COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Investigation into Distributed Generation) D.P.U. 11-75

COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION ON THE DISTRIBUTED GENERATION INTERCONNECTION WORKING GROUP REPORT AND DRAFT TARIFF LANGUAGE

The Solar Energy Industries Association (SEIA) hereby responds to the notice issued on November 26, 2012, by the Department of Public Utilities (DPU), requesting comments no later than December 7, 2012, on the Distributed Generation (DG) Interconnection Working Group Report submitted to the DPU on September 14, 2012, and related proposed tariff language to implement Report recommendations filed with the DPU on October 31, 2012.

I. INTRODUCTION

SEIA was pleased to participate in the discussions of the DG Working Group that produced the Report and wholeheartedly supports prompt adoption of its recommendations by the DPU.[1] These improvements include measures to help assure utility compliance with applicable interconnection timelines, a more definitive process for withdrawal of non-viable DG projects from the interconnection queue, a common Technical Standards manual, and a Technical Standards Review Group to consider non-tariff technical barriers.[2]

[1] Order Establishing Distributed Generation Working Group, D.P.U. 11-75-A (Jan. 23, 2012) ("DPU Order.")

[2] Raab and Associates, Ltd., "Final Report from the Massachusetts Distributed Generation Interconnection Working Group" (Sept. 14, 2012) ("Working Group Report.")

The Working Group also reached agreement on a "Supplemental Review" process to expedite and reduce the cost of DG interconnection for projects on the "Expedited Track."[3] However, the Working Group participants did not agree on the level of the minimum load screen that is a key facet of Supplemental Review.[4] Instead, DG proponents supported a 100% screen, and utilities supported a more restrictive 67% screen that would severely limit the applicability of Supplemental Review.[5] Therefore, the Working Group Report makes no recommendation on this important issue, but instead provides the DPU a choice.[6] SEIA strongly believes the 100% of minimum load screen to expedite interconnection for solar and other DG is the best policy. By contrast, the 67% screen will make interconnection unnecessarily costly and time consuming in many cases.

The 100% of minimum load screen is in effect today in California and is working to facilitate timely and cost-effective interconnection while maintaining electric system safety and reliability.[7] By contrast, the utilities' proposed 67% screen based on the Initial Sandia Report has not been adopted by any State.[8] Moreover, a subsequent Revised Report from Sandia National Lab concludes that it is inappropriate to use a 67% screen in the manner proposed by utilities in this proceeding.[9]

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[3] *Id.* at 11.

[4] *Id.* at Appendix C.

[5] *Id.*

[6] *Id.*

[7] Order Instituting Motion to Improve Distribution Level Interconnection Rules and Adopt Rule 21 Transition Plan, CPUC Decision 12-09-018 (Sept. 13, 2012) ("Rule 21 Order.")

[8] M. Ropp and A. Ellis, "Sandia Report: Suggested Guidelines for Anti-Islanding Screening," (Feb. 2012) ("Initial Sandia Report.") (Copy attached)

[9] M. Ropp and A. Ellis, "Sandia Report: Suggested Guidelines for Assessment of DG Unintentional Islanding Risk," (Nov. 2012) ("Revised Sandia Report.") (Copy attached)

SEIA believes that the adoption by the DPU of consensus recommendations from the Working Group Report combined with the 100% screen option will result in a much improved interconnection process. This will facilitate the efforts of the Commonwealth to achieve its ambitious goals for solar and other DG and at the same time maintain electric system reliability and safety.[10]

II. IDENTITY AND INTERESTS OF SEIA

SEIA is the national trade association of the United States solar industry, encompassing all solar technologies, including photovoltaics (PV), concentrating solar power, solar heating and cooling, and other technologies. Through advocacy and education, SEIA and its 1,000 member companies work to make solar energy a significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy.

SEIA's membership includes many companies with offices and facilities in Massachusetts. These companies operate in over 204 locations and include twenty-nine manufacturing facilities throughout the solar supply chain.[11] Solar generation in Massachusetts is ranked twelfth in the United States, producing 31 MW of installed solar power in 2011 and over 174 cumulative MW to date.[12] In addition, solar companies boast approximately 4,196 total solar PV installations in state.[13]

Notwithstanding the great progress that has been made, the current interconnection regulatory regime is simply not up to the task of timely interconnection as evidenced by the

[10] These comments represent the views of SEIA and not any one particular SEIA member.
[11] SEIA National Solar Database, *available at* http://www.seia.org/research-resources/national-solar-database.

[12] SEIA/GTM Solar Market Insight Report Q2 2012; Massachusetts CEC, *available at* http://www.seia.org/research-resources/solar-market-insight-report-2012-q2.

[13] *Id.*

utilities' inability to comply with current interconnection timelines and the lengthy interconnection queue. As a consequence, significant reforms are needed to reduce the cost and time necessary to interconnect.

III. INTERCONNECTION 100% OF MINIMUM LOAD SCREEN

In the Working Group Report, which was issued on September 14, 2012, the utilities object to the 100% screen on a number of grounds. They claim that the 100% screen "is not currently in use anywhere in the continental US."[14] However, on September 13, 2012, the California Public Utility Commission (CPUC) approved "Rule 21" interconnection reforms, including the 100% screen.[15] These reforms went into full effect 7 days later on September 20, 2012, when the relevant tariff language changes were filed by the three California utilities with the CPUC. Therefore, any claim that the 100% screen has not been thoroughly vetted and is not in effect is incorrect; it is in force in the largest state solar market in the U.S. today—California. SEIA respectfully requests that the Commonwealth of Massachusetts do the same in its Expedited Track interconnection process. Such a step will "ensure an efficient and effective interconnection process that will foster continued growth of DG in Massachusetts."[16]

The utilities also inaccurately state that "NJ recently decided not to implement this screen in recent interconnection proceedings that took place in the winter and spring of 2012 for many of the reasons cited here."[17] The utilities do not attribute this claim to any source. SEIA closely follows the activities of the New Jersey Board of Public Utilities ("BPU") and can affirm that no

[14] Working Group Report at Appendix C.

[15] Rule 21 Order

[16] DPU Order at 4.

[17] Working Group Report at Appendix C.

decision or position, either pro or con, has been adopted by New Jersey on the 100% screen. Instead, the BPU has filed positive comments regarding SEIA's Federal Energy Regulatory Commission (FERC) Petition to establish the 100% screen as federal policy.[18]

The utilities mention their obligation to maintain the reliability of the electricity system and say that "[a]ccordingly, the utilities must rely on proven technical and engineering assumptions when making decisions pursuant to this obligation."[19] SEIA agrees, and believes that the Interconnection Screens Report authored by highly qualified independent experts from the National Renewable Energy Lab (NREL), Sandia National Lab (Sandia) and the Electric Power Research Institute (EPRI) provide the necessary technical support for adoption of the 100% screen in Massachusetts.[20] The Interconnection Screens Report's conclusion that a 100% screen can be adopted and reliability and safety maintained is further bolstered by the on-the-ground experience with this screen in California.

The 100% screen was adopted with the full support and cooperation of the three largest utilities in California, Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric.[21] These utilities have more solar interconnection experience than any other group of utilities in the United States. Their conclusion that the 100% screen is an effective interconnection policy mechanism that can be implemented without compromising electric system reliability and safety is compelling evidence in support of adoption of such a policy.

Specifically, under the 100% screen a proposed solar DG project is eligible to be interconnected to the distribution system without costly and time consuming studies if it would

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[18] Intervention and Comments of the New Jersey Board of Public Utilities, FERC Docket No. RM12-10 (Mar. 27, 2012.)

[19] *Id.*

[20] NREL, Sandia National Laboratories, EPRI et al., "Updating Interconnection Screens for PV System Integration," (Jan. 2012) ("Interconnection Screens Report.") (Copy attached)

[21] *See* Rule 21 Order.

not cause the aggregate DG on a line section to exceed 100% of annual daytime minimum load and satisfy other related screens.[22] In other words, a proposed project would not cause reverse power flows to the substation when demand on a line section or circuit is lowest and solar generation is at its highest level possible.[23]

NREL Sandia EPRI Interconnections Screens Report

In addition to the on-the-ground experience of California utilities with the 100% screen, there is unimpeachable analytic support for the 100% screen from the independent experts that authored the NREL, Sandia and EPRI Interconnection Screens Report issued in January 2012 (copy attached).[24] Key conclusions include:

- "the existing 15% [fast track] screen is conservative and not an accurate method . . . [in many cases]".
- "There are many circuits . . . with PV penetration levels well above 15% where system performance, safety, and reliability have not been materially affected."
- "[I]t is possible to refine screening procedures . . . without compromising safety and reliability of the interconnected distribution system."
- "[I]t makes sense to consider minimum daytime load as a technical screening criterion".

The 15% of peak load screen included in the Working Group Report recommendations can serve as an initial expedited screen on circuits with minimal levels of DG penetration.[25] However, in many situations a supplemental screen is needed to allow additional generation to be eligible to be interconnected on an expedited basis. Therefore, the DPU should adopt an

[22] Diurnal resources such as solar DG are eligible for a minimum daytime load screen. Resources that generate power during the day and at night such as Combined Heat and Power (CHP) must comply with an absolute minimum load standard.

[23] Attached as Appendix 1 is a slightly modified version of a chart from the NREL Interconnection Screens Report.

[24] *Id.*

[25] Working Group Report at p. 14, Figure 1, Schematic of Massachusetts DG Interconnection Process. SEIA notes that the 15% screen was adopted by California in 2001 and by the FERC in 2005.

alternative supplemental screen for solar PV generation based on 100% of daytime minimum load from 10 a.m. to 2 p.m. as recommended in the Interconnection Screens Report.[26]

This 100% criterion is sufficiently restrictive to assure that the generation of electricity in excess of minimum load will not occur due to the interconnection of a solar or other DG project to a circuit.[27] Solar PV generation does not produce power at night, which is typically when minimum load levels occur on a circuit. Instead, solar generates power during daylight hours, when peak load levels on a circuit typically occur. Therefore, with a minimum load screen of 100%, the probability of an exceeding minimum load remains extraordinarily low.

The Interconnection Screens Report states:

> The fact that PV generation has a strictly daytime pattern is significant considering that voltage impacts tend to be greater during periods of highest instantaneous penetration. By the time PV systems are producing a substantial amount of power, loads are well above their nightly lows on most feeders. Therefore, it makes sense to consider minimum daytime load as a technical screening criterion. For example, a screen may set a threshold at minimum daytime load, where daytime is defined as the period between 10:00 a.m. and 2 p.m.[28]

The Interconnection Screens Report also recommended that, in cases where minimum daytime load information is not available, it "can be estimated based on standard load profiles for various customer classes that many utilities maintain and update on an annual basis."[29] SEIA is pleased to note that both the Working Group Report and the tariff language submitted authorizes use of calculations and estimates if actual data is not available.[30] The ability to rely on

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[26] Interconnection Screens Report at 6.

[27] *Id.* at 5-6.

[28] *Id.*

[29] *Id.* at 7-8.

[30] Working Group Report at 11.

calculations and estimates is a key part of the interconnection improvements made by California in the Rule 21 settlement.

IV. THE 67% SCREEN IS NOT SUPPORTED BY THE FINAL SANDIA REPORT

Utilities rely on a Sandia report as support for the 67% screen.[31] However, utilities' reliance on the Sandia Initial Report is misplaced. A revised report from Sandia subsequently completed in November 2012, clarifies that it is inappropriate to, in isolation, pluck the 67% screen from the Sandia Initial Report and use it as a supplemental screen as part of a regulatory process for consideration of Expedited Track interconnection. The Final Report states in reference to the 67% screen:

> [T]he technical guidelines contained in this document are designed for a purpose that is different from the screening criteria used in the FERC small generator interconnection procedures (SGIP) initial review process.[32]

Instead, the Sandia Revised Report states that the 67% figure "could be applied at a stage of the interconnection process where detailed studies are being conducted, to help determine whether or not anti-islanding study is needed."[33] In other words, the 67% screen is proposed by Sandia only to be utilized in interconnection processes where a decision has already been made to engage in a study process, not a process where expedited interconnection is being considered.

The Sandia Revised Report also makes clear that the "procedure described here leads to reasonable conclusions about the risk of unintentional islanding only if it is applied in its entirety."[34] By selectively plucking out of the Sandia Initial Report the 67% figure, without

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[31] M. Ropp, Northern Plains Power Technologies and A. Ellis, Sandia National Laboratories, "Suggested Guidelines for Anti-Islanding Screening" (Feb. 2012) ("Sandia Initial Report.")

[32] M. Ropp, Northern Plains Power Technologies and A. Ellis, Sandia National Laboratories, "Suggested Guidelines for Assessment of DG Unintentional Islanding Risk," (Nov. 2012) ("Revised Sandia Report.")

[33] *Id.*

[34] *Id.*

adopting the entire procedure proposed, the utilities have done exactly what the Report states should not be done.

In summary, the utilities proposed 67% figure was neither appropriate nor constructive. Indeed, their reference to the Initial Sandia Report 67% figure spurred the Report's authors to put out a revised and clarified report in order to avoid confusion in this proceeding and elsewhere.

By contrast, SEIA's advocacy of the 100% screen has been entirely supported by the facts and regulatory recommendations in the Interconnection Screens Report authored by NREL, Sandia and EPRI. In sum, the overwhelming weight of the evidence in support of the adoption of the 100% screen should give the DPU every confidence that adoption of this screen is in the public interest, including providing the necessary assurance that reliability and safety are fully protected.

V. CONCLUSION

SEIA respectfully requests that the DPU promptly adopt interconnection reforms consistent with those recommended in the Working Group Report, the Draft Tariff language and SEIA's comments herein regarding the 100% of minimum load screen.

SEIA thanks the DPU for the opportunity to participate and comment in this proceeding.

Sincerely,

Solar Energy Industries Association

Carrie Cullen Hitt
Vice President of State Affairs
Solar Energy Industries Association
505 9th Street, NW
Suite 800
Washington, DC 20004
chitt@seia.org
(202) 682-0556

Daniel M. Adamson
Vice President of Regulatory Affairs &
Counsel
Solar Energy Industries Association
505 9th Street, NW
Suite 800
Washington, DC 20004
dadamson@seia.org
(202) 682-0556

ATTACHMENTS

Slightly modified version of a chart from the NREL, Sandia and EPRI Interconnection screens report that illustrates how the 100% of minimum load screen works. *Updating Interconnection Screens for PV System Integration*, NREL, Sandia National Laboratories, et al. (July 20, 2012

National Renewable Energy Laboratory Sandia National Laboratory Electric Power Research Institute Interconnection Screens Report (Jan.2012)

SANDIA REPORT- *Suggested Guidelines for Anti-Islanding Screening*, M. Ropp, Northern Plains Power Technologies, et al. (Feb. 2012)

SANDIA REPORT -"*Suggested Guidelines for Assessment of DG Unintentional Islanding Risk*" (Nov. 2012)

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties of record in this proceeding. Dated at Washington, D.C. this 7th day of December 2012.

Heather Whitpan
Government Affairs Administrator
Solar Energy Industries Association
505 9th Street, NW
Suite 800
Washington, DC 20004
hwhitpan@seia.org
(202) 682-0556

ATTACHMENT 1

Slightly modified version of a chart from the NREL, Sandia and EPRI Interconnection screens report that illustrates how the 100% of minimum load screen works. *Updating Interconnection Screens for PV System Integration*, NREL, Sandia National Laboratories, et al. (July 20, 2012)

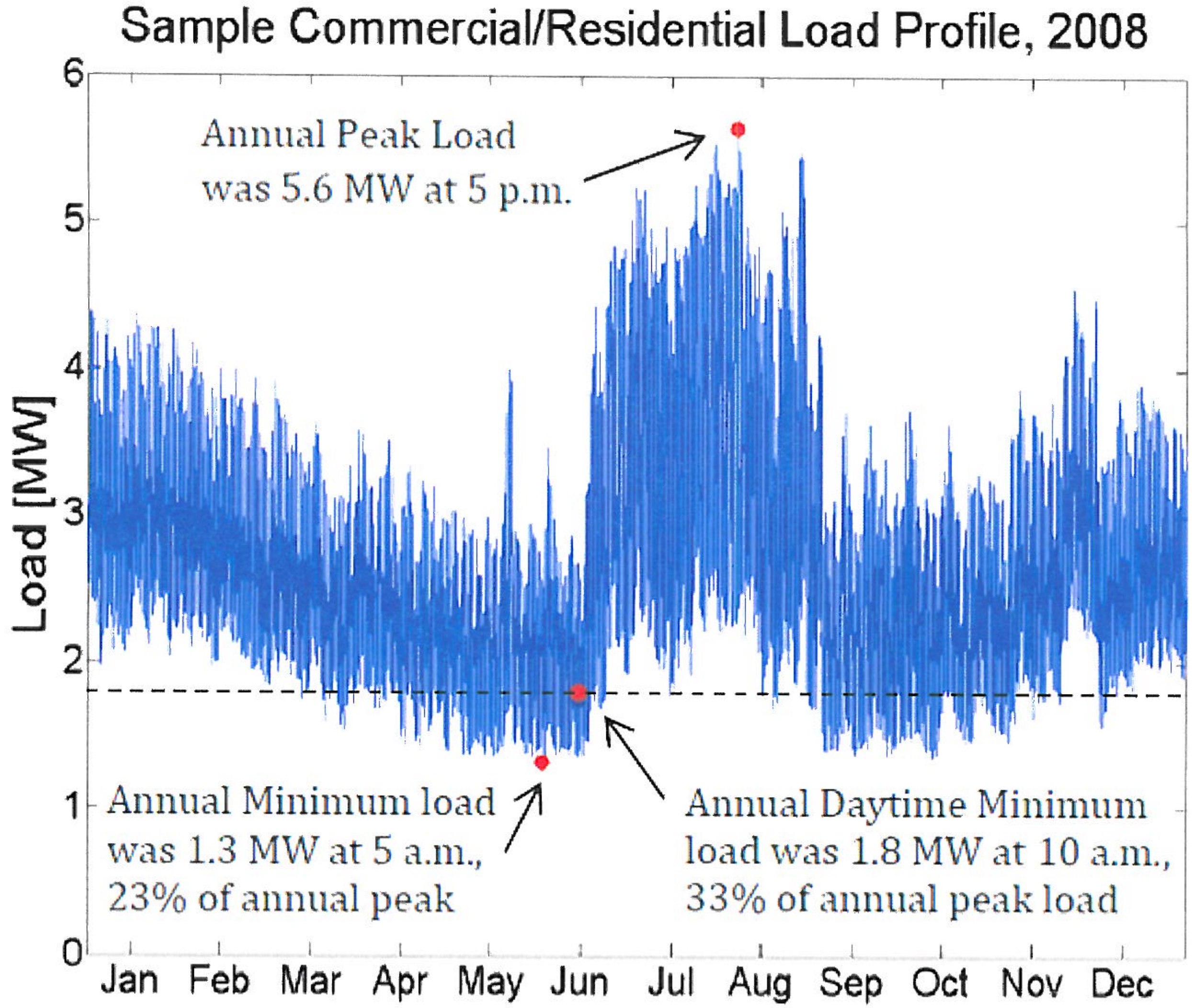

Figure 4 – This load profile indicates that minimum daytime load is significantly higher than absolute minimum load

(15% of peak load = 0.84 MW)

Source: NREL screens report,
January 2012

ATTACHMENT 2

National Renewable Energy Laboratory Sandia National Laboratory Electric Power Research Institute Interconnection Screens Report (Jan.2012)

NATIONAL RENEWABLE ENERGY LABORATORY

Updating Interconnection Screens for PV System Integration

Michael Coddington, Barry Mather, Benjamin Kroposki
National Renewable Energy Laboratory

Kevin Lynn, Alvin Razon
U.S. Department of Energy

Abraham Ellis, Roger Hill
Sandia National Laboratories

Tom Key, Kristen Nicole, Jeff Smith
Electric Power Research Institute

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National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, Colorado 80401
303-275-3000 • www.nrel.gov

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Finally, we thank Connie Komomua, NREL, for her editing support.

Contents

1 Overview and Purpose

Solar photovoltaics (PV) is the dominant type of distributed generation (DG) technology interconnected to electric distribution systems in the United States and deployment of PV systems continues to increase rapidly. In states such as California, Hawaii, and New Jersey alone, the number of new PV interconnection applications is in the thousands each year. Considering the rapid growth and widespread deployment of PV systems embedded in United States electric distribution grids, it is important that interconnection procedures be as streamlined as possible to avoid unnecessary interconnection studies, costs, and delays.

Since many PV interconnection applications involve high penetration scenarios, the process needs to allow for a sufficiently rigorous technical evaluation to identify and address possible system impacts. Existing interconnection procedures are designed to balance the need for efficiency and technical rigor for all DG. However, there is an implicit expectation that those procedures will be updated over time in order to remain relevant with respect to evolving standards, technology, and practical experience. Modifications to interconnection screens and procedures must focus on maintaining or improving safety and reliability, as well as accurately allocating costs and improving expediency of the interconnection process.

The purpose of this paper is to evaluate the origins and usefulness of the capacity penetration screen, offer short-term solutions which could effectively allow fast-track interconnection to many PV system applications, and consider longer-term solutions for increasing PV deployment levels in a safe and reliable manner while reducing or eliminating the emphasis on the penetration screen. Short-term and longer-term alternatives approaches are offered as examples; however, specific modifications to screening procedures should be discussed with stakeholders and must ultimately be adopted by state and federal regulatory bodies.

2 Interconnection Procedures

Interconnection procedures vary depending on state or federal jurisdiction, and implementation practices vary by utility system. In May 2005, the Federal Energy Regulatory Commission (FERC) adopted small generator interconnection procedures for distributed energy resources up to 20 megawatts in capacity. The FERC document titled Small Generator Interconnection Procedures (SGIP) applies to facilities that fall under federal jurisdiction, those that participate in and interconnect with wholesale market transactions with "facilities that are already subject to the transmission provider's Open Access Transmission Tariff (OATT) at the time the interconnection request is made."[1] The FERC SGIP was also intended to be a "model rule" for consideration by state public utility commissions who commonly regulate distribution level interconnection procedures.

Most procedures allow for expedited interconnection without additional technical studies if the proposed interconnection passes a series of technical screens. If a proposed interconnection fails one or more of the screens, supplemental interconnection studies may be required before it can proceed to interconnection. These supplemental studies may only add a few weeks or months to the interconnection approval process, but they have a

[1] FERC Order 2006 Paragraph 5, Page 4 http://www.ferc.gov/eventcalendar/files/20050512110357-order2006.pdf.

significant impact on the time, cost, and uncertainty of the proposed project. And for many utilities and PV developers, the potential impacts from PV are not clearly understood and the supplemental studies are not well defined.

3 The 15% Penetration Threshold

In 1999, before the FERC SGIP was established, the California Public Utilities Commission (CPUC) issued an order instituting a rulemaking to address interconnection standards for devices to the electric grid in California. The order resulted in the reform of CPUC Rule 21, which identified screens that allowed low-impact generators to be interconnected relatively quickly and made the review process more efficient for small, low-impact generation at low penetration levels. During the reformation of CPUC Rule 21, a 15% threshold was established to identify situations where the amount of DG capacity on a line section exceeds 15% of the line section annual peak load. The 15% threshold was then adopted in the FERC SGIP and is used by most states as a model for developing their interconnection procedures. Under most applicable interconnection screening procedures, penetration levels higher than 15% of peak load trigger the need for supplemental studies.

The 15% threshold is based on a rationale that unintentional islanding, voltage deviations, protection miscoordination, and other potentially negative impacts are negligible if the combined DG generation on a line section is always less than the minimum load.

There are three commonly used measures to describe penetration levels: instantaneous, energy, and capacity. *Instantaneous penetration*[2] is defined as the output power of total DG on a circuit divided by the circuit load at any particular instance in time. This value will change over time depending on the load conditions and power output from DG. *Energy* penetration is the ratio of energy generated on a circuit divided by energy consumed by load over a specific period of time (typically one year). *Capacity* penetration is defined as the nameplate capacity of the combined DG on a circuit divided by the peak annual load on that circuit. The capacity penetration threshold is expressed in terms of peak load, as opposed to the intended metric (minimum load) because peak load data is tracked and accessible to utilities.

Figure 1 summarizes the FERC SGIP initial review process, from which many states have adopted the same or a similar set of screens. The first screen examines total penetration by capacity, defined as the ratio of total DG capacity to the peak load, and determines whether penetration level is less than 15% of the line-section peak load. This 15% threshold applies to radial distribution circuits, which is the most common type of distribution circuit with interconnected PV systems. For typical distribution circuits in the United States, minimum load is approximately 30% of peak load.[3] The actual ratio varies widely depending on many factors such as the type of load served. Based on this generalization, the 15% penetration level (one half of the 30%) was selected as a conservative penetration level for general screening purposes.

[2] Load data is often tracked in intervals of 15 or 30 minutes by utilities, so the "instantaneous" is actually more discrete in nature.

[3] This is considered a rule of thumb for electric distribution engineers and is based on observation that the minimum load is, on average, approximately 30% of the peak annual load.

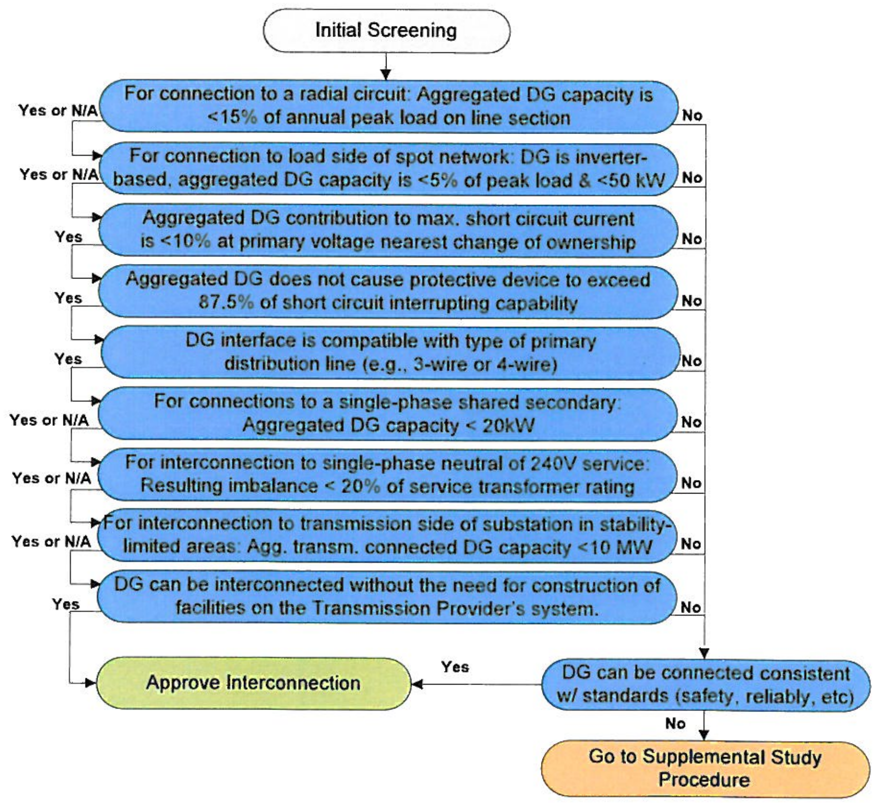

Figure 1 – FERC SGIP initial review screens summarized

Originally, the purpose of the 15% screen was to identify situations where the amount of DG penetration may be large enough to sustain an unintentional island, a condition deemed hazardous to utility personnel and possibly damaging to loads. The threshold was also intended as a "catch all" rule to eliminate other possible problems related to voltage control and system protection. There is considerable debate on whether or not more efficient and appropriate screening criteria can be used, especially in light of the fact that that this screen, more than any other, triggers the need for additional studies. In addition, PV systems have unique technical characteristics that, if taken into account, could lead to a more efficient and effective screening procedure. The following sections discuss these PV characteristics and how the current 15% screen does not always take them into account.

3.1 Unintentional Islanding

Risks from unintentional islanding conditions include unacceptable voltage and frequency levels, transient over-voltage conditions, equipment damage, and operational safety concerns. Grid-connected PV inverters have anti-islanding features built into the controls, and are required to be "certified" for the intended use, meaning that they must have UL

1741[4] certification and meet IEEE 1547 grid compatibility requirements. The possibility of PV inverters unintentionally islanding is very low because UL 1741-listed inverters use anti-islanding algorithms that detect and drop off line within two seconds after an island is formed.

Unintended islanding remains a particular concern when PV and synchronous generators, such as diesel generators or other DG without anti-islanding features, are connected onto the same line section. These machines may mimic normal grid conditions, causing the PV inverters to stay online.

Another significant utility concern is that the unintentional islanding test in UL 1741 is conducted on only a single inverter at a time. For this reason, some argue that multiple inverters could interfere with each other in such a way as to increase the chances that an unintentional island not be detected. While it is not possible to reduce the risk to zero, the reality is that the risk is extremely low, considering all the factors that need to be concurrently present. The most compelling substantiation is that incidents of unintentional islanding are extremely rare in actual field experience despite numerous examples of high penetration scenarios that exist. While a complete discussion of anti-islanding techniques is outside the scope of this paper, there are some simple concepts that can be incorporated in screening procedures to assess the risk of unintentional islanding.[5]

3.2 Voltage Control

A major concern and most commonly reported problem associated with high penetration of PV on distribution feeders is high steady-state voltage. When power is injected into a part of the electric power system that normally serves load the voltage at that location tends to increase. With higher penetration, higher voltages are expected along a feeder. The voltage effect depends on the feeder characteristics (voltage rating, conductor size, conductor material, overhead or underground) and location of PV along the feeder. Because feeders are often designed to be higher ampacity (thus lower impedance), thus "stiffer[6]", near the substation, and because the substation will often contain voltage control equipment, the impact from PV on steady-state voltage is generally lessened as the distance to the substation is decreased. Conversely, as PV systems are located longer distances from the substation, the stiffness often decreases and the potential for high voltages becomes greater (especially during periods of light load such as weekend days).

Figure 2 illustrates the possible impact of PV on steady-state voltage. On a circuit with no DG present (red line) the voltage along the feeder decreases as distance from the substation increases. If PV power injected into the circuit (blue line) is high enough, the voltage will increase, potentially taking the voltage above normal operational conditions (5% above nominal). PV located close to the substation can also affect steady-state voltage regulation by "masking" part of the load and thus interfering with load-controlled voltage regulation equipment. In either case, the net result is that high penetration would make it more challenging to maintain acceptable voltage regulation. It should be kept in mind that 15%

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[4] Information on UL 1741 can be found at http://ulstandardsinfonet.ul.com/scopes/1741.html.

[5] S. Gonzalez, M. R, A. Fresquez, M. Montoya, and N. Opell, "Multi-Inverter Utility Interconnection Evaluations", Proc, 37th IEEE PVSC, 2010.

[6] A "stiff" location on a feeder would typically have a lower than average impedance and larger conductor capable of serving many megawatts of power to utility customers.

penetration threshold, by itself, is not a good indicator of when steady-state high voltage are likely to occur.

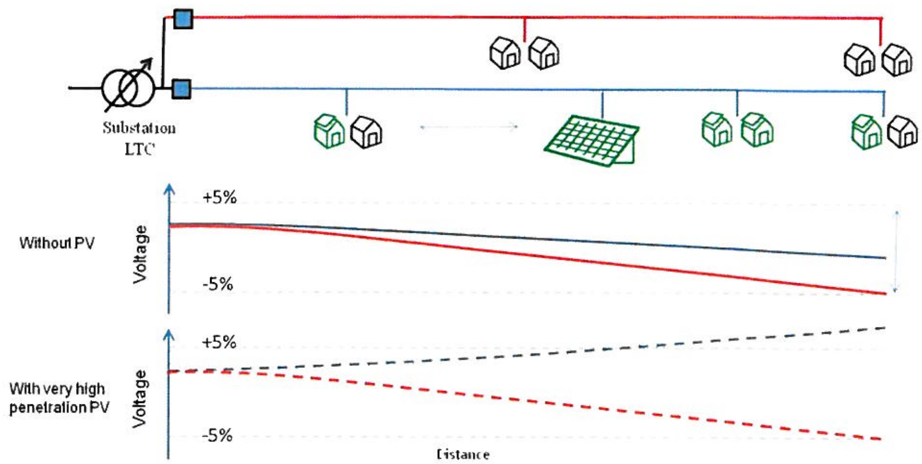

Figure 2 – Example of voltage rise problem for a high penetration scenario

Similar to steady-state voltage issues, if the PV system is located further from the distribution substation, PV output variability can result in significant voltage variability. Possible consequences are poor voltage regulation and increased cycling and stress on voltage control equipment (line regulators and switched capacitor banks) leading to more frequent and costly maintenance. A series of case studies on high penetration circuits is being developed and is planned for publication in 2012.[7]

3.3 Protection Coordination

A PV inverter's contribution to fault current is limited and not as likely to cause protection problems[8] as rotating machines; however, screening procedures routinely check for coordination and grounding compatibility. In some PV inverter installations, an effectively grounded neutral is required to reduce the potential for transient overvoltage during unbalanced system faults. Multiple ground sources can increase ground current contribution and affect the sensitivity of ground current protection functions at the substation.

4 Upgrading the 15% Screen

During review of PV interconnection requests in regions with a high level of PV deployment, the 15% interconnection screen often triggers the need for supplemental studies. In many cases, even when PV penetration is substantially above 15%, the supplemental review does not identify any necessary system upgrades. There are many circuits across the United

[7] NREL case studies on high penetration distribution circuits to be published 2012.

[8] Keller, J., Kroposki, B. (2010). Understanding Fault Characteristics of Inverter-Based Distributed Energy Resources. NREL Report No. TP-550-46698.

States and Europe with PV penetration levels well above 15% where system performance, safety, and reliability have not been materially affected.[9]

These observations offer some indication that the existing 15% screen is conservative and is not an accurate method of determining the hosting capability (ability to add more PV without system upgrades) of a particular feeder. The following short-term, mid-term, and long-term approaches may be considered as possible steps to improve interconnection procedures for distribution-connected PV systems.

5 Short-Term Solutions

Inverter-based PV has unique technical characteristics that reduce the impacts on grid operations. Unlike other DG resources, the output pattern of PV is strictly diurnal (active in daytime). The grid-PV interface is an electronic inverter with adjustable settings and short circuit current much lower than synchronous generators of the same output rating. PV inverters are designed to comply with IEEE 1547 standards and UL-1741 certification without the need for external protection or controls. By taking into account these technical characteristics, it is possible to refine screening procedures to be more efficient and effective, substantially reducing interconnection process time and effort for PV deployment without compromising safety and reliability of the interconnected distribution system. Several possible approaches could be undertaken in the short term to improve screening procedures for distribution-connected PV systems.

There are three conceptual examples discussed in this section. The first approach is to include a PV-specific screening criterion that utilizes the minimum daytime load instead of the absolute minimum load. The second approach is to apply additional screens to identify possible technical issues, regardless of penetration level. Finally, the third approach is to increase the penetration levels by identifying zones of higher penetration based on the utility distribution feeder configuration and location of substations.

5.1 Base Screen on Minimum Daytime Load

The fact that PV generation has a strictly daytime pattern is significant considering that voltage impacts tend to be greater during periods of highest instantaneous penetration. By the time PV systems are producing a substantial amount of power, loads are well above their nightly lows on most feeders. Therefore, it makes sense to consider minimum daytime load as a technical screening criterion. For example, a screen may set a threshold at minimum daytime load, where daytime is defined as the period between 10:00 a.m. and 2:00 p.m. A simple modification of the SGIP screening criteria to implement this PV-specific screening criterion is depicted in Figure 3. If the PV system passes the additional screen it passes the penetration screen.

[9] M. Braun et al. "Is the Grid Ready to Accept Large Scale PV Deployment? - State of the Art, Progress and Future Prospects", Submitted to Progress in PV, to be published in 2012.

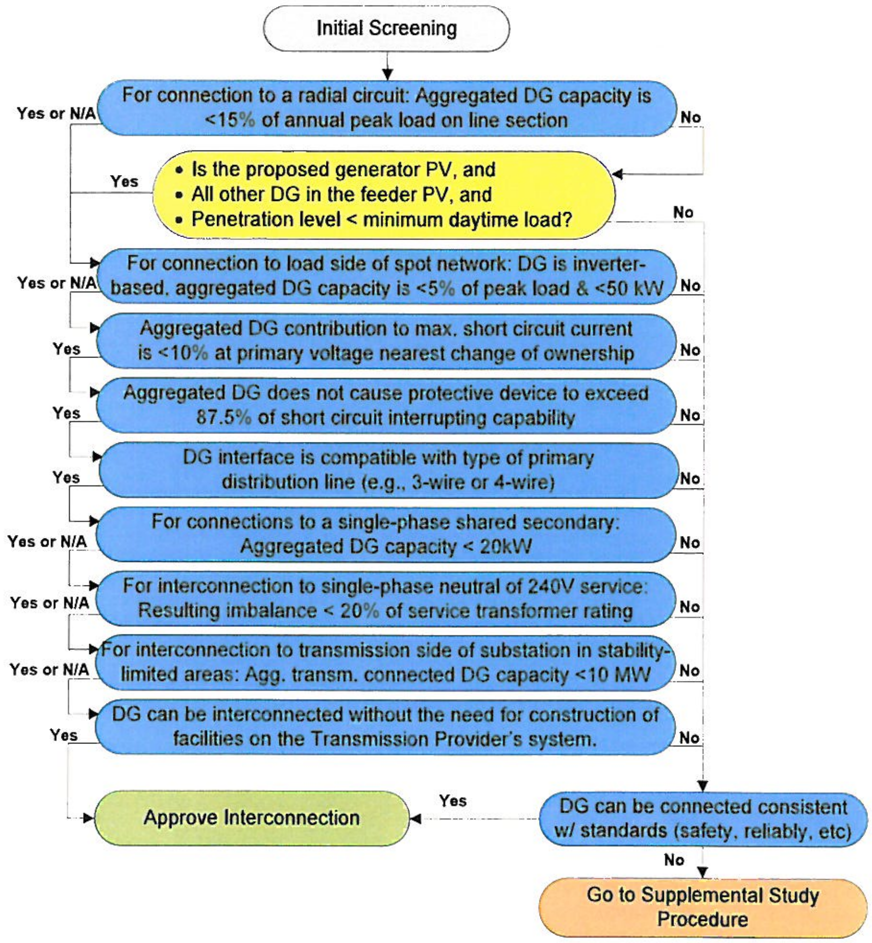

Figure 3 – Modified SGIP screens to address PV interconnection based on minimum daytime load

If actual historical data is available, load data in areas of interest could be analyzed to establish factors that relate minimum daytime load levels to peak load levels. Some utilities already use minimum daytime load as a screening criterion and have determined these load levels for their service territory. Figure 4 illustrates an example circuit where the annual minimum daytime load is significantly higher than the minimum 24-hour load. Figure 5 shows the comparative ratios of minimum load to peak load, and minimum daytime load to peak load, for 500 residential and commercial feeders in a southwest U.S. city. The figure shows the percentage of the feeders which have a minimum to peak load ratio between zero and 20%, 20%-30%, 30%-40%, and 40%-50% based on minimum daytime load (10 a. m. - 2 p.m.) and minimum 24-hour load.

It may be difficult to establish minimum daytime load unless reliable historical data is available; however, most utilities now have access to feeder minimum load and feeder peak load data via Supervisory Control and Data Acquisition (SCADA) systems. If SCADA data is unavailable, minimum daytime load can be estimated based on standard load profiles for various customer classes that many utilities maintain and update on an annual basis.[10] It should be noted that historical minimum loads are no guarantee of future minimum load levels, which creates some uncertainty and need for better communication between DG and the utility operations and control, especially when DG is in the megawatt scale. And sections of distribution circuits are frequently switched onto adjacent circuits, which add to the uncertainty of minimum and peak load values, and there are times when large loads may be offline. Load variability and circuit segment switching must be considered by utility planning engineers when determining minimum daytime load of sections of feeders.

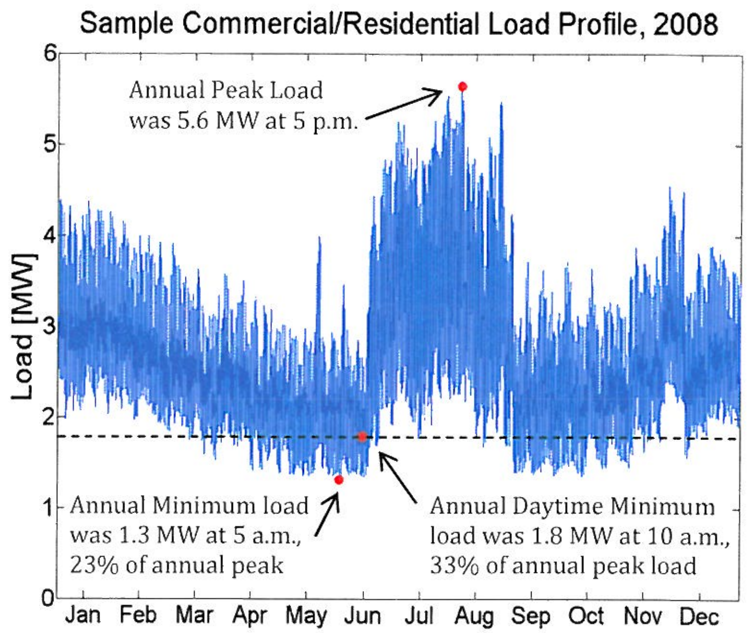

Figure 4 – This load profile indicates that minimum daytime load is significantly higher than absolute minimum load

[10] See http://www.sce.com/AboutSCE/Regulatory/loadprofiles/2011loadprofiles.htm.

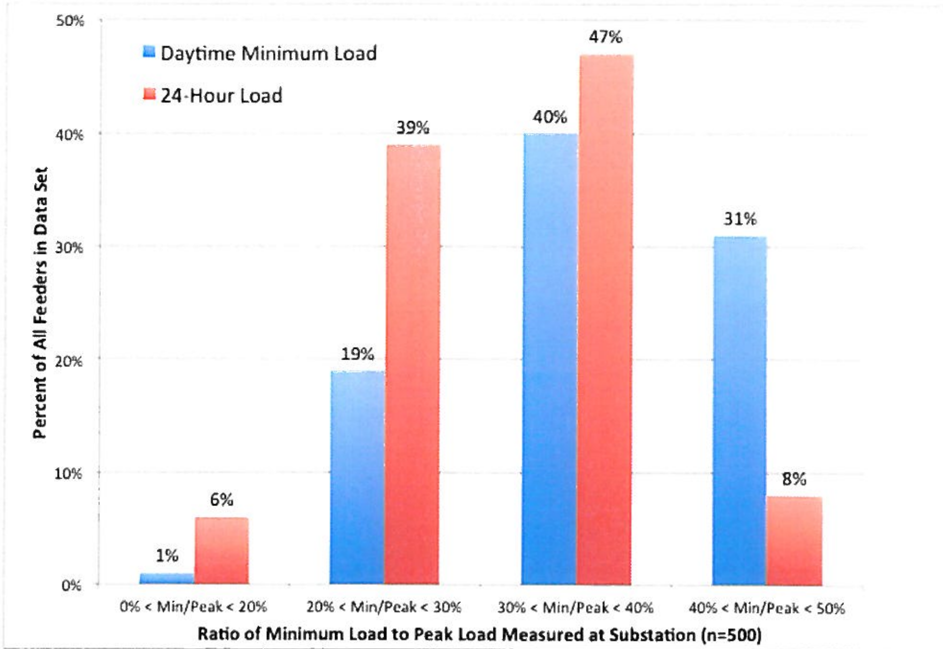

Figure 5 – Ratio of minimum load to peak load for daytime minimum load (10 a.m. - 2 p.m.) and 24-hour minimum load.

5.2 Apply Supplementary Screens

Applying supplementary screens to identify possible technical issues, regardless of penetration level, focuses on utilizing more comprehensive analyses as part of the initial review in order to eliminate the possibility of voltage regulation issues and the creation of unintentional islands. An example of this concept is shown in Figure 6.

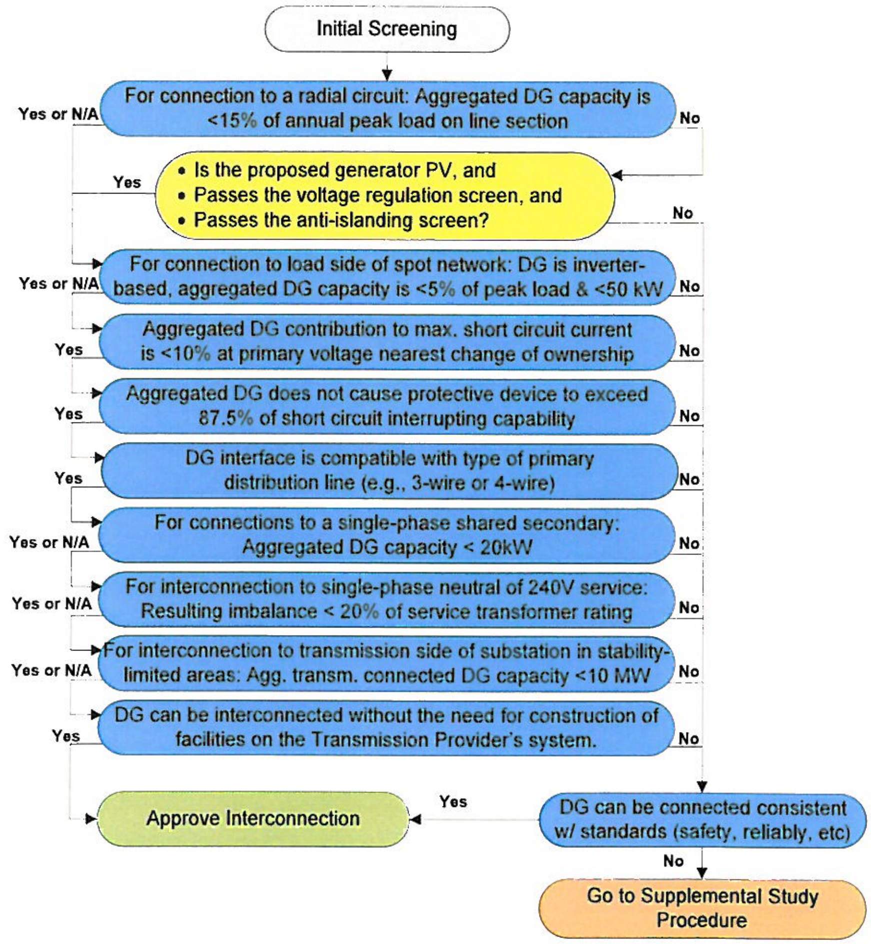

Figure 6 – Modified SGIP screens to address PV interconnections regardless of penetration level

It is important that the additional screens are effective and relatively easy to apply with well-defined costs and timeline to complete the screens, established through a transparent and open process administered by a regulatory body that takes into account stakeholder input. For example, Hawaii's revised Rule 14H[11] has clear timelines for when an application must be deemed complete, examined through initial review, and processed through supplemental review. Further, the California Rule 21 Supplemental Review Guideline contains several simple procedures that can be incorporated into the initial review screen for PV systems.[12] With respect to voltage regulation, a procedure similar to Figure 7 is recommended for consideration. Note that the 15% in this drawing refers to the peak export on the line section, which is different than the SGIP 15% screen. The 15% peak export implies an instantaneous penetration level greater than 100% for these systems with export levels less than 200kW.

[11] HPUC news release http://puc.hawaii.gov/news/pressreleases/2011/2011-11-29%20PUC%20Press%20Release%20HECO%20Rule%2014h%20Approval.pdf/?searchterm=rule%2014h.

[12] http://www.energy.ca.gov/distgen/interconnection/model_rule.html.

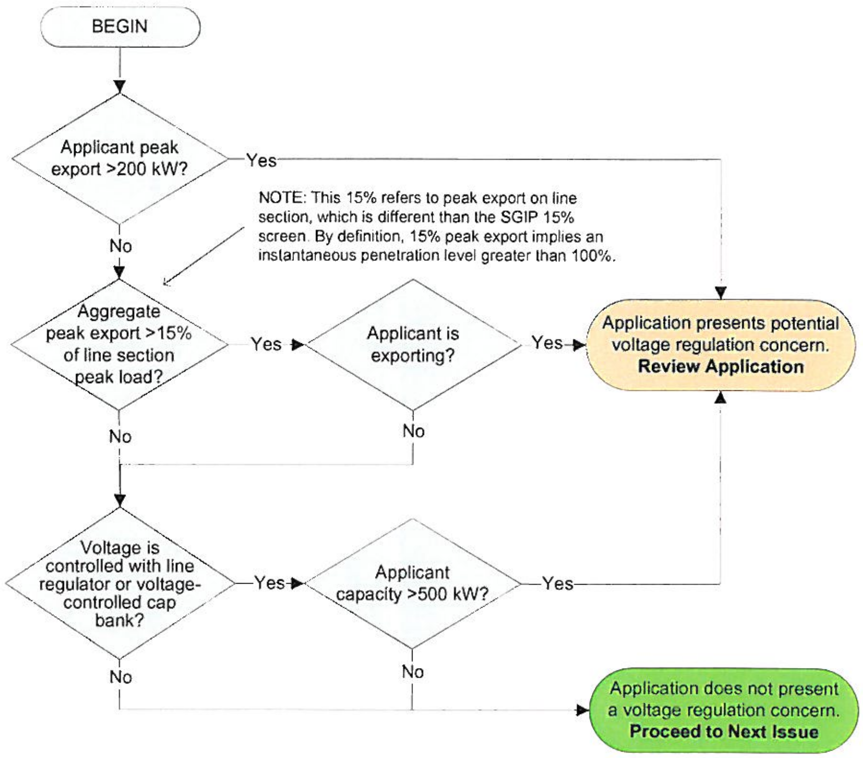

Figure 7 – Possible additional screening procedure for PV systems addressing voltage issues

Similarly for anti-islanding, Rule 21 Supplemental Review Guide contains a simple screen that can be applied as part of the initial review as seen in Figure 8. Application of the screen is more involved, but could be reasonably carried out as part of the Initial review since only a minimal amount of information is required.

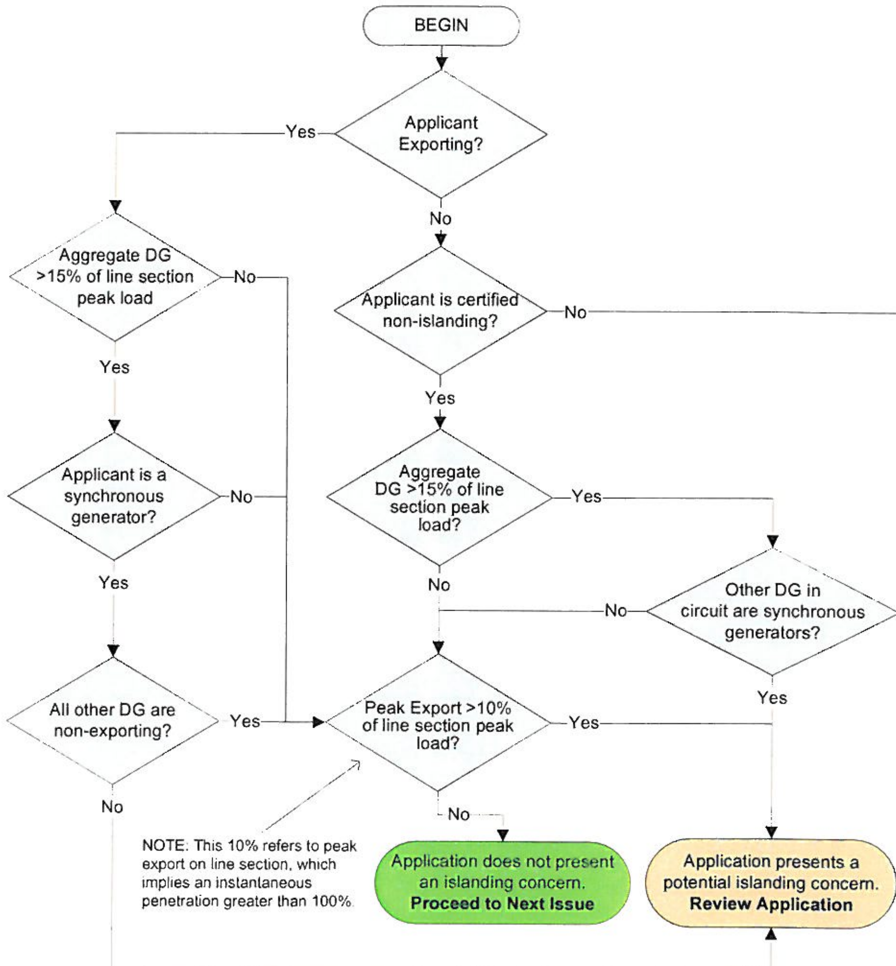

Figure 8 – Possible supplemental screening procedure for PV systems addressing unintentional islanding issues

5.3 Utility Identified Zones of Penetration Levels

One concept for increasing penetration criteria is to identify zones where higher penetration is acceptable. These zones would be identified by utilities through a transparent and open process administered by a regulatory body that takes into account stakeholder input, and should not exclude PV interconnection outside the zones as shown in Figure 9.

These zones would likely be located in areas closer to substations or with low-impedance conductors, thus having a lower potential for voltage abnormalities or protective system miscoordination. Figure is an example area displaying zones that allow for greater penetration and those that require further study. These zones would change over time as new installations of DG come online. One shortcoming of this conceptual drawing is the difficulty presented in measuring load, thus penetration, and how adjacent zones will affect one another. Implementing this would likely be labor-intensive, and require greater utility staffing levels. The California Energy Commission recently published a report that proposes several criteria for identifying project areas requiring minimal detailed studies.[13] The report discusses a modeled system in which a wholesale PV project might have acceptable impact if connected in one location in a circuit, but may have significant impacts requiring mitigation or upgrades if connected in another location.

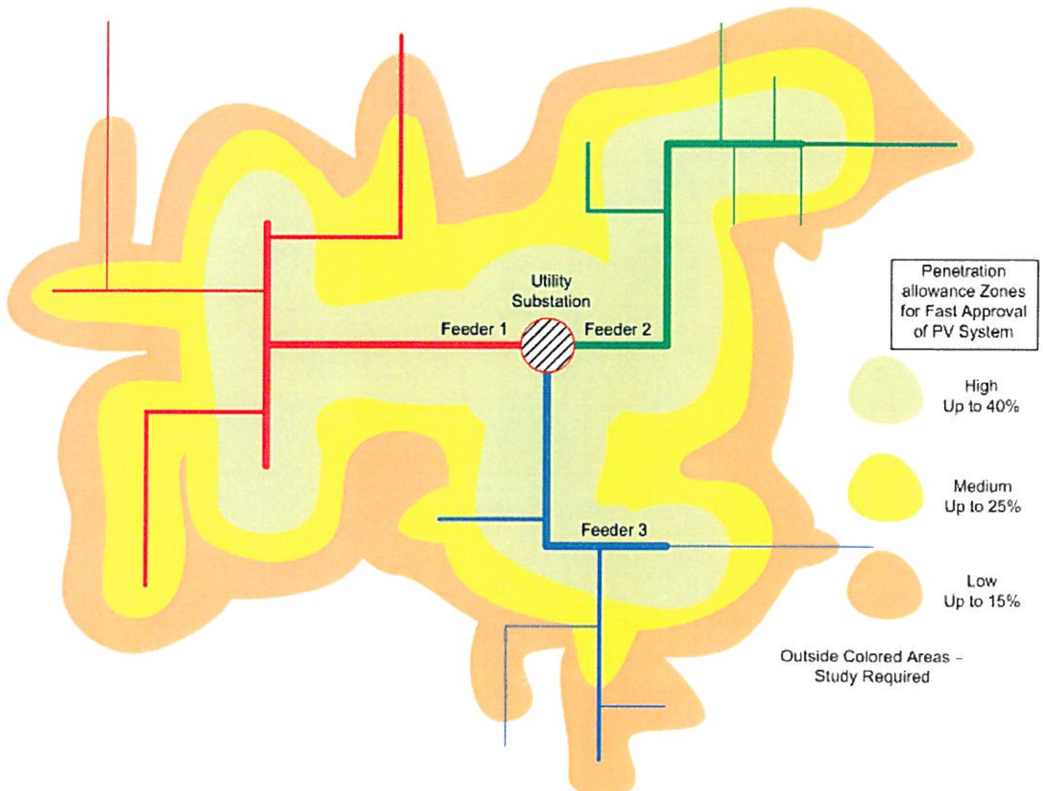

Figure 9 – An example area with zoned penetration limits

6 Mid-Term and Long-Term Solutions

While short-term solutions may be applied in a one-year or less time frame, there are more promising solutions to be considered that will take longer to develop and implement. Mid-term solutions, for this paper, might be those that happen in the one- to five-year range, while long-term solutions are likely those beyond the five-year horizon.

6.1 Develop Higher Accuracy Screening Metrics and Formulas

PV penetration metrics alone are insufficient indicators of the expected distribution system level impacts from PV interconnection. One potential solution is to develop more accurate screening metrics that can be used in a revised screening process. An interconnection impact metric for each PV interconnection concern, e.g. voltage effects, unintentional islanding, and protection coordination, could be developed. These metrics are functions of multiple distribution and PV system characteristics. For example, from previous high-

13 http://www.energy.ca.gov/2011publications/CEC-200-2011-014/CEC-200-2011-014.pdf.

penetration PV integration case study data, it is known that a PV system's nameplate capacity, circuit impedance, and distance from the distribution substation are key indicators of the expected voltage impacts of the PV system interconnection. A more reliable voltage impact metric can be formulated through extensive distribution system modeling using verified models that incorporate both the PV system nameplate capacity and the location of the interconnection on the distribution system. Other circuit characteristics and parameters, such as circuit voltage, conductor sizing, voltage regulation scheme, and the required service voltage range can also be considered in the development of a more reliable PV voltage impact metric. A sensitivity analysis for each considered circuit characteristic would then be performed and only the characteristics that largely determine the system impacts due to PV interconnection would be included in the final PV impact metric in order to simplify the calculation of the metric as much as possible.

The proposed PV impact metrics are more difficult to calculate than the current penetration metric (15%) but are still calculated based on available distribution circuit and PV system parameters. The developed PV impact metrics is a set of formulas that indicate whether the impacts of an individual PV interconnection exceed a given range agreed by the utilities and regulators similar to the PV penetration metric currently under use. Since PV impact metrics are developed for each interconnection concern and each metric takes into account a number of system characteristics and parameters, the resulting PV interconnection screening process allows more safe and compatible PV system to be interconnected without a supplemental interconnection study.

6.2 Upgrade Distribution Circuit Design for PV-Hosting Applications

Upgrading existing distribution feeders with larger-sized (thus lower impedance) conductors, installing voltage regulation devices, and increasing operating voltages (e.g. from 4kV to 13.2kV), are ways to maintain acceptable voltage levels and increase the PV hosting capacity of a feeder. Larger conductors and higher operating voltages allow greater levels of power delivery to loads as well as maintaining voltage levels, but there are financial impacts associated with these approaches.

New circuits designed and built in areas where there is significant PV development should be evaluated for increased conductor size and installation of voltage regulators. Existing distribution circuits can also be upgraded, but the process is often more complicated. The cost of such upgrades might be shared between utilities and PV developers, but that policy issue is not discussed in detail in this paper. Costs may range from a few thousand dollars for modifying controls for bi-directional voltage regulators, for example, to hundreds of thousands of dollars for replacing several miles of smaller conductors with larger conductors.

Capital expenditures by utilities are constrained by the availability of financial resources and limited by regulatory agencies and financial organizations. If greater expenditures are encouraged, then regulated utilities will need approval from utility commissions and by the organizations that have financial oversight over the utilities. Investor-owned utilities have specific revenue to capital investment requirements necessary to maintain stock ratings, and this could be a significant issue when considering upgrading distribution circuits. Investor-owned utilities often issue stock to raise money for capital expenditure programs that include new and rebuilt distribution circuits. Other types of utilities, such as cooperatives and municipal-owned utilities have other difficulties in paying for upgrades.

6.3 Deploy Inverters with Advanced Functions

Today, the challenge involves integrating PV into the existing electrical distribution systems that were not designed for significant reverse power. Inverter grid support functions are either unavailable or unused. Future investments and application of new technologies are expected to significantly increase PV hosting capability. Although it will take time to implement, a new generation of inverters is available with advanced functions designed to interact and support the grid. Enabling these functions will involve setting up, programming, reacting to grid condition signals, and potentially implementing two-way communications with distribution system operators. Also evolving is a smart grid with more automated distribution equipment and the ability to process information fed into both a central distribution management system and dispersed management systems that will manage accordingly. Advanced communication and control will enable the future distribution systems to better coordinate settings and limits of switch, protection, and voltage control devices as conditions change. Together, advanced inverter functions and distribution automation are expected to significantly increase the PV hosting capability of the existing infrastructure.

Relative to other devices connected to utility distribution systems, PV inverters are highly capable in terms of responsiveness, controllability, processing capability, and memory. Advanced inverters and controllers will provide real-time reactive power compensation, real power curtailment, watt-voltage, and watt-frequency management. Configurable autonomous actions can support the grid during abnormal voltage or frequency conditions. Previous studies have shown that advanced inverters can mitigate voltage-related issues and potentially increase the hosting capacity of solar PV by as much as 100%.[14] This point is further illustrated in Figure 10, where the feeder voltage response is shown to improve with the use of advanced volt-VAr control.

[14] Braun, M., Stetz, T., Bründlinger, R., Mayr, C., Ogimoto, K., Hatta, H., Kobayashi, H., Kroposki, B., Mather, B., Coddington, M., Lynn, K., Graditi, G., Woyte, A. and MacGill, I. (2011), Is the distribution grid ready to accept large-scale photovoltaic deployment? State of the art, progress, and future prospects. Progress in Photovoltaics: Research and Applications. doi: 10.1002/pip.1204.

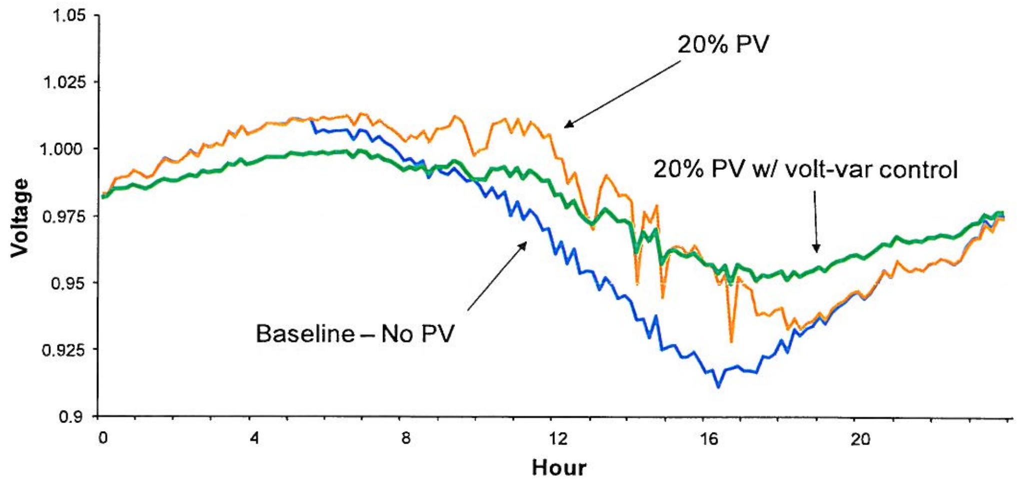

Figure 10 – Feeder voltage response with advanced VAr control[15]

Other functions, such as voltage and frequency ride-through, short-term or dynamic AC voltage support, inverter response to active anti-islanding, and arc-fault detection and mitigation, can increase reliability and safety.

Taking advantage of advanced inverter functions, along with other opportunities for demand management, will require communication and control and, consequently, opportunities will evolve with a smarter distribution system. For PV inverters there will be potential to perform a large number of grid-supportive functions. The value of this functionality depends on the degree in which a grid operator can integrate PV functions with other distribution equipment.

Interconnection standards must be defined and developed before these advanced inverters are deployed in larger numbers on electric distribution systems. IEEE P1547.8[16] is the standard recommended practice under development that will help define how these advanced inverters will be integrated into an electric distribution system. Completion of this standard will pave the way for a future interconnection standard which will supplant IEEE 1547™.[17]

7 Conclusion and Next Steps

Thousands of applications are submitted in the United States each year for PV installations and many states have aggressive renewable portfolio standards that encourage these installations. Therefore, it is critical that interconnection procedures be as streamlined as possible to avoid unnecessary interconnection studies, costs, and delays. There is an implicit expectation that existing interconnection procedures will evolve over time to

[15] Smith, J., Sunderman, W. Dugan, R., Seal, B., "Smart Inverter Volt/VAr Control Functions for High Penetration of PV on Distribution Systems", 2011 Power Systems Conference and Exposition, Phoenix, Arizona, March 2011.

[16] For additional information see http://grouper.ieee.org/groups/scc21/1547.8/1547.8_index.html.

[17] For additional information see http://grouper.ieee.org/groups/scc21/1547/1547_index.html.

reflect changes in standards, technology, and practical experience. Modifications to interconnection screens and procedures must have a focus on maintaining or improving safety and reliability, as well as reducing costs and improving expediency of the interconnection process.

Three short-term approaches have been presented for consideration. The first approach suggests utilizing PV-specific screening criteria that would utilize minimum daytime load for a circuit rather than absolute minimum load or a percentage of peak load. The second approach is to apply additional screens to evaluate potential voltage or unintentional island problems, regardless of penetration levels. The third approach would increase penetration levels in specific areas or zones based on substation location, circuit design, and existing DG. These three conceptual approaches may be considered as solution frameworks for increasing levels of PV deployment.

Mid-term and long-term solutions require close cooperation between regulatory agencies, electric utilities, national laboratories, DOE, EPRI, equipment manufacturers, and PV developers. These solutions ultimately produce straightforward approaches to understand how much PV can be deployed on a circuit, and at what locations, while maintaining a focus on safety, reliability and cost. Modeling, observation, testing, failure analysis, success analysis, and technology development is attainable through mutual cooperation and a focus on success.

ATTACHMENT 3

SANDIA REPORT- *Suggested Guidelines for Anti-Islanding Screening*, M. Ropp, Northern Plains Power Technologies, et al. (Feb. 2012)

SANDIA REPORT
SAND2012-1365
Unlimited Release
Printed February 2012

Suggested Guidelines for Anti-Islanding Screening

M. Ropp, Northern Plains Power Technologies
A. Ellis, Sandia National Laboratories

Prepared by
Sandia National Laboratories
Albuquerque, New Mexico 87185 and Livermore, California 94550

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Suggested Guidelines for Anti-Islanding Screening

Michael Ropp
807 32nd Avenue
Brookings, SD 57006-4716

Abraham Ellis
Photovoltaics and Distributed Systems Integration
Sandia National Laboratories
P.O. Box 5800
Albuquerque, New Mexico 87185-1033

Abstract

As increasing numbers of photovoltaic (PV) systems are connected to utility systems, distribution engineers are becoming increasingly concerned about the risk of formation of unintentional islands. Utilities desire to keep their systems secure, while not imposing unreasonable burdens on users wishing to connect PV. However, utility experience with these systems is still relatively sparse, so distribution engineers often are uncertain as to when additional protective measures, such as direct transfer trip, are needed to avoid unintentional island formation. In the absence of such certainty, utilities must err on the side of caution, which in some cases may lead to the unnecessary requirement of additional protection. The purpose of this document is to provide distribution engineers and decision makers with guidance on when additional measures or additional study may be prudent, and also on certain cases in which utilities may allow PV installations to proceed without additional study because the risk of an unintentional island is extremely low. The goal is to reduce the number of cases of unnecessary application of additional protection, while giving utilities a basis on which to request additional study in cases where it is warranted.

Contents

Figures

Scope

The purpose of this document is to suggest a screening procedure that may be used by utility protection engineers when assessing the risk of unintentional islanding of a proposed distributed generator (DG) installation. While the content applies to any DG, this document focuses on photovoltaic (PV) installations. The document describes cases in which islanding for any extended period of time is virtually impossible, and thus additional studies or protection mitigation measures are not justified; and also cases in which additional studies should be considered. This document does not specifically address temporary overvoltage-related issues.

Introduction

An island is any stand-alone power system with its own generation and loads operating in balance. Islanding itself is not necessarily undesirable, but unintentional islanding can have undesirable impacts on customer and utility equipment integrity. If the unintentional island is sustained for a significant period of time, personnel safety could become a concern. For these reasons, unintentional islanding must be prevented. Applicable standards such as IEEE 1547 and IEC 62116 require that a DG detect an islanding condition and cease to energize within 2 s, even in the worst-case condition of very close load-generator balance. For this reason, DG equipment connected to the lower-voltage parts of utility systems usually incorporates islanding detection and prevention schemes, or so-called "Loss of Mains Detection" (LOMD), of varying levels of sophistication. Interconnection procedures applicable to commercial and residential PV systems require that the utility interface (the inverter itself in most cases) be certified specifically for LOMD. Existing LOMD certification tests, including UL 1741, are applied to a single inverter connected to an RLC (resistive-inductive-capacitive) circuit where real power demand matches the inverter output, and the capacitive and reactive elements are resonant at 60 Hz with a circuit quality factor of 1.0. In practice, the certification effectively rules out the possibility of unintentional islanding in the vast majority of cases, but not all.

To understand how an unintentional island may form, consider the schematic representation shown in Figure 1. This figure shows a DG at the left, which in this case is labeled as a PV system; a local load; a circuit interrupter, indicated by the switch; and the utility, represented by the voltage source labeled "Grid V." The PV plant is an inverter-based DG controlling output current magnitude and phase with respect to terminal voltage. In order for this system to enter a sustained unintentional island when the switch is opened, the fundamental-frequency grid current i_{grid} must be nearly zero at the moment when the switch is opened. This means that the PV output and the local load demand must match closely in terms of both real and reactive power. If this is not the case, either the voltage or the frequency will quickly drift outside of normal operating range when the switch opens, and the Loss of Mains condition is detected. If such a balance does exist, then the island may "self-excite," in the sense that the PV output current flowing into the load creates a voltage V_{load} that appears sufficiently similar to the grid voltage that the inverter cannot tell the difference. In that case, LOMD may fail, and the loading condition that could result in unintentional islanding is referred to as a non-detection zone (NDZ). In a way, the extent of the NDZ is a measure of the effectiveness of the anti-islanding scheme.

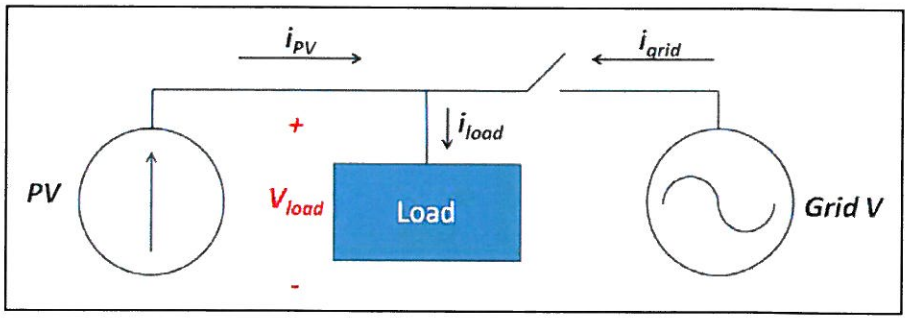

Figure 1. Simplified schematic representation of a distributed generator (in this case, a PV plant), local load, circuit interrupter, and utility voltage source.

LOMD techniques are usually subdivided into the following categories [1-3]:

- Passive methods. Passive methods monitor various parameters of the inverter's terminal voltage, and trip the inverter if the selected parameter exceeds some threshold. What defines them as passive is that the inverter does not actively try to change the value of the parameter being monitored; it simply monitors. Some parameters that have been used in passive anti-islanding methods include the following:

    - Over/undervoltage and over/underfrequency
    - Voltage phase (the phase is monitored for a sudden jump)
    - Voltage or current harmonic distortion (THD)
    - Rate of change of frequency (RoCoF)
    - Rate of change of real power
    - Rate of change of voltage vector
    - Various harmonic pattern recognition methods, using FFTs, wavelets, Kalman filters, or other spectral techniques

    In general, passive methods have great difficulty eliminating all NDZs because it is difficult to find thresholds or patterns that are totally unique to islanding, and do not occur under normal operating conditions. Thus, passive methods usually involve a trade-off between the extent of the NDZ and the rate of occurrence of nuisance trips. The behavior and performance of passive methods is difficult to predict when multiple inverters are present in the potential island.

- Active methods. Effectively, active methods are similar to passive methods in that the inverter watches for some threshold to be exceeded. The difference is that the inverter takes an active role in driving the system state toward that threshold. Active methods are generally more successful in LOMD than passive methods because they tend to destabilize the potential island by making the generation-load balance more difficult to achieve. Active methods include the following:

    - Impedance detection. In impedance detection, the inverter periodically perturbs its output current and checks to see whether there is a corresponding change in voltage, thereby measuring the source impedance as seen from the inverter. If the detected impedance is too high, the inverter trips.
    - Positive feedback based methods, such as the Sandia Frequency Shift (SFS) or Sandia Voltage Shift (SVS). In these methods, the inverter employs positive feedback on voltage or frequency. If the inverter detects a change in one of these parameters, it attempts to "push" on that parameter in the same direction, trying to drive it out of bounds. If it can, the inverter trips.
    - Impedance detection plus positive feedback. Most commercial inverters today use some variant of this technique, in which the benefits of positive feedback are combined with the benefits of impedance detection. This method has been vetted in simulation, laboratory tests, and field deployments.

- Communications-based methods. In these methods, communications are used to send utility status information back to the inverter. Communications-based methods include the following:

    - Direct transfer trip (DTT). In DTT, the utility's breaker or other isolation device is tied to a transmitter that sends the breaker's status to the DG.
    - Power line carrier communications (PLCC). PLCC is a form of DTT in which the communications channel is the power line itself.
    - Integration of inverters into utility SCADA.
    - Synchrophasor-based methods [4].

Where Can Islands Form?

In this document, the phrase "potential island" is used to describe some section of the local electric power system (EPS) that can be isolated and that contains DG and loads. Theoretically, any subsection of the local EPS that contains both a DG and loads, and can be fully isolated from the utility voltage source by automatic protection/control or operator action, could be considered a potential island. If a particular feeder contains downstream reclosers, sectionalizing switches, or other circuit interrupters, the section of the local EPS that is isolated by these devices would be a "potential island" as defined in this document. Also, again in theory, if a PV system is within the customer premises, the customer premises themselves could be a potential island.

Cases in Which the Possibility of Unintentional Islanding Can Be Ruled Out

There are several cases in which the literature, accumulated experience, and physical reasoning suggest that islanding is so unlikely as to be considered impossible for all practical purposes. Those cases include the following:

- Cases in which the aggregated nameplate AC rating of all DG systems within the potential island is less than some fraction of the minimum real power load within the potential island. If PV is the only type of DG in the potential island, then the value that should be used is the minimum load during daylight hours. Considering that load and PV output both rise during the morning hours, the time at which the fraction of PV output to load may realistically become meaningful is not sunrise, but rather closer to 10 a.m., at which point feeder load is well above absolute minimums. In the case in which the aggregate DG rating is below the specified loading fraction, after the switch opens, the load's voltage (V_{load} in Figure 1) will quickly drop. Theoretically, the definition of "some fraction" would be 77% (88% squared), because below this level, the voltage should drop to less than 0.88 p.u. and the inverter would enter a regime in which IEEE 1547 requires a 2-second trip, but this is strictly true only for impedance loads. A practical screening rule may be to say that a sustained island is not possible if the sum of the AC nameplate ratings of all the DG in a potential island is less than 2/3 of the minimum feeder load within the potential island. The 2/3 fraction is somewhat conservative and easy to remember. This screening rule assumes that reliable data on minimum load exists, which of course is not always the case. It is important to note that if IEEE 1547 is changed to allow low-voltage ride through (LVRT) capability, this criterion will need to be revisited.

- Cases in which it is not possible to balance reactive power supply and demand within the potential island. In order for an island to be sustained, both the real and reactive power demand of the load and power system components must be satisfied. Since most loads and power system components absorb VArs, there must be a source of VArs in the potential island in order for islanding to be sustained. The most obvious VAr source is capacitance, which may be deliberately added for power factor correction or may arise as a parasitic from underground cabling. Most of today's PV inverters are designed to operate at unity power factor, but, increasingly, larger inverters are being equipped with the ability to operate at a fixed power factor according to a schedule or command. In this case, the inverters may source or sink VArs. If the load VAr demand is larger than the VAr sources in the island, then the risk of a sustained run-on is very close to zero, because the frequency within the island will quickly rise beyond the IEEE 1547 mandated limit of 60.5 Hz. The mechanism of this frequency change is the phase locked loop (PLL) used by the inverters to synchronize to the grid frequency. (Not all inverters use an actual PLL, but they all do have some kind of synchronization mechanism, and these behaviorally are roughly equivalent to an actual PLL, so the discussion here holds in all cases.) When the grid source is lost, the PLL will change the frequency of the inverters' output current to bring the inverters' voltage and current into whatever phase relationship the PLL is programmed to maintain (usually, zero). If there is VAr imbalance in the island, that steady-state frequency will lie above 60.5 Hz. Most of today's inverters use active anti-islanding that incorporates positive feedback on frequency. Because of this, there must be an exceedingly close VAr balance in order for islanding to be sustained [5,6]. The term "exceedingly close" is quantified below.

- Cases in which DTT is used. Note that "power line carrier permissive" (PLCP), in which a power line carrier signal is used for island detection, is included here as a form of DTT. If DTT is properly implemented, only a failure of the DTT communications system would result in a failure to detect an unintentional island. Other forms of communications-based anti-islanding, such as SCADA and synchrophasor-based methods, may also fall into this category if future accumulated experience suggests that they are sufficiently effective. In some cases, DTT implemented on a dominant large DG [M1] within the potential island is sufficient to rule out the possibility of unintentional islanding..

Cases in Which Additional Study May Be Considered

There are several cases that are known to be difficult for LOMD methods to detect. These include the following:

- Cases in which the potential island contains large capacitors, *and* is tuned [M2]such that the power factor within a potential island is very close to 1.0 [1-3]. Under common deployment situations, a small amount of reactive power imbalance is sufficient to rule out the possibility of unintentional islanding. Reference 5 suggests the following screening procedure for determining when there is sufficient capacitance in a potential island to trigger additional study, assuming that (a) all of the inverters in the potential island are from the same manufacturer, and (b) there is little impedance between the inverters:

    1. Based on PV forecasts and daylight-hours load data, determine the range of PV power levels at which the PV is producing more than 2/3 of the load demand in the potential island.
    2. Calculate the expected reactive power draw of the load at this matching condition, Q_{load}:

    $$Q_{load} = P_{match} \tan[\cos^{-1}(pf)] \qquad \text{Eq. (1)}$$

    where P_{match} is a power level at which PV-load matching is likely and pf is the expected power factor of the feeder or load section (including losses) at this condition, again based on the historical load data. If the sum of Q_{load} and Q_{PV} (the PV system's VAr output, with absorption being positive and consumption being negative) is within 1% of the capacitor's VAr rating for any expected value of P_{match}, this indicates that the capacitor's VAr output could match the load demand, and further study may be advisable. In equation form, this criterion is:

$$0.99 \leq \frac{Q_{cap}}{Q_{PV}+Q_{load}} \leq 1.01 \qquad \text{Eq. (2)}$$

Past results suggest that the 1% matching requirement is quite conservative for inverters incorporating positive feedback on frequency. If the inverters do NOT use positive feedback on frequency, then a larger value should be used and further study may be prudent.

- Cases with very large numbers of inverters. The literature indicates that the speed with which inverters detect an island degrades as the number of inverters in the island increases [5-8], and that the amount by which the effectiveness decreases depends on both the specific anti-islanding method used [9] and on the configuration of the potential island [5,6]. The definition of "very large number" depends on several factors. Results to date suggest that there is little to no degradation in LOMD performance, if (a) all of the multiple inverters use positive feedback-based LOMD, *and* (b) the interconnecting impedances between the inverters are low. An example of such a deployment may be a commercial installation using multiple inverters on a common distribution transformer. In such a case, even feeders with more than 20 inverters still reliably trip within IEEE 1547 mandated limits. Multi-inverter problems seem to arise when:
    - different types of LOMD are mixed, which can occur when inverters from several different manufacturers are used together (see below); or
    - when there is significant interconnecting impedance between the inverters. "Significant" in this context is difficult to define; however, as a rule of thumb, results to date suggest that this effect can be significant if there is a difference in fault currents of more than a factor of three between any two PV point of common couplings (PCCs). This can occur if two PV plants are connected to the feeder via separate transformers and are separated by a considerable length of line.

- Cases with inverters from several different manufacturers [8-10]. Some studies have found that mixing different types of LOMD, or even mixing inverters with the same type of LOMD but different implementations, leads to a degradation of islanding detection effectiveness in the multi-inverter case. This situation could represent a case in which a multi-inverter installation uses units from several different manufacturers.

- Cases including both inverters and rotating generators [4]. If a potential island includes both rotating and inverter-based DGs, the case should be scrutinized carefully. It has been shown that the rotating generator, particularly if it is a synchronous machine, can lead to greatly increased run-on times for the inverter-based DG because the synchronous machine simply looks too much like the grid for the inverters to be able to tell the difference. Similarly, some of the most common anti-islanding methods used in synchronous machines, such as positive feedback based or governor clustering methods [11], are largely defeated by the much faster action taken by inverter-based DG.

Screening Tool

The screening tool in Figure 2 can be useful in assisting a distribution system engineer in determining whether there is any realistic probability of a failure of LOMD for a given DG plant. The screening tool summarizes the preceding discussion in a graphical format, and runs through a list of criteria for determining when a possible risk of LOMD failure justifies additional study of the problem. The screening tool itself never suggests that islanding is a problem; instead, it indicates when additional study would be prudent to determine whether islanding is a problem that warrants additional protective measures, such as DTT or more restrictive trip setpoints.

The numbers given in the screening tool are conservative guidelines, based on a considerable amount of accumulated experience. Of course, no set of values could accommodate every situation, and the utility distribution or protection engineer must exercise his/her judgment when evaluating any specific situation. When in doubt, additional study is recommended.

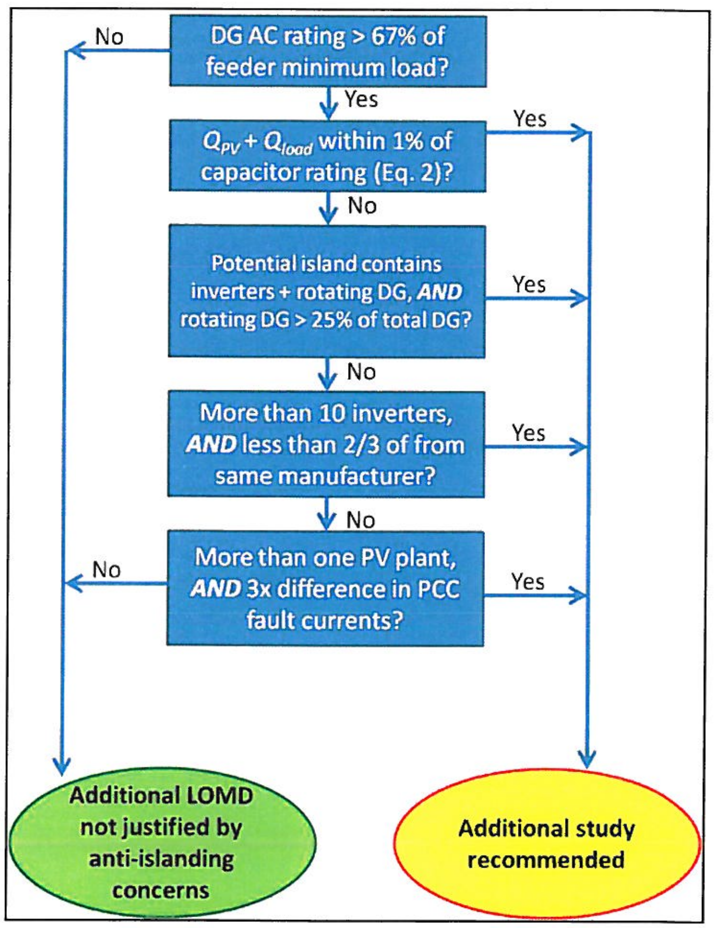

Figure 2. Suggested screening procedure for use in determining when additional study is and is not justified on the basis of a risk of islanding. References to load refer to daytime periods for PV.

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ATTACHMENT 4

SANDIA REPORT -"*Suggested Guidelines for Assessment of DG Unintentional Islanding Risk*" (Nov. 2012)

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Unlimited Release
Printed February 2012
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Suggested Guidelines for Assessment of DG Unintentional Islanding Risk

M. Ropp, Northern Plains Power Technologies
A. Ellis, Sandia National Laboratories

Prepared by
Sandia National Laboratories
Albuquerque, New Mexico 87185 and Livermore, California 94550

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Suggested Guidelines for Assessment of DG Unintentional Islanding Risk

Michael Ropp
807 32nd Avenue
Brookings, SD 57006-4716

Abraham Ellis
Photovoltaics and Distributed Systems Integration
Sandia National Laboratories
P.O. Box 5800
Albuquerque, New Mexico 87185-1033

Abstract

As increasing numbers of Distributed Generation (DG) systems are connected to utility systems, distribution engineers are becoming increasingly interested in evaluating the risk of unintentional islanding. Utilities desire to keep their systems secure, while not imposing unreasonable burdens on customers wishing to connect DG. However, utility experience with these systems is still relatively sparse, so distribution engineers often are uncertain as to when additional protective measures, such as direct transfer trip, are needed to avoid unintentional islanding. Utilities tend to err on the side of caution, which in some cases may lead to the unnecessary requirement of additional protection. The purpose of this document is to provide distribution engineers with guidance on when additional measures or a more in-depth evaluation may be prudent. The guide also describes situations in which utilities may be able to ascertain that the risk of an unintentional island is extremely low and no additional mitigation or study are needed. The goal is to reduce the *unnecessary* application of additional protection for DG interconnection. While the content applies to any DG, this document has a focus on photovoltaic (PV) installations.

Contents

Figures

Scope and Applicability

The purpose of this document is to suggest a technical evaluation procedure that may be used by utility protection engineers to assess the risk of unintentional islanding of a proposed distributed generator (DG) installation. While the content applies to any DG, this document focuses on photovoltaic (PV) installations. The document describes cases in which islanding for any extended period of time is virtually impossible, and thus the need for additional technical evaluation or protection mitigation measures are not justified. It also describes cases in which additional technical evaluation should be considered. This document does not specifically address temporary overvoltage-related issues.

The guidelines provided in this document are technically involved and data intensive. As such, the technical guidelines contained in this document are designed for a purpose that is different from the screening criteria used in the FERC small generator interconnection procedures (SGIP) initial review process. However, the guidelines could be applied at a stage of the interconnection process where detailed studies are being conducted, to help determine whether or not anti-islanding study is needed. **The procedure described here leads to reasonable conclusions about the risk of unintentional islanding only if it is applied in its entirety.**

Introduction

An electrical island is any stand-alone power system with its own generation and loads operating in balance. Islanding itself is not necessarily undesirable, but unintentional islanding can have undesirable impacts on customer and utility equipment integrity. If the unintentional island is sustained for a significant period of time, personnel safety could become a concern. Even if the unintentional islanding period is short, the potential degraded power quality could still be a concern. For these reasons, the risk of unintentional islanding must be kept low. Applicable standards such as IEEE 1547 and IEC 62116 require that a DG detect an unintentional islanding condition and cease to energize within 2 s, even in the worst-case condition of very close load-generator balance. For this reason, DG equipment connected to the lower-voltage parts of utility systems usually incorporates islanding detection and prevention schemes, or so-called "Loss of Mains Detection" (LOMD), of varying levels of sophistication. Interconnection procedures applicable to commercial and residential PV systems require that the utility interface (the inverter itself in most cases) be certified specifically for LOMD. Existing LOMD certification tests, including UL 1741, are applied to a single inverter connected to an RLC (resistive-inductive-capacitive) circuit where real power demand matches the inverter output, and the capacitive and reactive elements are resonant at 60 Hz with a circuit quality factor of 1.0.

To understand how an unintentional island may form, consider the schematic representation shown in Figure 1. This figure shows a DG at the left, which in this case is labeled as a PV system; a local load; a circuit interrupter, indicated by the switch; and the utility, represented by the voltage source labeled "Grid V." The PV plant is an inverter-based DG controlling output current magnitude and phase with respect to terminal voltage. In order for this system to enter a sustained unintentional island when the switch is opened, the fundamental-frequency grid current i_{grid} must be nearly zero at the moment when the switch is opened. This means that the PV output and the local load demand must match closely in terms of both real and reactive power. If this is not the case, either the voltage or the frequency will quickly drift outside of normal operating range when the switch opens, and the Loss of Mains condition can be detected. If such a balance does exist, then the island may "self-excite," in the sense that the PV output current flowing into the load creates a voltage V_{load} that appears sufficiently similar to the grid voltage that the inverter cannot tell the difference. In that case, LOMD may fail. The loading condition that could result in unintentional islanding is referred to as a non-detection zone (NDZ). In a way, the extent of the NDZ is a measure of the effectiveness of the anti-islanding scheme.

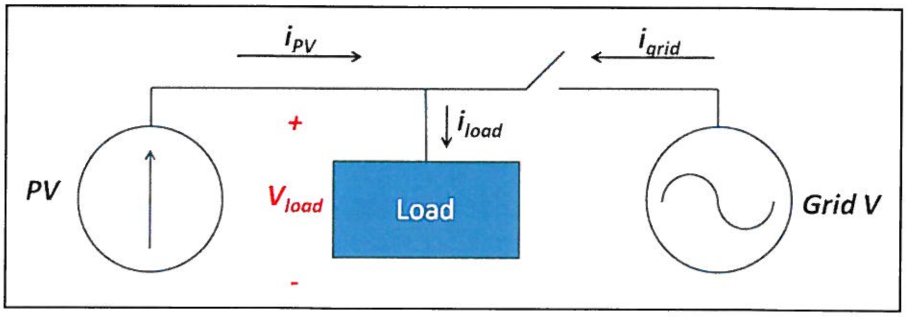

Figure 1. Simplified schematic representation of a distributed generator (in this case, a PV system), local load, circuit interrupter, and utility voltage source.

LOMD techniques are usually subdivided into the following categories [1-3]:

- Passive methods. Passive methods monitor various parameters of the inverter's terminal voltage, and trip the inverter if the selected parameter exceeds some threshold. What defines them as passive is that the inverter does not actively try to change the value of the parameter being monitored; it simply monitors, processes and reacts. Some parameters that have been used in passive anti-islanding methods include the following:

    - Over/undervoltage and over/underfrequency
    - Voltage phase (the phase is monitored for a sudden jump)
    - Voltage or current harmonic distortion (THD)
    - Rate of change of frequency (RoCoF)
    - Rate of change of real power
    - Rate of change of voltage vector
    - Various harmonic pattern recognition methods, using FFTs, wavelets, Kalman filters, or other spectral techniques

    In general, passive methods have great difficulty eliminating all NDZs because it is difficult to find thresholds or patterns that are totally unique to islanding, and do not occur under normal operating conditions. Thus, passive methods usually involve a trade-off between the extent of the NDZ and the rate of occurrence of nuisance trips. The behavior and performance of passive methods is difficult to predict when multiple inverters are present in the potential island.

- Active methods. Effectively, active methods are similar to passive methods in that the inverter watches for some threshold to be exceeded. The difference is that the inverter takes an active role in driving the system state toward that threshold. Active methods are generally more successful in LOMD than passive methods because they tend to destabilize the potential island by making the generation-load balance more difficult to achieve. Active methods include the following:

    - Impedance detection. In impedance detection, the inverter periodically perturbs its output current and checks to see whether there is a corresponding change in voltage, thereby measuring the source impedance as seen from the inverter. If the detected impedance is too high, the inverter trips.
    - Positive feedback based methods, such as the Sandia Frequency Shift (SFS) or Sandia Voltage Shift (SVS). In these methods, the inverter employs positive feedback on voltage or frequency. If the inverter detects a change in one of these parameters, it attempts to "push" on that parameter in the same direction, trying to drive it out of bounds. If it can, the inverter trips.
    - Impedance detection plus positive feedback. Most commercial inverters today use some variant of this technique, in which the benefits of positive feedback are combined with the benefits of impedance detection. This method has been vetted in simulation, laboratory tests, and field deployments.

- Communications-based methods. In these methods, communications are used to send utility status information back to the inverter, which the inverter can interpret to determine whether an island has been formed. Communications-based methods include the following:

    - Direct transfer trip (DTT). In DTT, the utility's breaker or other isolation device is tied to a transmitter that sends the breaker's status to the DG.
    - Power line carrier communications (PLCC). PLCC is a form of DTT in which the communications channel is the power line itself.
    - Integration of inverters into utility SCADA.
    - Synchrophasor-based methods [4].

Where Can Islands Form?

In this document, the phrase "potential island" is used to describe some section of the local electric power system (EPS) that can be isolated and that contains DG and loads. Theoretically, any subsection of the local EPS that contains both a DG and loads, and can be fully isolated from the utility voltage source by automatic protection/control or operator action, could be considered a potential island. If a particular feeder contains downstream reclosers, sectionalizing switches, or other circuit interrupters, the section of the local EPS that is isolated by these devices would be a "potential island" as defined in this document. Also, again in theory, if a PV system is within the customer premises, the customer premises themselves could be a potential island.

Cases in Which the Possibility of Unintentional Islanding Can Be Ruled Out

There are several cases in which the, accumulated field experience, findings described in the literature, and physical reasoning suggest that islanding is so unlikely as to be considered impossible for all practical purposes. Those cases are described below.

- Cases in which the aggregated nameplate AC rating of all DG systems within the potential island is less than some fraction of the minimum real power load within the potential island. If PV is the only type of DG in the potential island, then the value that should be used is the minimum load during daylight hours. Considering that load and PV output both rise during the morning hours, the time at which the fraction of PV output to load may realistically become meaningful is not sunrise, but rather closer to 10 a.m., at which point feeder load is well above absolute minimum load levels. In the case in which the aggregate DG rating is well below the specified loading fraction, after the switch opens, the load's voltage (V_{load} in Figure 1) will quickly drop to levels that the inverter can easily detect as abnormal. Theoretically, the definition of "some fraction" would be 77% (88% squared), because below this level, the voltage should drop to less than 0.88 p.u. and the inverter would enter a regime in which IEEE 1547 requires a 2-second trip. Said another way, provided the DG has protection programmed to comply with the IEEE 1547 0.88 p.u. static voltage threshold, the 77% fraction effectively rules out the possibility of unintentional islanding, regardless of the effectiveness of the anti-islanding algorithm. This rationale is strictly true only for impedance loads. Very conservatively, one could say that a sustained island is not physically possible if the sum of the AC nameplate ratings of all the DG in a potential island is less than 2/3 of the minimum feeder load within the potential island. If all of the DG are PV systems, then the minimum load to be considered is the minimum daylight-hours feeder load. The 2/3 fraction is somewhat conservative and easy to remember. Application of this evaluation assumes that reliable data on minimum load exists, which of course is not always the case. It is important to note that if IEEE 1547 is changed to allow low-voltage ride through (LVRT) capability, this criterion may need to be revisited.

- Cases in which it is not possible to balance reactive power supply and demand within the potential island. In order for an island to be sustained, both the real and reactive power demand of the load and power system components must be satisfied. Since most loads and power system components absorb VArs, there must be a source of VArs in the potential island in order for islanding to be sustained. The most obvious VAr source is capacitance, which may be deliberately added for power factor correction or may arise as a parasitic from underground cabling. Most of today's PV inverters are designed to operate at unity power factor, but, increasingly, larger inverters are being equipped with the ability to operate at a fixed power factor according to a schedule or command. In this case, the inverters may source or sink VArs. If the load VAr demand is larger than the

VAr sources in the island, then the risk of a sustained run-on is very close to zero, because the frequency within the island will quickly rise beyond the IEEE 1547 mandated limit of 60.5 Hz. The mechanism of this frequency change is the phase locked loop (PLL) used by the inverters to synchronize to the grid frequency. (Not all inverters use an actual PLL, but they all do have some kind of synchronization mechanism, and these behaviorally are roughly equivalent to an actual PLL, so the discussion here holds in all cases.) When the grid source is lost, the PLL will change the frequency of the inverters' output current to bring the inverters' voltage and current into whatever phase relationship the PLL is programmed to maintain (usually, zero). If there is VAr imbalance in the island, that steady-state frequency will lie above 60.5 Hz. Most of today's inverters use active anti-islanding that incorporates positive feedback on frequency. The action of active anti-islanding is such that for an unintentional island to persist there must be an *exceedingly* close VAr balance in order for islanding to be sustained [5, 6], and also that VAr balance must be maintained during the unintentional islanding duration. The term "exceedingly close" is quantified below.

- Cases in which DTT is used. Note that "power line carrier permissive" (PLCP), in which a power line carrier signal is used for island detection, is included here as a form of DTT. If DTT is properly implemented, only a failure of the DTT communications system would result in a failure to detect an unintentional island. Other forms of communications-based anti-islanding, such as SCADA and synchrophasor-based methods, may also fall into this category if future accumulated experience suggests that they are sufficiently effective. In some cases, DTT implemented on a dominant large DG within the potential island is sufficient to rule out the possibility of unintentional islanding.

Cases in Which Additional Study May Be Considered

There are several cases that are known to be difficult for LOMD methods to guarantee a negligible risk of failure to detect. Some of these cases, as described below, correspond to conditions commonly encountered in distribution systems. The examples refer to PV generation, but could be adapted to apply to other inverter-based DG as well.

- Cases in which the potential island contains large capacitors, *and* is tuned such that the power factor within a potential island is very close to 1.0 [1-3]. Under common deployment situations and with active anti-islanding in operation, a very small amount of reactive power imbalance is sufficient to rule out the possibility of unintentional islanding. Reference 5 suggests the following approach for determining when there is sufficient capacitance in a potential island to trigger the need for further evaluation, assuming that (a) all of the inverters in the potential island are from the same manufacturer, (b) there is little impedance between the inverters, and (c) all inverters are utilizing some form of positive feedback based active anti-islanding:

1. Based on PV forecasts and daylight-hours load data, determine the range of PV power levels at which the PV is producing more than 2/3 of the load demand in the potential island.
2. Calculate the expected reactive power draw of the load at this matching condition, Q_{load}:

$$Q_{load} = P_{match} \tan[\cos^{-1}(pf)] \quad \text{Eq. (1)}$$

where P_{match} is a power level at which PV-load matching is likely and pf is the expected power factor of the feeder or load section (including losses) at this condition, again based on the historical load data. If the sum of Q_{load} and Q_{PV} (the PV system's VAr output, with absorption being positive and production being negative) is within 1% of the capacitor's VAr rating for any expected value of P_{match}, this indicates that the capacitor's VAr output could match the load demand, and more detailed evaluation may be advisable. In equation form, this criterion is:

$$0.99 \leq \frac{Q_{cap}}{Q_{PV}+Q_{load}} \leq 1.01 \quad \text{Eq. (2)}$$

If measurements of the real and reactive power flowing through the interrupting device are available, those data can substitute for this calculation. In that case, the distribution engineer should check to see whether the feeder power factor, with capacitors but without the DG, is higher than 0.99 (lag or lead) for an extended period of time. For PV, only daytime hours need to be reviewed. Past results suggest that the 1% matching requirement is quite conservative for inverters incorporating positive feedback on frequency. If the inverters do not use positive feedback on frequency, then Equation (2) or the power factor thresholds described above may be insufficient to determine the risk of islanding. Depending on other factors described in this document, further study may be prudent.

- Cases with very large numbers of inverters. The literature indicates that the speed with which inverters detect an island decreases as the number of inverters in the island increases [5-8], and that the amount by which the effectiveness degrades depends on both the specific anti-islanding method used [9] and on the configuration of the potential island [5,6]. The definition of "very large number" depends on several factors. Results to date suggest that there is little to no degradation in LOMD performance, if (a) all of the multiple inverters use positive feedback-based LOMD, *and* (b) the interconnecting impedances between the inverters are low. An example of such a deployment may be a commercial installation using multiple inverters on a common distribution transformer. In such a case, even feeders with more than 20 inverters still reliably trip within IEEE 1547 mandated limits. Multi-inverter problems seem to arise when:

    - different types of LOMD are mixed, which can occur when inverters from several different manufacturers are used together (see below); or

    - when there is significant interconnecting impedance between the inverters. "Significant" in this context is difficult to define, and work to quantify this factor is ongoing.

- Cases with inverters from several different manufacturers [8-10]. Some studies have found that mixing different types of LOMD, or even mixing inverters with the same type of LOMD but different implementations, leads to a degradation of islanding detection effectiveness in the multi-inverter case. This situation could represent a case in which a multi-inverter installation uses units from several different manufacturers.

- Cases including both inverters and rotating generators [4]. If a potential island includes both rotating and inverter-based DGs, the case should be scrutinized carefully. It has been shown that the rotating generator, particularly if it is a synchronous machine, can lead to greatly increased run-on times for the inverter-based DG because the synchronous machine simply looks too much like the grid for the inverters to be able to tell the difference. Similarly, some of the most common anti-islanding methods used in synchronous machines, such as positive feedback based or governor clustering methods [11], are largely defeated by the much faster action taken by inverter-based DG.

Summary of Methodology to Evaluate DG Unintentional Islanding Risk

The evaluation procedure shown in Figure 2 can be useful in assisting a distribution system engineer in determining whether there is any realistic probability of a failure of LOMD for a given DG plant. The procedure summarizes the preceding discussion as a sequence of steps, and runs through a list of criteria for determining when a possible risk of LOMD failure justifies a more in-depth evaluation of the problem. The procedure never suggests that islanding is a problem; instead, it indicates when the risk may not be negligible. In such cases, a more detailed technical evaluation or additional protective measures, such as DTT or more restrictive trip setpoints, may be warranted.

The numbers given in the evaluation procedure are conservative guidelines, based on a considerable amount of accumulated experience. Of course, no set of values could accommodate every situation, and the utility distribution or protection engineer must exercise his/her judgment when evaluating any specific situation.

It must be emphasized that these suggestions assume a) that the inverters are utilizing positive feedback based active anti-islanding; and b) that the DG is compliant with existing IEEE 1547 requirements[1]. Future experience may indicate that either of these assumptions are not required, but at present, if either of these assumptions does not hold the utility engineer should exercise prudent judgment regarding further studies.

To emphasize, the guidelines provided in this document lead to reasonable conclusions about the risk of unintentional islanding only if it is applied in its entirety. The guidelines could be applied at a stage of the interconnection process beyond the initial review process, when detailed studies are being conducted, to help determine whether or not anti-islanding study is needed.

Step 1. Determine whether the aggregate AC rating of all DG exceeds 2/3 of the minimum feeder loading. If all of the DG in the case of interest are PV systems, then the appropriate loading value to use is 2/3 of the minimum daylight-hours load. If the aggregate AC DG rating is less than 2/3 of the minimum feeder load, then the voltage in any unintentional island will drop below the 88% IEEE 1547 undervoltage trip setting, and the risk of a persistent unintentional island is negligible. In this case, no further assessment is warranted and one need not execute the next steps of this procedure. If the aggregate AC DG rating is above 2/3 of the minimum rest of the appropriate minimum feeder load, then proceed to Step 2.

Step 2. Determine whether $Q_{PV} + Q_{load}$ is within 1% of the total aggregate capacitor rating within the island (Equation (2)), or alternatively, use real and reactive power flow measurements or simulations at the point at which the island can form to determine whether the feeder power factor is ever higher than 0.99 (lag or lead) at that point for an extended period of time. If $Q_{PV} + Q_{load}$ IS within 1% of the capacitor rating, or the feeder power factor is higher than 0.99, then further study may be prudent. If $Q_{PV} + Q_{load}$ is not within 1% of the capacitor rating, or the feeder power factor is not higher than 0.99, then proceed to Step 3.

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[1] As of the date this report was printed, the current version of the standard is IEEE 1547 (2008).

Step 3. Determine whether the potential island contains both rotating and inverter-based DG, *and* the sum of the AC ratings of the rotating DG is more than 25% of the total AC rating of all DG in the potential island. If the sum of all rotating machine AC ratings is greater than 25% of the total DG, then further study may be prudent. If the sum of all rotating machine AC ratings is less than 25% of the total DG, then proceed to Step 4.

Step 4. Sort the inverters by manufacturer, sum up the total AC rating of each manufacturer's product within the potential island, and determine each manufacturer's percentage of the total DG. If no single manufacturer's product makes up at least 2/3 of the total DG in the potential island, then further study may be prudent. If the situation is such that more than 2/3 of the total DG is from a single manufacturer, then the risk of unintentional islanding can be considered negligible.

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