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ACRONYMS

CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
DG	Distributed generation
FERC	Federal Energy Regulatory Commission
FIT	Feed-in tariffs
GW	Gigawatts
IEEE	Institute of Electrical and Electronics Engineers
ISP	CAISO Independent Study Process
kV	Kilovolts
kVA	Kilovolt-Amps
MW	Megawatts
MWh	Megawatt hours
PCC	Point of Common Coupling
PG&E	Pacific Gas & Electric
PV	Photovoltaic
RPS	Renewable Portfolio Standards
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SEPA	Solar Electric Power Association
SGIA	Small Generator Interconnection Agreement
SGIP	FERC Small Generator Interconnection Procedures
UETA	Uniform Electronic Transaction Act
WDAT	Wholesale Distribution Access Tariffs

EXECUTIVE SUMMARY

This report recommends reforms to federal and state interconnection procedures to meet the demands of a growing national marketplace for solar photovoltaic (PV) and other small renewable generators that interconnect to electric distribution systems. Updating federal and state interconnection processes can have a significant, positive impact on the efficiency and transparency with which renewable energy systems are interconnected nationwide, which in turn can have a significant impact on the cost of meeting state policy goals. For instance, with increasing interconnection applications, recent experience shows many applications at the distribution system-level do not actually go forward to implementation. Thus, reforming interconnection procedures may indeed make the process more effective for everyone involved – system owner and integrators, as well as the electric utilities.

Interconnection processes serve two fundamental purposes: 1) they provide a transparent and efficient means to interconnect generators to the electric power system; and 2) they maintain the safety, reliability and power quality of the electric power system. Federal and state regulators are faced with the challenge of keeping interconnection procedures updated against a backdrop of evolving technology, new codes and standards, and considerably transformed market conditions. This report is intended to educate policymakers and stakeholders on beneficial reforms that will keep interconnection processes efficient and cost-effective while maintaining a safe and reliable power system. Although the discussion in this report focuses on PV, which is the dominant generating technology presently seeking interconnection to electric distribution systems, the interconnection reforms recommended in this report apply to all generating technologies.

Section 1 of the report provides a concise history of the major activities that helped shape the national landscape for interconnection procedure development between 2000 and 2006. Section 1 highlights the development of statewide interconnection procedures for small generators in California in 2000; the development of Institute of Electrical and Electronics Engineers (IEEE) Standard 1547: *The Standard for Interconnecting Distributed Resources With the Electric Power System* in 2003; the Federal Energy Regulatory Commission's promulgation of Small Generator Interconnection Procedures (SGIP) in 2005; and the federal Energy Policy Act of 2005 and its impact on state consideration of interconnection policies to facilitate growth in distributed energy resources.

Section 2 outlines three substantial market evolutions since 2006 that have triggered the need for interconnection reform across the United States. These new market conditions include: 1) tremendous growth in solar PV markets, prompted by state renewable energy goals; 2) an increase in generating system sizes and generators that do not primarily serve onsite load; and 3) growing areas of high solar penetration that raise new considerations for both utilities and developers in managing further development.

Section 3 discusses specific modifications worth considering, including expanding the amount of information made available to developers in a pre-application report process;

increasing the efficiency with which interconnection applications are processed, particularly for very small generators; updating initial technical review screens to increase the reliability and safety of interconnections; providing a supplemental review process for projects that fail initial review screens; and streamlining the study process to make more efficient use of utility resources and spread system upgrade costs across interconnection applicants.

Section 4 recaps and summarizes the recommendations provided in Section 3.

Attachment 1 provides California Rule 21 Supplemental Review Screens (Rule 21 G.2)

INTRODUCTION

By 2015, the United States will need to interconnect more than 30,000 MW of new renewable generating capacity to meet existing state and federal renewable energy policy goals.[1] By 2035, the additional generating capacity needed to satisfy existing policy goals increases to 100,000 MW.[2] Already, state and federal policies are promoting nearly 1,900 MW of solar PV installations annually.[3]

State and federal interconnection policies, which clarify the steps and responsibilities for interconnecting new generating facilities to the nation's electric power system, have a direct and substantial impact on the timing and cost of bringing new generating capacity online. An effective interconnection process, which contributes to lowering the cost of interconnection and therefore the overall cost of developing new capacity, facilitates market entry by smaller generators, increases wholesale market competition, and encourages investment in needed generating capacity and electric transmission and distribution system infrastructure.[4]

Ensuring that federal and state interconnection processes are adequate is a necessary step to achieving these goals. However, the effort required to update interconnection policy can overwhelm even a well-resourced regulatory agency. Interconnection policies address complex, technical issues, and the utilities and developers that engage in the process often have divergent views about the goals the process should aim to achieve.

Utilities are responsible for maintaining the safety and reliability of electric power systems. Many are liable to regulators for their failure to do so. From a utility standpoint, the interconnection of even a small generator can raise potential safety and reliability impacts that may need to be addressed. Utilities are thus inclined to want sufficient time to process interconnection applications to protect against any diminution in safety, reliability and service quality that may expose the utility to increased levels of risk. If there is any possibility for reliability or safety impacts, utilities will want to study those impacts to determine appropriate protective or mitigating measures.

For developers, the interconnection process is one of the most time-consuming and costly aspects of developing a generating facility. Frequently, developers claim that the process is opaque and consists largely of internal utility business practices such that implementation varies drastically from utility to utility.[5] Moreover, this lack of transparency and certainty introduces significant development risk. Delays in the interconnection process slow development and may undermine access to valuable tax incentives and utility solicitations.

Developers typically want greater access to information about the electric power system so they can better determine lower-cost, lower-impact places to interconnect. They also want more certainty and transparency regarding the cost and timeline for processing interconnection studies and greater justification by utilities as to why any interconnection upgrade requirements mandated by them are indeed necessary.[6]

Regulators are faced with the often challenging task of balancing these divergent perspectives to find "win-win" solutions that allow utilities to maintain the safety and reliability of electric power systems while providing developers a transparent, efficient, and cost-effective process that operates on reasonably predictable timeframes. Regulators are also faced with the challenge of keeping interconnection processes up to date against a backdrop of evolving technology, updates to relevant codes and standards, and changed market conditions.

Over the past decade, the combination of increasing electricity prices, decreasing cost of small generator technology, and strong financial incentives for renewable energy has triggered states such as California, Colorado, Hawaii, Massachusetts, New Jersey, and others to experience high volumes of interconnection applications and, in certain areas, high penetrations of solar PV and other renewable generators on their electric distribution systems. In these states, increased market interest in small to medium scale renewable projects has overwhelmed existing interconnection processes, leading to bottlenecks and significant delays.[7] Regulators have been called upon in those states to update interconnection policies to keep pace with the changed market conditions.

To assist with a reevaluation of existing interconnection policies, the National Renewable Energy Laboratory (NREL), United States Department of Energy, Sandia National Laboratories, and the Electric Power Research Institute published a February 2012 report titled *Updating Interconnection Screens for PV System Integration* ("*Interconnection Screens Report*").[8] The *Interconnection Screens Report* makes recommendations to improve the screening process for interconnection applications, with a focus on a ubiquitous 15% penetration screen that is found in many federal and state interconnection processes.[9] This screen is perceived as a significant barrier to PV deployment by many solar developers and other stakeholders.[10]

Recognizing the 15% screen as a perceived barrier to reaching higher penetrations of deployed solar PV systems, the *Interconnection Screens Report* makes short, medium and long-term recommendations to update this screen. The short-term recommendations include simple modifications to the screening process to include PV-specific screening criteria that better account for the daytime generating profile of solar PV. Longer-term solutions require cooperation among regulatory and governmental agencies, utilities, PV developers and others to work toward more widespread interconnection reform.

This paper follows up the *Interconnection Screens Report* to discuss ways in which state and federal regulators have recently reformed interconnection processes in light of changed market conditions, looking beyond just the 15% penetration screen. Relying on state practices and the *Interconnection Screens Report's* technical recommendations, this paper offers practical suggestions for updating state and federal interconnection policies. Recommendations in this paper focus on:

- Improved access to information about distribution system conditions at points of interconnection that enable applicants to self-screen projects in a manner that reduces applications for interconnections in certain areas
- Increased efficiency in the application process for very small, certified inverter-based systems that pose a low likelihood of adverse system impacts of the sort that require extensive study
- Modified fast track technical screens to accommodate generators interconnecting under new procurement programs and new renewable energy policies
- Expanded use of supplemental review for higher-penetration scenarios
- Improvements in the interconnection study process to streamline review and allow for efficiencies in processing applications.

Where appropriate, this paper suggests model interconnection procedure language to help inform decisions of federal and state regulators exploring this topic.

1. HISTORY OF SMALL GENERATOR INTERCONNECTION PROCEDURES

Existing interconnection processes for small generators were largely developed between 2000 and 2006 with few significant updates since that time. Prior to 2000, few states had uniform interconnection procedures. Instead, utilities regularly determined the procedural requirements that would govern the interconnection process on a case-by-case basis.[11]

For lack of another proven approach, many utilities applied interconnection procedures they had in place for qualifying facilities under the federal Public Utility Regulatory Policies Act of 1978. These procedures were largely designed for facilities interconnecting to high-voltage transmission lines and were often more cumbersome and expensive than what was needed for smaller facilities interconnecting to low- and medium-voltage distribution lines.[12] This created inefficiencies in which lengthy and costly studies were often required only to determine that upgrade costs would make a generator financially infeasible. This was particularly problematic for modestly-sized residential and commercial solar PV systems that were primarily intended to serve onsite energy needs.

A series of developments from 2000 to 2006 led to a rapid evolution in the development of standard interconnection processes for small generators interconnecting to distribution systems. This section provides an overview of the rapid evolution and deployment of interconnection procedures in the U.S. during that period.

December 2000: California's Rule 21

In 2000, California was among the first states to adopt comprehensive procedures for distribution system interconnections when the California Public Utilities Commission adopted Rule 21.[13] Rule 21 implemented a screening process through which utilities could easily and objectively review an interconnection application to determine whether further studies or additional protective measures may be required. The initial review screens were designed primarily to ease the interconnection process for generators intended to serve onsite load. Rule 21 also included timelines to ensure the interconnection process would move forward in a timely manner.

Since California was among the first states to thoroughly address the interconnection process for a distribution system interconnection, the state's Rule 21 served as a basis for the development of technical standards, federal rules and other state procedures in subsequent years.

June 2003: IEEE 1547 Standard

In 2003, the IEEE developed technical Standard 1547: *The Standard for Interconnecting Distributed Resources with the Electric Power System.* Standard 1547 provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of distributed generation (DG) interconnection with electric power systems. Specifically, it provides comprehensive guidelines for "responses to abnormal conditions, power quality, islanding, and test specifications and requirements for design, production, installation evaluation, commissioning, and periodic tests."[14] It was developed through an extensive, consensus-based stakeholder process and has since received widespread support and has informed the technical requirements found in federal and many state interconnection policies for small generators.

The IEEE 1547 standard is not a single static standard. However, it is the first in a family of standards, with the intent that later IEEE 1547.1 through .8 standards be used in conjunction with standard IEEE 1547. The evolving series of IEEE 1547 standards include IEEE subgroups currently developing guidance and recommended practices: a) to determine the appropriate criteria, scope and extent of distribution impact studies for distributed resource interconnections, and b) to address changes to the current standard to accommodate high penetrations of intermittent generators. These will be standards 1547.7 and 1547.8 respectively. Although this work will undoubtedly inform future modifications to state and federal interconnection processes, there is much in the way of screening and processing of interconnection applications that IEEE standards do not address.

A notable limitation of the 1547 standard is that it does not address technical considerations defining the maximum allowable amount of generation beyond the point of common coupling—the point at which one generating facility is physically interconnected to the utility electric power system.[15] Standard IEEE 1547 does not address operations and impacts upstream or downstream from that point. In addition, it does not address non-technical issues such as the timeframe or cost of interconnection..

These issues are left to the determination of regulators in the development of interconnection processes and other valuations.

May 2005: FERC Small Generator Interconnection Procedures

In 2005, the Federal Energy Regulatory Commission (FERC) adopted Small Generator Interconnection Procedures (SGIP) and a corresponding Small Generator Interconnection Agreement (SGIA).[16] The SGIP and SGIA are based on FERC's Large Generator Interconnection Procedures and Agreement, but apply to generating facilities of 20 Megawatts (MW) in capacity or less.[17]

The FERC SGIP was vetted by a broad range of industry participants and adopted through FERC Order 2006 in May 2005, and Orders 2006-A and 2006-B in the subsequent year.[18] The SGIP and SGIA apply to FERC jurisdictional interconnections, including facilities that a) interconnect to FERC-jurisdictional transmission systems, or b) interconnect to FERC-jurisdictional distribution systems to sell wholesale generation in interstate commerce (e.g. a wholesale generator is already interconnected with the specific distribution line and the distribution line is covered by a FERC-approved Open Access Transmission Tariff).

SGIP includes three levels of review: Level 1 is a simplified screening process for certified inverter-based systems less than 10 kilowatt (kW); Level 2 is a "Fast Track Process," for eligible generators no larger than 2 MW; Level 3 is a "Study Process" for all other systems 20 MW or less. SGIP applies ten interconnection screens for the first two review levels, including the previously noted screen that requires an interconnection study for generators that cause aggregate generation capacity to exceed 15% of annual peak load on a line section of a radial distribution circuit.

SGIP was developed both to govern FERC-jurisdictional interconnections and to serve as a model that state regulators may use as a starting point for developing their own interconnection procedures and agreement.[19]

August 2005: Energy Policy Act of 2005

A survey in 2000 by NREL found that virtually all distributed-generation projects met some sort of resistance from utilities when they try to interconnect with the grid.[20] Partly in response to that finding, Congress included Section 1254 in the Energy Policy Act of 2005 (EPAct '05), which required state regulatory commissions and certain non-regulated utilities to consider adopting interconnection procedures based on the IEEE 1547 Standard and current "best practices."[21]

At least 31 states adopted or amended their interconnection processes in some form or another in the years following the enactment of EPAct '05.[22] Many of these states modeled their interconnection policies on FERC's SGIP. A few Western states modeled their procedures on California's Rule 21.[23] It is not clear whether these policies were adopted as a result of federal law. It is evident, however, that EPAct '05 had a significant impact by raising awareness about interconnection issues and by spurring dialogue at a state regulatory level. As of August 2012, 43 states plus the District of Columbia and Puerto Rico had adopted interconnection policies.[24]

2. INTERCONNECTION NEEDS GOING FORWARD

Many key steps in the development of standard interconnection processes for small generators occurred prior to 2006. As the U.S. market for solar PV technologies and small renewable generators has diversified and expanded in recent years, it has become increasingly important to reevaluate and update existing interconnection processes to properly accommodate and encourage this growth now and into the future without compromising the safe and reliable operation of the nation's electric power systems.

The growth and expansion in the solar market has largely been a result of the widespread adoption of state Renewable Portfolio Standards (RPS) over the last decade. Most of the country's 30 RPS policies have been established or considerably expanded since 2005,[25] and 17 of these policies include a solar or DG carve-out.[26] Available data shows that by 2010, national RPS obligations extended to half of the retail electric load consumed in the United States[27] and required utilities to generate or purchase close to 100 million Megawatt hours (MWh) of renewable and alternative energy generation.[28]

To meet new demands for solar energy generation, state policies have expanded traditional mechanisms that supported smaller customer-owned installations, such as residential rooftop PV, to include larger systems that supply multiple customers. For example, since 2005, community solar programs have emerged in at least 15 states.[29] Definitions of community solar vary from state to state, and even from project to project, but generally speaking, community solar programs allow multiple customers to receive benefit from, or assume shared ownership of, a single solar system. Most community solar installations have been large, ground-mount systems, with little or no onsite load being served.

Solar policies have also expanded to include wholesale programs designed to encourage power exports to the electric power system. These wholesale generators may serve little or no onsite load. Wholesale policies aimed at DG have expanded rapidly over the past five years and include feed-in tariffs (FIT), auction mechanisms, and competitive solicitations. By 2010, 7 of the top 10 states for installed solar capacity had one or more types of wholesale DG programs.[30] In the last few years alone, California has authorized almost 3 gigawatts (GW) of DG procurement programs, mostly through requests for proposals, auctions, and FIT programs.[31]

As a result of the growth in DG procurement programs, many utilities across the nation have experienced an increasingly high volume of interconnection applications, both for large and small generators. In 2005, only 79 MW of grid-connected PV capacity was installed across the United States. Five years later, the grid-connected solar PV capacity installed in just one year totaled 878 MW,[32] over ten times the cumulative amount installed just five years earlier and double the capacity that had been installed the prior year. Annual grid-connected PV capacity more than doubled again in 2011 to 1,845 MW (see Figure 1 below), which brought the grid-connected PV capacity in the United States to 4,000 MW by the end of that year.[33] That is a 500% increase in 7 years.

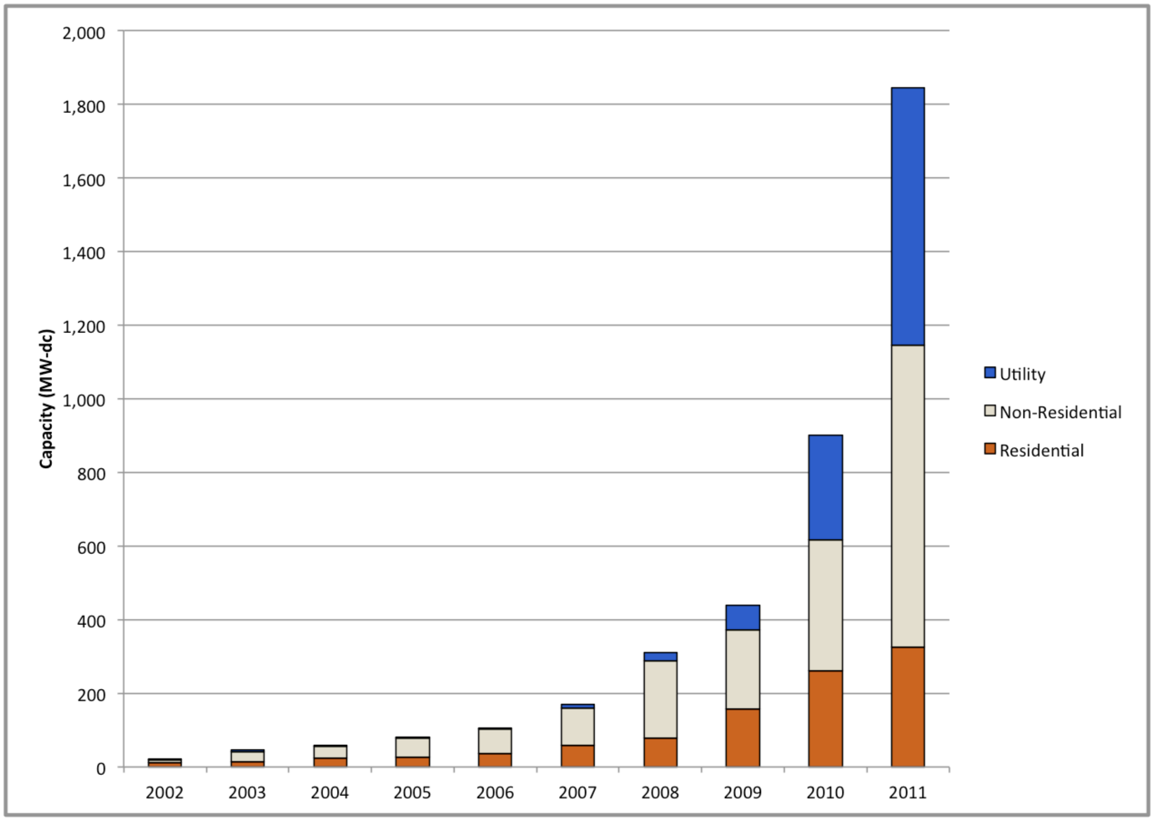

Figure 1. Annual Installed Grid-Connected PV Capacity

Solar Electric Power Association (SEPA)'s 2011 Utility Solar Rankings report describes the incredible undertaking this can mean, particularly for utilities in the top solar states:

> "Utilities are adapting to solar as their fastest growing electricity source. In 2011, utilities interconnected over 62,500 PV systems, 89% of which were residential homes, and which was a 38% growth over 2010. Thirteen utilities interconnected more than 1,000 PV systems and 22 interconnected more than 500 systems. To put this in perspective, about 350 non-solar power plants (> 1 MW) were expected across the entire U.S. in 2011. This annual volume of smaller, distributed solar interconnections is unlike anything the utility industry has previously managed, and conservative forecasts indicate that this number will grow to more than 150,000 interconnections in 2015."[34]

Although dramatic, the installed-capacity figures for solar PV do not fully convey the total number of interconnection applications being received by utilities in states with robust renewable energy policy requirements. Many interconnection applications do not lead to installed capacity because the applicants abandon project development after learning that expensive upgrades may be needed. Thus, the number of interconnection applications—and the work associated with every interconnection application—can greatly exceed both the total installed capacity and the number of systems that are ultimately interconnected. For example, the California Independent System Operator claims its queue has four times the amount of new generating capacity than is necessary to meet California's 33% RPS goal, and it expects 75% of projects currently in the queue will not be completed.[35]

As the amount of installed PV and DG capacity has increased, utilities have begun to experience high penetrations of PV on areas of their distribution systems. Continued rapid growth in solar and DG markets will inevitably result in more areas with a high penetration of DG resources. There is no technical consensus on the percentage of DG resources that defines high penetration on a given utility distribution feeder. Moreover, the impact of DG on the distribution system varies according to factors such as a) the type of resource, b) the expected performance of the resource, c) the usage patterns of customers on the distribution feeder, and d) the location of the DG on the feeder.

From an engineering perspective, a circuit has reached "high penetration" when utility engineers determine that upgrades need to be made to the circuit before additional generation can be installed. There are no absolute technical limits to grid penetration. However, many utilities and research organizations around the country have begun studying the impact that high-penetration PV is having, or may have, on electric power systems in their regions.[36] For example, Hawaii's Kauai Island Utility Cooperative has been testing a 1.2 MW PV project that supplies up to 90% of a distribution circuit's demand and has not experienced any disruption to the overall power quality on that circuit.[37] This is an important preliminary finding, given that Hawaii has an RPS mandate to achieve 40% renewable energy by 2030—the most ambitious in the country.[38]

Although most utilities do not publish information about penetration levels on their distribution feeders, it is clear that several regions of the country are already experiencing high penetration due to the sheer volume and concentration of DG that has interconnected or is requesting interconnection. In SEPA's 2011 Utility Solar Rankings report, the authors noted that, "[t]he nation's most solar active utilities integrated almost 1,500 megawatts (MW-ac) of new solar, equivalent to six natural gas power plants…"[39]

It is also clear that these high penetration solar regions have expanded beyond just California and are now moving into Eastern states. In 2008, 93% of the nation's total annual solar capacity was installed in the Western region. By 2011, however, Western states held only 61% of the nation's annual installed solar capacity,[40] and only two California utilities were among the top ten for Cumulative Solar Watts-per-Customer (see Figure 2 below).[41]

2011	2010	Utility	Watts (AC)
1	Not Ranked	Vineland Municipal Electric (NJ)	991.2
2	5	Maui Electric Co. (HI)	209.3
3	66	Blue Ridge Mountain EMC (GA)	194.7
4	11	Atlantic City Electric (NJ)	185
5	2	Kauai Island Utility Co-op (HI)	179.1
6	18	Arizona Public Service - APS (AZ)	176.3
7	1	Southern California Edison (CA)	151.9
8	117	Fayetteville Public Utilities (TN)	150.1
9	9	Hawaiian Electric Co. (HI)	148.5
10	6	Pacific Gas & Electric (CA)	146.2

Figure 2. 2011 Cumulative Solar Watts-per-Customer

As U.S. and individual state energy needs grow and evolve, it has become increasingly important for regulators to revisit and update interconnection procedures to ensure they remain adequate in the face of a dynamic and growing market. In 2011, the California Public Utilities Commission (CPUC) opened a rulemaking to re-examine California's Rule 21 interconnection procedures in light of changed market conditions, stating:

> "…when a generator seeks to primarily offset on-site load, interconnection under the existing Rule 21 generally occurs efficiently. In contrast, generators seeking to export a portion or all of their generation to the utility's distribution system lack a straightforward means of interconnection under the effective Rule 21. Exporting generators eligible to use Rule 21 as the interconnection tariff include those participating in a number of procurement programs administered by the Commission, including the renewable feed-in tariff, the efficient combined heat and power feed-in tariff and Qualifying Facilities up to 20 megawatts."[42]

Several other states such as Hawaii, Massachusetts, and New Jersey have engaged in similar interconnection reform processes. Many of the reforms being considered are an attempt to accommodate the influx of interconnection applications being filed by participants in programs implemented to meet state policy goals. In Hawaii, a multi-party stakeholder process convened from 2010 to 2011 produced a broad range of recommendations to reform Hawaii's Rule 14H interconnection process. Likewise, the CPUC-initiated rulemaking from 2011 led to a broadly-supported proposal put forth by a range of parties, including California's three largest investor-owned utilities, to significantly overhaul the California Rule 21 interconnection process. Efforts to reform state interconnection processes in Massachusetts and New Jersey were ongoing as of this publication. Not surprisingly, these states have a diverse and rapidly-growing solar market and have experienced the most pressing need to address interconnection reform.

3. DISCUSSION OF POSSIBLE SGIP MODIFICATIONS

With the exception of the handful of states and utilities that have recently updated their interconnection processes, most existing interconnection processes were implemented prior to significant changes in the solar market that have occurred over the last seven years, and were designed for lower penetrations that are increasingly being reached.

The FERC SGIP process and the state processes modeled after SGIP provide a reasonably cost-effective and efficient process for small DG at penetrations up to 15% of peak load on a distribution feeder. However, the SGIP process becomes more expensive, time consuming, and less certain once that penetration level is reached. In many parts of the country, this penetration has been reached, and the *Interconnection Screens Report* notes that the lack of a well-defined process for interconnecting generators to the distribution system at higher penetrations has become a barrier to continued PV system deployment.[43] Some developers have claimed that some utilities are closing feeders to new interconnections after 15% of peak load penetration is reached.[44]

Interconnection procedures must be updated if they are to continue to provide an efficient and cost-effective process for interconnecting small generators. A well-designed interconnection process allows utilities to maintain the safety and reliability of the electric power system while providing a transparent, efficient, and cost-effective process that operates on predictable timeframes. Such a process can lower the cost of developing new generating capacity, facilitate market entry by smaller generators, increase wholesale market competition, and encourage investment in needed infrastructure.

SGIP has been an influential interconnection model in the United States. It has been incorporated into the tariffs of FERC-jurisdictional utilities and therefore has a foothold in nearly every state within the continental United States. Also, many states have used SGIP as a template for the development of their state interconnection processes. SGIP's three levels of review were incorporated into interconnection procedures in numerous states across the U.S. including, but not limited to, Colorado, Connecticut, Florida, Indiana, Maine, Michigan, Oregon, New Jersey, New Mexico, New York, North Carolina, Ohio, Utah, and Virginia.[45] Many states also use screens that are based on, or are very similar to, those used in the SGIP Fast Track.[46]

Because SGIP has been widely adopted and very influential, it is an appropriate focus for a discussion about interconnection reform in this report. In light of significant changes in the marketplace over the last six years, modifications to SGIP and the state processes modeled on SGIP will help ensure the interconnection process remains relevant in the face of a rapidly-evolving marketplace and will ensure continued open access for small generators. Updates to SGIP will also ensure that SGIP continues to serve as a relevant model for state policymakers to use in updating state interconnection processes.

The following sections examine key components of the SGIP process and discuss potential improvements and/or areas that warrant further study to respond to the increased volume and high-penetration scenarios discussed above. The "Pre-application Information" section discusses the information presently available to an applicant prior to submitting an interconnection request, and possible ways to increase access to relevant information to enable applicants to pre-screen suitable locations. This information would, in turn, reduce the number of applications utilities may need to process for projects in locations that are not likely to be financially viable.

The subsequent three sections focus on the three levels of SGIP review: the Level 1 10 kW Inverter Process, the Level 2 Fast Track process for generators 2 MW or less, and the Level 3 full Study Process for all other generators up to 20 MW in capacity. These sections highlight areas of SGIP that may be creating inefficiencies in the interconnection process or provide inadequate screening for potential technical issues. Where possible, each of these sections discusses modifications that have been approved by FERC or state regulatory agencies.

PRE-APPLICATION INFORMATION

As markets for solar PV and DG grow, utilities are increasingly being faced with lengthy interconnection queues. However, a significant number of projects in the queue drop out after they receive study and/or Fast Track results, or other conditions make it apparent that a proposed interconnection is not economically viable. The number of dropouts is likely to increase as higher penetrations are reached and fewer generators are able to interconnect without triggering expensive upgrades.

One method to avoid interconnection queues being clogged with projects that may ultimately prove unviable is to provide potential applicants with additional information about system conditions at a proposed point of interconnection in advance of an application being submitted. If applicants have access to additional utility-supplied information, they may be able to avoid filing speculative interconnection requests and can relieve some of congestion in utility interconnection queues. Additional information may also facilitate more efficient use of the existing electric power system by helping identify areas with available capacity where interconnections may proceed at lower cost with no or few upgrades.

SGIP Section 1.2 currently provides potential applicants with the option of requesting information on the electric system at a proposed point of interconnection:

> "Electric system information provided to the Interconnection Customer should include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Transmission Provider's Transmission System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements."

However, Section 1.2 does not provide a timeframe for when information must be provided in response to a request or the level of detail about a proposed point of interconnection that a potential applicant can expect to receive.

California has taken two important steps in providing additional information about proposed points of interconnection to potential applicants. First, as part of revisions to

California Rule 21, a pre-application report would allow developers to request specific system information about a proposed point of interconnection for a $300 fee.[47] A developer must provide sufficient information to clearly identify the proposed point of interconnection. Once a request is received, a utility must provide the information within 10 business days of a request. The type of information that Rule 21 requires utilities to provide, where available, includes total, queued, and available circuit capacity, line voltage, distance of proposed point of interconnection to substation, peak and minimum load data, and, number of phases available at site.[48]

The revisions to California Rule 21 only require a utility to provide pre-existing information, meaning the utility is not required to conduct any new analysis in order to respond to a request. The information provided is also understood to be subject to change prior to an application being submitted. Conditions on the electric power system are dynamic, and thus the information provided may be outdated by the time an application is submitted.

In addition to the pre-application report, the CPUC has required utilities to publish maps of their distribution systems that identify areas with capacity available. Hawaii has taken a similar approach in providing information via online maps on the penetration levels that have been reached on distribution circuits. These maps enable developers to screen wider areas for potentially good locations for interconnection. Though they do not provide sufficient detail to accurately predict the outcome of application of the Fast Track screens, they provide a useful initial screening tool. These maps may also help the utilities reduce the number of specific information requests to which they may need to respond.

The pre-application provision in SGIP currently allows for the exchange of relevant information, but does not provide specific timeframes, or allow utilities to be compensated for time spent preparing information, or provide applicants with certainty as to what information will be made available. In order to reduce the number of speculative applications and increase the efficiency of the interconnection study process for potential applicants, SGIP section 1.2 could be modified to include greater specificity.

Below, we have provided a possible modification to SGIP Section 1.2 modeled on California Rule 21 revisions:

1.2.2 In addition to the information described in Section 1.2.1, which may be provided in response to an informal request, an Interconnection Customer may submit a formal request along with a non-refundable processing fee of $300 for a pre-application report on a proposed project at a specific site. The Transmission Provider shall provide the pre-application data described in Section 1.2.3 to the Interconnection Customer within 10 Business Days of receipt of the written request and payment of the $300 processing fee.

1.2.3 Subject to Section 1.2.4, the pre-application report will include the following information:

a. Total capacity (in MW) of substation/area bus, bank, or circuit based on normal or operating ratings likely to serve proposed site.

b. Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank, or circuit (i.e., amount of generation online) likely to serve proposed site.

c. Aggregate queued generation capacity (in MW) for a substation/area bus, bank, or circuit (i.e., amount of generation in the queue) likely to serve proposed site.

d. Available capacity (in MW) of substation/area bus or bank and circuit most likely to serve proposed site (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

e. Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

f. Nominal distribution circuit voltage at the proposed site.

g. Approximate circuit distance between the proposed site and the substation.

h. Relevant line section(s) peak load estimate, and minimum load data, when available.

i. Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed site and the substation/area. Identify whether substation has a load tap changer.

j. Number of phases available at the site.

k. Limiting conductor ratings from proposed point of interconnection to distribution substation.

l. Based on proposed point of interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

1.2.4 The pre-application report need only include pre-existing data. A pre-application report request does not obligate the Transmission Provider to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the Transmission Provider cannot complete all or some of a pre-application report due to lack of available data, the Transmission Provider shall provide Interconnection Customer with a pre-application report that includes the data that is available. The provision of information on "available capacity" does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the pre-application report may become outdated at the time of submission of the complete Interconnection Request.

LEVEL 1 (10 KW INVERTER PROCESS) – POSSIBLE MODIFICATIONS

The 10 kW Inverter Process uses the Level 2 Fast Track technical screens to evaluate the safety and reliability of a proposed interconnection (see discussion on Level 2 below), but it allows qualified generators to use a shorter application that integrates an interconnection agreement.[49] This process allows a utility reviewing an application to execute and return an interconnection agreement to the customer quickly, after initial review is complete and all the Fast Track screens are passed. FERC intended the 10 kW Inverter Process to be "quick, inexpensive, and user friendly"[50] and this proposal supports those goals.

A number of states have adopted modifications to the 10 kW Inverter Process that improve the efficiency of review for very small generators. These changes are discussed below.

Possible Modification: Increase Eligible System Sizes

The SGIP 10 kW Inverter Process is intended for generators that are unlikely to trigger adverse system impacts. Inverter-based equipment has a lower likelihood of causing adverse system impacts because such equipment can quickly disconnect when a disturbance occurs.[51] Despite a reduced likelihood of adverse impacts, this process requires the same amount of technical screening as is given to generators up to 2 MW participating in Fast Track. The primary benefits of the 10 kW Inverter Process are the reduced cost and ability to submit a relatively short, combined application and interconnection agreement. These benefits accrue to both a) customers installing small, inverter-based systems, and b) utilities through the reduction in administrative time spent processing a separate interconnection agreement.

Many states feature a 10 kW Inverter Process or "Simplified" interconnection option for very small generators similar to SGIP. For example, New Mexico,[52] Pennsylvania[53] and Florida[54] provide simplified processes for systems 10 kW or less. Other states have expanded the quick, inexpensive, and user-friendly aspect of the 10 kW Inverter Process to systems of larger sizes. For example, Oregon provides a simplified process for inverter-based systems 25 kW or less that are UL 1741 certified.[55] In Oregon's case, the residential net metering eligibility limit is also 25 kW, meaning residential customers installing net-metered generation have a highly efficient interconnection path. Massachusetts provides a simplified review for systems up to 25 kW, so long as they are interconnecting using a three-phase service and meet other conditions.[56]

At the time SGIP was first adopted, most residential PV systems were well under 10 kW, but as the market has grown, so has the size of the average PV installation. Recent data shows that the size of residential systems, which still make up the bulk of the PV systems installed in the U.S., is 5.7 kW_{DC}.[57] Although the size of an average residential system is still less than 10 kW, many state programs allow for generators larger than 10 kW to net-meter. As the volume of residential interconnection applications increases, it makes sense to ensure continued administrative ease in the interconnection of these generators.

Because all generators that interconnect under the 10 kW Inverter Process are subject to the Fast Track screens, increasing eligibility above 10 kW will not reduce the screening applied to a generator for safety, reliability, and power quality issues. As the state examples demonstrate, it is unlikely that utilities need a more complicated application form or interconnection agreement for generators up to 25 kW, and possibly even larger generators. Thus, it may be reasonable to extend this process to a greater number of residential and small commercial systems by increasing the size limit of generators eligible for the Fast Track screens to 25 kW in order to reduce administrative burdens for both applicants and utilities.

To effectuate an increase in the 10 kW Inverter Process to accommodate generators up to 25 kW, references in SGIP and similar state procedures to "10 kW Inverter Process" can be replaced with "25 kW Inverter Process".

Possible Modification: Shorten Processing Timelines

The SGIP 10 kW Inverter Process follows the Level 2 Fast Track timelines. A utility is presently required to notify a customer that an application is complete within 10 business days from the date of submission, and the time to complete the initial technical review screens is 15 business days from time an application is deemed complete.

Several states have shortened timelines that apply to interconnection of very small generators. The states in Table 1 have adopted either 1) shorter timeframes for notifying a customer that an interconnection application is complete, or 2) the time to complete initial review.

Table 1. States with Fast Track Timelines Shorter than SGIP

State/Rule	Time to Notify Customer that Application is Complete	Time to Complete Initial Review
SGIP 10 kW Inverter Process	10	15
Maryland	5	15
New Jersey (PSE&G Tariff)	3	10
Massachusetts Interconnection Document	3	10

As the examples in Table 1 illustrate, a 10 kW interconnection request can be processed more quickly than is currently required in the SGIP. In addition, several states have established a default approval mechanism so that simplified interconnection requests will be deemed approved unless an applicant is notified otherwise. Vermont and Virginia both have provisions that "deem" an interconnection request approved for very small net metering generators when initial review has not been completed within the required timeframes. A recent Vermont law provides for automatic approval for net-metered generators 10 kW or less after 10 days, so long as a customer completes registration and certification of compliance and a utility does not deliver a letter to the customer detailing any issues concerning the interconnection.[58] In Virginia, net-metered generators 25 kW or less are deemed to be approved for interconnection unless a utility notifies a customer within 30 days.[59]

An advantage of the Vermont and Virginia approaches is that interconnection customers have a higher degree of certainty on the maximum time it will take to receive an approved interconnect. Incorporating a deemed-approval process into SGIP for the smallest inverter-based systems would help ensure that the interconnection of these generators may be processed in predictable timeframes. With the potential for "plug-and-play" solar PV systems to be brought to market through mainstream retailers, the processing of interconnection requests for very small inverter-based generators will need to be routine.

To increase the efficiency of processing interconnection applications, the 10 kW Inverter Process could be shortened to confirm that a customer's application is complete 3 business days after receipt. This would achieve a significant reduction in the time it takes an interconnection customer to interconnect using the Inverter Process as opposed to the standard Fast Track Process. In addition, an automatic approval process may be worth considering as well.

Proposed Redline of SGIP § 1.3 (insert the following after the fourth sentence of § 1.3)

1.3 Interconnection Request

[. . .] If the Interconnection Customer is applying electronically using the 25 kW Inverter Process Application and Agreement, the Transmission Provider shall notify the Interconnection Customer within three Business Days of the receipt of the Interconnect Request as to whether the Interconnection Request is complete or incomplete. For all other Interconnection Requests, the Transmission Provider shall notify the Interconnection Customer within ten Business Days of the receipt of the Interconnection Request as to whether the Interconnection Request is complete or incomplete. [. . .]

Possible Modification: Online Application and Electronic Signatures

Order 2006 envisioned a combined interconnection application and agreement (SGIP Attachment 5) as "eliminat[ing] the additional step of signing an interconnection agreement if the proposed interconnection passes the screens."[60] A combined application and agreement has been adopted in a number of states, and several states and utilities have simplified things further by moving to an online interconnection application. This reflects the general advance and acceptance to conduct more business online since the time Order 2006 was issued.

In California, both San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE) feature online applications for interconnections of small net-metered systems.

SDG&E allows net-metered systems up to 30 kW to complete an application and agreement through an online portal.[61] SCE offers online submittal of a simplified interconnection application for net metered generators via a Microsoft Excel spreadsheet that can be filled out and emailed directly to the utility's interconnection department.[62]

Online applications are efficient because they shorten the time it would take for a utility to process a complete interconnection request. They can also help to quickly identify deficiencies in an application, for both the applicant as well as the utility. In addition, online applications create an electronic trail that increases accountability. For example, Con Edison's general online document management system allows its customers in New York to confirm receipt of their application and associated documents and track major milestones in the process.[63] In addition to Con Edison, Pepco (Maryland), PSE&G (New Jersey), and National Grid (Massachusetts) feature an online application form for simplified interconnection that can be filled out and transmitted to the utility via email.

Incorporation of an online interconnection application into SGIP could increase the efficiency of interconnection and reduce mistakes and the number of incomplete applications without undermining or affecting the integrity of the review process. Following are possible redlines to incorporate the option of an electronic application submittal process.

Proposed Redline of Attachment 5 (Section 1.0 and 2.0 on p. 1):

1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the Transmission Provider ("Company"), by mail, email or online via the Transmission Provider's website.

2.0 If submitted electronically, the Company acknowledges receipt of the Application by creating an automatic email confirmation number and email transmission to the Interconnection Customer. If not submitted electronically, the Company acknowledges to the Customer receipt of the Application within three Business Days of receipt.

The time to process a simplified application is also affected by the requirement that a "wet" signature be included on an application. To effectuate the move to an electronic submittal method, as proposed above, SGIP could be modified to allow for electronic signatures. The standard 10 kW Inverter Process application form currently requires an interconnection customer to physically sign and mail an application.

Electronic signatures are generally recognized in commercial activities, and 47 states have adopted the substance of the Uniform Electronic Transaction Act (UETA), a model act developed by the National Conference of Commissioners on Uniform State Laws.[64] Accordingly, revisions to the 10 kW Inverter Process Application and Agreement form to allow use of electronic signatures could further streamline the administrative process for small generators without any detriment to safety, reliability or power quality. Although a utility may be concerned that there is a lack of verification when a customer submits an application without a signature, SCE's approach, which allows a customer to attach a digital copy of the customer's electric bill to the application, may be one means to provide identity verification.[65]

Below are proposed modifications to SGIP that would incorporate the option for electronic signatures of the 10 kW Inverter Application.

Proposed Redline of SGIP Attachment 5 [p.4]

> Interconnection Customer Electronic Signature
>
> By submitting this document, which includes electronic submission, I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

LEVEL 2 (FAST TRACK PROCESS) – POSSIBLE MODIFICATIONS

Fast Track consists of an initial review and, if necessary, a supplemental review. Initial review applies 10 technical screens that FERC intended to identify "proposed interconnections that clearly would not jeopardize the safety and reliability of the Transmission Provider's electric system."[66] FERC's use of "clearly" indicates that these screens were intended to allow interconnection without study in situations in which there is not a "close call" regarding possible impacts to safety, reliability, and power quality. Passage of these screens provides an expedited path to interconnection without additional study.[67] Supplemental Review serves as a second chance for generators that fail one or more of the initial review screens, providing the utility an opportunity to determine that a generator may nevertheless be interconnected consistent without unacceptable impacts to safety, reliability, or power quality.[68]

Several of the Fast Track screens may not be optimally designed to facilitate the rapid growth of solar PV and increasingly higher penetrations of DG. Although publicly available information on technical screen failure rates is limited, the information that exists shows that Fast Track failure in high-penetration markets is predominantly caused by SGIP Screen 2, which limits aggregate capacity on a line section to 15% of peak load.[69] High failure rates have also been found for Screen 9, which evaluates transmission impacts, and Screen 10, which fails projects needing any construction or upgrades on the utility system. Below, we discuss possible modifications to these screens as well as the Fast Track eligibility limit.

Possible Modification: Fast Track Eligibility

Before beginning the Fast Track screening process, a proposed generator must meet the eligibility criteria set out in SGIP section 2.1, which requires that a generator be "no larger than 2 MW" and meet "the codes, standards, and certification requirements" established in SGIP Attachments 3 and 4.[70] With a growing number of state policies facilitating an expansion of DG larger than 2 MW, there are an increasing number of generators seeking interconnection that exceed the 2 MW limit. Requiring all of these generators to proceed through a detailed study process may prove costly and resource-intensive. So, whether a size limit is appropriate, or even necessary, has come under increasing scrutiny in state and federal forums.

The 2 MW size limit for Fast Track was first adopted by FERC in Order 2006. In Order 2006, FERC rejected the argument that Fast Track should have no size limit, stating that it was adopting the 2 MW threshold "as a critical eligibility criterion for using the screens" because "[i]t helps ensure the safety and reliability of the Transmission Provider's electric system."[71] FERC did not elaborate on the specific safety and reliability issues the 2 MW eligibility limit was intended to address. Thus, the 2 MW limit may best be viewed as a proxy for the generator size, above which safety and reliability impacts were believed to potentially give rise to the need for a full study of interconnection impacts.

Despite FERC's statements in Order 2006, FERC has since approved deviations for specific utilities. In 2011, FERC approved an increase to 5 MWs for generators connecting to the California Independent System Operator (CAISO) transmission system.[72] Following FERC's approval of modifications to the CAISO Fast Track eligibility limit, SCE and Pacific Gas & Electric (PG&E) sought modifications to their FERC-approved Wholesale Distribution Access Tariffs (WDAT).[73] SCE chose to retain the 2 MW limit,[74] but PG&E kept the Fast Track eligibility of 2 MW on a 12kV interconnection and raised the eligibility to 3 MW on a 21 kV interconnection and 5 MW for interconnections at higher voltages.[75] FERC deferred to the utilities' chosen size limits, respecting SCE's argument that differences in its system prevented it from moving to the higher size limit chosen by PG&E.[76]

State procedures typically use one of three approaches in determining eligibility for Fast Track review. The majority of states mirror the SGIP size limit of 2 MW.[77] A number of state interconnection procedures limit their applicability to the size of the local net metering eligibility limit, which is generally no larger than 2 MW.[78] Finally, a handful of states, particularly those that based their interconnection standards on the former California Rule 21, do not limit the size of systems eligible for Fast Track.[79]

Although California Rule 21 did not have a size threshold for a number of years, recent modifications to California's Rule 21 introduce the following size thresholds on Fast Track eligibility:

> "Non-Exporting and Net Energy Metered Generating Facilities are eligible for Fast Track evaluation regardless of the Gross Nameplate Rating of the proposed Generating Facility. Exporting Generating Facilities with a Gross Nameplate Rating no larger than 3.0 MWs on a 12 kV, 16 kV or 33 kV interconnection for Southern California Edison, 1.5 MW on a 12 kV interconnection for San Diego Gas & Electric, and 3.0 MW on a 12 kV or higher interconnection for PG&E are also eligible for Fast Track evaluation."[80]

Although there is no clear technical justification for setting Fast Track eligibility at any particular level, establishing a size threshold can serve both a technical and process-oriented function. Generator size is a critical factor in determining whether a generator may have potential impacts on the distribution and/or transmission system. The larger a generator, the more likely it is to fail one or more of the Fast Track screens and require Supplemental Review or detailed study. Establishing a reasonable threshold provides transparency regarding the timeframe likely to interconnect, and it helps ensure that generator interconnections that may pose impacts on safety or reliability may be studied so a utility has an opportunity to determine the requirements necessary to mitigate those impacts.

Another purpose of a size limit is to reduce the number of generators that are needlessly run through the Fast Track screens if they are almost certainly going to require further study. In light of the increasing number of interconnection requests, the cap can set realistic expectations about the speed with which interconnection can proceed for larger generators. A size limit also relieves utilities of the burden of processing a high volume of applications through Fast Track that have little chance of interconnecting through that process. The cap may thus reduce tension between utilities and applicants and result in a more efficient interconnection process.

This does not, however, answer the question of whether 2 MW remains an appropriate threshold for Fast Track eligibility. As noted above, recent tariff modifications in California suggest it may be reasonable to vary the limit based on relevant technical considerations at the point of interconnection, such as the capacity of the distribution line to which a generator seeks to interconnect.[81] In addition to voltage of the distribution line, there may be other relevant factors to consider in setting a limit, including whether a generator is located on a network or radial distribution circuit and how far a generator is located from a utility substation.

This discussion suggests that it may be valuable to consider whether the size limit could be set in a more nuanced manner that takes into account system conditions at the point of interconnection. For example, generating facilities located close to a substation and on a main distribution line are less likely to raise impacts that may require study than generating facilities located at the end of a long distribution line. Table 2 provides an example of how these considerations could be integrated into a more nuanced Fast Track eligibility approach.

Table 2. Fast Track Eligibility

Line capacity	Fast Track Eligibility- regardless of location	Fast Track Eligibility- on > 600 amp line and < 2.5 miles from substation
< 4kV	< 1MW	< 2 MW
5kV – 14 kV	< 2MW	< 3 MW
15 kV – 30 kV	< 3MW	< 4 MW
31 kV – 60 kV	< 4MW	< 5 MW

Possible Modification: SGIP Screen 2 – Penetration Screen

SGIP, and the vast majority of state interconnection procedures, screen Fast Track applicants in part by looking at the penetration level of distributed generation interconnected to the nearby distribution system. Specifically, Screen 2 of SGIP asks whether a generator will cause aggregate generation to exceed 15% of the line section's annual peak load.[82] With increased penetrations of distributed generation and larger generators seeking to interconnect, this screen is more likely to be failed.[83] An evaluation of whether the screen is set at the appropriate level, and whether there are alternate methods of assuring system safety and reliability at higher penetrations without requiring detailed studies may be appropriate to respond to changed conditions.

The penetration screen was first established in California's Rule 21 to address the possibility that operating requirements may be different for generators at higher penetrations and therefore may require additional study to safely interconnect.[84] As penetration increases, the risk of "unintentional islanding, voltage deviations, protection miscoordination, and other potentially negative impacts" may increase.[85] These risks become more significant when there is a possibility that generation will exceed minimum load on a circuit or when distances from the substation grows.

At the time Screen 2 was created, few utilities were collecting minimum load data for most circuits, thus the 15% of peak load measurement was identified "as a surrogate for knowing the actual minimum load on a line section."[86] The *California Interconnection Guidebook* explains: "A typical line section minimum load is at least 30% of the peak load, therefore at 15% aggregate, the generating capacity would be no more than 50% of the minimum load of the Line Section."[87]

It is still true that utilities do not consistently have minimum load data for all circuits, however as more utilities install Supervisory Control and Data Acquisition (SCADA) systems and roll-out smart grid features there is an increasing amount of data available. In addition, the *Interconnection Screens Report* concludes that "minimum load can be estimated based on standard load profiles for various customer classes that many utilities maintain and update on an annual basis."[88] Other methods are also available for calculating or estimating minimum load that may be similar to methods used for determining peak load levels of line sections. Use of an equivalent minimum load measurement may enable a greater number of generators to interconnect without study on certain circuits, but on other circuits, such as those with highly seasonal load patterns, use of minimum load may reduce the number of generators that can connect without study.

Some states have incorporated minimum load screening into their interconnection procedures. Montana's interconnection procedures require total generation capacity to be below 15% of peak load screen *or* "the annual minimum load of the line section."[89] In Arizona, model interconnection procedures developed by stakeholders state that aggregate generation must be below 15% of peak load, and "must also be less than 50 percent of the minimum daytime feeder or line section load, where these data are available, unless the minimum load is zero."[90]

These states have modified initial review screens to evaluate minimum load where data exists or can be calculated. According to the *California Interconnection Guidebook* the equivalent to 15% of peak load would be 50% of minimum load, although a less conservative minimum load level could also be considered (i.e. 75% or 100% of minimum load). Montana appears to use 100% of minimum load.

Rather than modifying the 15% screen in the initial review process, utilities in Hawaii and California recently agreed to incorporate a minimum load threshold into Supplemental Review processes of their respective state procedures. In both states, if a generator fails the 15% of peak load screen, it will be required to undergo Supplemental Review. In Hawaii, Rule 14H then specifies that if "the aggregate generating capacity per Line Section is no greater than 50% of the Line Section minimum kW load during the period when the proposed generation is available (including noon on Sunday for solar photovoltaic systems)," a generator will be allowed to interconnect without detailed study.[91] Under procedures in California, if it is determined that the generating capacity is less than 100% of minimum load on a line section a generator may be allowed to interconnect without detailed study if two additional supplemental review screens determine the interconnection does not raise potential power quality, voltage, safety, or reliability concerns that require detailed study.[92] If the generating capacity exceeds 100% of minimum load, the generator will likely require detailed study.

Data regarding minimum and peak loads on a circuit are necessarily based on historic levels combined with reasonable forecasts for growth or diminishment of load. These estimates are no guarantee of future load levels, however, as load can shift with changes in the economy, investments in energy efficiency, and other conditions outside of the utility's control. Minimum load can also change as a result of distribution system reconfigurations. Allowing generators to interconnect at penetrations levels close to—or at—a circuit's minimum load via the Fast Track on Supplemental Review gives utilities an opportunity to identify whether additional interconnection requirements are necessary without requiring the time and expense of a detailed study.

Both Hawaii and California will utilize minimum load measurements that are relevant for the time period that a generating facility will be online. This is important for solar PV technologies that are only online during daylight hours when minimum loads tend to be highest in most parts of the country. Thus, the minimum load can be measured between the hours of 10 a.m. and 2 p.m. for fixed solar systems. California's Rule 21 also includes a longer time period for generators using tracking systems.

In California, if minimum load data is not available, the utility will try to calculate minimum load, estimate it from existing data, or determine it from a power flow. If none of these options are available, the utility will default to using the 15% of peak load screen.[93]

The approaches agreed upon in California and Hawaii have potential to allow a greater number of generators to interconnect quickly while also providing the utility with sufficient opportunity to evaluate whether modifications need to be made to ensure safe and reliable operation at higher penetrations. Although increasing penetrations of generators boost the likelihood of unintentional islanding, high steady-state voltage, and the need to ensure protection coordination, it may be possible to properly evaluate those risks and identify modifications through a brief additional review without subjecting a proposed interconnection to a detailed study process. The merits of a refined Supplemental Review are discussed in more detail below.

Possible Modification: SGIP Screen 5 – Short Circuit Duty

SGIP Screen 5 determines whether the addition of the proposed Small Generating Facility will cause the short circuit current contribution ratio on the distribution system to exceed acceptable limits. This screen provides an important system check, but is one that is unlikely to be triggered by very small generators, including synchronous and induction generators.

For a number of years in California, generators below 11 Kilovolt-Amps (kVA) have been exempt from the short circuit duty screen.[94] In addition, to increase the efficiency of the review process, Hawaii recently adopted modifications to its Fast Track equivalent process to allow generators below certain sizes to skip screens where they are unlikely to cause issues of the sort addressed by the screen. In particular, Rule 14H contains an exemption that allows all generators below 10 kW to skip the short circuit contribution screen.[95] In addition, Hawaii allows generators up to 250 kW that are inverter-based to skip the short-circuit contribution screen.[96] Allowing very small generators to skip this screen is possible because their fault current level is insignificant compared to the feeder and thus they do not contribute significantly to short circuit current ratio issues.

At this time, it is appropriate to consider allowing very small systems of up to 25 kW to skip SGIP Screen 5. Allowing inverter-based systems up to or exceeding 250 kW to skip the screen may also be possible without significant system impacts but may require additional technical study before being adopted in SGIP. The approach of allowing generators up to 25 kW to skip the screen will enable distribution engineers to review applications more quickly, benefitting both the utility and the interconnection applicant, and will align well with an increase in the 10 kW Inverter Process to 25 kW, as recommended above.

Proposed Redline Modification of SGIP Section 2.2.1.5:

> 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 be proposed for a circuit that already exceeds 87.5 % of the short circuit interrupting capability. Proposed Small Generating Facilities below 25 kW shall be exempt from this screen.

Possible Modification: SGIP Screen 6 – Line Configuration

The sixth SGIP Fast Track screen reviews the type of electrical service provided to a proposed generating facility and the line configuration at the point of interconnection and the transformer connection. This screen assesses the potential for overvoltage on the distribution system as a result of a loss of ground, or a phase, during a system fault.[97] The threat of overvoltage occurs on certain line configurations; the screen identifies those that are not a problem and allows those generators to proceed. However, generators connecting to a three-phase, four-wire primary distribution line with a three-phase transformer will fail the screen unless they are "effectively grounded."[98]

IEEE Standard 1547-2008 covering interconnection of distributed generation resources notes the need to ensure that the generating facility under review "shall not cause overvoltages that exceed the rating of the equipment connected to the Area EPS [Electric Power System] and shall not disrupt the coordination of the ground fault protection on the Area EPS."[99] However, the Standard does not recommend appropriate grounding methods to prevent overvoltages. As a result, the line configuration screen may push generators into a detailed study despite the fact that an appropriate grounding method can often be determined without a detailed study.

California's Rule 21 and Hawaii's Rule 14H include additional options that allow generators connecting to a three-phase, four-wire service to pass the line configuration screen if the aggregate nameplate rating of the generating facility is less than or equal to 10% of the line section's peak load.[100] In addition, in Rule 21, the line configuration screen "does not apply to Generating Facilities with a Gross Rating of 11 kVA or less."[101] In Hawaii, generators below 10 kW also bypass this screen.[102]

Currently, generators that fail the line configuration screen may be required to undergo a full study. However, once sufficient information is known about the proposed generator type and the point of interconnection, there is a relatively fixed number of known grounding solutions that are available to resolve overvoltage concerns.[103] Thus, rather than subjecting generators that fail the line configuration screen to a full study, specific equipment configurations that address overvoltage concerns may be addressed through a quicker review.

In recent revisions to Rule 14H, Hawaii added an option that allows generators that fail the line configuration screen to resolve overvoltage concerns through Supplemental Review. The utility and applicant may select from a list of pre-identified solutions based upon the technology and interconnection location.[104] Likewise, California's Rule 21 contains a general option embedded in the initial review screens that would allow generators that fail the line configuration screen to undergo "a quick review" of the failed screen to determine the requirements to address any failure.[105] This is similar to an option in SGIP that allows a utility to interconnect a generator through Fast Track despite the failure of a screen if it determines that the generator "may nevertheless be interconnected consistent with safety, reliability, and power quality standards…"[106]

Since identification of a technical solution for resolving the risk of overvoltage identified in the line configuration screen does not require full study, a revision to SGIP to clarify that resolution of this issue is appropriate through the Initial Review and/or Supplemental Review process may improve the efficiency and clarity of the procedures.

Based upon the experiences in California and Hawaii, the following SGIP revisions warrant consideration. Screen 6 could be modified in two ways: All generators below 11 kVA could be allowed to skip the screen, and generators below 10% of the line section's peak load could be allowed to pass the screen regardless of line configuration. For example:

2.2.1.6 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. This screen does not apply to Generating Facilities with a gross rating of 11 kVA or less.

Primary Distribution Line Type Configuration	Type of Interconnection to be Made to Primary Distribution Line	Results/Criteria
Three-phase, three wire	Any type	Pass Screen
Three-phase, four wire	Single-phase, line-to-neutral	Pass Screen
Three-phase, four wire (For any line that has such a section OR mixed three wire and four wire)	All others	To pass, aggregate Generating Facility nameplate rating must be less than or equal to 10% of Line Section peak load

These modifications will allow utilities to continue to maintain safety, reliability, and power quality by identifying generators that pose overvoltage concerns and mitigating them through a technical solution. However, these modifications will also improve the efficiency and cost-effectiveness of the interconnection process by avoiding a full study when one is not needed. Although utilities currently have discretion under SGIP to resolve the overvoltage issues though section 2.2.3 or Supplemental Review, an explicit articulation of this option will improve transparency and certainty for applicants.

Possible Modification: SGIP Screen 9 – Transient Stability

SGIP Screen 9 examines whether a proposed generating facility will contribute to transient stability issues in the vicinity of the proposed point of interconnection. This screen evaluates whether the addition of the proposed generating facility will impact the ability of the electric power system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.[107] It requires that any generating facility that would cause the aggregate generation on the circuit to exceed 10 MW in an area with known or posted transient stability limitations to undergo further study.

Recent conversations on this topic in California, in PJM's service territory, and nationally have highlighted that the question posed by this screen may not actually be identifying the precise issue of central concern for small distribution level interconnections. A survey done in 2008 of electrical engineers and other experts in this area found that there was a general consensus that this screen should be modified to improve its ability to identify generators that need full study before they can be safely interconnected.[108] The current screen inquires whether a generating facility may contribute to known or posted transient stability issues, however there are no transient stability issues posted by most of the ISOs and thus it is often hard for utility distribution engineers to apply this screen.

In addition to the ambiguity in the current screen, it also does not address an issue of particular concern for small, distribution-interconnected generators being reviewed through Fast Track: whether the proposed generating facility has interdependencies with other queued generators on the transmission or sub-transmission system and thereby needs further study. As DG reaches higher penetrations, there is an increased likelihood aggregate generating capacity on the distribution system will have upstream impacts on the transmission system.

Recent variations to this screen have emerged in California and New Jersey to address this issue. In Rule 21, California recently adopted a modification to the transient stability test to more accurately address the transmission dependency issue.[109] The revised Rule 21 screen now asks whether the generator is interconnecting in an area with known transient stability limitations and whether it has interdependencies with any earlier queued transmission system interconnection requests. A generator will require detailed study if either circumstance exists.

In the Eastern United States, PJM recently sought approval for modifications to its FERC-regulated tariff to adopt a separate queue and expedited review process for non-transmission dependent generators.[110] The intent behind this change was to reduce the number of generators that need to be re-studied because an earlier queued generator with which they may interact dropped out of the queue.[111] PJM thus adopted a screening process to identify generators that would not impact the transmission system. The process evaluates the potential impacts of a proposed generator on the transmission system using a linear (DC) power flow program to analyze each transmission facility and to determine whether any contingencies can overload it. The results are then unitized in a manner that enables PJM to determine the MW impact a generator would have on a particular flowgate.[112] This process is different than a straightforward Fast Track screen because it is also used to determine cost allocation and deliverability. Nevertheless, it provides an example of another approach to evaluating transmission dependency as part of the interconnection process.

Taking into account the approaches in California and PJM's territory, it may be appropriate for SGIP Screen 9 to be modified in a manner that also examines whether a generator has dependencies with other generators yet to be studied on the transmission system. Since California's approach fits more neatly within the Fast Track screening process, it is proposed here.

Proposed Redline Modification of SGIP Section 2.2.1.9:

> 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), or the proposed Small Generating Facility shall not have interdependencies, known to the Transmission Provider, with earlier queued Transmission System interconnection requests.

Possible Modification: SGIP Screen 10 – No Construction

Currently, generators that are eligible for and pass through the first nine screens of the SGIP Fast Track process may be unable to interconnect without Supplemental Review or a full study if they require construction of any facilities by the utility on its system, as they will fail SGIP Screen 10.[113] This includes generators that need low-cost upgrades such as a service entrance or other interconnection facilities, as well as higher-cost modifications that require construction deeper into the distribution provider's system.

Generators that fail Screen 10 may be able to proceed through Supplemental Review, but only if construction is limited to "minor modifications to the Transmission Provider's electric system."[114] Generators that require more significant construction must go through the full study process. State procedures that mimic SGIP generally include a similar no construction screen.[115] Procedures modeled after California Rule 21 do not contain a similar restriction.[116]

When SGIP was developed, the type of facility most likely to utilize Fast Track was an onsite generator designed to primarily serve onsite load, with only excess generation sent to the local distribution system through an existing service entrance. These generators are less likely to require construction by the utility on its system. However, as the number of distributed generation facilities selling wholesale power has expanded, the no-construction screen has become one of the more commonly failed screens.[117]

Screen 10 serves at least two purposes in the interconnection process. First, a study may be needed to determine the extent of the construction needed by a utility on its own system. Second, a study may be needed to provide an estimate of the cost of upgrades for which the applicant will be responsible. In both cases, however, if upgrades are limited to those that only serve the interconnecting generator, a full study process may not be necessary. Therefore, modifications to this screen may be appropriate to help increase the efficiency of the Fast Track process.

When PG&E and SCE modified their federal small generator interconnection procedures in 2011, FERC approved modifications to their Fast Track and Supplemental Review processes to allow generators that require limited upgrades to proceed with a Fast Track interconnection without a full study. SCE modified its tenth screen to allow generators to pass Fast Track review so long as the upgrades needed are limited to those "solely attributable to the Generating Facility."[118] Applicants wishing to interconnect without a full study must agree to pay the full cost of those upgrades without the benefit of an estimate. PG&E retained the original SGIP language in Screen 10, however it added to the "customer options meeting" a step that allows generators to proceed to Supplemental Review if interconnection facilities are required.[119] In Supplemental Review, the customer is given the option of agreeing to pay the costs upfront or of selecting to have a facilities study completed.[120] Generators that require distribution or network upgrades are required to proceed to a full study.[121]

In considering ways to increase the efficiency of the interconnection process while also ensuring continued safety and reliability, it is important to keep in mind the purpose of interconnection study processes. As discussed more in a later section, interconnection studies identify potential safety and reliability issues with a proposed generating facility and what upgrades, if any, may be required to address those issues. A study process also identifies the likely cost of required upgrades and how the associated costs will be allocated. However, as the updates in California illustrate, not all construction requires a detailed study to identify and mitigate potential safety and reliability issues. In addition, interconnection customers may be willing to accept responsibility for costs of certain upgrades with less specificity in exchange for a more efficient interconnection process.

Thus, with an increase in the number of small wholesale generators seeking interconnection to distribution systems, it may be possible to replace the tenth screen with a more suitable process that provides a utility increased time to estimate costs for necessary construction as the potential construction becomes more complex. For example, for generating facilities needing only interconnection facilities or minor modifications to the distribution provider's electric system, the utility could be given 15 days to develop a cost estimate and provide an interconnection agreement. For generators requiring more than minor upgrades, the distribution provider could be given 30 days to develop the cost estimate and provide an interconnection agreement. Alternately, the utility could opt to conduct a Facilities Study, if necessary, but no feasibility or system impact study would be required. Similar changes and timeframes could be incorporated into the Supplemental Review process. In all cases, the applicant would have to agree to pay the costs associated with the upgrades after reviewing the good-faith estimate provided by the utility.

In addition, a process could be created to allow a customer to opt into a Facilities Study (either after initial review or Supplemental Review) to determine the likely cost of upgrades prior to committing to them, or proceed directly to an interconnection agreement if agreement is received to pay the full costs of any upgrades.

Possible Modification: Supplemental Review

When a generator fails any one of the ten SGIP Fast Track screens, SGIP provides the applicant an opportunity to request a Supplemental Review if the utility concludes that such review might determine that the generator could interconnect without a full study.[122] The procedures do not define what the scope of the review will be or what issues may be resolved through the process.

As the number of applicants failing the initial review screens grows, Supplemental Review offers an opportunity to serve the twin goals of interconnection by providing additional time to resolve some of the safety and reliability concerns identified by the initial review screens while still allowing for efficient and cost-effective interconnection overall. In most cases, if the proposed generation facility is below 100% of the minimum load measured at the time the generator will be online, then the risk of power backfeeding beyond the substation is minimal and thus there is a good possibility that power quality, voltage control and other safety and reliability concerns may be addressed without the need for a full study.

Recent modifications to the state procedures in Hawaii and California demonstrate how Supplemental Review may be used to evaluate generators connecting at higher penetrations. First, both states define the scope of the review process and what issues will be examined. In Hawaii, the "intent of the Supplemental Review is to provide a slightly more detailed review of only the conditions that cause the Generating Facility to fail the Initial Technical Review."[123] In California, the intent is to provide the utility with time to address certain specified conditions that may be adequately addressed with only limited additional review rather than requiring a full study. Defining the intent of the process and putting in place specific technical screens and timelines gives developers more certainty on what they can expect out of the process.

Both Hawaii and California retained the 15% of peak load screen in initial review, but the Supplemental Review procedures were then drafted to allow generators below a higher minimum load threshold to connect without a full study if any concerns identified at the higher penetration can be resolved. In Hawaii, for generators that fail the 15% of peak load screen, a full study shall not be required if the aggregate generating capacity is below 50% of minimum load on a line section for most generators[124] and 75% of minimum load for single-phase PV generators up to 10 kW on single-phase transformers that participate in net metering.[125] For generators that fail the line configuration screen, the tariff states that a full study will not be required where "a feasible solution from a pre-identified list of solutions maintained by the Company has been identified and agreed upon between the Company and the Customer."[126] The utilities may also address other issues identified in the initial review screens including short-circuit contribution, interconnection to networked systems (spot networks or area networks), the need for a dedicated transformer, and protective device requirements.[127]

In California, the Supplemental Review process has three technical screens that are applied similar to those in the initial review. The first screen determines whether the generator will cause the aggregate generation capacity on the line section to exceed 100%

of the minimum load, measured when the proposed generator is expected to be operating.[128] If a generator passes that screen, it will be subject to two additional screens.[129] The second screen applies power quality and voltage tests to identify operating requirements for the interconnecting generator or to determine whether a full study is required to identify those requirements. The third screen looks generally at whether the location of the proposed facility or the aggregate generation capacity on the line section could adversely impact safety or reliability, and if so, whether those can be addressed without requiring a full study.[130]

Under the SGIP rules for Supplemental Review, utilities have discretion to allow generators to interconnect that fail one or more of the initial review screens. Improving the clarity of the Supplemental Review process will likely provide additional certainty to applicants about the technical issues that will be considered in evaluating an interconnection and may guide them in site selection and planning. A revision to the Supplemental Review process may also enable a greater number of generators to proceed without further study, even without relaxation of the initial technical screens.

For a more defined and transparent Supplemental Review, the following modifications could be considered:

- Incorporate a requirement that generators below 100% of minimum load on a distribution feeder line section, measured during the hours the proposed facility will be online, be allowed to proceed through Supplemental Review.
- Include specific screens for Supplemental Review that provide additional guidance on the power quality, voltage regulation, safety, and reliability considerations that will be reviewed.

The Rule 21 Supplemental Review screens are attached to this report as Attachment 1.

LEVEL 3 (STUDY PROCESS) – POSSIBLE MODIFICATIONS

For generators that do not pass Fast Track, or are ineligible for Fast Track, SGIP requires generators to participate in a Study Process that consists of an initial scoping meeting and potentially three sequential studies: 1) a Feasibility Study; 2) a System Impact Study; and 3) a Facilities Study.

The Study Process determines potential impacts a proposed generator may have at or near the point of interconnection and what facilities or upgrades are necessary to maintain the safety, reliability and power quality of the electric power system. Perhaps the most important consideration for both the applicant and the utility is the level of study needed to determine interconnection requirements for a particular interconnection request. Put another way, what specifically should be addressed in an interconnection Study Process?

The answer may depend on the system configuration at the point of interconnection. For example, an interconnection to a spot or area distribution network may require a utility to look at impacts of reverse power flow to network protectors located at or near the point of interconnection. Likewise, impacts to service quality and the maintenance of voltage within normal operating ranges may depend on a proposed generator's distance from a substation, the type and location of voltage regulation devices, and the presence or absence of other generators (and types of generators) interconnected or proposed to interconnect to the same distribution feeder.

Failure of Fast Track technical review screens may help determine the appropriate focus of the Study Process. However, for interconnection applications that are not eligible for Fast Track, and therefore have not been subject to the application of Fast Track technical review screens, such screens would not provide any guidance in helping to determine the appropriate scope of an interconnection study. The Fast Track technical review screens also do not attempt to screen for every possible impact to electric power system reliability that may need to be assessed in the Study Process. For example, the present Fast Track screens do not look at the impact of reverse power flow on voltage regulation devices.

The three SGIP studies allow utility distribution engineers to take a fairly broad look at potential impacts to system reliability. Each has a different purpose. The Feasibility Study is a preliminary technical assessment of the proposed interconnection that looks for any potential adverse system impacts.[131] The System Impact Study is a detailed assessment of the effect the interconnection would have on the transmission provider's electric system and any other affected systems.[132] Depending on the generating facility, the System Impact Study may be required for both the transmission system and, separately, the distribution system.[133] The Facilities Study determines what modifications to the transmission provider's electric system are needed, including the detailed costs and scheduled completion dates for these required modifications.[134] This differentiated study process provides a developer with opportunities to exit the process as interconnection costs become clearer.

Prior to beginning the studies, the transmission provider and customer may attend a scoping meeting at which they may decide to skip the Feasibility Study and proceed directly to either a System Impact Study or a Facilities Study.[135] The parties may also agree to skip the Facilities Study and proceed directly to an interconnection agreement following the results of the Feasibility Study or System Impact Study.[136] Agreement on the scope and cost of a study is reflected in an interconnection study agreement entered between the applicant and the utility.

The length of time allowed for completion of the SGIP studies varies. The following table lists the time SGIP allows for each study, along with an estimate of the total time required after accounting for the time necessary to enter various study agreements.

Table 3. SGIP Study Timeframes

Stage of Study Process	Study Time	Total Time
Feasibility Study	30 business days	45-50 business days
System Impact Study	30-65 business days	45-70 business days
Facilities Study	30-45 business days	35-50 business days

As the ability to skip one or more of the three studies suggests, it is not clear that a three-study process is necessary for small generators, particularly for small residential and commercial installations. The ability to skip one or more of these studies may be enhanced if modifications to the Fast Track screening process can help to identify potential issues that may need a closer look during the Study Process.

A number of examples exist of recent changes made to shorten the study process from three to either one or two studies. In 2010, the CAISO adopted modifications to its interconnection tariff that made a number of changes to the study process. The CAISO moved most projects that used to proceed through the three serial studies into one annual "cluster study" that is composed of two different study phases. Phase I provides a preliminary look at the possible upgrades needed and options at the point of interconnection that could reduce overall upgrade costs, and provides a maximum cost responsibility for transmission system network upgrades along with a good-faith cost estimate of the interconnection facilities.[137] After this study is completed, there is an opportunity for applicants to decide whether they want to proceed with interconnection, and if they do, to put down a financial security deposit. The Phase II study is a more detailed look that updates the results of Phase I to account for withdrawal of some interconnection requests, and provides a final assessment of upgrades and cost allocation.[138]

In addition to the adoption of the cluster process, the CAISO also retained a serial study process for certain qualified applicants that were not electrically related to other queued generators and thus did not need to be studied in the cluster.[139] The CAISO's Independent Study Process (ISP) is similar to the SGIP Study Process, but it eliminates the Feasibility Study and consolidates the study process into a System Impact Study and a Facilities Study (which can be waived if no interconnection facilities or upgrades are identified). SCE and PG&E mirrored these changes for the most part in the modifications to their FERC-approved interconnection tariffs, which were approved in 2011.

The CAISO and SCE tariffs provide 90 calendar days for the completion of a System Impact Study.[140] CAISO and SCE provide 90 calendar days for the completion of a Facilities Study where upgrades are required, and 60 calendar days where only interconnection facilities are identified.[141]

The original California Rule 21, and numerous state procedures modeled on it, only provides for a single "Interconnection Study" rather than a three-part study process. Under the approved revisions to Rule 21, projects that do not qualify for interconnection under Fast Track will either be studied under an ISP process similar to the CAISO's process described above, or will be studied as part of the cluster study being conducted under the IOU's WDATs.[142]

The one-study process in place in many states and the two-study process recently adopted in California suggest that a full three-study process may not be necessary, particularly for small generators. In particular, the role of the Feasibility Study is fairly limited since much of the crucial detail of interest to generators, particularly regarding cost, does not come until the later studies.

The changes adopted in California do not necessarily shorten the overall study process, since the duration of each study is greater than that provided for in SGIP.[143] However, it is worth considering whether the times required for the System Impact Study and Facility Study can be kept the same in SGIP, or only modestly increased, even if the Feasibility Study is eliminated.

Possible Modification: Moving from Serial Study to Group/Cluster Study

As discussed above, the SGIP uses a serial study process for determining interconnection requirements for a particular generator.[144] Under a serial study approach, interconnection requests are studied one at a time, on a first-come, first-served basis. The order of requests received is made publicly available through posted interconnection queues.[145] Under this approach, an interconnection request may not be studied until all queued-ahead generators have been studied. The reason is two-fold. First, the amount of utility resources that can be devoted to the processing of interconnection requests may be limited. If utility resources are limited, it may be necessary to complete the study of generators further ahead in line to free up resources to study later-queued interconnection requests.

A second factor is the necessity to complete the interconnection of queued-ahead generators to determine the anticipated system configuration for the study of later-queued generators. This is an important consideration, because upgrades that may be required to interconnect a generator that is ahead in the queue may facilitate the interconnection of generators further behind in the queue. On the other hand, if a generator earlier in the queue decides not to move forward with its interconnection, and therefore upgrades that would have been completed to accommodate that generator are not completed, the study of later-queued generators would not assume the existence of those upgrades. The result is that a generator further back in the queue may be responsible for the completion of the upgrades that would have otherwise been completed to facilitate the interconnection of the queued-ahead generator, if it had gone forward.

There may also be a need to re-study the later interconnection requests. A high number of speculative projects in an interconnection queue that drop out during or after the study process can result in a ripple effect that can impact and necessitate restudy of applicants further back in the interconnection queue. This lengthens the serial study process and increases costs. In sum, the requirements for a generator further back in the queue may not be able to be determined until the status of all generators that are ahead in line have been determined.

The serial study process may work well in situations where a utility is a) processing a low volume of interconnection applications such that existing resources are sufficient to timely handle the volume of interconnection requests being received, and b) generators seeking interconnection are sufficiently independent such that the ability to move forward with studies is not significantly delayed by the need to process earlier interconnection requests to determine the base case for generators farther back in the queue. The serial study process becomes less efficient when the volume of interconnection requests and interrelatedness of interconnection requests reaches a point where significant delays in processing interconnection requests results. Under these conditions, the serial study process can lead to long delays, and other options may need to be explored.[146]

When a utility begins to receive sufficiently high volumes of interconnection requests, and high penetrations are reached such that multiple interconnection requests may impose impacts on the same area of an electric power system, a group or cluster study process may be more efficient. ISOs and individual utilities in the United States have identified some of the possible benefits of studying interconnection requests in groups or clusters and have adopted changes to implement these procedures. FERC recently approved modifications to the Open Access Transmission Tariffs for CAISO, MISO and PJM that reflect a move toward group studies.[147] Two of the California IOU's followed CAISO's lead and adopted a cluster study process for interconnection requests interrelated with the transmission system.[148] Finally, the CPUC is considering adopting a group study process for distribution-level interconnections under Rule 21.[149]

There are a number of advantages to a group study approach. First, a group study process may make more efficient use of limited utility resources by enabling multiple studies to be combined. Second, a group study process may allow interconnection applications to be processed more quickly. Studying a group of projects at once eliminates the need for later queued projects to wait in line. Finally, a group study process may allow for a beneficial sharing of costs across generators, both for study and for upgrades that may be necessary to accommodate the interconnection of multiple generators. Imposing the full cost of upgrades—which may facilitate the interconnection of multiple generators—on the first generator that triggers the upgrades may pose a barrier to market growth. By studying generators together, the costs of upgrades can be spread equitably across the generators that may ultimately benefit.

There may also be negatives to the group study approach. First, the transmission cluster study process in California takes nearly two years to complete. Thus, while it may place a lower burden on utility resources, it also may require more time overall.[150] However, in California the serial study queues were so clogged that there was an expectation that it could take many years to complete the process.[151] Second, where a location has a high number of speculative projects in its interconnection queue, utilities may need to develop a method of sorting out how many total combined MW to realistically study and how to estimate and assign the cost of upgrades. Assuming that only a percentage of interconnection requests will actually move forward, studying the full number of proposals could result in inflated estimates of the amount of upgrades actually required.

An important consideration in a group study process is which interconnection requests to study together. The answer should generally depend on which interconnection requests pose interrelatedness considerations. Projects that are transmission dependent likely need to be studied with other transmission-dependent projects. However, projects that do not interact with the transmission system could be studied in smaller groups with only the other projects they interact with on the distribution system.

The group study approaches being implemented across the United States appear to offer significant promise for dealing with high volume and high penetration situations at the distribution level. Each region has taken a slightly different approach to the issue at this stage and further information is needed on what the pros and cons are of each approach. This is a possible area for improvement of SGIP that warrants further consideration.

4. RECOMMENDATIONS

This section recaps and summarizes the recommendations provided in Section 3:

- Update federal and state interconnection procedures to meet the demands of a growing national marketplace for solar PV and other small renewable generators interconnecting to electric power distribution systems.
- Incorporate a pre-application report through which an interconnection applicant can request information about specific, relevant technical conditions at a proposed point of interconnection.
- Extend the 10 kW Inverter Process to generators up to 25 kW.
- Shorten the time for determining a 10 kW Inverter Process application is complete to 3 business days after receipt.
- Consider automatic approval of 10 kW Inverter Process applications after an identified timeframe unless an applicant is notified otherwise by a utility.
- Allow for online submission of interconnection applications.
- Allow for electronic signatures to be provided on interconnection applications.
- Consider modifying Fast Track eligibility to take into account system conditions at the point of interconnection. A proposed approach is provided in Table 2.
- Allow generators up to 25 kW to skip the short circuit duty screen (SGIP Screen 5).
- Modify the line configuration screen (SGIP Screen 6) in two ways: allow generators less than 11 kVA to skip the screen; and allow generators below 10% of the line section’s peak load to pass the screen regardless of line configuration.
- Modify the transient stability screen (SGIP Screen 9) in a manner that examines whether a generator has dependencies with other generators yet to be studied on the transmission system.
- Replace the no construction screen (SGIP Screen 10) with a process that provides a utility increased time to estimate costs for necessary construction as potential construction becomes more complex.
- Allow a customer to opt into a Facilities Study (either after Initial Review or Supplemental Review) to determine the likely cost of upgrades prior to

committing to them, or allow a customer to proceed directly to an interconnection agreement if agreement is received to pay the full costs of any upgrades.

- Provide a more defined and transparent Supplemental Review process, including consideration of the following: incorporate a requirement that generators below 100% of minimum load on a distribution feeder line section, measured during the hours the proposed facility will be online, be allowed to proceed through Supplemental Review; and include specific screens for Supplemental Review that provide additional guidance on the power quality, voltage regulation, safety and reliability considerations that will be reviewed.
- Consider replacing a three-study process with a two-part study process, and consider whether the times required for the System Impact Study and Facility Study to be completed can be kept the same, or only modestly increased, even if the Feasibility Study is eliminated.
- When a utility begins to receive sufficiently high volumes of interconnection requests and high penetrations are reached such that multiple interconnection requests may impose impacts on the same area of an electric power system, a group or cluster study process may be more efficient than a serial study process.

5. CONCLUSIONS

The U.S. solar industry is fast approaching the limits of the practicality of existing interconnection processes. Interconnection reform is necessary and unavoidable if we hope to achieve the renewable energy goals of states, federal departments, and the private sector. This report serves as an extension of the NREL *Interconnection Screens Report*, and, as such, provides an important procedural bridge to that next iteration of interconnection reforms needed in the United States.

The report focuses on the federal SGIP, specifically recommending changes to the pre-application process and the 10 kW, Fast Track, and Study Processes; however, these recommendations could generally be applied to many state interconnection procedures as well. Many of these recommendations result from the work of stakeholder collaborations in states like Hawaii and California, which are currently experiencing high-penetration areas and high volumes of interconnection applications.

When we consider the experience of these states, we begin to get a glimpse of the emerging scenarios in the rest of the country. As the cost of solar PV systems decline and demand increases, it will be increasingly important to streamline interconnection processes in other states. This interconnection reform process will not only result in a more responsive, agile solar industry but also a safer and cleaner electric power system.

6. ATTACHMENT 1: California Rule 21 Supplemental Review Screens (Rule 21 G.2)

G. Engineering Review Details

2. Supplemental Review Screens

The Supplemental Review consists of Screens N through P. If any of the Screens are not passed, a quick review of the failed Screen(s) will determine the requirements to address the failure(s) or that Detailed Studies are required. In certain instances, Distribution Provider may be able to identify the necessary solution and determine that Detailed Studies are unnecessary. Some examples of solutions that may be available to mitigate the impact of a failed Screen are:

1. Replacing a fixed capacitor bank with a switched capacitor bank

2. Adjustment of line regulation settings

3. Simple reconfiguration of the distribution circuit.

a. Screen N: Penetration Test

Where 12 months of line section minimum load data is available, can be calculated, can be estimated from existing data, or determined from a power flow model, is the aggregate Generating Facility capacity on the Line Section less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the Generating Facility?

- If yes (pass), continue to Screen O

- If no (fail), a quick review of the failure may determine the requirements to address the failure; otherwise Electrical Independence Tests and Detailed Studies are required. Continue to Screen O. (Note: If Electrical Independence tests and Detailed Studies are required, Applicants will continue to the Electrical Independence Tests and Detailed Studies after review of the remaining Supplemental Review Screens).

Note 1: If none of the above options are available [for determining minimum load], this screen defaults to [the 15% peak load screen].

Note 2: The type of generation will be taken into account when calculating, estimating, or determining circuit or Line Section minimum load relevant for the application of this screen. Solar generation systems with no battery storage use daytime minimum load (i.e. 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for systems utilizing tracking systems), while all other generation uses absolute minimum load.

Note 3: When this screen is being applied to a [net energy metered] Generating Facility, the net export in kW, if known, that may flow across the Point of Common Coupling into Distribution Provider's Distribution System will be considered as part of the aggregate generation.

Note 4: Distribution Provider will not consider as part of the aggregate generation for purposes of this screen Generating Facility capacity known to be already reflected in the minimum load data.

Note 5: NEM Generating Facilities with net export less than or equal to 500 kW that may flow across the Point of Common Coupling into Distribution Provider's Distribution or Transmission System will not be studied in the Transmission Cluster Study Process, but may be studied under the Independent Study Process.

Significance: Penetration of Generating Facility installations that does not result in power flow from the circuit back toward the substation will have a minimal impact on equipment loading, operation, and protection of the Distribution System.

b. Screen O: Power Quality and Voltage Tests

In aggregate with existing generation on the line section,

a) Can it be determined within the Supplemental Review that the voltage regulation on the line section can be maintained in compliance with Commission Rule 2 and/or Conservation Voltage Regulation voltage requirements under all system conditions?

b) Can it be determined within the Supplemental Review that the voltage fluctuation is within acceptable limits as defined by IEEE 1453 or utility practice similar to IEEE 1453?

c) Can it be determined within the Supplemental Review that the harmonic levels meet IEEE 519 limits at the Point of Common Coupling (PCC)?

- If yes to all of the above (pass), continue to Screen P

- If no to any of the above (fail), a quick review of the failure may determine the requirements to address the failure; otherwise Electrical Independence Tests and Detailed Studies are required. Continue to Screen P. (Note: If Electrical Independence tests and Detailed Studies are required, Applicants will continue to the Electrical Independence Tests and Detailed Studies after review of the remaining Supplemental Review Screens).

Significance: Adverse voltages and undesirable interference may be experienced by other Customers on Distribution Provider's Distribution System caused by operation of the Generating Facility(ies).

c. Screen P: Safety and Reliability Tests

Does the location of the proposed Generating Facility or the aggregate generation capacity on the Line Section create impacts to safety or reliability that cannot be adequately addressed without Detailed Study?

- If yes (fail), review of the failure may determine the requirements to address the failure; otherwise Electrical Independence Tests and Detailed Studies are required. Continue to Section G.3

- If no (pass), Supplemental Review is complete.

Significance: In the safety and reliability test, there are several factors that may affect the nature and performance of an Interconnection. These include, but are not limited to:

- Generation energy source

- Modes of synchronization

- Unique system topology

- Possible impacts to critical load customers

- Possible safety impacts.

The specific combination of these factors will determine if any system study requirements are needed. The following are some examples of the items that may be considered under this screen:

1. Does the Line Section have significant minimum loading levels dominated by a small number of customers (i.e. several large commercial customers)?

2. Is there an even or uneven distribution of loading along the feeder?

3. Is the proposed Generating Facility located in close proximity to the substation (i.e. <2.5 electrical line miles), and is the distribution line from the substation to the customer composed of large conductor/cable (i.e. 600A class cable)?

4. Does the Generating Facility incorporate a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time?

5. Is operational flexibility reduced by the proposed Generating Facility, such that transfer of the line section(s) of the Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues?

6. Does the Generating Facility utilize certified anti-islanding functions and equipment?

Endnotes

[1] Lori Bird, David Hurlbut, Pearl Donohoo, Karlynn Cory, and Claire Kreycik, *An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015*, National Renewable Energy Laboratory, Technical Report NREL/TP-6A2-45041, p.3 (March 2009), *available at* www.nrel.gov/docs/fy10osti/45041.pdf.

[2] 2011 National Summit on RPS, Presentation of Lawrence Berkeley National Laboratory, Oct. 26-27, slide 22: http://www.cleanenergystates.org/assets/Uploads/2011-RPS-Summit-Combined-Presentations-File.pdf.

[3] Larry Sherwood, *U.S. Solar Market Trends 2011* (Interstate Renewable Energy Council), p. 5 (July 2012).) *available at* http://www.irecusa.org/news-events/publications-reports/.

[4] *See Standardization of Small Generator Interconnection Agreements and Procedures,* Order No. 2006, FERC Stats. & Regs. ¶ 31,180 (Order 2006), order on reh'g., Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005)(Order 2006-A), *order on reh'g*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006)(Order 2006-B), *available at* http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.

[5] *See* Solar Energy Industries Association Petition for Rulemaking to Update Small Generator Interconnection Rules and Procedures for Solar Electric Generation, FERC Docket No. RM12-10-000 (SEIA Petition) (February 16, 2012).

[6] *See Massachusetts Distributed Generation Interconnection Report*, Prepared for Massachusetts Department of Energy Resources and Massachusetts Clean Energy Center by KEMA, pp. 25-26 (July 2011), *available at* www.mass.gov/eea/docs/doer/renewables/dg-inter.pdf.

[7] *See, e.g., PJM Interconnection, L.L.C.*, FERC Docket No. ER12-1177-000, Transmittal Letter, p. 1 (February 29, 2012) ("[PJM] hereby submits modifications to its Open Access Transmission Tariff ("PJM Tariff") to implement interconnection queue process reforms that are intended to relieve bottlenecks in the interconnection queue and provide for greater certainty and transparency."); *Cal. Independent System Operator Corp.,* FERC Docket No. ER11-1830-000, Transmittal Letter, p. 2 (October 19, 2010) ("[S]ince 2008, the ISO has experienced a large and rapidly increasing volume of small generator interconnection requests, to a level which has made it impossible for the ISO to study these projects serially under the method within the timelines of the current [SGIP]"); *So. Cal. Edison Co.,* Docket No. ER11-2977-000, Transmittal Letter, p. 3 (March 1, 2011) ("The revisions proposed by SCE will create a set of comparable rules for processing Small and Large Generator Interconnection Requests ("IRs") and address the delays in processing the WDAT's SGIP queue."); *Pacific Gas & Electric Co.*, FERC Docket No. ER11-3004-000, Transmittal Letter, p. 4 (March 2, 2011) ("Like the CAISO, PG&E has similarly experienced a dramatic increase in the number of small generator interconnection requests to interconnect with PG&E's distribution system. These requests, which are processed through PG&E's WDT SGIP, have also arisen as a result of California's RPS requirements. Currently, PG&E has a backlog of over 170 interconnection requests for small generators."); *see also Hawaiian Elec. Co.*, Hawaii Public Utilities Commission Docket No. 2010-0015 (2011) (addressing reforms to Rule 14H); Order Instituting Rulemaking, California Public Utilities Commission (CPUC) Docket No. R.11-09-011 (2012) (addressing reforms to California's Rule 21 to accommodate increasingly large numbers of interconnection requests to the distribution grid from exporting and wholesale generators).

[8] Michael Coddington, Benjamin Kroposki, Barry Mather (National Renewable Energy Laboratory); Kevin Lynn, Alvin Razon (Department of Energy); Abrahim Ellis, Roger Hill (Sandia National Laboratories); Tom Key, Kristen Nicole, Jeff Smith (Electric Power Research Institute), *Updating Interconnection Screens for PV System Integration,* National Renewable Energy Laboratory Technical Report NREL/TP-5500-54063 (Interconnection Screens Report) (January 2012), *available at* www.nrel.gov/docs/fy12osti/54063.pdf.

[9] FERC SGIP § 2.2.1.2 ("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.").

10 *See* SEIA Petition, p.1.

11 *See* Kevin Fox and Jason Keyes, *Comparison of the Four Leading Small Generator Interconnection Procedures* (Solar America Board for Codes and Standards), p. 1 (2008), *available at* http://www.solarabcs.org/about/publications/reports/interconnection/index.html.

12 *See Id.*

13 *See* CPUC Decision 00-12-037 (December 21, 2000), *available at* http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION//4117.pdf.

14 http://standards.ieee.org/findstds/standard/1547-2003.html.

15 IEEE Std 1547™ -2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems ("It is beyond the scope of this standard to address the methods used for performing EPS impact studies, mitigating limitations of the Area EPS, or for addressing the business of tariff issues associated with interconnection.").

16 FERC Order 2006, *available at* http://www.ferc.gov/EventCalendar/Files/20050512110357-order2006.pdf.

17 *Id.*

18 FERC Order 2006, FERC Order 2006-A, and FERC Order 2006-B, *supra*, note 4.

19 *See* FERC Order 2006 at P 512.

20 R. Brent Alderfer, Thomas Starrs, and M. Monika Eldridge, *Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects*, NREL/SR-200-28053 (Revised July 2000), *available at* www.nrel.gov/docs/fy00osti/28053.pdf.

21 The mention of 'best practices' was an indirect reference to the National Association of Regulatory Commissioners (NARUC) Small Generation Resource Interconnection Procedures.

22 *See Connecting to the Grid* (Interstate Renewable Energy Council), vol. 12, no. 1*, available at* http://www.irecusa.org/wp-content/uploads/January_2009_-_Connecting_to_the_Grid.pdf.

23 For example, Hawaii (Rule 14H), Nevada (Rule 15), and New Mexico incorporate significant portions of Rule 21 into state commission-approved interconnection tariffs.

24 *Database of State Incentives for Renewables and Efficiency* (DSIRE), Summary Maps, Interconnection, *available at* http://www.dsireusa.org/documents/summarymaps/interconnection.pdf.

25 *See* 2011 National Summit on RPS, Presentation of Lawrence Berkeley National Laboratory, Oct. 26-27, slide 8: http://www.cleanenergystates.org/assets/Uploads/2011-RPS-Summit-Combined-Presentations-File.pdf.

26 *See* DSIRE, Summary Maps, RPS Policies, *available at* http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

27 *See* 2011 National Summit on RPS, Presentation of Lawrence Berkeley National Laboratory, Oct. 26-27, slide 7: http://www.cleanenergystates.org/assets/Uploads/2011-RPS-Summit-Combined-Presentations-File.pdf.

28 *See* Lawrence Berkeley National Laboratory, RPS Compliance Data Spreadsheet, *available at* http://www.dsireusa.org/rpsdata/index.cfm (June 2012).

29 *See, e.g., The Bottom Line On…: Answers to frequently asked questions about climate and energy policy* (World Resources Institute)*,* Issue 19, pp.1-2 (January 2011), *available at* http://pdf.wri.org/bottom_line_emerging_solar_metering_policies.pdf; *Connecting to the Grid* (Interstate Renewable Energy Council), Vol. 13, No. 8, p.2 (August 2010), *available at* http://www.irecusa.org/2010/08/august-2010-connecting-to-the-grid-newsletter/.

[30] Kevin Fox & Laurel Varnado, *Sustainable, Multi-Segment Market Design for Distributed Solar Photovoltaics* (Solar America Board for Codes and Standards), p. 31 (October 2010), *available at* http://www.solarabcs.org/about/publications/reports/market-design/pdfs/ABCS-17_studyreport.pdf.

[31] *See* CPUC, RPS Procurement website, *available at* http://www.cpuc.ca.gov/PUC/energy/Renewables/procurement.htm (last visited June 28, 2012).

[32] *See* SEIA Petition, p. 6.

[33] *See U.S. Solar Market Trends 2011*, p.5, *supra*, note 3.

[34] Becky Campbell & Mike Taylor, *2011 SEPA Utility Solar Rankings,* p. 6 ("Utility Solar Rankings") (May 2012), *available at* www.solarelectricpower.org/media/257582/final%202011%20utility%20solar%20rankings%20report.pdf.

[35] *See Cal. Independent System Operator Corp.*, 140 FERC ¶ 61,070, at P 4 (July 24, 2012) (noting the CAISO's claims that its queue has four times the amount of new generating capacity necessary to meet a 33% RPS goal and that it expects that 75% of these projects will not be completed). *See also Briefing on Generation Interconnection Trends*, presentation by Bob Emmert to the CAISO Board of Governors Meeting, General Session, July 13-14, 2011, slide 2 (Reporting that the CAISO had over 70 GW of renewable energy projects in its current queue, including over 35 GW of solar PV), *available at* www.caiso.com/2bba/2bba799624040.pdf; *Briefing on Renewable Integration in the ISO Generator Interconnection Queue*, presentation by Bob Emmert to the CAISO Board of Governors Meeting, General Session, October 27-28, 2011, slide 2 (*showing that a significant amount of queued capacity dropped out of the queue between July 2011 and October 2011, including approximately 7 GW of solar PV)*, *available at* http://www.caiso.com/Documents/BriefingRenewableIntegration_in_ISO_GeneratorInterconnectionQueue_Presentation.pdf.

[36] *See* United States Department of Energy SunShot Initiative, High Penetration Solar Portal, *available at* https://solarhighpen.energy.gov/projects/does_high_penetration_solar_deployment_projects (last accessed June 30, 2012).

[37] K. Burman, J.Keller, and B. Kroposki (National Renewable Energy Laboratory); P. Lilienthal, R. Slaughter, and J. Glassmire (Homer Energy, LLC), *Renewable Power Options for Electrical Generation on Kaua'i: Economics and Performance*, NREL/TP-7A40-52076, p. 34 (November 2011), *available at www1.eere.energy.gov/office_eere/pdfs/52076.pdf.*

[38] DSIRE, Summary Maps, RPS Policies, *supra*, note 26.

[39] Utility Solar Rankings, p. 7, *supra*, note 34.

[40] *Id.* at p. 22.

[41] *Id.* at p. 14.

[42] Scoping Memo and Ruling of Assigned Commissioner, CPUC Docket No. R.11-09-011, (Order Instituting Rulemaking to improve distribution level interconnection rules for certain classes of electric generators), (6/20/2012), *available at* http://docs.cpuc.ca.gov/EFILE/RULC/169188.htm.

[43] Interconnection Screens Report, p. 10.

[44] *See, e.g.,* Motion to Intervene and Comments of SunPower Corporation, FERC Docket No. RM-12-10-000, p. 3 (March 26, 2012) (alleging that certain utilities rejects are rejecting all projects, whether state or federal jurisdictional, once "the amount of proposed solar generation exceeds 15% of a circuit's rated peak capacity"), *available at* http://elibrary.ferc.gov/idmws/File_list.asp?document_id=14006815; Motion to Intervene and Comments of enXco Development Corporation, FERC Docket No. RM-12-10-000, pp.3-4 (March 27, 2012) (alleging that a distribution utility in Massachusetts has a practice of setting hard capacity

limits on individual circuits based on voltage class), *available at* http://elibrary.ferc.gov/idmws/File_list.asp?document_id=14006814.

45 A summary of each state's interconnection procedures is available at DSIRE: http://www.dsireusa.org.

46 For example, Connecticut, Illinois, Kentucky, North Carolina, Pennsylvania, South Dakota, and others adopted the SGIP technical screens for their respective Fast Track processes. Other states feature slight variations to certain of the SGIP screens, or do not include certain of the screens, including Virginia and Oregon and high penetration states such as Colorado, New Jersey and Massachusetts. Though initial review in Hawaii and California is structured differently, the technical review screens are highly consistent with the SGIP.

47 Rule 21, E.1. The California Public Utilities Comission approved revisions to Rule 21 through Decision No. 12-09-018, issued on September 20, 2012. The previously effective Rule 21 and the newly adopted, revised version of Rule 21 are included as Attachments to the decision: Attachment E and Attachment A, respectively. Decision No. 12-09-018 is *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M028/K168/28168335.pdf.

48 *Id.*

49 SGIP Attachment 5 contains the terms and conditions of the 10 kW Inverter Process agreement, and establishes the procedure for utility processing. Since the interconnection agreement is embedded within the application documents, the customer does not need to complete a separate interconnection agreement.

50 FERC Order 2006 at P 405.

51 FERC Order 2006 at P 403; *see also* Interconnection Screens Report at p. 2.

52 N.M. Code R. § 17.9.568.10.

53 52 Pa. Code §§ 75.34(1), 75.37.

54 Fla. Admin. Code § 25-6.065(4)-(6).

55 O.A.R. 860-082-025(2)(a).

56 Massachusetts Model Interconnection Tariff: Standards for Interconnecting Distributed Generation § 3.0, D.P.U. Order No. 09-03-A, Appendix B, *available at* www.env.state.ma.us/dpu/docs/electric/09-03/82009noiapb.pdf.

57 *US Solar Market Trends 2011*, p. 7, *supra*, note 3.

58 Vermont Public Service Board, "Order implementing registration procedure for net-metered photovoltaic generation systems up to 10 kilowatts in capacity, pursuant to 30 V.S.A. § 219a(c)(1)" (May 31, 2012).

59 20 V.A.C. 5-315-30.

60 FERC Order 2006 at P 402.

61 SDG&E's online application for interconnection and net metering of systems 30 kW or less, *available at* https://nemapplication.sempra.com.

62 SCE's online NEM application, *available at* http://www.sce.com/customergeneration/solar-nem-application.htm.

63 Con Edison's Solar Energy Interconnection website, *available at* http://www.coned.com/dg/solarenergy/interconnection.asp.

64 *See* National Conference of State Legislatures' map of states that have adopted UETA, *available at* http://www.ncsl.org/issues-research/telecom/uniform-electronic-transactions-acts.aspx; *see also* Electronic Signatures in Global and National Commerce Act, Pub. L. No. 106-229, 114 Stat. 464 (2000) (codified at 15 U.S.C. § 7001 et seq.) (applies to the three states that have not adopted the UETA).

65 SCE's online NEM application for systems 10 kW or less, *supra*, note 62.

66 FERC Order 2006 at P 18.

67 FERC Order 2006 at P 171.

[68] SGIP § 2.4.1.

[69] Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) currently track the queues for WDAT applications and provide screen failure data. Queue data with screen failure detail is available for SCE at www.sce.com/nrc/aboutsce/regulatory/openaccess/wdat/wdat_queue.xls (Based on data updated on July 6, 2012); and for PG&E at www.pge.com/includes/docs/word_xls/b2b/newgenerator/wholesalegeneratorinterconnection/PGE_WDT_Queue_29June2012.xls (Based on data updated on June 29, 2012).

[70] SGIP § 2.1.

[71] FERC Order 2006 at P 172.

[72] CAISO GIP at § 5.1. CAISO explained: "From a transmission engineering perspective, a 5 MW generating facility is relatively small and generally would cause no greater impact than a 2 MW generator, such that including 5 MW facilities in the Fast Track Process will not jeopardize the safety and reliability of the ISO controlled grid." *Cal. Independent System Operator Corp.,* FERC Docket No. ER11-1830-000, Transmittal Letter to FERC, p. 21 (Oct. 19, 2010). FERC agreed, noting that SGIP was designed for distribution level interconnections and "may have been more restrictive than necessary when applied to the CAISO [transmission] grid." *Cal. Independent System Operator Corp.,* 133 FERC ¶ 61,223, at P 115 (December 16, 2010).

[73] PG&E's tariff is known as their Wholesale Distribution Tariff (WDT), but for simplicity sake we will refer to both the utility tariffs as WDATs.

[74] SCE WDAT GIP at Section 1.

[75] PG&E WDT GIP at § 2.1 ("The Fast Track Process is available . . . if the Generating Facility is no larger than 5 MW (up to 3 MW for a 21kV interconnection, and up to 2MW on a 12kV interconnection) . . .").

[76] *See So. Cal. Edison Co.*, 135 FERC ¶ 61,093, at PP 74-75.

[77] *See, e.g.,* DSIRE, State Interconnection Pages: Connecticut, Indiana, Maine, Iowa, Oregon, Utah, Colorado, South Dakota, Illinois, North Carolina, Virginia, District of Columbia, Delaware, Pennsylvania, New Jersey, and New Mexico, *supra*, note 45.

[78] *See, e.g.,* DSIRE, State Interconnection Pages: Nebraska, Georgia and Louisiana, *supra*, note 45.

[79] *See, e.g.,* DSIRE, State Interconnection Pages: Massachusetts, Nevada, Hawaii, *supra*, note 45.

[80] Rule 21 at E.2.b.i, *supra*, note 47. The SDG&E eligibility limit for fast track differs from those of SCE and SDG&E due to differences in the voltage level and conservation voltage requirements of SDG&E's distribution system.

[81] *See So. Cal. Edison,* 135 FERC ¶ 61,093, at P 65 ("[SCE] agrees that the screens are the limiting factor in determining fast track eligibility, particularly at voltages of 16 kV and below. [SCE] states, however, that for voltage circuits greater than 16 kV, the screens would not necessarily be able to filter out projects larger than 2 MWs due to higher average peak loads on higher voltage circuits.").

[82] *See, e.g.,* SGIP § 2.2.1.2; Rule 21 Screen M, *supra*, note 47; *but see, e.g.,* Massachusetts Standards for Interconnecting Distributed Generation, Appendix B, Figure 1 (applying as the penetration screen a threshold of 7.5% of circuit annual peak load.); New Jersey Interconnection Procedures, N.J.A.C. § 14:8-5.5(f) (Setting the aggregate generation capacity at "10 percent (or 15 percent for solar electric generation) of the total circuit annual peak load.").

[83] *See* SCE and PG&E queue data, *supra*, note 69.

[84] *See, e.g.,* Rule 21 (old) Screen 4 Significance Notes, *supra*, note 47 (Attachment E to Decision No. 12-09-018); California Energy Commission (CEC), *California Interconnection Guidebook: A Guide to Interconnecting Customer-owned Electric Generation Equipment to the Electric Utility Distribution System Using California's Electric Rule 21*, p. 43 (CEC Guidebook) (September 2003), *available at* www.energy.ca.gov/reports/2003-11-13_500-03-083F.PDF.

[85] Interconnection Screens Report, p. 2.

86 CEC Guidebook, p. 43, *supra*, note 84; Interconnection Screens Report, p. 2 ("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.").

87 CEC Guidebook, p. 43, *supra*, note 84; Interconnection Screens Report, p. 2 ("For typical distribution circuits in the United States, minimum load is approximately 30% of peak load.").

88 Interconnection Screens Report, p. 7.

89 Administrative Rules of Montana 38.5.8410(2)(a) (Montana Small Generator Interconnection Procedures).

90 Arizona Interconnection Document, Section 4.2(a), *available at* http://images.edocket.azcc.gov/docketpdf/0000074361.pdf (attached as Exhibit to Decision No. 69674).

91 Hawaii Rule 14H, Appendix III, 3(d).

92 Rule 21 G.2, Screen M & N.

93 *Id.* (Note 1).

94 *See, e.g.,* Rule 21 (old) I.3.f (allowing projects 11 kVA or less to skip the short-circuit contribution and line configuration screens), *supra*, note 47 (Attachment E to Decision No. 12-09-018); Rule 21 § G.1.f, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

95 Rule 14H, Appendix III, Section 2, Screen 6.

96 Rule 14H, Appendix III, Section 2.

97 SGIP § 2.2.1.6.

98 *Id.*

99 IEEE Standard P.1547-2008 (4.1.2) Integration with Area EPS Grounding (working group draft).

100 Rule 21 at G.2.h, *supra,* note 47 (Attachment A to Decision No. 12-09-018). For further explanation, see Mike Sheehan, *Photovoltaic Generation: Temporary Overvoltage Impact and Recommendations* (Solar America Board for Codes and Standards), p.16 ("The 10% limit ensures that the local load is much greater than the output of the generating facility so that the load causes a significant voltage drop and prevents the possibility of overvoltage caused by loss of system neutral grounding.") (Temporary Overvoltage Report) (*publication pending*).

101 *Id.*

102 Hawaii Rule 14H at 38D-8, 38D-12.

103 For a more complete discussion of the grounding options see Temporary Overvoltage Report, *supra*, note 100.

104 Hawaii Rule 14H at 38D-17.

105 Rule 21 at G.1, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

106 SGIP § 2.2.3.

107 North American Electric Reliability Corporation, Glossary of Terms Used in Reliability Standards, Apr. 20, 2009, available at: www.nerc.com/files/Glossary_2009April20.pdf.

108 Michael Sheehan and Thomas Cleveland, *Updated Recommendations for Federal Energy Regulatory Commission Small Generator Interconnection Procedures Screens* (Solar America Board for Codes and Standards), p. 8 (July 2010).

109 Rule 21 § G.1.l, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

110 PJM Interconnection L.L.C., Transmittal Letter and Clean Tariff, Docket No. ER12-1177-000 (Feb. 29, 2012).

111 *Id.* at 12-13.

112 Proposed PJM Tariff Sections 110.1.1, 111.1.1, and 112.1.1s.

113 SGIP § 2.2.1.10.

[114] SGIP §§ 2.3.1 (providing changing meters, fuses, or relay settings as examples of minor modifications), 2.4.1.2, 2.4.1.3.

[115] *See, e.g.* DSIRE, State Interconnection Pages: Illinois, Colorado, and North Carolina; *but see* Indiana and South Dakota, *supra*, note 45.

[116] *See, e.g.* DSIRE, State Interconnection Pages: New Mexico, Massachusetts, and Nevada, *supra*, note 45.

[117] *See* SCE and PG&E queue data, *supra*, note 69.

[118] SCE WDAT § 6.5.10; *see also So. Cal. Edison Co.,* 135 FERC ¶ 61,093, at P 94.

[119] PG&E WDT § 2.3.3; *see also Pacific Gas & Electric Co.*, 135 FERC ¶ 61,094, at P 65.

[120] PG&E WDT § 2.4.1.1.

[121] PG&E WDT § 2.3.4.

[122] SGIP § 2.3.2.

[123] Hawaii Rule 14H, Sheet No. 34D-16.

[124] Hawaii Rule 14H, Appendix III, 3(d).

[125] "Hawaiian Electric companies ease pay to solar electric power", Hawaiian Electric Company News Release, September 18, 2012, *available at*: http://www.heco.com/vcmcontent/StaticFiles/pdf/20120918-easier2addsolar2roofs.pdf.

[126] Hawaii Rule 14H, Appendix III, 3(d).

[127] Hawaii Rule 14H, Sheet No. 34B-9 – 12.

[128] Rule 21 G.2, Screen N, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

[129] Rule 21 G.2, Screen O, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

[130] Rule 21 G.2, Screen P, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

[131] SGIP § 3.3; SGIP Attachment 6.

[132] SGIP § 3.4; SGIP Attachment 7.

[133] SGIP § 3.4.2.

[134] SGIP § 3.5; SGIP Attachment 8; FERC Order 2006 at P 44.

[135] SGIP § 3.2.2.

[136] SGIP § 3.3.4; 3.4.5.

[137] CAISO Tariff § 6.4.

[138] CAISO Tariff § 7.1.

[139] CAISO Tariff § 4.0.

[140] CAISO Tariff § 4.4.4; SCE WDAT § 5.8.1.2. PG&E provides for 60 *business days,* which is roughly similar to 90 calendar days. PG&E WDAT Attachment 7, § 7.0 & 9.0.

[141] CAISO Tariff § 4.5.3; SCE WDAT § 5.8.2.3. PG&E provides 60 business days where upgrades are required and 45 business days where only interconnection facilities must be studied. PG&E WDAT Attachment 8, § 7.0.

[142] Rule 21 E.2.b, *supra*, note 47 (Attachment A to Decision No. 12-09-018).

[143] Though it should be noted that in California the utilities were rarely able to keep the time allocated for each study due to the increasing volume of requests they were reviewing. This may be the case in other high volume states.

[144] SGIP § 1.6.

[145] *See, e.g.,* www.oatioasis.com/FPC/FPCdocs/GIS_Queue_Table_061212.mht (Florida Power Corporation generator queue); www.oatioasis.com/DUK/DUKdocs/genqueuedetails.pdf (Duke Energy Carolinas generator queue).

[146] *See, e.g., Cal. Independent System Operator Corp.,* FERC Docket No. ER11-1830-000, Transmittal Letter, p. 2 (October 19, 2010) ("[A]s more projects enter the queue, a study backlog develops and becomes increasingly large as more projects enter the queue, because subsequent projects must wait for the results of the studies of any electrically related earlier queued projects to be studied."); *So. Cal. Edison Co.,* Docket No. ER11-2977-000, Transmittal Letter, p. 3 (March 1, 2011) ("SCE similarly estimates that it would take as long as six to seven years to complete the studies for all of the Small Generators currently in the SCE queue."); *Pacific Gas & Electric Co.*, FERC Docket No. ER11-3004-000, Transmittal Letter, p. 4 (March 2, 2011) ("Because each project has its own separate timeline, a study for one project can not be undertaken until the studies for previous, electrically-related projects are completed. As additional small generator interconnection requests enter the queue, a study backlog develops and becomes increasing large.").

[147] *See, e.g., PJM Interconnection, L.L.C.*, Docket No. ER12-1177-000, 139 FERC ¶ 61,079 (2012); *Cal. Independent System Operator Corp.,* Docket No. ER11-1830-000, 133 FERC ¶ 61,223 (2010); *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER08-1169-000, 124 FERC ¶ 61,183 (2008). The approved tariffs are *available at* www.pjm.com/~/media/documents/manuals/m14a.ashx (PJM Manual 14A); www.caiso.com/Documents/AppendixY_2012-04-18.pdf (CAISO Appendix Y); https://www.midwestiso.org/_layouts/MISO/ECM/Download.aspx?ID=19304 (MISO Attachment X).

[148] *See, e.g., So. Cal. Edison Co.*, 135 F.E.R.C. ¶ 61,093 (2011); *Pacific Gas & Elec. Co.*, 135 F.E.R.C. ¶ 61,094 (2011). The approved tariffs are *available at* http://asset.sce.com/Documents/About%20SCE/WholesaleDistributionAccessTariffv3.pdf (SCE Attachment G); www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/tariffs/PGE_Wholesale_Distribution_Tariff.pdf (PG&E Attachment I).

[149] *See* Motion for Approval of Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations, CPUC Docket R.11-09-011, p.7 (March 16, 2012) (recommending that the CPUC consider distribution group studies as part of Phase II of the rulemaking in Docket No. R.11-09-011), *available at* http://docs.cpuc.ca.gov/EFILE/MOTION/162852.PDF.

[150] *See* Interstate Renewable Energy Council's Motion to Intervene in FERC Docket No. ER11-3004-000, Attachment G: Cluster Timeline (slide from January 25, 2011 presentation on "Redefined PG&E WDT Generation Interconnection Proposal: Generation Interconnection Procedures") (March 23, 2011), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12594944.

[151] *See So. Cal. Edison Co.,* 135 FERC ¶ 61,093 at P 28.