ENERGY TRANSITION INITIATIVE

Islands

A discussion paper for fostering open dialogue on energy challenges

Sun Screens

Maintaining Grid Reliability and Distributed Energy Project Viability through Improved Technical Screens

Introduction

Renewable distributed energy resources (DERs) have represented a growing share of new energy resources globally over the past 10 years, with technologies including wind, small hydropower, battery storage systems, and solar photovoltaics (PV) among the most popular. In the United States, the most prominent renewable DER is solar PV, the vast majority of which is connected to local utility grids through a specific interconnection process. Distributed solar PV systems are often small enough that utility companies can review and approve an interconnection request quickly and easily, whereas larger PV systems may take months of detailed electrical study and often require mitigation measures to overcome challenges identified through the interconnection processes. This report focuses on the interconnection process for smaller PV systems (less than or equal to 10 kilowatts [kW]), as this process can have a major impact on project success.

Interconnection Process and Technical Screens

Process

The process of interconnection determines whether and how a specific installation can safely operate when connected to the utility distribution system. If the combined features of the system (e.g., power capacity, technology, etc.) do not meet the requirements at the proposed system location, the system may need to go through detailed impact studies where mitigation strategies may be evaluated and applied. For small PV systems, this additional level of scrutiny is uncommon, but if triggered can greatly reduce a project's financial viability. The typical interconnection process is shown in Figure 2 and is based on National Renewable Energy Laboratory (NREL) interviews with 21 U.S. electric utilities in 2013.

Interconnection Process

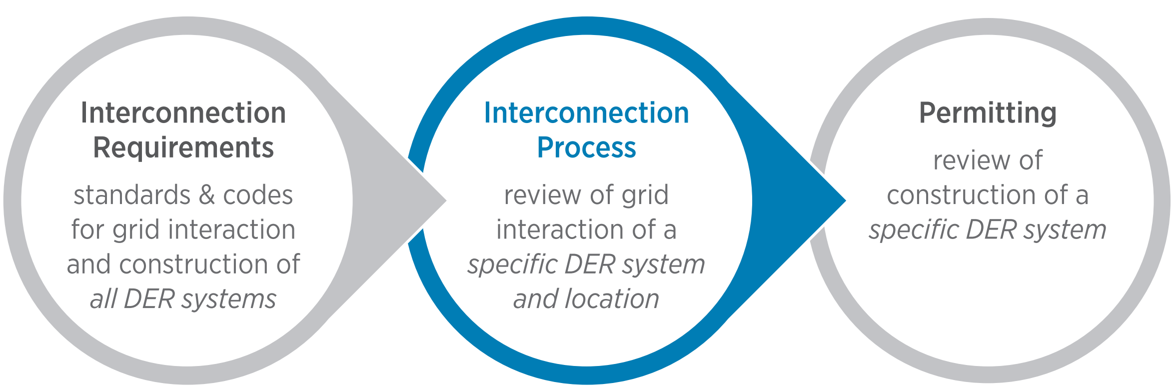

Figure 1. This paper focuses on the interconnection process as a key component of overall solar PV project development.

Implementation of Technical Screens

In order to connect a PV system to the grid, a developer must submit an interconnection application to the electric utility (the application is often available and explained on the utility website). The interconnection application may be simple or complex and must be completed accurately before the utility can evaluate the proposed solar PV system design, location, and impact on the electric utility distribution system.

When an application is received by the utility and deemed complete, the application is typically reviewed using a set of technical screens. Technical screens are basic questions applied to a proposed interconnected system that determine whether a proposed project would pose a risk to the safety and reliability of the grid. The screens may vary from utility to utility or from state to state, but are typically based on Federal Energy Regulatory Commission (FERC) and state regulatory agency recommendations.

As shown in Figure 2, once an application is deemed complete, the first step a utility takes to evaluate the proposed PV system is applying a set of "fast-track screens." These screens consist of technical questions used to evaluate the impact of the proposed system and, if passed, lead directly to quick approval of the interconnection application. For the PV developer, passing these fast-track screens can minimize approval time and the overall installation cost. If any of the fast-track screens are failed, the utility may apply more sophisticated supplemental review screens. This should typically represent a marginal increase in time and cost for the developer or customer, and passing all of the supplemental screens would then result in project approval. For the utility, both sets of technical screens are intended to catch possible problems with minimal analytical effort and are thus an important tool for evaluating the interconnection of a proposed PV system.

Most small, residential PV systems will pass the technical screens so long as the number of DER systems, or the total amount of DER capacity, on a utility feeder is low. If these screens are failed for any reason, the utility may require detailed impact studies and even electrical system upgrades. Such studies and actions may prove cost-prohibitive, resulting in an abandoned project and wasted investment of time and effort by the developer.

Examining FERC's SGIP Technical Screens

The most widely adopted set of technical screens are those found in the FERC Small Generator Interconnection Procedure (SGIP). These screens were originally established by FERC Order 2006 in May 2005 and were subsequently amended by Order 792 in November 2013. The procedure now includes two sets of technical screens, one for fast-track and a second, newer set for supplemental review. Most U.S. states and utilities use some form of these technical screens to evaluate interconnection applications. Appendix A presents the 10 original fast-track technical screens found in the FERC SGIP.

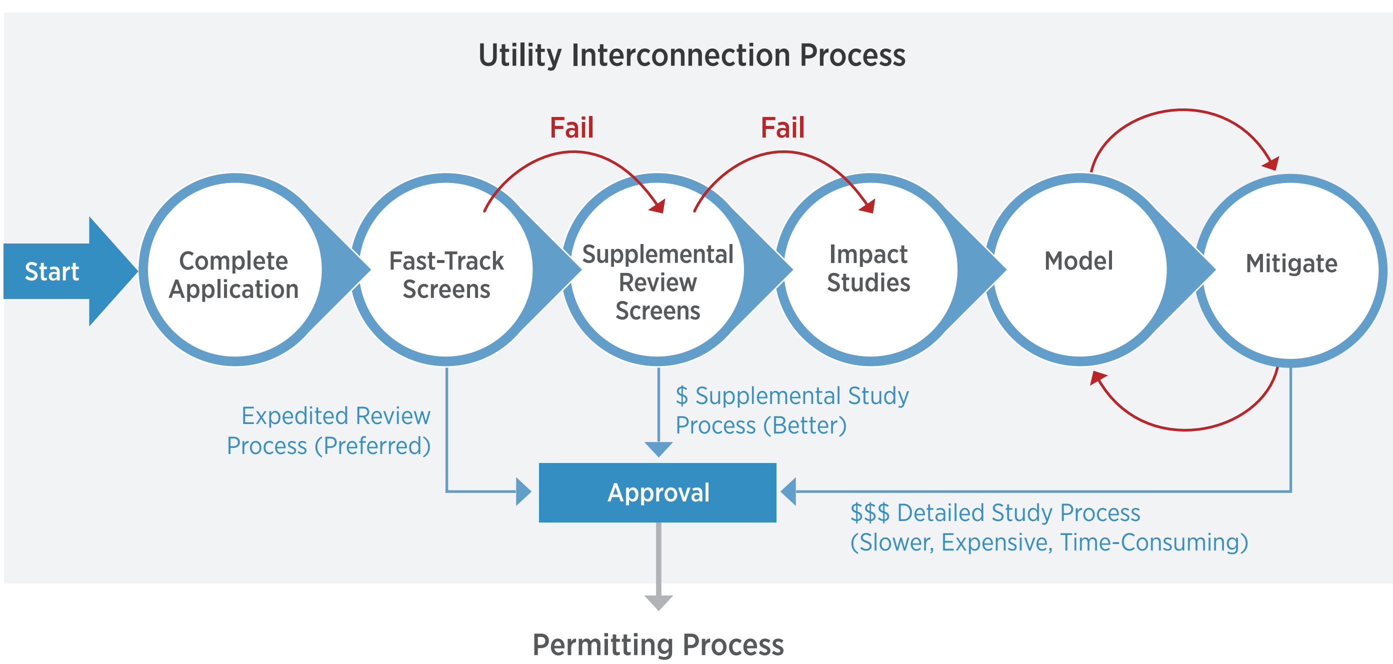

Figure 2. The major phases of the interconnection process, with special focus on utility actions at each step. As the review process grows more rigorous (e.g., impact studies) the time and cost burden increases significantly, potentially threatening project viability.

Focus on 15%—Origins, Impacts, and Alternatives[1]

Origins of the 15% Capacity Penetration Screen

Of the fast-track screens detailed in the FERC SGIP, the most well-known is the capacity penetration screen, which restricts maximum aggregate distributed generation capacity to 15% of the historical peak load on the distribution circuit. This screen originated as a way to address two major challenges to the integration of distributed generation on the distribution system: unintentional islanding and voltage control.

Concern #1: Unintentional Islanding

Unintentional islanding describes an event during which (1) a segment of an electric utility system becomes separated from the rest of the utility, typically as a result of an electrical outage, and (2) the distributed generation systems interconnected to the separated segment continue generating power and supplying load on the same separated segment, with a complete loss of utility control over generation and load. These "islands" are most likely to persist when generation and load are roughly balanced on the separated segment. Due to the lack of connection to the rest of the gird, the electrical service on these "islands" is uncontrolled, creating the potential for damage to customer and utility equipment from excursions of voltage and frequency levels outside of acceptable ranges. The electric utility industry has also expressed concern that an unintentional island could pose a risk to the safety of line workers and to the general public.

Concern #2: Voltage Control

Electric distribution systems were traditionally designed for the one-way flow of power from substation to customer and manage voltage levels accordingly, with voltage generally declining along the distribution lines as power flows from substation to load. The effect of adding distributed generation to this paradigm depends heavily on the configuration of the distribution circuit and the connected loads, but any new distributed generation may raise the local voltage at the point of interconnection. This increase in voltage can potentially disrupt the voltage management scheme established by the utility and can lead to over- or under-voltages for adjacent customers.

Related Topics for Interconnection

Interconnection Standards

To streamline the interconnection process in many areas, a utility will publicly specify its requirements for any distributed generation (DG) system proposed within its service territory. This set of requirements, commonly known as interconnection standards, ensures that the PV system meets the technical requirements for interaction with the local electrical distribution system and for the design of the distributed generation system itself. Four sets of technical standards and codes—Institute of Electrical and Electronics Engineers (IEEE) 1547, UL 1741, American National Standards Institute (ANSI) C84.1, and the National Electrical Code (NEC)—have been widely incorporated into the state-level interconnection standards in the United States. More information on these is provided in Appendix B.

Permitting

Permitting is the process by which a system owner or developer works with the local authority having jurisdiction to gain approval for construction. Often developers may initiate the permitting process in parallel with the utility interconnection process, so that interconnection can be made shortly after the project is permitted, constructed, and inspected for compliance with codes and standards. After a system passes inspection, the utility grants final permission to operate the system.

Permitting Process

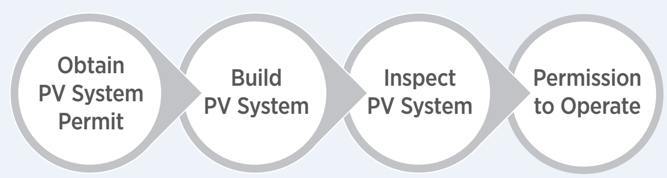

Figure 3. The permitting process is overseen by the local authority having jurisdiction. The completed permit is submitted to the utility alongside the completed interconnection application in order to obtain permission to operate.

1. This section borrows heavily from Coddington et al. 2012. *Updating Interconnection Screens for PV System Integration* (Technical Report), NREL/TP-5500-54063. National Renewable Energy Laboratory (NREL), Golden, CO (US). http://www.nrel.gov/docs/fy12osti/54063.pdf.

Implications of Screens for Distributed Generation Projects

For a given set of interconnection applications, some will pose no electrical difficulties, while others might present challenges. When this pool of applications is processed, the applications may either pass or fail. This gives rise to four outcomes: no issues–pass, issues–pass, no issues–fail, issues–fail, as shown below.

Four Possible Outcomes for Interconnection Applications and Technical Screens

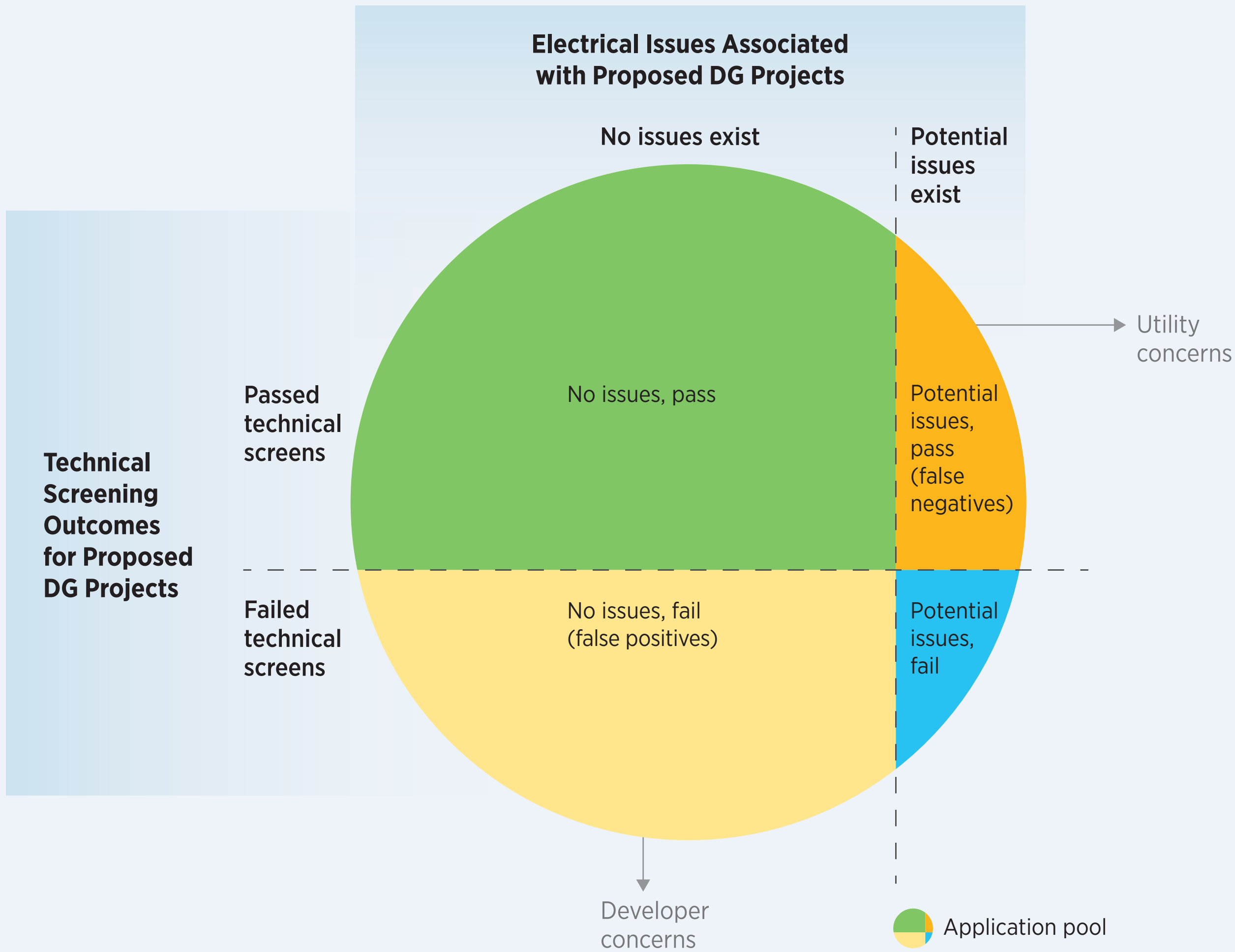

Figure 4. The four possible outcomes for a given set of interconnection applications and technical screens are shown in this hypothetical diagram.

The utility and developer are most concerned with two different outcomes of this technical screening process. The utility is preoccupied with the potential for "false negatives"—applications for projects that could cause problems on the grid but manage to pass the technical screens. Conversely, developers are frustrated by "false positives"—applications for projects that would not actually cause problems but fail one or more technical screens, triggering costly and time-consuming impact studies that can derail a project.

These groups seek to address their concerns in different ways. The utility could advocate for more stringent technical screens that catch all possible projects that cause problems. While such an approach would ensure that no problematic projects would slip through the cracks, it would tie up far more utility resources in detailed impact studies while provoking developer and customer dissatisfaction. At the opposite extreme, developers might desire more lenient screens that allow a far greater number of compliant projects to pass. However, this position may be untenable in the long term; one of the PV developer's greatest assets is being able to export electricity to the grid rather than requiring on-site storage. The more lenient screens could also allow more problematic projects to interconnect to the grid, potentially jeopardizing the stability of the grid, limiting the ability to export power, and provoking more rigorous utility screening of future projects.

Impacts of the 15% Threshold

More than any other screens in the FERC SGIP, the 15% capacity penetration threshold has been a key trigger for additional review of otherwise compliant DG projects. Investor-owned utilities in California, which adopted the 15% screen in their initial review and which report quarterly on the processing of DG interconnection applications, consistently rank the 15% screen as a top reason for flagging applications for further review.[2] Given the high number of additional reviews triggered by this screen and the large adverse impacts of such reviews on project viability, it is critical that the screen fulfill the intended purpose of avoiding unintentional islands and voltage control issues.

Why 15%?

The key factor in the formation of the unintentional islands is a balance between instantaneous demand and supply on the local system. Thus, this screen was designed to determine the maximum amount of distributed generation that could be added to the system such that it could never equal or exceed the load on the system. To do this, the aggregate distributed generation capacity would always need to be less than load, or specifically less than the minimum load level on the feeder. Design of distribution systems has traditionally centered on designing for peak load, so historical data for this value is almost always readily available, while assessing the minimum load was more difficult. The limited data available when this standard was first established suggested that minimum load is typically about 30% of the peak load. This number was then halved as a safety margin to 15% of peak load. Under the formal definition in the FERC screen, the capacity penetration is calculated as aggregate distributed generation nameplate capacity divided by the historical peak load. The screen is failed if the proposed project would raise the aggregate distributed generation capacity beyond 15% of the historical peak load.

Alternatives to the 15% Threshold

Some stakeholders involved in the development and implementation of technical screens believe that some screens are inadequate, too conservative, or not useful. The capacity penetration screen in particular has been considered as overly conservative or a poor metric to evaluate proposed DG systems. In considering potential alternatives to the 15% capacity penetration threshold, it is useful to revisit the graphical construct for screening of the applicant pool. So long as the set of technical screens remains unchanged and only threshold values are raised or lowered, the impact on outcomes will manifest as vertical movement of the dividing line. This means that a decrease in false negatives will lead to an increase in false positives and vice versa. Given that utilities and developers are primarily concerned about false negatives and false positives, respectively, this can create a potentially adversarial situation and frustration on both sides. Similarly, enhancing the electrical capabilities of the grid through physical upgrades alone will reduce the portion of applications that would actually cause electrical problems on the grid, but without a change to the screening procedure this would likely increase the share of false positives (see Figure 5).

However, there are opportunities to find common ground. One option to simultaneously achieve reductions in false positives and negatives would be to better align the technical screens with DG project characteristics that are likely to cause problems. This way, more problematic applications fail the screens, while a greater number of harmless applications pass. A second alternative is to shift the application pool to include a larger share of nonproblematic and nonfailing applications.

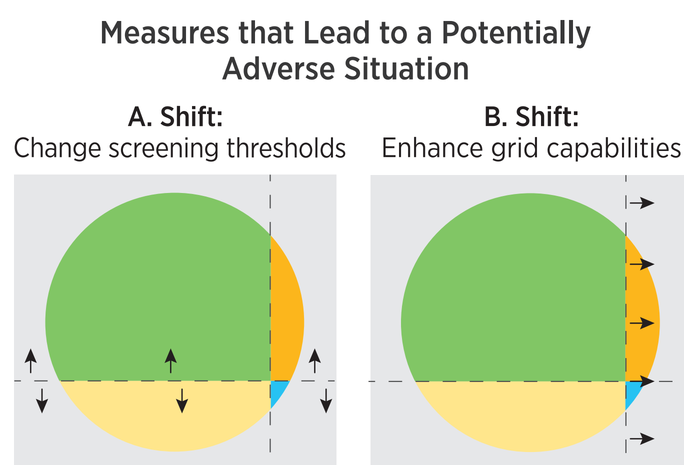

Figure 5. Measures such as changing screening threshold values (a) or increasing the grid's electrical capabilities (b) create tradeoffs between utilities, which are concerned with the potential for false negatives (orange), and developers that are frustrated by false positives (yellow), leading to potentially adversarial situations.

2. "Quarterly IOU Interconnection Data Reports," California Public Utilities Commission, accessed Dec. 15, 2016, http://www.cpuc.ca.gov/General.aspx?id=4117.

Greater transparency into grid conditions, as described below, can actually deter developers from submitting problematic applications in the first place, increasing the overall share that pass with no potential issues. There is no inherent conflict between these two strategies; both could be implemented to maximize the accuracy of the technical screening process (see Figure 6).

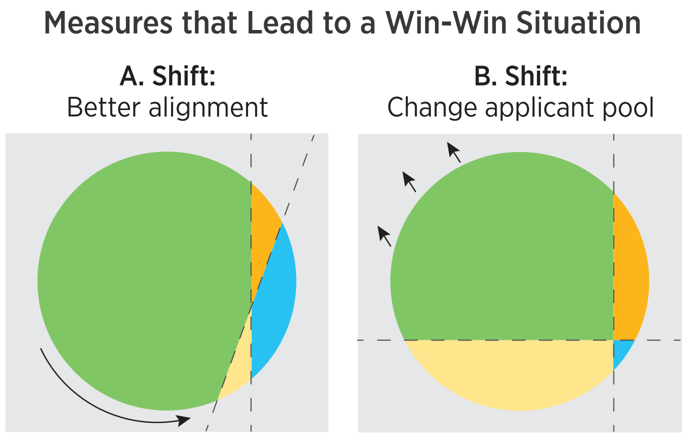

Figure 6. Complementary measures such as better alignment between screens and electrical issues (a) or shifting the applicant pool (b) create win-win situations that decrease both false negatives (orange) and false positives (yellow), leading to better outcomes for both utilities and developers.

When applying these constructs to the 15% capacity penetration screen, there are opportunities to both improve the alignment of screening outcomes with true grid issues and to shift the makeup of the applicant pool. In the long term, incorporation of new technologies and grid upgrades can also help to improve interconnection outcomes, provided that they are paired with changes to the technical screens. These alternatives are presented below in increasing order of implementation cost and complexity.

Alternative #1: Use a More Accurate Capacity Penetration Metric (Minimum Daytime Load)

As described above in the "Why 15%?" text box, the entire reason for the development of the capacity penetration metric as a ratio of peak load was that reliable data on historical minimum loads was unavailable, as utilities previously had no reason to track such information. The statistical uncertainty in the relationship between minimum and peak loads led to the acceptable level of capacity penetration being cut in half (from 30% to 15% of peak load). Put another way, historical data indicated that distributed generation could be kept below load in all hours so long as total DG capacity remained below 30% of peak load (i.e., 100% of minimum load was equal to 30% of peak load), but due to the uncertainty in this calculation, that level was reduced by half as a safety margin (to 15% of peak, effectively 50% of minimum load).

As data collection around minimum loads has improved and distributed PV has grown, the value of using the minimum load metric directly has become apparent to many stakeholders. FERC Order 792, issued in 2013, adopted minimum load as the first supplemental review screen; so long as the aggregate generating capacity on the line segment is less than 100% of the line's historical minimum load, the screen is passed. The supplemental screen also accommodates the particular issues related to solar PV by considering minimum daytime load for those systems to avoid generation exceeding load in the hours when PV is operating at highest output. For solar PV systems with a fixed orientation, "daytime load" is measured between 10 a.m. and 4 p.m., while the daytime load for systems that rotate to track the sun is 8 a.m. to 6 p.m. The incorporation of this supplemental screen directly addresses the anti-islanding concerns of the 15% screen while removing the calculation uncertainty, potentially doubling allowable capacity penetration while still flagging all potentially troublesome situations where aggregate DG could exceed load during daytime hours.

Alternative #2: Use Metrics That Directly Target Concerns

Despite offering an improvement to the peak load capacity penetration screen, gross minimum daytime load is still a step removed from the challenges it seeks to address. In essence, it implies a linkage between some level of DG penetration and the two main technical concerns, unintentional islanding and voltage control. An alternative to this arrangement would be to dispense with a capacity penetration metric entirely and develop new metrics that more directly target the conditions that could cause unintentional islands and voltage control issues, respectively.

In 2012, NREL, the U.S. Department of Energy, Sandia National Laboratories, and the Electric Power Research Institute published a report titled "Updating Interconnection Screens for PV System Integration," in which they developed more highly focused screening subprocedures for the issues of unintentional islands and voltage control. Diagrams showing these processes are reproduced in Figures 7 and 8. While each entails additional steps in comparison to the capacity penetration metrics it would replace, both subprocedures employ simple yes-or-no questions and would not require detailed analysis by the utility. As such, the incremental processing burden would be minimal, while the increased targeting of grid challenges could again reduce the incidence of false positives with no impact on grid reliability.

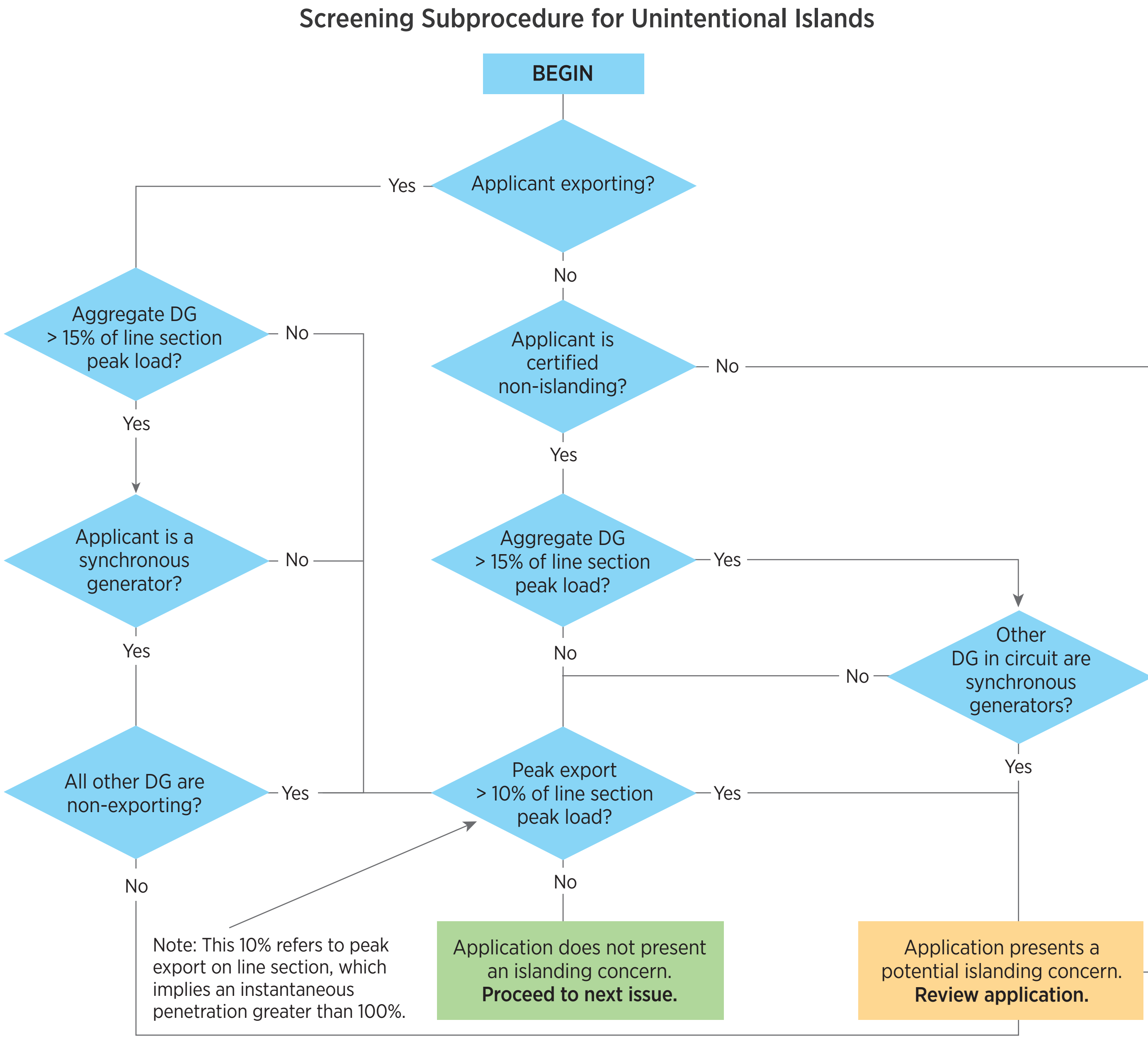

Figure 7. The subprocedure to screen for islanding risk includes new factors such as peak power exports and the presence of synchronous generators.

Alternative #3: Preemptively Analyze DG Suitability

The prior two improvements to the 15% penetration screen both accept the entire interconnection process as-is. While each improves on a component of the process, the entire arrangement is problematic from the developer perspective, as it is built on a "guess-and-check" structure, under which the developer must guess whether a site is suitable for PV, then check with a utility to determine whether that is the case.

An alternative approach would be for the utility to proactively evaluate all sites for suitability for DG PV and make those results publicly available. While such an effort undoubtedly requires more initial work from the utility and would need to be updated as more DG is added, it could be a boon to project developers, who could then avoid areas where costly studies and upgrades might be required and instead focus their efforts in low-penetration, potentially lower-cost areas. Hypothetically, such an effort could also reduce the overall utility workload; given developer desires to avoid studies and upgrades, the number of applications that trigger such activities would likely drop based on the availability of this new information. While the increased effort to produce the pre-analysis may not be entirely offset by a reduction in the burden of impact studies, there would likely be at least some corresponding reduction in overall workload. This is the rationale behind the development of interconnection capacity analysis maps in California and similar maps made public by other utilities (see Figure 9). Ironically, the primary evaluation criterion to date has been the 15% capacity penetration metric, but future analyses could present results that incorporate additional technical factors.

Alternative #4: Utilize Advanced Inverter Functionality

The terms "advanced inverters" and "smart inverters" describe solar PV inverters that can perform more functions than simply converting the DC power supplied by solar panels to AC for local use or export to the grid. Among the additional functionalities are several that can directly address the concerns that the 15% capacity penetration screen sought to ameliorate—unintentional islanding and voltage control (see Figure 10). Specifically, advanced inverters often feature enhanced island-detection capabilities along with volt-watt and volt-VAR functions that can adjust the real and reactive power output of solar PV systems to avoid over- or under-voltage violations on the electric distribution system. These functions have now been incorporated into the UL 1741 SA standard and devices are being certified to perform them safely, making this another tool in the utility's kit for integrating distributed PV (see Appendix B for more on codes and standards). In addition, these functions can be performed autonomously according to predefined parameters, eliminating the need for the utility to develop a costly communications infrastructure to control these devices directly.

Alternative #5: Make the Distribution System More Robust

The last step to manage increased distributed generation could be to simply make the distribution system more inherently robust. In practice, this could entail steps such as increasing conductor size or raising the operational voltage levels to minimize losses along a line and deploying more voltage regulation devices that closely manage the voltage along the feeder. While these approaches could raise the local "hosting capacity" for distributed PV, they are high-cost measures requiring significant capital expenditures and utility labor to implement and, as noted in Figure 5(b), will not yield benefits to solar developers unless screening procedures are updated to reflect such changes.

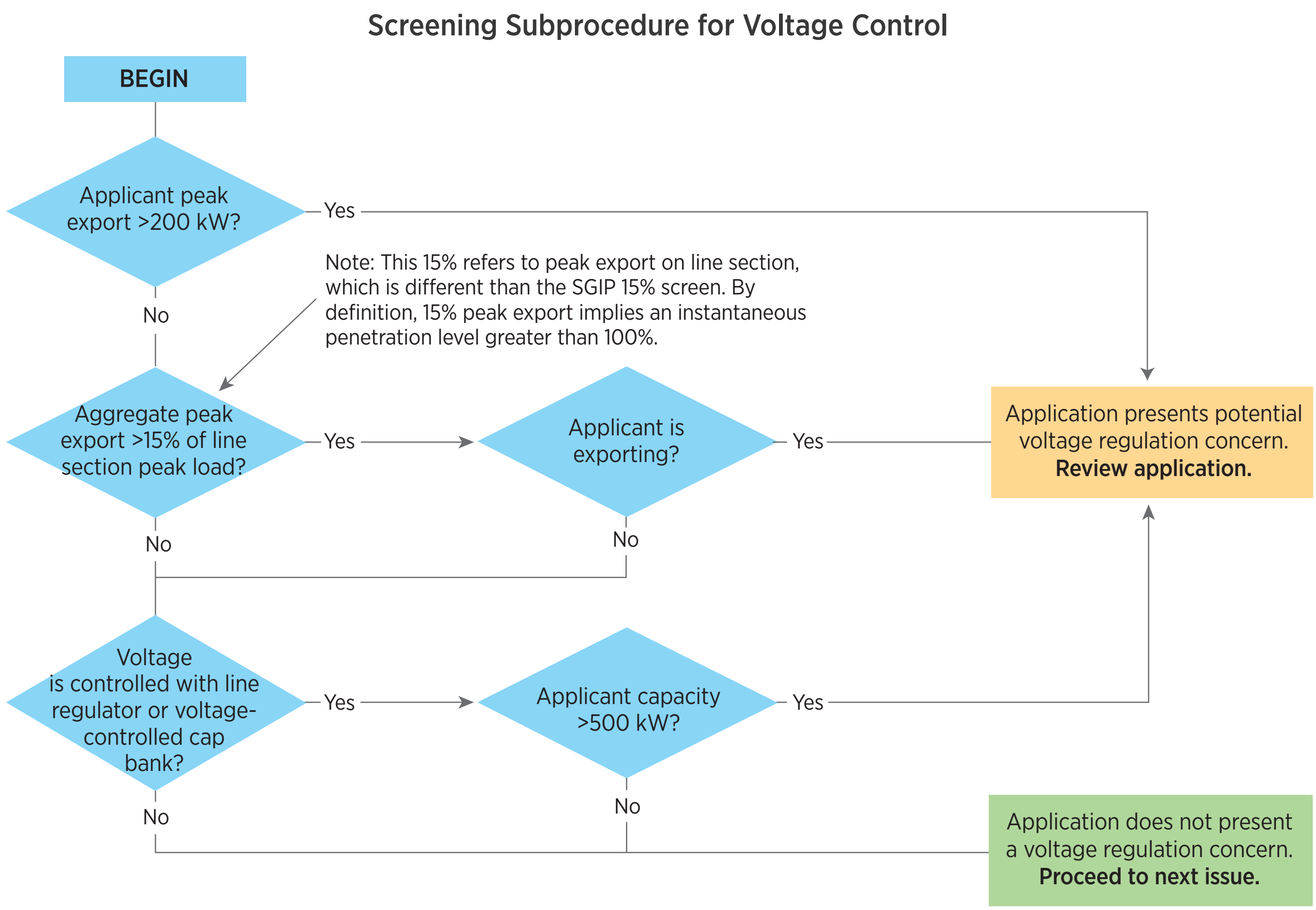

Figure 8. The voltage regulation subprocedure focuses on peak exports, system capacity, and presence of voltage regulation devices on the line section.

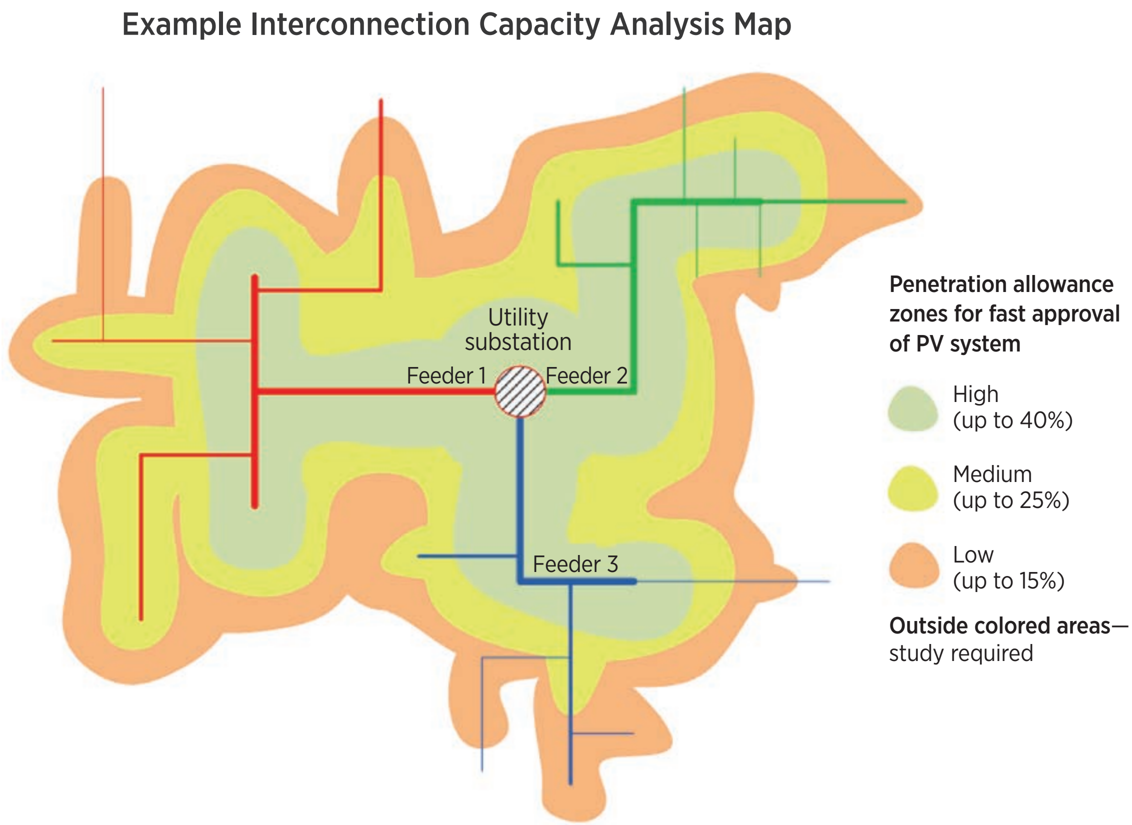

Figure 9. This conceptual diagram shows how a utility might define different allowable penetration levels based on certain locational characteristics, such as proximity to the substation, and make this information available to the public. Developers looking to avoid failing that screen and the costly impact studies that can result may choose to focus development and marketing efforts in areas with greater available capacity and likelihood of screen passage.[3]

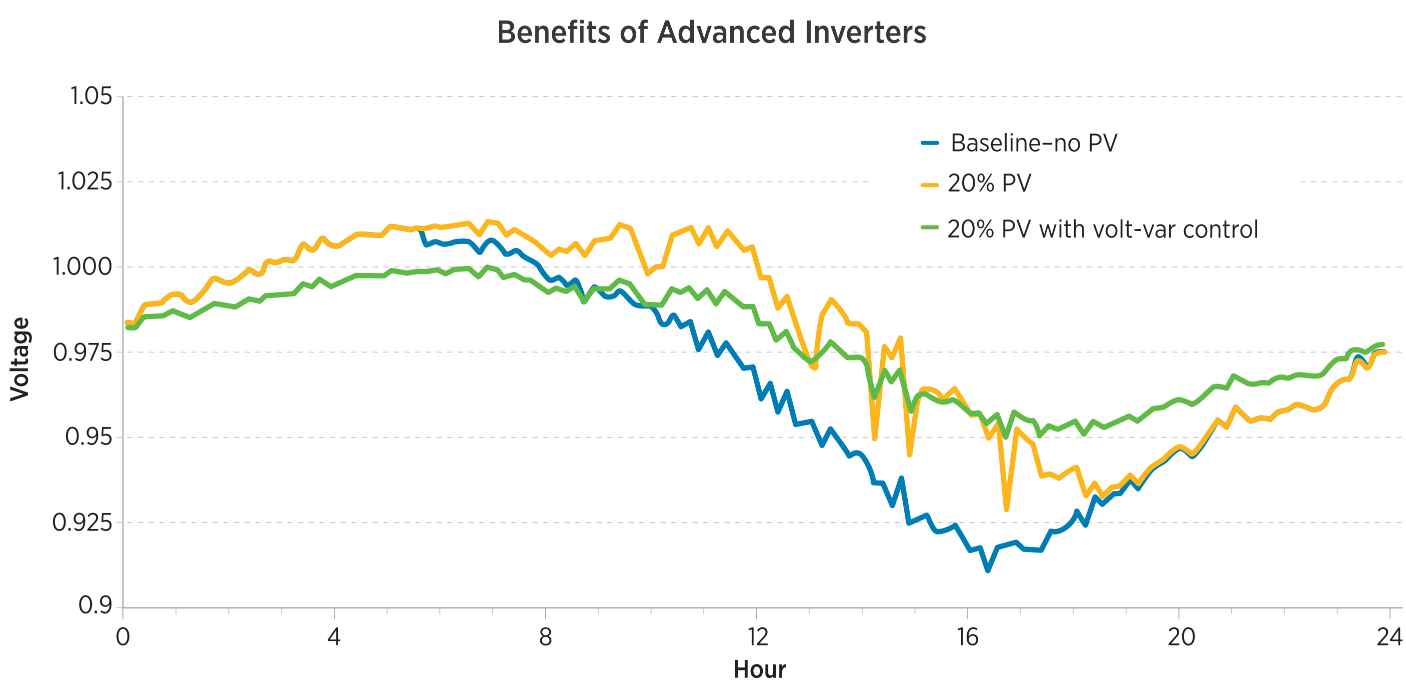

Figure 10. This chart illustrates how advanced inverters can improve voltage control over both the baseline case (blue) and the base 20% PV case (orange). As discussed above, technical screens will need to be modified in order to realize the full benefits of these enhanced capabilities.[4]

3. Coddington et al. 2012. *Updating Interconnection Screens for PV System Integration* (Technical Report), NREL/TP-5500-54063. National Renewable Energy Laboratory (NREL), Golden, CO (US). http://www.nrel.gov/docs/fy12osti/54063.pdf.

4. Ibid.

Conclusion

Interconnection technical screens, including those found in FERC's SGIP, are a set of technical questions used to identify potentially problematic distributed generation systems before they are allowed to interconnect to the utility distribution system. Failing one or more screens does not prohibit a system from interconnecting, but simply flags it for more detailed review and study. Technical screens are designed to reduce the workload on utility staff by allowing them to process more applications more quickly. Many states and electric utilities across the United States have adopted some version of the technical screens outlined in this paper.

These technical screens are an excellent starting place for electric utility interconnection specialists and engineers, and they can be used as-is or can be modified to fit the needs of the utility. As solar PV penetration grows, utilities, regulatory agencies, and other stakeholders should closely monitor the effects of the chosen technical screens on solar PV project outcomes and grid reliability. In particular, recent research has illustrated several alternatives to the 15% capacity penetration screen that are worth considering as DG penetration increases and the screen is failed by more and more projects. They include using minimum daytime load in the penetration metric calculation, overhauling metrics to better align with electrical concerns, preemptively analyzing and publishing grid-hosting capacity data, using advanced inverter technologies, and making the grid more robust. These alternatives can improve alignment between screening outcomes and actual electrical issues, increasing the success rates of solar PV projects while enabling the utility to protect power quality and grid reliability.

Acknowledgments

This paper was funded through the Energy Transition Initiative (ETI), a partnership effort between the U.S. Department of Energy, government entities, and other stakeholders that provides technical assistance and resources to support communities that want to achieve clean energy goals and transition to a clean energy economy. For additional information and questions about this paper, contact the authors, NREL's Michael Coddington (michael.coddington@nrel.gov) or Emerson Reiter (emerson.reiter@nrel.gov), or ETI Program Lead Stephen Walls (stephen.walls@ee.doe.gov).

Appendix A: Summary of the 10 Original FERC SGIP Screens

The original technical screen language is shown and is followed by comments on background, benefits, and drawbacks of each screen. A short name has been added for reference (e.g., "Subject to Tariff"); these are not original to the FERC SGIP documents. In considering these screens, it is important to remember that the systems are not prohibited if they do not pass all the screens. Instead, failing the screens only flags those particular projects for future study.

No.	Name	Original Language	Background	Advantages and Benefits	Disadvantages and Harmful Impacts
1	**Subject to Tariff**	"The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Transmission Provider's Distribution System that is subject to the Tariff."	This screen states that an application for interconnection must be made to the owner of the system that has a tariff (or rate) associated with that section, ensuring that the application is going to the correct organization. The FERC SGIP and FERC Large Generator Interconnection Procedures refer to "Transmission Provider," which is synonymous with "utility," "distribution system operator," or "electric utility provider."	While simple, this screen is critical, as many transmission providers either border other utilities (other transmission providers) or have other entities involved in the provision of energy to the applicant (e.g., energy retailers).	There are no true disadvantages to this screen, but it may be eliminated in certain locations where there are no alternatives for submission of applications (such as islands with a single transmission provider or utility).
2	**15% of Maximum Capacity Penetration**	"For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Transmission Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line."	The screen is failed if the proposed project would raise the aggregate generation capacity beyond 15% of the historical peak load.	For a detailed discussion of this screen, please see Section 2, "Focus on 15%."	

No.	Name	Original Language	Background	Advantages and Benefits	Disadvantages and Harmful Impacts
3	**Secondary Networks**	"For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW."	Spot networks are one of two types of "secondary network distribution systems" and are more difficult to interconnect with. Secondary networks utilize a specific protection device known as a network protector (NP), which is very sensitive to reverse power flow. Thus, DG systems backfeeding an NP could create an outage.	The screen allows for some smaller amounts of DG to be tied to spot networks and be able to pass the basic screen as long as the system is inverter-based.	The screen did not mention area networks, the second type of network used in the U.S. utility system, and only allows a small amount of inverter-based DG to be considered. There have been various case studies and approaches used to interconnect inverter-based DG since the original FERC order. This screen is irrelevant for utilities that have no secondary networks.
4	**Maximum Fault Current**	"The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership."	This would cap the DG contribution to maximum fault current at 10% of the total on the circuit (generally measured at the feeder breaker), a level that would not be overly disruptive of the protection design on the circuit.	This screen rightly limits the fast-track approvals of DG to maintain reliability on the circuit. Beyond this amount, more detailed study may be required.	This screen has no true disadvantages or harmful impacts; it would require a very significant amount of DG to reach 10% of the available maximum fault current, at which point more detailed study is fully justified.
5	**Short Circuit Capability**	"The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability."	The intent of this screen is to prevent the equipment on the distribution circuit from experiencing potentially damaging fault current levels. To prevent such damage, this screen requires 12.5% of the published available short circuit capability of the feeder components to be set aside as headroom.	This screen is meant to protect the distribution circuit components and maintain safety, reliability, and power quality. Beyond this amount, more detailed study may be required.	This screen has no significant or harmful impacts. Failure of this screen would rightfully trigger more detailed study.

<table>
<tr><th>No.</th><th>Name</th><th>Original Language</th><th>Background</th><th>Advantages and Benefits</th><th>Disadvantages and Harmful Impacts</th></tr>
<tr><td>6</td><td>Service to Transformer Compatibility</td><td>“Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Transmission Provider’s electric power system due to a loss of ground during the operating time of any anti-islanding function.”
<table>
<tr><th>Primary Distribution Line Type</th><th>Type of Interconnection to Primary Distribution Line</th><th>Result/ Criteria</th></tr>
<tr><td>Three-phase, three wire (Note: delta type)</td><td>Three-phase or single-phase, phase-to-phase</td><td>Pass screen</td></tr>
<tr><td>Three-phase, four wire (Note: ground Wye type)</td><td>Effectively-grounded three-phase or single-phase, line-neutral</td><td>Pass screen</td></tr>
</table></td><td>The screen ensures that the utility line type and interconnection type are compatible and will not contribute to temporary overvoltage conditions.</td><td>By preventing overvoltages, this screen ensures that interconnecting DG will not damage utility or customer equipment on that utility line.</td><td>The disadvantage of this screen lies in the time and effort for utility engineers to complete the initial evaluation to recognize incompatible systems. The interconnection process could be improved if each utility published line configurations and compatible transformer arrangements for both internal use and DG developer use.</td></tr>
<tr><td>7</td><td>20-kW Shared Secondary</td><td>“If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.”</td><td>This screen is meant to identify DG systems that share a single-phase secondary line and could potentially overload those secondary wires and devices.</td><td>As a “one-size-fits-all” approach, it is effective at flagging systems that could overload the secondary line.</td><td>While this screen focuses on service drop wire overload prevention, a more accurate screen would incorporate two factors: (1) 100% of the transformer nameplate rating and (2) the standard service drop wire size to each single-phase customer (or the smallest size standard service drop conductor capacity). Each utility could use these factors to ensure that the DG system would not overload the secondary wires or the service transformer.</td></tr>
</table>

No.	Name	Original Language	Background	Advantages and Benefits	Disadvantages and Harmful Impacts
8	**Split Neutral 20% Limit**	"If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer."	This screen was designed to protect transformers and service equipment in the event that DG systems tie to half the system (typically, one of the two 120-volt legs and neutral). DG systems that use half the service voltage may impact components on the utility and consumer sides of the meter and could potentially reduce reliability and safety.	This is meant to catch interconnections that may overload the service equipment or transformer.	Few DG systems are designed to tie to one of the two lines on a transformer, so this screen is rarely triggered. One way to replace this screen (or ensure that it will be passed) would be to modify the interconnection standards to require the DG system to use both lines on a 240-volt service, thus making it fully compatible and ensuring that it would not use the neutral in the circuit.
9	**Transient Stability Limitations**	"The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection)."	This screen is meant to protect utility areas that have preexisting transient stability issues that may, if disturbed, create other reliability and equipment problems.	This screen is meant to protect sensitive utility systems where power quality problems may be a risk.	Utilities with such transient stability issues should seek to address these issues, independent of any potential DG interconnections to their system. In the interim, they should publish any limitations due to transient stability via maps.
10	**Construction of Facilities**	"No construction of facilities by the Transmission Provider on its own system shall be required to accommodate the Small Generating Facility"	This screen simply states that no construction should be required to approve and install a DG system.	This is a reasonable screen that limits fast-track approval to systems that don't require system upgrades or other construction.	This screen does not precisely define "construction" or place any limit on construction costs. On one hand, it seems unfair for a facility that requires utility equipment to "catch up" to modern utility standards to fail this screen. On the other, construction that is explicitly required to accommodate the facility is an ideal reason to trigger more detailed study. Defining potential exceptions would improve this screen.

Appendix B: Summary of Interconnection Standards and Supporting Codes

Every jurisdiction considering distributed generation, such as solar PV, must have a strong foundation of grid codes and standards in order to have a safe, reliable, and affordable clean energy program. The following four sets of technical standards and codes have been widely incorporated into the state-level interconnection standards in the United States. Taken together, they form a solid foundation for regulating DERs.

IEEE 1547

The IEEE 1547 family of standards is the critical foundation for distributed generation interconnection to the electric utility distribution grid. The standard establishes criteria and requirements for how DERs can interact with the local electric power systems. The full family of standards provides requirements relevant to the performance, operation, testing, safety considerations, monitoring, and maintenance of the interconnected distributed generation system.

UL 1741

In the United States, UL 1741 is the equipment safety standard all inverters and converters must meet to be certified. UL 1741 is harmonized with IEEE 1547 and with IEEE 1547.1, the testing substandard in that group. UL 1741 ensures that every inverter is manufactured, programmed, and tested to safely perform its allowed functions. Inverters without the proper UL 1741 label should never be permitted or operated on any electric power system. In September 2016, UL 1741 published a Supplement A (known as UL 1741 SA) to the existing standard that allows for testing and certification of the safety of inverters while performing advanced functions such as high- and low- frequency ride-through and volt-VAR control.

NEC

The NEC is the national electrical building code to which all PV and DG systems should be designed, built, and operated. All PV systems should be designed to follow NEC requirements and, when completed, inspected to ensure that all NEC requirements have been followed. The NEC contains several articles specific to PV, such as Sections 690.4 (B), 690.35 (G), and 705.4, but also contains many articles specific to the design of the noninverter electrical systems, such as conductors and conduits, fuses and other protection, grounding, etc.

ANSI C84.1

The ANSI C84.1 standard is adhered to by most electrical utilities and is used to set guidelines for maintaining voltage levels within tolerances that will support the integrity of the utilization equipment served by the electric power system. The ANSI C84.1 "Range A" is most often used to set the parameters to be "*nominal voltage +/- 5%.*" Equipment will perform best when operated inside Range A, and may be damaged if operated outside that range for an extended time (see ANSI C84.1 for specifics). PV systems have the potential to impact voltage levels, typically causing higher voltages, and ANSI C84.1 helps define the range for proper operation of all utilization equipment and distributed generation.

ENERGY TRANSITION INITIATIVE
Islands

The Energy Transition Initiative leverages the experiences of islands, states, and cities that have established a long-term vision for energy transformation and are successfully implementing energy efficiency and renewable energy projects to achieve established clean energy goals. Through the initiative, the U.S. Department of Energy and its partners provide government entities and other stakeholders with a proven framework, objective guidance, and technical tools and resources for transitioning to a clean energy system/economy that relies on local resources to substantially reduce reliance on fossil fuels.

Learn more at www.energy.gov/eere/energy-transition-initiative.

DOE/GO-102017-4946
April 2017