WESTERN INTERSTATE ENERGY BOARD

Distributed Energy Resource Interconnection Timelines and Advanced Inverter Deployment

Their Improvement in the Western Interconnection

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Disclaimer

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Abbreviations

AC	alternating current
CPUC	California Public Utilities Commission
DC	direct current
DER	distributed energy resource
DGIC	Distributed Generation Interconnection Collaborative
IEEE	Institute of Electrical and Electronics Engineers
kW	kilowatts
MW	megawatts
NEM	net-energy metering
NREL	National Renewable Energy Laboratory
PG&E	Pacific Gas and Electric Power Company
PV	photovoltaic
SIWG	Smart Inverter Working Group
UL	Underwriters Laboratories

Introduction

Distributed energy resources (DERs) include generation and other energy sources that are not centrally-located. While residential solar photovoltaic (PV) power generation is the prototypical DER, several other types of DERs exist, including other generation technologies (e.g., combined heat and power), load management (also known as demand response), and storage, which can assume a variety of forms (e.g., large energy storage systems, hybrid solar PV generation/storage systems, electric vehicles). It has been estimated that, in the Western Interconnection alone, there will be more than 40,000 megawatts (MW) of DER nameplate capacity available by year 2022.[1] DERs have attracted significant attention from the electric power sector in recent years.

In order for the energy of DERs to be grid-available, they must be interconnected with the grid. Processes for interconnection are in evolution as utilities and regulators improve their understanding of interconnection requirements and of potential streamlining of these processes. In addition to interconnection processes, reliability must be ensured with grid-interconnected DER. This policy paper addresses these two topics in detail, culminating in recommendations for streamlining interconnection processes and ensuring grid reliability.

The Process of Interconnection of DERs

The energy of DERs can be used on-site to meet facility loads. In order for the energy and other services of DERs to be useful to other facilities, however, DERs must be interconnected with a distribution system. Using a distributed solar PV generating system as a DER example, there are four stages to establishing this interconnection (see Figure 1 below), including:

1. Interconnection application review and approval –utility review of application completeness to interconnection approval by the utility

2. Construction –installation of the solar PV system

3. Building inspection by local permitting jurisdiction –local jurisdiction’s completion and submission of verification of a passed building inspection (i.e., compliance with building and fire codes) to utility

4. Permission to operate – permission provided by the utility to the solar PV installer

[1] EQL Energy, *Emerging Changes in Electric Distribution Systems in Western States and Provinces*, 1-3, 2015, http://westernenergyboard.org/wp-content/uploads/2015/05/04-2015-EQL-WIEB-Emerging-Changes-Electric-Distribution-Systems-Western-States-Provinces.pdf

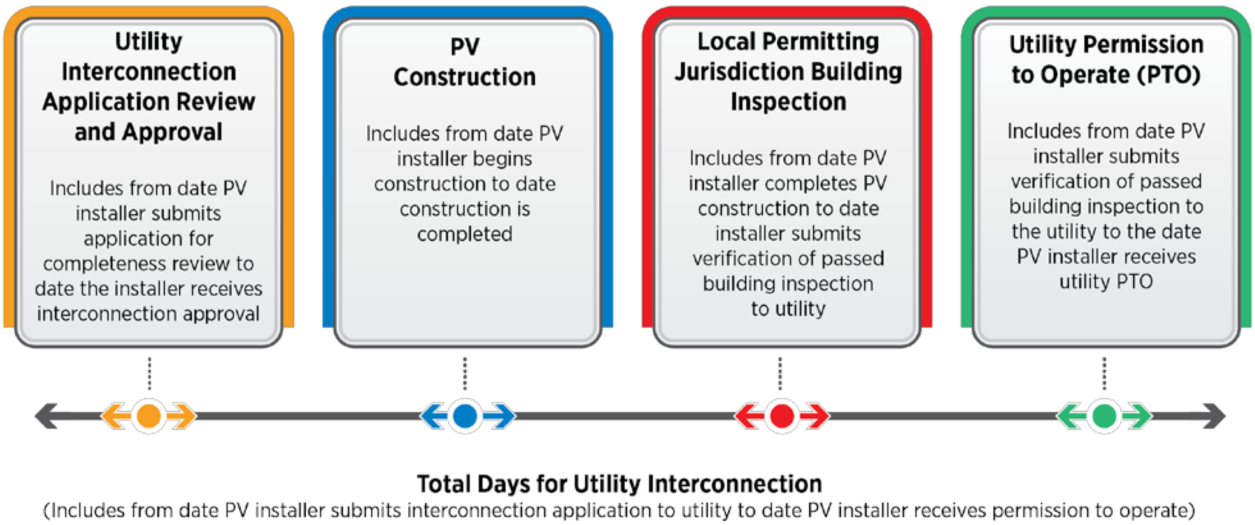

Figure 1 – Stages of DER Interconnection Establishment (see Note 2 for source)

A study by the National Renewable Energy Laboratory (NREL)[2] assessed the median duration of each of these stages for both residential and commercial solar PV systems during years 2012-2014; we will focus here on residential systems. In this study, a residential system was defined as one ranging from 0 to 10 kilowatts (kW) in nameplate capacity. The study's sample size was more than 30,000 residential systems, distributed among 87 utilities in 16 states. This study, completed in 2015, was timely because several utilities in the Southwest, including Arizona Public Service, Pacific Gas and Electric, and San Diego Gas and Electric, process 1000 or more interconnection applications per month.

Interconnection application review and approval required a median duration of 18 business days to complete. Construction, on the other hand, required a median time of just 2 business days. Building inspection had a median duration of 4 business days, and the permission to operate stage had a median time of 10 business days. The entire interconnection process for residential solar PV systems had a median duration of 52 business days. Commercial systems (nameplate capacities of 10-50 kW) required slightly longer times for all stages. It is likely that variation in requirements and processes across utilities and local permitting jurisdictions contribute to these relatively lengthy timelines.

In order to identify and disseminate utility best practices for solar PV interconnection, NREL and the Solar Electric Power Association jointly facilitate the Distributed Generation Interconnection Collaborative (DGIC). The DGIC is a consortium of more than 200 stakeholders from utilities, regulatory agencies, solar PV installers, and other groups. It has the purpose of sharing

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[2] Kristen Ardani et al., *A State-Level Comparison of Processes and Timelines for Distributed Photovoltaic Interconnection in the United States (Technical Report NREL/TP-7A40-63556)*, v-vi, 2015, http://www.nrel.gov/docs/fy15osti/63556.pdf

knowledge and data related to distributed solar PV interconnection practices, research and innovation.[3]

In addition to the above-mentioned, national-level study, NREL recently published a case study of the California investor-owned utility Pacific Gas and Electric (PG&E).[4] This utility was selected for study because it had interconnected more than 130,000 solar PV systems within its distribution systems by the end of year 2014, ranking it first among U.S. utilities. PG&E classifies interconnection applications as follows: standard net energy metering (NEM) systems (solar PV and wind generation up to 30 kW in nameplate capacity), expanded NEM systems (30 kW to 1 MW in capacity), and power exporting systems; we will focus on standard NEM system interconnection applications. After eliminating unnecessary application requirements (e.g., detailed insurance review), PG&E focused on streamlining and automating the interconnection application stage. PG&E's online application process is associated with several benefits (e.g., allows the processing of an application to be tracked). Automation of the initial engineering review, due in part to aggregation of applications and distribution-feeder information from the utility's asset management system, has reduced duration of the application stage. These improvements have resulted in typical interconnection application stage duration of 3 days in spite of an increase in applications received from approximately 1000 to 5000 per month over years 2012-2014. This time compares very favorably with a median national-level duration over the 2012-2014 period of 18 days (see above). Moreover, per unit processing cost for PG&E has been reduced by nearly 70% over the same time period.

Technical Standards for Interconnection of DER

Two organizations are prominent in developing national standards for interconnection of DER, the Institute of Electrical and Electronics Engineers (IEEE) and Underwriters Laboratories (UL). National standards are important because they are often referenced by state-level entities; for example, the California Public Utility Commission's (CPUC) Revisions to Electric Tariff Rule 21 (see below)[5] references IEEE Standard 1547, as well as UL Standard 1741.

IEEE Standard 1547 concerns the interconnection of DER with electric power systems and has been adopted by most jurisdictions as the basis for DER interconnection. The base IEEE 1547 standard was approved by the IEEE Standards Board and the American National Standards Institute in year 2003. A series of related guides and recommended practices has been

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[3] Available at: http://www.nrel.gov/tech_deployment/dgic.html. Last visited December 7, 2015. The DGIC meets electronically several times per year, and makes available speaker slides and a recording of each presentation. As an example, the upcoming knowledge-sharing session, to be held on April 28, 2016, is entitled "Emergent Considerations for Advanced Inverter Deployment".

[4] Kristen Ardani & Robert Margolis, *Decreasing Soft Costs for Solar Photovoltaics by Improving the Interconnection Process: A Case Study of Pacific Gas and Electric (Technical Report NREL/TP 7A40-65066),* 1-11, 2015, http://www.nrel.gov/docs/fy15osti/65066.pdf

[5] Public Utilities Commission of the State of California, *Interim Decision Adopting Revisions to Electric Tariff Rule 21 for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company to Require "Smart" Inverters;* 2, 5-6; 2014.

developed by IEEE since 2003 for specific issues, including conformance testing requirements (1547.1; 2005), communications requirements (1547.3; 2007), islanded systems (1547.4; 2011), secondary-networked power systems (1547.6; 2011), DER impact study requirements (1547.7; 2013), and use of expanded DER capabilities (1547.8; release pending). IEEE 1547.a is a 2014 amendment to the base IEEE 1547 standard that permits DER to participate in voltage regulation, as well as making several minor changes to protective settings. In addition, IEEE 1547.1, which details conformance testing requirements for equipment that interconnects DER with distribution systems, is being updated to reflect changes in the base 1547 standard. This sub-standard is scheduled for full revision immediately following revision of the base IEEE 1547 requirements document. IEEE 1547.1a is an amendment to IEEE 1547.1 and is this sub-standard's most recent version.[6] It allows use of other protective settings if the DER owner/operator and the area electric power system operator mutually agree upon their use. IEEE 1547.1 is significant in that, once published, it will be referenced by both UL 1741 (see below) and state regulations such as the above-mentioned CPUC Rule 21.

UL Standard 1741,[7] similar to IEEE 1547, is a national-level standard. UL participated in the IEEE Standard 1547 development in 2003, and is also a participant in its revision. UL is a safety science company; thus, an emphasis of UL 1741 is safety. Sections 34-38 of UL 1741, for example, generally concern protection against risks to persons. Included in UL 1741 are safety standards for electric shock, fire and mechanical hazards. The standard provides a certification basis for interconnection of inverters with electric power systems, and most jurisdictions require UL 1741 certification of equipment before they can be interconnected. In the interim period before base IEEE 1547 and 1547.1 are revised, UL 1741 Supplement A will be in effect. Supplement A is in preparation, and is anticipated to be finalized in mid-2016. This supplement will provide a certification test standard for equipment manufacturers and utilities that need advanced inverter functionality prior to publication of revised IEEE 1547 and 1547.1. Upon publication of the IEEE standards, UL 1741 will be re-harmonized with the IEEE standards and Supplement A will be eliminated.

California Electric Tariff Rule 21

CPUC Electric Tariff Rule 21 generally concerns interconnection of distributed power generation with distribution systems. Rule 21 has been revised twice in recent years. The first revision, which occurred in late 2012, concerned studies of impacts of DER interconnection on distribution systems. This revision led to interconnection applications being assigned to either a so-called fast track (for NEM, non-exporting, and small exporting facilities) or a more detailed study process (for more complex power-generating facilities).

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[6] Available at: http://grouper.ieee.org/groups/scc21/1547.1a/1547.1a_index.html. Last visited December 3, 2015.
[7] Available at: http://ulstandards.ul.com/standard/?id=1741_2. Last visited December 4, 2015.

A CPUC decision that adopted additional revisions to Rule 21 was issued in late 2014. This decision included an adoption date of the later of December 31, 2015 or approval date of the above-mentioned Supplement A to UL 1741.[8] The 2014 revisions to CPUC Rule 21 were recommendations of the Smart Inverter Working Group (SIWG), and were termed Phase 1 Recommendations by the SIWG. The SIWG was formed in January, 2013, and consisted of representatives of three principal stakeholder groups – utilities, DER manufacturers, and DER installers and aggregators. Although of differing positions initially, these stakeholder groups became cognizant of the numerous benefits of advanced inverters.[9] These benefits include anti-islanding protection, voltage and frequency ride-through, dynamic volt-var operations, ramp rate control, adjustable fixed power factor, and soft start re-connection capability.[10] These technological capabilities of advanced inverters will be detailed below. The SIWG has also developed Phase 2 Recommendations for utility communications that are being incorporated into Rule 21. The SIWG is currently developing Phase 3 Recommendations that concern additional advanced inverter capabilities. The SIWG has a variety of resources related to CPUC Rule 21 available.[11]

Technological Capabilities of Inverters

It is important to first appreciate how an inverter functions. Certain capabilities of advanced inverters will then be examined; that is, the SIWG's Phase 1 Recommendations for CPUC Rule 21. These capabilities can enhance reliability of the grid, as well as improve coordination between DER and area electric power system operators.

Solar PV modules produce direct electric current (DC), whereas electric power systems carry alternating current (AC). An inverter converts the DC output of a solar PV system to AC that can be carried by a distribution system with which a PV system is typically interconnected (see Figure 2 below). Contemporary inverters use transistors to convert DC to AC by reversing voltage polarity at a rate of 60 times per second (60 Hertz). Voltage remains identical to that produced by the solar PV system; current exiting the inverter, therefore, varies. Inductive coils and capacitors within the inverter smooth rapid changes in current and voltage, respectively.[12]

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[8] Public Utilities Commission of the State of California, *supra* note 5, at 10.
[9] EQL Energy, *supra* note 1, at 24.
[10] Public Utilities Commission of the State of California, *supra* note 5, at 4-5.
[11] Available at: http://www.energy.ca.gov/electricity_analysis/rule21. Last visited December 10, 2015.
[12] Andy Walker, *Solar Energy: Technologies and the Project Delivery Process for Buildings*, 81-82, 2013; John Wiley & Sons, Hoboken, NJ.

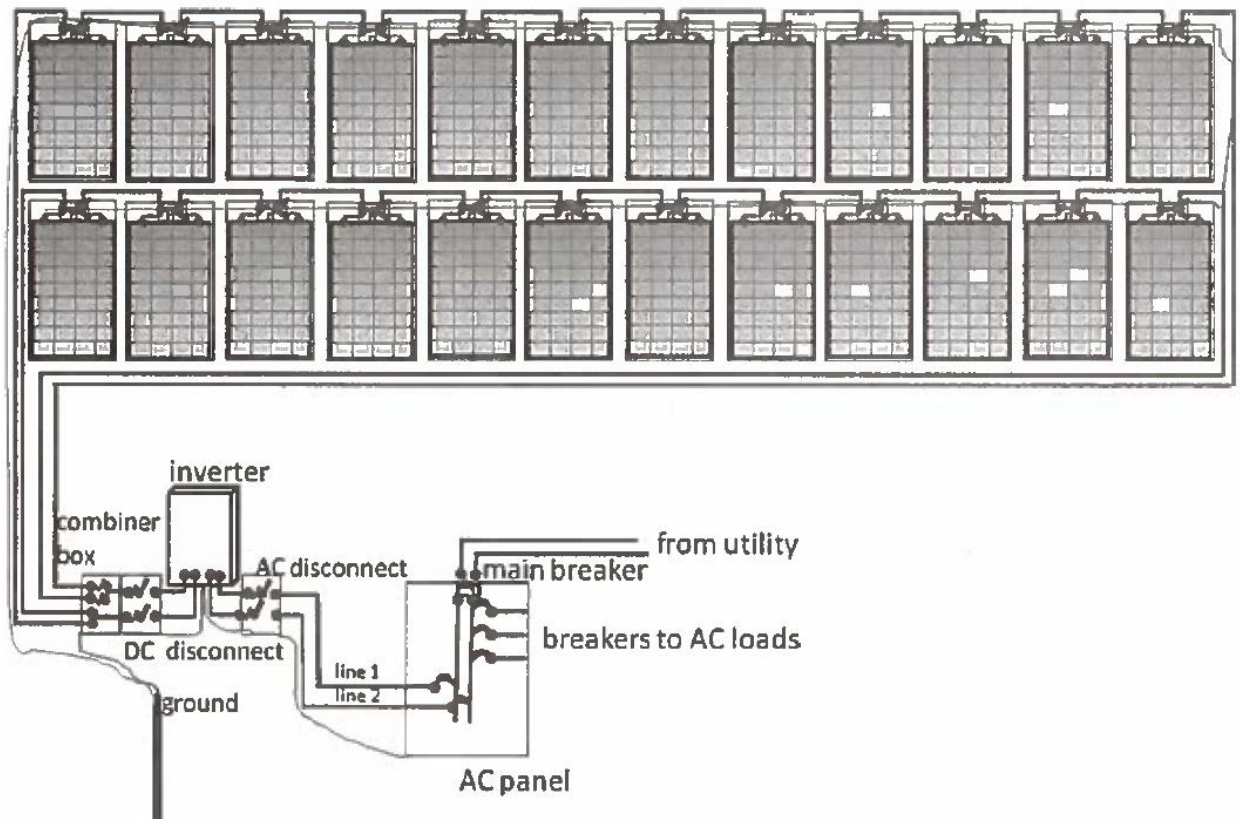

Figure 2 – Positioning of Inverter Relative to Solar PV Generating and Distribution Systems. Note that inverter converts DC output from solar PV system to AC for distribution system compatibility (see Note 12 for source).

Advanced inverters, also known as smart inverters, are typically controlled by sophisticated microprocessors or digital signal processors which allow them to provide a number of advanced functions that can be utilized to enhance grid stability and reliability.

CPUC Rule 21 (2014 revision) incorporates several of these capabilities as technical operating standards per the SIWG's Phase 1 Recommendations. An excellent overview of these advanced functions is an Electric Power Research Institute technical update.[13] Brief descriptions of these autonomous capabilities and how they can enhance grid reliability follow; further technical information is provided in the Appendix.

Anti-islanding protection. This protection ensures that, when a distribution system is unintentionally de-energized, a DER such as a solar PV system does not re-energize this unintentional electrical island.[14] An electrical island develops when a portion of the grid,

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[13] B. Seal, *Common Functions for Smart Inverters, Version 3,* 2014, http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?productid=000000003002002233.
[14] Smart Inverter Working Group, *Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources*, 21, 2014, http://www.energy.ca.gov/electricity_analysis/rule21/documents/recommendations_and_test_plan_documents/Recommendations_for_updating_Technical_Requirements_for_Inverters_in_DER_2014-02-07-CPUC.pdf.

typically a distribution system, is isolated from the remainder of the grid. An island can, however, continue to operate if a DER provides its output to the island. Mandatory disconnection of a DER prevents damage to individuals and/or equipment involved in repairing the electrical island by maintaining it in a de-energized state.

Inverters can detect electrical islands.[15] There are three general detection approaches: passive, active, and remote (i.e., residing at the utility level).[16] The first two approaches make use of capabilities that reside within an inverter. Passive methods involve the monitoring of certain variables (e.g., voltage) on the interconnected distribution system, and stopping the inverter from converting DC to AC if a variable exhibits sufficient deviation from its normal range. Passive methods of island detection resemble how utility low and high voltage or frequency (see below) relays function. Active methods have historically attempted to introduce a disturbance to the interconnected distribution system and monitor the system's response. Under normal operation, an attempted disturbance will not disturb the stability of distribution system variables such as voltage. If an electrical island is present, however, a variable may not exhibit stability. If instability is present, an inverter will stop converting DC to AC.

Low/high voltage and low/high frequency ride-through capabilities. These technological capabilities also concern the connection status of a DER such as a solar PV system, but during anomalous voltage and/or frequency conditions. Concerning voltage, the SIWG Phase 1 Recommendations proposed that there are voltage levels (and corresponding durations) for which a solar PV system should remain connected to a distribution system, and voltages and durations for which a DER should disconnect from a distribution system. CPUC Rule 21, now revised to be consistent with the SIWG Phase 1 Recommendations, will permit DER – distribution system connection during voltage anomalies of greater deviation and for longer durations than in the past. Connection is desirable because, given ever-increasing cumulative nameplate capacity of DERs, exacerbation of voltage anomalies (and possibly even outages) could occur if widespread disconnection of DERs takes place. IEEE 1547 (2003) requires DERs to disconnect within 2 seconds of detecting a voltage anomaly. SIWG's Phase 1 Recommendations, now incorporated into CPUC Rule 21, allow greater deviations in voltage (and durations of such deviations).[17] Advanced inverters can accomplish this so-called voltage ride-through.

Similar to voltage, the SIWG Phase 1 Recommendations proposed that there are frequency levels (and corresponding durations) for which a solar PV system should remain connected to a distribution system, and frequencies and durations for which a DER should disconnect from a

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[15] *Id.*, at 21.

[16] Ward Bower & Michael Ropp. *Evaluation of Islanding Detection Methods for Utility-Interactive Inverters in Photovoltaic Systems (SAND2002-3591),* 10-11, 2002, http://prod.sandia.gov/techlib/access-control.cgi/2002/023591.pdf

[17] Smart Inverter Working Group, *supra* note 14, at 22-26. As an example, an overvoltage event of up to 120% of nominal voltage can be tolerated for 13 seconds before disconnection of DER(s), according to SIWG's Phase 1 Recommendations.

distribution system. Connection preservation for minor frequency anomalies or for more significant anomalies, albeit for only brief durations, is desirable for the same reasons as noted above for voltage anomalies.[18] Advanced inverters can also accomplish this so-called frequency ride-through.

Dynamic volt/var operations. Dynamic volt/var operations are synonymous with dynamic reactive power compensation. With this capability, DER can counteract voltage deviations by either producing (in the event of a decrease in voltage on a distribution system) or absorbing reactive power (with increased voltage on a system). The former has historically been more common on a distribution system, particularly at increasing distances from a system's substation, but with increasing DER penetrations increased voltage can also be problematic.

Reactive power develops because a distribution system and loads served by it possess capacitance and inductance. Both capacitance and inductance are forms of reactance, and impede power flow because of alternating storage of energy in and release of energy from fields surrounding a distribution line. This storage and release of energy is, in turn, due to the nature of AC that flows on distribution lines. Capacitance involves energy stored in and released from electrical fields, whereas inductance involves energy stored in and released from magnetic fields. The result, regardless of which form of reactance is involved, is that current changes phase relative to voltage; the magnitude of this phase change is termed phase angle. The larger the phase angle, the greater the absolute magnitude of reactive power. With capacitance, current leads voltage; with inductance, current lags voltage.

Dynamic modification of voltage was prohibited prior to the 2014 revision of CPUC Rule 21. The SIWG recommendation for dynamic volt/var operations is that smaller, residential-type DERs can operate over a power factor range of +/- 0.90 (see *Adjustable fixed power factor* below for explanation of power factor).[19] Allowing dynamic volt/var operations can compensate for voltage impacts due not only to DERs, but also to motors and other types of load, on a distribution system.

Ramp rate control. A DER such as a solar PV system or a storage system can control, via an advanced inverter, the rate at which its power output to a distribution system increases or decreases. This inverter capability smooths transitions between power output levels. Importantly, ramp rate control allows for more orderly transitions in the case of aggregated DERs that could otherwise negatively impact a distribution system. Power quality issues on a distribution system can develop without ramp rate control.

Adjustable fixed power factor. Real power, the product of voltage and current and expressed in units of watts, is only one type of power present in distribution systems. As noted

[18] *Id.*, at 26-31. As an example, an overfrequency event of up to 62.0 Hertz can be tolerated for 300 seconds before disconnection of DER(s), according to SIWG's Phase 1 Recommendations.
[19] *Id.*, at 31-35.

above under *Dynamic volt/var operations,* reactive power is also present. The vector sum of real and reactive power is apparent power, and power factor is the ratio of real to apparent power. While a power factor of 1.0 (i.e., no reactive power present) is optimal for efficient system operations, it is rarely achievable in distribution systems because loads and DERs may generate reactive power, meaning that power factor will be lowered from the optimal value of 1.0. The presence of large numbers of DER on a distribution system can cause voltage to rise due to apparent power flow from DER towards the substation. A technique to manage such a voltage increase is setting DER power factor to absorb a small amount of reactive power to offset this increase in voltage. On the other hand, DER power factor can be set to produce reactive power on circuits where reduced voltage at the distal end of the distribution system is an issue.

Re-connection by so-called soft-start methods. Soft-start methods refer to re-connection of a DER(s) to a distribution system following an outage. Two general soft-start approaches to re-connection – staggering the re-connection of DERs to a distribution system or ramping aggregate DER re-connection – will mitigate overly-large increases in voltage and/or frequency on the distribution system.[20] While either approach will avoid a sharp increase in aggregate power output of DERs during re-connection, staggered re-connection does not discriminate among system capacities. Thus, the presence of a single, large-capacity DER might introduce local voltage and/or frequency disturbances. Soft-start ramping of aggregate re-connection is therefore preferred because increases in DER output are very predictable regardless of DER capacity.

Policy Implications

Enabling certain smart inverter capabilities will allow the Western U.S. to avoid recent negative experiences of areas with high penetration of DER. In 2010 it was determined that in a power system event that could affect Germany and Italy, of the 14,000 megawatts (MW) of total distributed solar PV nameplate capacity, 9000 MW of capacity was determined to have been at risk of disconnecting from the grid instantaneously. Given that the European grid can only withstand an instantaneous loss of 3000 MW, in 2012 the German government passed an ordinance requiring either output reduction or smooth shutdown of output by distributed solar PV systems during overfrequency events. Retrofitting of inverters was required for more than 300,000 solar PV systems. For many of these systems, changes in operating software and/or inverter operating parameters were able to accomplish this retrofitting, specifically for low/high frequency ride-through capability, but inverter replacement was nonetheless required for older inverters. The estimated cost of this retrofitting has ranged between $90 and 200 million.[21]

For the Hawaiian island of Oahu, the possibility that a large fraction of its total of 140 MW of solar PV nameplate capacity was at risk of being instantaneously disconnected from the grid

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[20] *Id.*, at 38.

[21] National Renewable Energy Laboratory, *Advanced Inverter Functions to Support High Levels of Distributed Solar: Policy and Regulatory Considerations,* 6, 2014, http://www.nrel.gov/docs/fy15osti/62612.pdf

during low/high frequency events led to re-programming of 800,000 inverters. Fortunately, prior deployment of advanced inverters with remote programming capability permitted remote updating of low/high voltage and frequency ride-through parameters. This remote enabling was done at a savings for ratepayers estimated to be nearly $50 million, and was facilitated by Hawaiian Electric Company Rule No. 14H that requires remote inverter programming capability. It also illustrates the wisdom of the yet-to-be-adopted SIWG Phase 2 Recommendations (see California Electric Tariff Rule 21 above).

Given these experiences of Germany, Italy and Hawaii, the following policy recommendations are offered for Western states and provinces:

● Strive for consistency in requirements and processes across authorities having jurisdiction. Such consistency is especially important for reducing the time and cost of interconnection and building permitting processes among utilities and local permitting jurisdictions, respectively. Consistency will also benefit the solar PV sector that operates in multiple jurisdictions.

● Adopt revised IEEE 1547 (target publication date of 2016) that includes the advanced inverter capabilities introduced in the SIWG's Phase 1 Recommendations to the CPUC. Importantly, adoption of revised IEEE 1547 that will enable the use of advanced inverter capabilities will enhance reliability of the Western Interconnection.

● Require remote inverter programming capability for inverters, permitted by communication of DERs, facility systems, and aggregators with a utility. Such communication will permit remote enabling and updating of advanced inverter capabilities, and will allow more coordinated management of DERs within distribution systems. Remote enabling, in turn, requires interconnection agreements that allow utilities to change operational characteristics of inverters when necessary. IEEE 2030.5 (last version, 2013; currently being revised by the Smart Energy Profile 2.0 working group) is the most likely standard to be adopted in order to enable remote programming capability. IEEE 2030.5 is based on based on the International Electrotechnical Commission's (IEC) communication standard 61850. IEC 61850 is a standard that defines mechanisms for exchanging application messages.

Appendix

This section contains more specialized technical information related to the advanced inverter capabilities that underlie the SIWG's Phase 1 Recommendations for CPUC Rule 21 (2014 revisions). This section also contains figures that illustrate either those technical capabilities or specifics of the SIWG's Recommendations.

Anti-islanding protection. While voltage and frequency ride-through capabilities are unlikely to interfere with island detection, dynamic volt/var capability and other stabilizing functions may interfere with island detection by advanced inverters. In response to this concern, UL and Sandia National Laboratories have developed much more sophisticated anti-islanding testing requirements designed to address detection of islands in combination with advanced inverter functionality. These new testing requirements are incorporated into UL 1741 Supplement A.

Low/high voltage and low/high frequency ride-through capabilities. Figure 1 below, a voltage – time graph, shows the specific deviations in voltage (and durations of such deviations) that will be permitted (green lines) under the SIWG's Phase 1 Recommendations, thereby reducing risk of exacerbation of voltage anomalies or even outages.

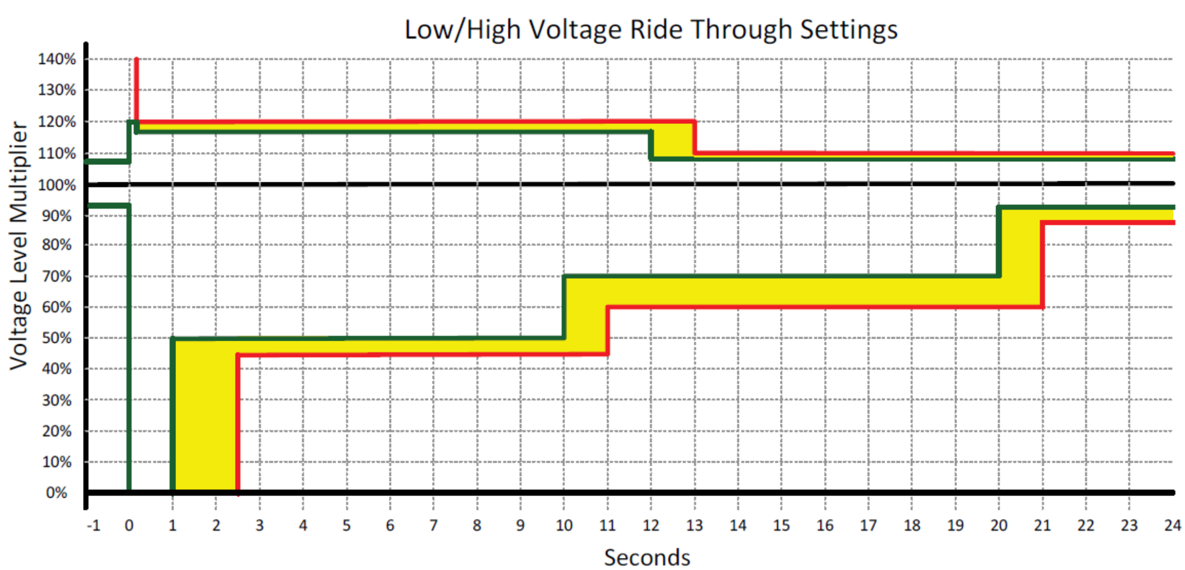

Figure 1 –Must-Remain-Connected (green lines) and Must-Disconnect (red lines) Voltage Limits for CPUC Rule 21 (see Note 5 for source)

Figure 2 below, a frequency – time graph, shows the specific deviations in frequency (and durations of such deviations) that will be permitted (red lines) under the SIWG's Phase 1 Recommendations, thereby reducing risk of exacerbation of frequency anomalies or outages.

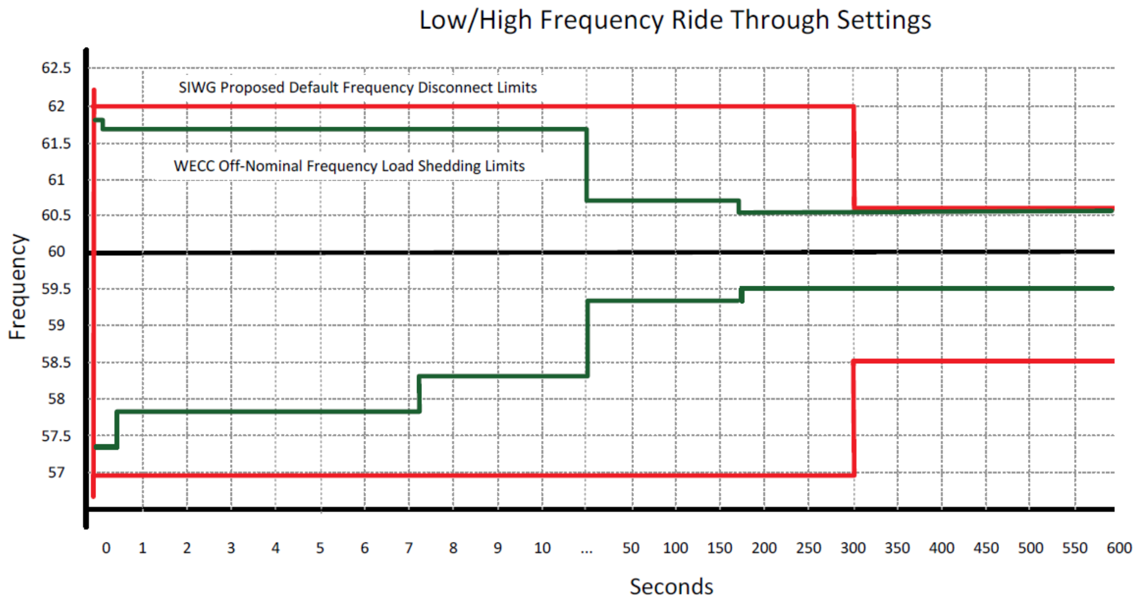

Figure 2 –Must-Disconnect (red lines) Frequency Limits for CPUC Rule 21 (see Note 5 for source). Current Western Electricity Coordinating Council Must-Disconnect limits are shown in green.

Dynamic volt/var operations. Reactive power is measured in units of volt-ampere reactive (var), and is calculated using the following formula:

$$Q = V_{rms} * I_{rms} * \sin(\phi)$$

Where Q = reactive power, V_{rms} = root mean square voltage, I_{rms} = root mean square current, and sin (ϕ) = sine of phase angle between current and voltage. The formula indicates that the larger the phase angle, the greater the absolute magnitude of reactive power.

The SIWG recommendation for dynamic volt/var operations is that larger DERs (i.e., greater than 15 kW in nameplate capacity) can operate dynamically in the range between +/- 0.85 power factor, while smaller DERs (i.e., less than 15 kW in capacity) can operate over a power factor range of +/- 0.90. Figure 3 illustrates the capability of advanced inverters to counteract voltage deviations.

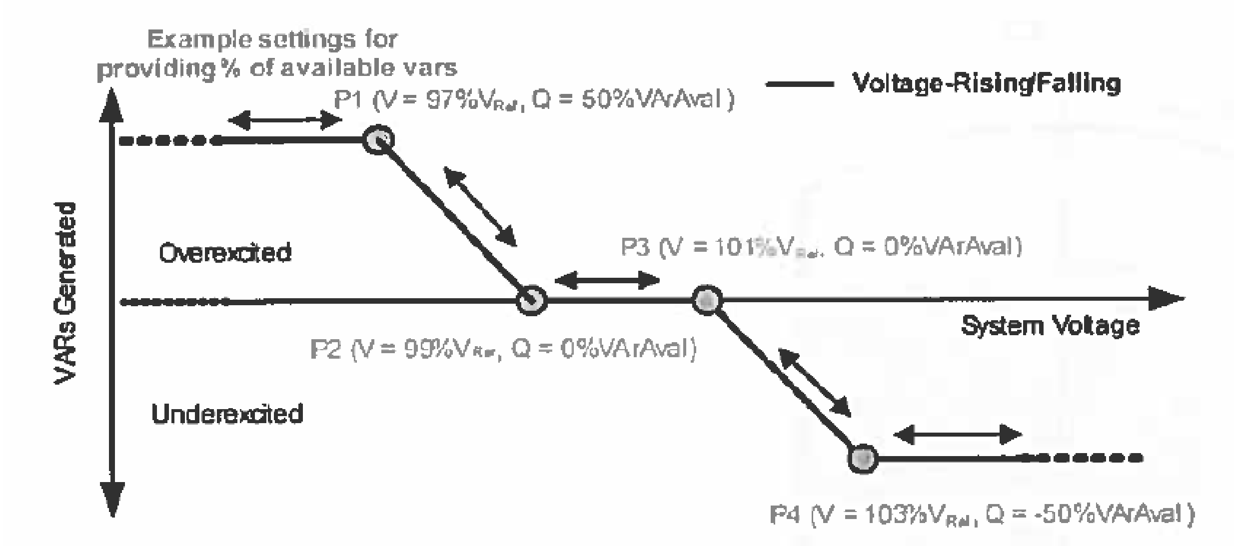

Figure 3 – Dynamic Volt/Var Operations via Either Producing Reactive Power (with low distribution system voltage; P2 to P1) or Consuming Reactive Power (with high system voltage; P3 to P4) (see Note 5 for source)

The SIWG further proposed that, in order to avoid problems with electrical island detection (see *Anti-islanding protection* above), response time for reactive power compensation, while not necessarily immediate, would occur within 10 seconds.

Ramp rate control. The SIWG Phase 1 Recommendations for ramp rate control include 2 ramp-up rates. One rate is for normal conditions (i.e., transitions from lower to higher power output levels); the SIWG proposed a rate of 100% of maximal current output per second. The other rate is for startup or re-start conditions (i.e., soft-start connect ramp-up rate), and is 2% of maximal current output per second.[22] The startup/re-start ramp rate is necessarily smaller in magnitude than the normal conditions ramp-up rate.

Adjustable fixed power factor. The original CPUC Rule 21 permitted power factor of a DER to be fixed at levels other than 1.0, within a range of +0.9 through -0.9. The SIWG Phase 1 Recommendations allow a given DER's power factor to be fixed within a wider range; this recommendation will lead to an overall distribution system's power factor being closer to 1.0.[23]

Re-connection by so-called soft-start methods. The SIWG Phase 1 Recommendation for soft-start re-connection is that DER should not be re-connected until voltage and frequency have remained within acceptable ranges for at least 0-5 minutes; a fixed time of a full 5 minutes can

[22] Smart Inverter Working Group, *Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources*, 35-36, 2014, http://www.energy.ca.gov/electricity_analysis/rule21/documents/recommendations_and_test_plan_documents/Recommendations_for_updating_Technical_Requirements_for_Inverters_in_DER_2014-02-07-CPUC.pdf.
[23] *Id.*, at 37.

be also be employed.[24] At that time, DERs can be re-connected, but either the staggering or ramping (preferred) approach must be used.

[24] *Id.*, at 39.