list of screening criteria[10].

- Control may be required for lower PV system sizes if located on feeders operating at lower distribution system voltage (5kV and below)
- Control might be needed to increase PV hosting capacity on certain feeders.
- Recloser (control) at the point of common coupling (PCC) may be required to satisfy anti-islanding requirements
- Monitoring will be required for PV systems less than 50kW that only marginally pass or fail a given SIR screen; similarly, "borderline" systems rated 50kW to 300kW may require control.
- Monitoring will be required if the PV systems is subject to ISO requirements and control may also be required
- Control might be required for proposed PV systems that exceed a certain capacity limit (to be determined) of the minimum daytime load to address concerns related to voltage, thermal limits, and power system protection.
- Monitoring and control may be required if the proposed PV system exceeds a certain (TBD) capacity of the minimum daytime load to address concerns related to voltage, thermal and power system protection
- Monitoring and control may be required if the proposed PV system is on a single phase line section and creates a greater than (TBD) imbalance a the next upstream three phase location

[10] JU ITWG Monitoring and Control Screens, 03/29/17; affirmed and iterated as *Appendix*: JU Draft Monitoring and Control Requirements for Solar Photovoltaic Projects in NY, 06-14-2017.

4 Photovoltaic System Key Concepts

The major components of a grid-connected PV system, as shown in Figure 10**,** are the PV array (modules), inverter, local loads, and main distribution panel (interconnection). Depending on the size of the PV system, there might or might not be a step-up transformer that increases the voltage to a level suitable for connection to the utility distribution circuit.

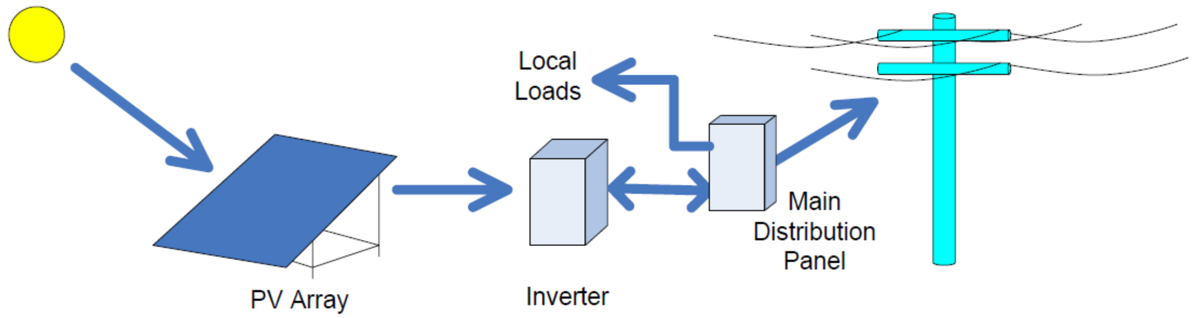

Figure 10. Simplified diagram of a PV system (Whitaker, Newmiller, et al., Distributed Photovoltaic Systems Design and Technology Requirements 2008)

This system can be represented by the simplified equivalent circuit shown in Figure 11. To the distribution grid, the PV system (*PV_Sys*) appears as a controlled current source. Local loads may include resistive (*R1*), inductive (*L1*), and capacitive elements (*C1*). The utility source is represented by its Thevenin-equivalent model, which includes voltage source *Utility_V* with series impedance *Utility_Z* (Whitaker et al. 2008). The utility impedance includes such parameters as the impedances of transformers and cables.

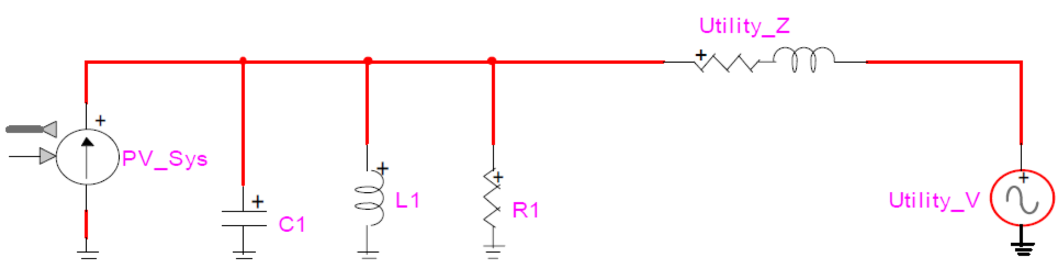

Figure 11. Simplified equivalent circuit of a grid-connected PV system (Whitaker, Newmiller, et al., Distributed Photovoltaic Systems Design and Technology Requirements 2008)

The inverter typically operates to provide only active power to the grid (unity power factor) and attempts to adjust its interface to the PV array to maximize power production (maximum power point tracking) given the temperature and available solar resource. The inverter is responsible for managing all grid interface functions, such as synchronization, overvoltage/undervoltage, overfrequency/underfrequency, disconnects, anti-islanding, and PV array control functions such as maximum power point tracking.

PV inverters, in addition to delivering PV energy to the grid, must act to meet utility concerns and requirements, such as anti-islanding, prevention of backfeed into a fault, provision of voltage and frequency range protection, limitation of harmonics, and provision of DC injection protection.

Several SIR requirements ensure compliance with specific concerns, as outlined below.

SIR Section II.A.1 on common design requirements for undervoltage/overvoltage and frequency protection states:

> The generator-owner shall have, as a minimum, an automatic disconnect device(s) sized to meet all applicable local, state, and federal codes and operated by over and under voltage and over and under frequency protection.

SIR Section II.A.1 on common design requirements for frequency response states:

> The required operating range for the generators shall be from 59.3 Hz to 60.5 Hz If deemed necessary due to abnormal system conditions the utility may request that the generator operate at frequency ranges below 59.3 Hz in coordination with the load shedding schemes of the utility system . For excursions outside these limits the protective device shall automatically initiate a disconnect sequence from the utility system as detailed in the most current version of IEEE Std. 1547. Clearing time is defined as the time the range is initially exceeded until the generator owner's equipment ceases to energize the PCC and includes detection and intentional time delay. Other static or dynamic frequency functionalities shall be permitted as agreed upon by the utility and generator-owner

SIR Section II.A.5 on minimum protective function requirements states:

> Minimum protective function requirements shall be as detailed in the table below. Function numbers, as detailed in the latest version of ANSI C37.2, are listed with each function. All voltage, frequency, and clearing time set points shall be field adjustable.

Table 6. Minimum Protection Functions

Inverters
Overvoltage/undervoltage (Function 27/59)
Overvoltage/underfrequency (Function 81O/81U)
Anti-islanding protection
Overcurrent (Function 50P/50G/51P/51G)

SIR Section II.E on power quality states:

> The maximum harmonic limits for electrical equipment shall be in accordance with the latest version of IEEE Std. 519 IEEE Recommended Practices and

> Requirements for Harmonic Control in Electric Power Systems to limit the maximum individual frequency voltage harmonic to 3% of the fundamental frequency and the total harmonic distortion (THD) to 5% on the utility side of the PCC.

SIR Section II.F on power factor states:

> If the average power factor, as measured at the PCC, is less than 0.9 (leading or lagging), the method of power factor correction necessitated by the installation of the generator will be negotiated with the utility as a commercial item. If the average power factor of the generator is proven to be above the minimum of 0.9 (leading or lagging) by the customer and accepted by the utility, that power factor value shall be used for any further utility design calculations and requirements.

4.1 Photovoltaic Hosting Capacity

Distributed PV hosting capacity describes the total amount of distributed solar electric power generation systems that can be connected to a specific electric power system. This hosting capacity can be thought of in similar fashion to the ability of a power system to accommodate a certain amount of load. In both cases, the capacity of the system will dictate this hosting capacity. Two important factors in determining capacity are voltage drop capacity and thermal capacity. Generally, the capacity of the system is greatest closest to the substation and decreases farther along the feeder, as shown in Figure 12 (McGranaghan, et al. 2008).

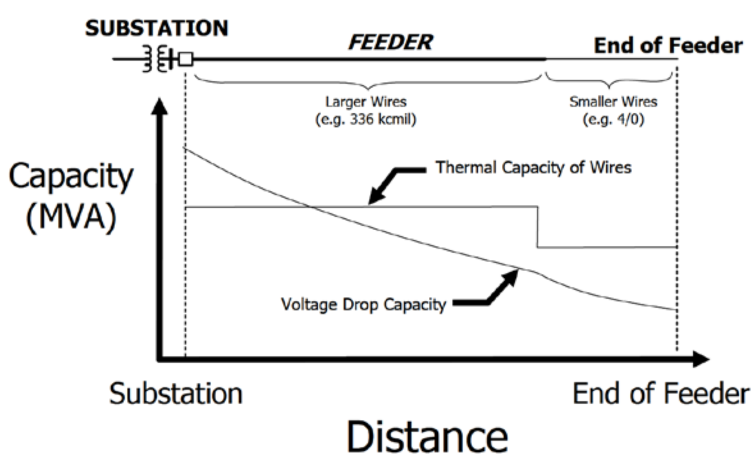

Figure 12. Key feeder capacity considerations (McGranaghan, et al. 2008)

Several SIR screens are designed to quickly identify instances where the feeder is capable of hosting a given amount of PV. These included preliminary screens E and F:

- Preliminary Screening Analysis (SIR Appendix G) Screen E: Simplified Penetration Test

Is the aggregate Generating facility capacity on the Line Section less than 15% of the annual peak load for all Line Sections bounded by automatic sectionalizing devices?

- Preliminary Screening Analysis (SIR Appendix G) Screen F: Simplified Voltage Fluctuation Test:

In aggregate with existing generation on the Line Section: Can the Generating Facility parallel with the Distribution Provider's Distribution System without causing a voltage fluctuation at the PCC greater than 5% of the prevailing voltage level of the Distribution System at the PCC?

4.1.1 Voltage Response

SIR Section II.A.1 on common design requirements for voltage response states:

> The required operating range for the generators shall be from 88% to 110% of nominal voltage magnitude. In addition, the generator shall not cause the system voltage at the PCC to deviate from a range of 95% to 105% of the utility system voltage. For excursions outside these limits the protective device shall automatically initiate a disconnect sequence from the utility system as detailed in the most current version of IEEE Std. 1547. Clearing time is defined as the time the range is initially exceeded until the generator-owner's equipment ceases to energize the PCC and includes detection and intentional time delay. Other static or dynamic voltage functionalities shall be permitted as agreed upon by the utility and generator-owner.

This requirement addresses the possibility of voltage rise caused by the addition of PV on a circuit and that the voltage rise will exceed the acceptable service voltage range. Voltage rise is caused by the PV system sending current back through the power system impedance. This has been described by Whitaker et al. (2008):

Recall that the utility can be represented by its Thevenin equivalent consisting of voltage source and series impedance (see Figure 11). Typically, the series impedance of the utility is quite small and has a correspondingly small voltage drop across it. In some cases (such as a large load at the end of a circuit or a very long circuit), the load current is high relative to its impedance, and the utility must increase the sending-end voltage (*Utility_V* in Figure 11) to maintain acceptable service voltage (load node voltage).

If a PV system backfeeds into the grid, the reverse power flows through the utility series impedance and causes a voltage drop across it. At the PV end of the circuit, the voltage now increases from the utility service voltage plus the voltage across the series impedance. There is a concern that in some cases this resulting local node voltage might exceed the utility service voltage limits defined in ANSI C84.1. This concept is illustrated in Figure 13 (Mather et al. 2016), which shows an example of service voltage needing to be increased (blue line). The increase is achieved through the use of voltage-regulating capacitors (black line); however, with PV added (red line), the voltage exceeds the high-voltage limit.

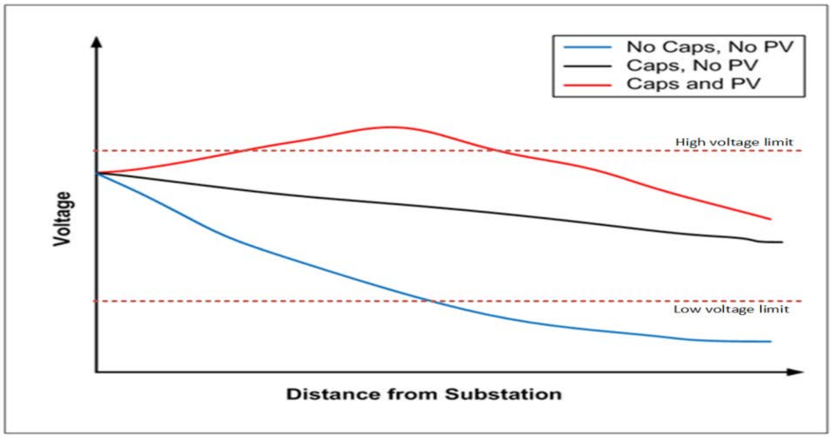

Figure 13. Example impacts of PV on the distribution circuit voltage profile (Mather, et al. 2016)

4.1.2 Solutions

Several methods can be implemented to limit this voltage rise (Whitaker et al. 2008). These include:

- Decrease utility series impedance—through larger or multiple conductors, larger derating factors on transformers, or the use of more transformers.
- Require customers to improve their power factors.
- Curtail power production under high-voltage conditions. (However, this is not a desirable solution because it decreases PV system efficiency, energy production, and results in revenue loss for the DER. It might also interfere with positive feedback-based anti-islanding.)
- Use energy storage to divert some of the PV power under high-voltage conditions.
- Add transformers with voltage-regulating capability.
- Allow PV inverters to operate with voltage-control capability so they can operate off-unity and provide (or consume) VAR. Note that the revision of IEEE 1547 allows this.

4.2 Grid-Supportive Inverters

In addition to meeting the requirements for energy production, basic power quality, and protective functions described above, modern, advanced inverters can provide additional grid-supportive functions under both normal and abnormal grid conditions. Modern inverters are able to operate as a voltage or current source. And depending on specific design features, they may be configured to provide positive and negative real and reactive power. This four-quadrant power capability, shown in Figure 14 (McGranaghan, et al. 2008), allows inverters to provide many grid-supportive functions, such as active voltage and frequency regulation. These functions become increasingly beneficial as the amount of variable generation on a circuit increases. Expected benefits include:

- Improvement in system reliability through voltage and frequency ride-through

- Improvement in power quality through reactive power support to prevent or mitigate voltage fluctuations
- Potential deferral of capital investments in generation and distribution system infrastructure through local energy supply and active voltage regulation
- Increased situational awareness of circuit conditions by leveraging inverter telemetry.

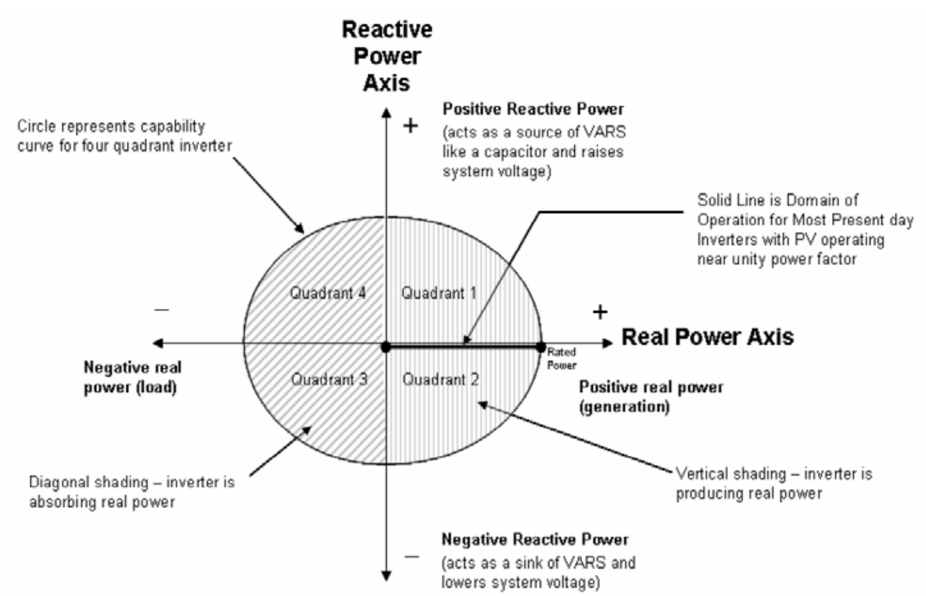

Figure 14. PV inverter four-quadrant real and reactive power capabilities (McGranaghan, et al. 2008)

4.3 National and State Standards for Grid-Supportive Inverters

As discussed above, in areas that have high deployment levels of PV generation, grid-supportive inverters can provide several important benefits. Several efforts have been underway in the United States to demonstrate the capabilities of these technologies. In parallel, efforts have been underway at the state and national level to revise interconnection standards to allow the use of these next-generation inverter capabilities.

4.3.1 IEEE 1547

SIR Section II.A.1 on common design requirements according to IEEE 1547[11] states:

[11] Note that IEEE 1547 is intended to be used in conjunction with IEEE 1547.1, UL1741, and the National Fire Protection Association 70 from the National Electric Code. The National Electric Code, adopted throughout the United States, is the primary standard for safe electrical design, installation, and inspection for all residential, commercial, and industrial facilities. The National Electric Code is revised every 3 years (the current edition is from 2017). The current edition includes material to address privately owned DER. Note that specific requirements for topics related to DER are discussed in Article 690: Solar Photovoltaic Systems and Article 691: Large-Scale Photovoltaic Electric Power Production Facility (≥ 5 MW).

> The requirements set forth in this document are intended to be consistent with those contained in the most current version of IEEE Std. 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems. The requirements in IEEE Std. 1547 above and beyond those contained in this document shall be followed and any other Standards included in or referenced to in IEEE Std. 1547 shall be adhered to.

4.3.2 IEEE 1547 Full Revision

More than 121 industry experts on the IEEE P1547 working group have been meeting via phone weekly for more than a year to develop consensus language[12]. The revisions include many new details on reactive power capabilities and voltage/power control requirements, maximizing hosting capacity while maintaining distribution grid safety (cease to energize, trip on voltage or frequency when necessary), and supporting bulk power system reliability (ride through voltage and frequency disturbances).

With approval of this standard, New York and other jurisdictions can leverage a uniform and consistent method for interconnecting new devices to enable more coordinated operation under normal conditions and improved performance under abnormal conditions.

4.3.3 Advanced Inverter Requirements in California

California has taken an active approach toward grid-supportive inverters and will require their use after September 2017. (They can be used today, but they will be required in September 2017.)

4.3.4 Advanced Inverter Requirements in Hawaii

Hawaii has several motivations to explore advanced inverters. Hawaii has a goal of reaching 100% renewable energy by 2045, and thus advanced grid-support functions are viewed as a means to increase PV hosting capacity. Hawaii has experienced a large increase in PV installations and currently has more than 475 MW of solar capacity, the majority of which are customer-sited. More than 13% of customer accounts have PV (more than 60,500 interconnections) (Reiter, Edge, and Berdner 2016). Improved inverter response to abnormal voltage and frequency under such high deployment levels is considered a critical reliability need, requiring wider frequency and voltage ride-through settings initially and then voltage support.

Hawaii has taken steps to address reliability concerns by updating the state's interconnection standard to widen underfrequency trip limits from 59.7 Hz to 57 Hz in 2011. In 2014, Hawaii revised the state's interconnection standard to require voltage and frequency ride-through. In 2015, the state's interconnection standard was again updated to require voltage support and remote configurability. These requirements are being implemented in the field, and preliminary results from additional laboratory testing are expected to provide guidance for future field demonstrations.

[12] 1547WG approved (3/2017), and sent to IEEE-SA for review and balloting.

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