Comparison of the Four Leading Small Generator Interconnection Procedures

Prepared by
Jason B. Keyes and Kevin T. Fox
Interstate Renewable Energy Council

Solar America Board for Codes and Standards

http://www.solarabcs.org

□□□□

Solar American Board for Codes and Standards Report

Comparison of the Four Leading Small Generator Interconnection Procedures

Prepared by

Jason B. Keyes and Kevin T. Fox

Interstate Renewable Energy Council

October 2008

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States government. Neither the United States government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States government or any agency thereof

Download a copy of the report:

www.solarabcs.org/interconnection

Executive Summary

Public interest in distributed generation, particularly solar energy systems, has fostered federal and state legislation calling for streamlined procedures for interconnection of generators to the electric grid. Existing procedures have proven inadequate in many cases, with high costs, lengthy timelines, bureaucracy, and uncertainty acting as formidable barriers to entry. In response to the continuing wave of legislation, utility regulators at the state and local levels are actively revising their interconnection procedures and will continue to do so in the future. This paper is intended to serve as a guide for those regulators.

This paper reviews four sets of interconnection procedures that regulators often consider when developing state and local procedures. As a framework for review, the paper uses the grading criteria developed by the Network for New Energy Choices (NNEC) and used in that organization's review of state interconnection procedures (*Freeing the Grid*, 2008).

The four interconnection procedures that are reviewed based on the NNEC criteria are:

1. The federal procedures, in two parts: the Small Generator Interconnection Procedure (SGIP) and the Small Generator Interconnection Agreement (SGIA) developed by the Federal Energy Regulatory Commission (FERC) in 2005 and refined in 2006.
2. California's Rule 21 (CA Rule 21), first approved in December 2000, modified slightly through utility tariff filings, and used for the interconnection of the majority of solar facilities and other distributed generation facilities in the United States.
3. The Mid-Atlantic Demand Resource Initiative procedures (MADRI Procedures developed in 2005 by the utility commissions of Delaware, New Jersey, Maryland, Pennsylvania, the District of Columbia, the PJM Interconnection (the regional transmission organization for the states just listed), and various federal agencies.
4. The Interstate Renewable Energy Council's Model Interconnection Standards and Procedures for Small Generator Facilities (IREC Procedures) finalized in late 2006.

The SGIP/SGIA and CA Rule 21 were developed through the efforts of utilities, regulators, industry representatives, consumer and environmental advocates, and other interested parties. The MADRI Procedures are the product of a regional effort in an area with minimal distributed generation, which tended to limit representation to utilities and regulators. The IREC Proceduresare an assemblage of best practices from the SGIP/SGIA, the MADRI Procedures, and various state procedures. The Interstate Renewable Energy Council (IREC) is a nonprofit organization that has actively participated in dozens of state rulemakings and helped NNEC develop the criteria in *Freeing the Grid* (2008). NNEC is a nonprofit organization primarily funded by a family trust without ties to the solar industry. Citations and links to the four procedures and *Freeing the Grid* (2008) are provided in the references section of this paper.

Background on the four procedures and the development of interconnection procedures generally is presented in the introduction and literature review sections. Review of the four procedures using the NNEC criteria is provided in the analysis section, along with a description of the relevance of each criterion. The analysis section is the most detailed portion of the paper, and one could skip directly to the conclusions and recommendations sections depending on one's level of interest. A table summarizing the scores for the four sets of procedures for each *Freeing the Grid* (2008) criterion is presented in the conclusions section.

Summary of Conclusions

The NNEC grading criteria in *Freeing the Grid* (2008) are all set at a score of zero for the SGIP/SGIA (the federal procedures), and state procedures receive positive or negative points for each of the criterion based on a comparison with the SGIP/SGIA. The SGIP/SGIA is given a grade of "C," and only twelve state procedures score higher. One of those is CA Rule 21, receiving a "B." As the NNEC looked to the IREC Procedures to determine what features should be awarded maximum criterion scores, it is not surprising that the IREC Procedures receive an "A." The MADRI Procedures receive a low C, which surpasses the procedures (or lack of procedures) in 35 states as of October 2008, according to *Freeing the Grid* (2008).

The procedures reviewed in this report have similar provisions on three key points that regulators should recognize as essential: one standard for all technologies, applicability to systems up to at least 10 MW, and use of national engineering standards. On a fourth important point, all of the procedures except the SGIP/SGIA do not require insurance for most systems, and the authors of this report recommend that insurance not be required. As well, all but CA Rule 21 use the basic format of the SGIP/SGIA, and the authors consider this uniformity a useful benefit because industry and utilities are already familiar with the federal procedures.

There are two key differentiators between the IREC Procedures and the other three: whether an external disconnect switch is required and size limitations for interconnection to spot networks and area networks. NNEC and IREC believe that both issues are viewed with excessive caution by utilities while the other procedures reviewed here err on the side of caution. A third differentiator is the dispute-resolution process, with the IREC Procedures settling on use of a technical master to make binding decisions rather than relying on costly arbitration and litigation, which are impractical solutions for minor disputes. And finally, the IREC Procedures and CA Rule 21 adopt simplified processes to interconnect systems that cannot export power to the electric grid while the other procedures do not.

Summary of Recommendations

The authors are attorneys who represent IREC in interconnection and net metering rulemakings before state utility commissions. In 2007-2008, this representation entailed travel to a dozen states to participate in workshops and formal rulemakings. As well, the authors participated in the refinement of *Freeing the Grid* for 2008. Obviously, this biases the authors in favor of the NNEC grading methodology and the IREC Procedures. Nevertheless, the authors believe that *Freeing the Grid* (2008) provides a fair and objective set of criteria for assessing state interconnection procedures in light of the goal of facilitating the interconnection of distributed generation. A concerted attempt has been made to present differing viewpoints as fairly as possible and to critique the IREC Procedures.

The authors' primary recommendation is that utility regulators use familiar procedures as a starting point for the development of their own rules. Any of the four procedures discussed here can serve as a suitable starting point, though the authors favor the IREC Procedures. As regulators develop rules starting from selected procedures, each NNEC criterion should be considered, and regulators should either adjust the procedures they are using to maximize the NNEC score or articulate why they are choosing an alternative approach. Especially with respect to criterion related to cost causation, regulators should consider whether there are offsetting benefits that justify applying a particular cost to ratepayers generally. And finally, beyond the NNEC criteria, the authors recommend that regulators strive to achieve the somewhat conflicting goals of simplicity and comprehensiveness. Distributed generation is far more likely to be deployed if developers and utility customers can easily discern what the costs of interconnection are and how long the approval process will take.

Author Biographies

Jason B. Keyes and Kevin T. Fox

Jason Keyes

Jason Keyes co-founded Keyes & Fox, LLP in 2008. Primarily, he represents the Interstate Renewable Energy Council in state utility commission rulemakings related to net metering and interconnection of renewable energy systems. His background includes regulatory work related to renewable energy project development and finance, eight years of government contract management for a solar energy start-up, and integrated resource planning for a major electric utility. Jason holds a JD from Seattle University School of Law, an M.A. in Economics from the University of Washington and a B.A. from Dartmouth College.

Kevin Fox

Kevin Fox co-founded Keyes & Fox, LLP with Jason Keyes. Kevin's background includes regulatory work for electric, natural gas and water utilities as well as regulatory and project finance work for renewable energy project developers. He also completed research fellowships with two United States Department of Energy laboratories and worked in the Demand Analysis Division of the California Energy Commission. Like Jason, Kevin's current practice focuses on representation of the Interstate Renewable Energy Council in rulemakings related to net metering and interconnection of renewable energy systems. Kevin holds a J.D. from the University of California at Berkeley and a B.S. in Energy Policy Analysis and Planning from the University of California at Davis.

Interstate Renewable energy Council Web site:

www.irecusa.org

Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds Solar ABCs as part of its commitment to facilitate wide-spread adoption of safe, reliable, and cost-effective solar technologies.

Solar America Board for Codes and Standards Web site:

www.solarabcs.org

Acknowledgements

This material is based upon work supported by the Department of Energy under Award Number DE-FC36-07GO17034.

Table of Contents

Disclaimer ii

Executive Summary iii

Summary of Conclusions iv

Summary of Recommendations iv

Author Biographies v

Solar America Board for Codes and Standards v

Acknowledgements v

Introduction 1

A brief history of interconnection procedures 1

NNEC's *Freeing the Grid* 3

Overview of the four interconnection procedures 5

FERC's small generator interconnection procedures and agreement 6

California's Rule 21 7

MADRI small generator interconnection procedures 9

IREC's interconnection procedures 10

Literature review 11

Analysis 12

1. Eligible Technologies 12
2. System Capacity 12
3. Breakpoints 12
4. Timelines 14
5. Interconnection Charges 16
6. Engineering Charges 17
7. External Disconnect Switch 18
8. Certification 19
9. Technical Screens 19
10. Spot Network Interconnection 20
11. Area Network Interconnection 21
12. Standard Form Agreement 22
13. Insurance Requirements 22
14. Dispute Resolution 23
15. Rule Coverage 23
16. Miscellaneous 24

Conclusions 24

NNEC grading of the SGIP 24

NNEC grading of CA Rule 21 25

NNEC grading of the MADRI Procedures 25

NNEC Grading of the IREC Procedures 26

Recommendations 28

References 29

Procedures reviewed in this paper 29

Other procedures and standards 29

Reports and other publications 29

Legislation, statutes, regulations and administrative issuances 30

Introduction

The focus of this paper is on the practical matter of how four of the most well used interconnection procedures are graded under the Network for New Energy Choices (NNEC) grading criteria, with the intent of helping regulators and utilities select useful starting points for the development of their own rules. Provided in this section are introductions to the four procedures that are analyzed in depth in the analysis section. To preface that discussion, this introduction provides a description of the sixteen NNEC grading criteria used in NNEC's publication, *Freeing the Grid* (2008), which is the basis of the analysis in this paper.

It is helpful to be familiar with the history of interconnection procedures, prior to the review of the NNEC grading criteria and the four procedures; therefore, this introduction begins on that note.

A brief history of interconnection procedures

Prior to 2003, few states had comprehensive rules for interconnection of distributed generation, which can be described roughly as anything from a hundred-watt solar panel up to a 20-megawatt combustion turbine. Rules for interconnection of larger, traditional utility-scale generators were applied to distributed generation, with varying degrees of recognition that these smaller systems were less complex. The existing rules were based on interconnection to high-voltage transmission lines, where generation was traditionally located, though small distributed generators more often tie into medium-voltage utility distribution lines. For the most part, utilities had broad discretion to study the impact of an interconnection at the customer's expense. In addition, because few small generator interconnections were proposed, a lack of utility experience with these interconnections meant that the cost of the review process could overwhelm the cost of the system itself, particularly for modest residential-scale systems. Following on interconnection rule development in Texas and New York, California was among the first states to attempt a comprehensive rule for interconnection of distributed generation with the development of CA Rule 21 in the year 2000, but few other states followed that lead.

Three critical events in 2003 foreshadowed the widespread adoption of interconnection procedures for distributed generation that exists today. First, the Institute of Electrical and Electronic Engineers (IEEE) finalized IEEE 1547—the Standard for Interconnecting Distributed Resources with Electric Power Systems. This provided the basic technical requirements for interconnection. Second, the Federal Energy Regulatory Commission (FERC) issued Order 2003, the Large Generator Interconnection Procedure (LGIP) for interconnections over 20 MW. The LGIP was the model for FERC's Small Generator Interconnection Procedure (SGIP) in several ways and preceded the SGIP by two years. And third, the National Association of Regulatory Commissioners (NARUC) finalized its Small Generation Resource Interconnection Procedures (NARUC Procedures, 2003). NARUC submitted its new procedures to FERC in the early stages of the docket that led to FERC Order 2006, which set the SGIP/SGIA as the federal procedures.

The NARUC Procedures are the genesis of the three interconnection procedures other than CA Rule 21discussed in this paper, though the NARUC Procedures are not themselves widely referenced any longer because they have not been updated since 2003. In turn, CA Rule 21 is the source of many of the concepts in the NARUC Procedures, though their organizational structures differ.

The NARUC Procedures (and, to an extent, CA Rule 21) established:

- much of the application process
- many of the technical screens used in current rules
- a fast-track process for generators that passed the technical screens

- the 20-MW threshold adopted by the SGIP (CA Rule 21 has no capacity limit)
- the standard three-step structure for utility study of more complex generators (feasibility, impact, and facilities studies)
- the use of a standard form agreement between the utility and the customer
- reliance on IEEE 1547.

Beyond all of this, perhaps the most important contribution of the NARUC Procedures and CA Rule 21was their recognition of a fundamental dividing line between interconnection to transmission lines and interconnection to distribution lines. The NARUC Procedures and subsequent procedures uphold the traditional approach to transmission line interconnection, which allows extensive utility discretion to study proposed interconnections at great length at the applicant's expense. But for distribution line interconnections, the NARUC Procedures established that, under certain conditions, additional study is rarely required.

By the time the NARUC Procedures were being cited as exemplifying "best practices" in federal law, they were already being supplanted by other procedures. In August 2005, the Energy Policy Act of 2005 (EPAct 2005) required all state regulators and unregulated utilities, with over 500 million kWh of annual load, to consider the implementation of interconnection procedures. Referencing the NARUC Procedures indirectly, EPAct 2005, section 1254, states that agreements and procedures should be considered to:

> "promote current best practices of interconnection for distribute generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential."

NARUC was the only "association of state regulatory agencies" with interconnection procedures and the obvious referent in this provision. EPAct 2005 established that regulators and utilities had one year from enactment of the law to begin their consideration of interconnection agreements and procedures and two years to finish their consideration.

"... the Energy Policy Act of 2005 (EPAct 2005) required all state regulators and unregulated utilities, with over 500 million kWh of annual load, to consider the implementation of interconnection procedures."

Although the two-year window established in EPAct 2005 has passed, the development of interconnection procedures is still actively underway in many states, often driven by state legislation requiring interconnection rules. Several states continued past the two-year deadline of August 8, 2007, with the implicit or explicit reasoning that consideration of whether to implement rules was made by the deadline, while the initial rulemaking could extend beyond that date. For example, Illinois explicitly made this argument by the deadline and adopted its interconnection procedures in August 2008.

For those reviewing EPAct 2005, it seems that, on cursory review, all utilities are required to adopt interconnection procedures. In fact, EPAct 2005 places what appears to be a requirement into the Public Utility Regulatory Policies Act of 1978 (PURPA), but the placement within PURPA actually makes the provision less than a requirement. EPAct 2005 § 1254(a) adds a "federal standard" to PURPA § 111(d), and PURPA § 111(a) says that state regulators and "each nonregulated utility" have to consider adopting the federal standards in § 111(d) but are not required to do so. The interconnection provisions placed into PURPA by EPAct 2005 are at PURPA § 111(d)(15) (or see 16 U.S.C. § 2621(d)(15)). PURPA applies to state utility commissions and to unregulated utilities with sales of over 500 million kWh per year, which is approximately 57 average MW.

Despite being referenced in EPAct 2005, the NARUC Procedures are rarely reviewed by state regulators developing procedures. Instead, for various reasons, the SGIP/SGIA, the MADRI Procedures, and the IREC Procedures have been used, along with various state interconnection procedures.

NNEC's *Freeing the Grid*

The Network for New Energy Choices (NNEC) first published *Freeing the Grid* in 2006 to analyze and compare net metering and interconnection rules from all of the states. In 2007, NNEC teamed with the Solar Alliance, the Vote Solar Initiative, and IREC to refine and expand its analysis. Thirty-four states and the District of Columbia had interconnection procedures as of the publication of the 2008 report and received letter grades based on sixteen criteria. The SGIP/SGIA is used as a reference point for grading, with a score of zero for each criteria and an overall grade of "C." The 2008 edition of *Freeing the Grid* was published in October 2008.

The analysis section of this paper is divided into the sixteen scoring criteria with analysis of each of the four interconnection procedures under each criterion. Briefly, the sixteen criteria are as follows:

1. Eligible technologies—deduction if not comprehensive
2. System capacity—deductions for capacity limits under 20 MW
3. Breakpoints—credit for applicant tracks, deduction for single approach for all applicants
4. Timelines—credit for faster than SGIP; deduction for slower
5. Interconnection charges—credit for application fees lower than SGIP; deduction for higher
6. Engineering charges—credit if fixed rather than variable
7. External disconnect switch—credit if prohibited; deduction if required
8. Certification—deduction if IEEE 1547 is not followed; credit for self-certification
9. Technical screens—deduction for screens beyond SGIP; credit for easier screens than SGIP unless safety is affected
10. Spot network—credit if systems over 50 kW allowed, deduction if not allowed
11. Area network—credit if clearly allowed; deduction if not allowed
12. Standard form agreement—credit if easier than agreement under SGIP; deduction if harder or left to utility discretion
13. Insurance requirement—credit if prohibited; deduction if required
14. Dispute resolution—credit if simplified and low cost
15. Rule coverage—credit if applicable to all utilities in state, zero if only applicable to investor-owned utilities
16. Miscellaneous—catchall for other issues (rarely used)

Any scoring methodology can be criticized and, certainly, *Freeing the Grid* will refine its criteria and scoring methodology in future years, but fundamentally, the publication offers a valuable service. State regulators considering a specific issue can look to *Freeing the Grid* to see how other states have addressed that issue. States with the lowest scores have almost no distributed generation, and it is reasonable to correlate those facts. Thus, if state regulators hope to encourage the installation of distributed generation, they can see which state procedures to avoid and which to consider.

All of the entities participating in development of the 2008 NNEC scoring criteria favor widespread installation of solar energy systems, which raises the question of whether safety, grid reliability, and cost issues are fairly addressed. Put another way, a reasonable criticism of the NNEC criteria is that a state rule that simply required all systems to be quickly interconnected at no cost to the customer would receive an "A." However, even such a simple rule would essentially come down to a matter of cost allocation between interconnection customers and ratepayers. Utilities would still have a duty to assure safe and reliable service and could comply with the simple interconnection rule by having staff and equipment on hand to respond to all interconnection requests rapidly.

Only five of the NNEC criteria relate to safety in any way: criteria 7 through 11. Regarding criteria 8 through 11, utilities argue that a relaxation of certification requirements, expansion of fast-track screens, or inclusion of network interconnection procedures may compromise reliability, and thereby, safety. In each case, the NNEC counters that reliability can be maintained while allowing some easing of the SGIP/SGIA procedures on which the scoring is based. The argument seems sound; the United States and other nations have much more experience with interconnection of distributed generation than was the case in 2005 when the SGIP/SGIA was implemented. The SGIP/SGIA set very cautious or incomplete standards on these points, and reconsideration is appropriate.

Safety is also asserted to be an issue with respect to criteria 7, regarding the external disconnect switch. Again, the NNEC believes that the experience of the past three years should inform policy. An extensive analysis by the US DOE's National Renewable Energy Laboratory (NREL) concluded in 2008 that the switches are unnecessary for systems under 10 kW. As well, a study funded by the Solar America Board for Codes and Standards on the topic, due to be released in late 2008, reaches a similar conclusion. New Jersey has prohibited utilities from requiring the switches with no adverse effects, and several states prohibit the requirement for small facilities. All of these factors support at least an easing of the requirement, indicating that the NNEC scoring is appropriate.

Cost is directly an issue in criteria 4 through 6, regarding timelines and charges. Complying with shorter timelines arguably takes additional staff, and the application fees or fixed engineering fees may not cover all of a utility's costs. It is essentially a policy issue to set these levels, and renewable energy advocates favor low fees and short timelines. However, this raises the question of cost allocation. Regulators often question whether ratepayers without renewable generation are paying higher rates without corresponding benefits to cover the expense of interconnecting their neighbors' solar arrays and other generators. The value of distributed generation to ratepayers is therefore scrutinized; value beyond delivered energy is often found in capacity, environmental, and back-up attributes.

Interconnection cost allocation between owners of distributed generation and utility ratepayers is a frequently raised issue. Utilities often stress the need to have the owner bear all costs, but there are several counter-arguments. First, distributed generation provides a system benefit of reduced demand on the electric grid, which has some positive value. Second, distributed generation is typically renewable, providing emissions reductions that are important to society, including utility ratepayers. Third, the costs realized in states with more experience in interconnecting distributed generation may serve as a guide justifying a limit on recoverable utility costs based on the cost to perform the same function in other states. And fourth, program start-up costs per customer are very likely to be much higher than program costs per customer with a mature program, so establishing fees at a level that is below initial costs at early stages is justified to launch programs with recognizable benefits to utility ratepayers. As more experience is gained, the average cost to interconnect a system is likely to trend downward.

The remaining criteria have no affect on safety, reliability, or cost, but rather are structural. Among these is criterion 13, insurance provisions, which is typically based on a cost allocation argument. If something goes wrong with a customer's generator, utilities contend that other ratepayers should not bear the expense of damage to the utility grid. However, with over 50,000 solar arrays in the US, the authors are not aware of any case of line worker injury or significant utility property damage attributable to solar energy systems or any other systems. In any event, solar arrays are expensive assets that are almost always covered under a property owner's insurance. Such insurance would typically provide protection if damage or injury occur. In short, it appears unlikely that a prohibition on additional insurance requirements would have any cost impact for other ratepayers, but requiring additional insurance will add cost for the system owner.

To summarize, the NNEC grading methodology was created by solar energy advocates, but that does not mean that its results are unreasonable. Solar energy system owners, developers, and installers have a great deal of experience with interconnection issues. Many of these individuals came from the utility industry and appreciate the technical and administrative issues that utilities face when interconnecting distributed generation. The intent of the NNEC grading methodology is to foster the widespread installation of distributed generation in a way that does not compromise safety and reliability. In the authors' opinion, the NNEC grading methodology does that quite well.

Overview of the four interconnection procedures

Although this paper focuses on the differences between the SGIP/SGIA, CA Rule 21, the MADRI Procedures, and the IREC Procedures, their many commonalities establish a relative baseline of interconnection procedure essentials. These common elements are sometimes missing when state procedures are adopted; absence of any of these elements is a substantial hindrance and a cause for point deductions under the NNEC grading criteria.

Among the common elements of all four procedures under review here are the following:

- Coverage of all technologies, rather than just renewables
- Interconnection of systems up to at least 10 MW
- Pro forma interconnection agreements
- A simplified procedure for small solar arrays covering most residential installations
- A fast track procedure for systems up to 2 MW that allows interconnection without additional cost or delay if certain screens are met
- A scoping meeting if screens are not met to review expected costs and duration of studies
- A three-part study (feasibility, impact, and facilities) process for interconnection of more complex and larger systems (CA Rule 21 has an supplemental review process as a first step for systems that do not meet all of the screens and, failing that, a single study process that essentially includes the three study areas listed.)
- Comprehensive coverage of issues such that utility discretion to create substantive additional rules is largely foreclosed

A lack of basic elements such as these is a common theme among states receiving the lowest grades from NNEC.

While the analysis in this report focuses on differences between the procedures being reviewed, it is important to recall that there are central features to all of them. Background on each of the procedures and a summary of its grading under the NNEC criteria are provided below.

FERC's small generator interconnection procedures and agreement

FERC began the development of the SGIP in 2002 and, with extensive participation by utilities, regulators, renewable energy advocates, industry, and government experts, issued FERC Order No. 2006, on May 12, 2005. Accompanying the SGIP in Order 2006 was the Small Generator Interconnection Agreement (SGIA), a standard form agreement. Through subsequent orders, FERC developed its final version of the SGIP and SGIA on August 28, 2006, in Order 2006-B. It is this final version of the SGIP/SGIA that is reviewed in this paper.

The SGIP's significance rests in its application for large distributed generators, its widespread adoption, and its function as a model for state procedures. For interconnection of distributed generators under a few megawatts, which is the vast majority of such interconnections, it is rarely applicable.

Order 2006 requires all public utilities that own, control, or operate facilities under the FERC's jurisdiction to file standard procedures, the SGIP, and a standard agreement, the SGIA, to interconnect generating facilities up to 20 MW. FERC has jurisdiction over utility high-voltage transmission lines, but, except for limited situations, FERC does not have jurisdiction over distribution systems. One exception is that FERC may claim jurisdiction over a distribution line when a "non-qualifying facility" generator interconnects to a distribution line covered by a public utility's Open Access Transmission Tariff to make wholesale sales of electricity (FERC Order 2006, §§ 465-491, reviewing FERC's jurisdiction).

Distributed generators under a few MW rarely interconnect under the SGIP because they are typically interconnecting to state-jurisdictional distribution lines for the purpose of serving on-site load, not consummation of wholesale sales. In practice, it typically costs much more and takes much longer to interconnect a small generator to a transmission line than a distribution line, so developers typically try to interconnect smaller generators to a distribution line whenever feasible. As well, most smaller distributed generation systems are intended to serve the onsite load of utility customers that are located on a distribution system rather than a transmission line. Because the SGIP does not apply to these distribution line interconnections, state procedures or utility-specific procedures typically govern these interconnections.

Distributed generation systems larger than a few MWs are more likely to interconnect using the SGIP. There are two reasons. First, the likely cost of distribution circuit upgrades will dissuade applicants from proposing that their large systems interconnect on distribution lines. Second, relatively few distribution-served customers have loads larger than a few MWs, so larger systems are typically interconnected with the purpose of making wholesale sales.

Because most utilities (other than the very smallest) own or operate FERC-jurisdictional utility lines, they are required to adopt the SGIP for interconnections to such lines. For these utilities, there is a rationale to seek similar procedures for distribution lines that are subject to state jurisdiction. This rationale has not however been strong enough to lead to widespread adoption of the SGIP by states. State utility commissions tend to defend their jurisdiction against encroachment by FERC and feel no obligation to start with the SGIP in developing their state interconnection procedures. In addition, utilities, who are active and well connected participants at state commissions, may see an opportunity to seek more restrictive provisions than SGIP provides. As a result, although the SGIP may serve as a model in limited respects, state utility commissions often do not adopt it in its entirety.

Utilities not subject to state utility commission oversight typically do not bother to adopt interconnection procedures at all. EPAct 2005 required utilities with sales over 500 million kWh per year to consider adopting interconnection procedures. Many considered such procedures but decided not to adopt them.

California's Rule 21

Years before the NARUC Procedures, the SGIP, the MADRI Procedures, and the IREC Procedures were adopted, California was developing its own interconnection procedures. While not adopted elsewhere (other than Nevada), CA Rule 21 governs the majority of U.S. distributed generation interconnections due to the impact of California's solar incentives and various state policies related to distributed generation. A significant majority of U.S. solar energy systems and other distributed generators are installed in the service territories of California utilities that utilize CA Rule 21.

CA Rule 21 was drafted through a cooperative effort of stakeholders, including California's two principal energy agencies and the state's investor-owned and key municipal utilities. The effort started in October 1999 when the California Public Utilities Commission (CPUC) opened a rulemaking to address interconnection procedures. One month later, the California Energy Commission (CEC) began an investigation of policies to encourage distributed generation. The CEC presented its findings in the CPUC's rulemaking and this progressed into drafting CA Rule 21.

CA Rule 21 specifies standard interconnection, operating, and metering requirements for distributed generators that interconnect to the distribution system of a CPUC-jurisdictional utility, including Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). These utilities are required to adopt Rule 21 as a part of their tariffs. Although California utilities each have their own version of Rule 21, the versions are substantially identical except for references to utility names and tariff sections. Many California municipal utilities have also adopted interconnection procedures modeled after Rule 21, including the Los Angeles Department of Water and Power and the Sacramento Municipal Utility District (SMUD).

CA Rule 21 applies the same review process regardless of the size of a proposed generator. All interconnections start with an initial review, which applies eight screening criteria to determine whether a generating facility qualifies for a simplified interconnection. Failure to pass a screen does not mean that a generating facility cannot be interconnected; it only means that further review is necessary. Initial review determines whether a generating facility qualifies for a simplified interconnection, whether it may be made to qualify for a simple interconnection through a supplemental review, or requires an interconnection study. Generators that do not export power and are small compared to an on-site customer's load will likely qualify for a simplified interconnection.

> "CA Rule 21 was drafted through a cooperative effort of stakeholders, including California's two principal energy agencies and the state's investor-owned and key municipal utilities."

Unlike other interconnection procedures, including the SGIP, CA Rule 21 does not explicitly provide for a separate interconnection process for systems under 10 kW. However, facilities under 11 kW do take an abbreviated path through initial review by automatically satisfying three of the eight screens applied during initial review. As such, CA Rule 21 arguably provides a separate, expedited review despite its lack of an explicitly identified separate process.

Also unique among the procedures reviewed here, CA Rule 21 does not specify a system size limit to which the rule applies. There are significant advantages to this approach. First, under the federal Public Utility Regulatory Policies Act of 1978 (PURPA), states have jurisdiction over interconnections of certain generators, termed "qualifying facilities," when their entire output is sold directly to an interconnected utility. State jurisdiction applies in such situations regardless of the size of the generator and regardless of whether the interconnection is to a transmission or distribution line. Second, states have jurisdiction over large distributed generation systems (>20 MW) when those systems are used entirely to serve on-site load. For example, several refineries in Southern California operate distributed generation systems larger than 20 MW to provide electricity and process heat. Third, some utilities operate subtransmission systems that are under state jurisdiction and can accommodate systems larger than 20 MW. By establishing an upper limit to the applicability of a state interconnection standard, regulators may leave certain qualifying facilities, subtransmission systems, and large systems that serve on-site load without an applicable interconnection standard.

Table 1 below presents the number of systems of all types reviewed under Rule 21 Procedures for California's three main investor-owned Utilities: San Diego Gas and Electric, Southern California Edison, and Pacific Gas and Electric. These totals were compiled from data provided to the Rule 21 workgroup by the IOUs, from California Solar Initiative program data (https://csi.powerclerk.com/CSIProgramData.aspx) and from the California Energy Commission.

Table 1. Number of Systems Reviewed Under California Rule 21 Procedures

	PG&E	SCE	SDG&E	TOTAL
<1 MW**	6,381	9,852	23,015	39,248
1MW - 10MW**	261	717	66	1,044
10 MW - 20MW	-	47	14	61
>20MW	11	18	6	35
TOTAL	**6,653**	**10,634**	**23,101**	**40,388**
Largest single Application	51 MW	97 MW	25 MW	

** — *because of a small amount of possible overlap in the various data sources, these numbers are estimated*

Under CA Rule 21, generators passing the initial review process only incur application review fees. However, interconnection review fees, as well as any interconnection study fees and distribution system modification costs, are waived for generators eligible for net energy metering (Cal. Public Utilities Code § 2827). State legislation also waives the first $5,000 of application fees, interconnection studies fees, and distribution system modification costs for solar generating facilities up to 1 MW that do not sell power to the grid.

A clear and well-organized guidebook on California's Rule 21 is available on the California Energy Commission's website, as well as a supplemental review guide for addressing systems that fail one or more of the initial review screens.

MADRI small generator interconnection procedures

The MADRI Procedures were finalized in November 2005 by the utility commissions of Delaware, New Jersey, Maryland, Pennsylvania, the District of Columbia, the PJM

Interconnection (the regional transmission organization for the states just listed), and various federal agencies (FERC, the Department of Energy, and the Environmental Protection Agency). These stakeholders developed their procedures as an alternative to the SGIP, which came out six months earlier. In its model form, it was not meant to be applied anywhere, but the drafters intended that utilities and state regulators in the PJM Interconnection states would adopt the new procedures. All non-utility parties to the SGIP devoted years of attention to the SGIP process, which limited non-utility participation in the MADRI Procedures development. As a consequence, the procedures fell short on some key provisions and received a low "C" grade from NNEC. However, on many important issues, the MADRI Procedures are exemplary, and they are the basis of newly adopted procedures in Illinois and Oregon that are among the best in the nation.

Among the states in the PJM Interconnection, Pennsylvania adopted the MADRI Procedures in significant part, Maryland completed a rulemaking in June of 2008 with adoption of rules improving upon the MADRI Procedures, and the District of Columbia has initiated a rulemaking to consider similar rules. Delaware developed interconnection procedures with very low system capacity, along with other poor terms. None of these states have significant solar energy installations or other installations. New Jersey elected not to adopt the MADRI Procedures and developed what NNEC considers one of the best state procedures in the U.S. and now has the second most solar installations in the country. While the principal reason for New Jersey's success is its generous solar incentive program, its interconnection procedures helped facilitate the success.

Outside of the PJM Interconnection, the MADRI Procedures have been used in Illinois, Oregon, and are under consideration in Utah and South Dakota (which are considering Oregon's improved version). The procedures have had significant impact on state rulemakings, though limited association with successful state solar programs. With both Oregon and Maryland appearing to be on the verge of major growth in solar installations due to state incentive programs, it appears that the MADRI Procedures will be tested significantly, though both states improved the MADRI Procedures in multiple ways.

Two significant benefits of the MADRI Procedures can be attributed to the involvement of the Regulatory Assistance Project, which acted as a DOE-funded moderator in the development of the procedures. First, it established a third tier for applicants who would not export to the grid. Many large commercial solar systems are sized at well below the average usage of the building on which they are located, creating an opportunity to ignore SGIP technical screens regarding grid impacts caused by exported energy. In practice, the MADRI Procedures allows utilities the discretion to not abide by the rules for non-exporting generators, but the concept is good.

The second benefit of the MADRI Procedures is that it is well documented, with options for provisions that state regulators may want to consider. Many of these options create what the NNEC would consider a better rule. This facilitates transforming the MADRI Procedures into state procedures that would grade at higher levels, as has occurred in Maryland, Illinois, and Oregon. In practice, it would be more productive for regulators to start with the Illinois or Oregon procedures than with the MADRI Procedures themselves.

To facilitate complete rules for each of its four tiers, the MADRI Procedures are repetitive, with a great deal of identical language appearing in the description of requirements for each tier. As well, in its desire to document party comments extensively, MADRI allowed its procedures to stretch to 41 pages, plus 88 pages of attachments. This adds considerable length to the procedures and hinders change, since any desired change has to be effectuated at multiple points. By comparison, the SGIP is 14 pages with 79 pages of attachments (including the SGIA) and the IREC Procedures are 12 pages with 40 pages of attachments.

IREC's interconnection procedures

Through its participation in state and federal development of interconnection rules, the Interstate Renewable Energy Council has had extensive exposure to the various approaches taken. For instance, in 2007, IREC was active in the development of interconnection rules in New Mexico, Illinois, Florida, North Carolina, Utah and to a lesser extent, Maryland and Washington, DC.

The IREC Procedures were initially developed in 2005, with the final version analyzed here produced in November 2006. The intent of the procedures was to respond to EPAct 2005's call for states to consider adoption of best practices by creating its version of what best practices were as of late 2006. Coming at a later date than other procedures discussed in this paper, the IREC Procedures draw on SGIP/SGIA, the MADRI Procedures, the NARUC Procedures, and the progressive rules developed in New Jersey.

The IREC Procedures drew directly from the SGIP for its basic format, technical standards, application forms, and the simplified agreement for interconnection of inverter-based systems no larger than 10 kW (which is an exhibit to the SGIP and not part of the SGIA). In large part, the IREC Procedures also adopted the SGIA for any interconnections that require utility system upgrades, though it actually adopts the MADRI Procedures' modified version of the SGIA for those more complex interconnections. From the older NARUC Procedures, IREC adopted the more streamlined agreement for interconnections that do not entail utility-system upgrades.

Recognizing the value of the MADRI Procedures' simplified approach to non-exporting generators, the IREC Procedures adopted this innovation and unlike the MADRI Procedures, made the provisions non-discretionary for utilities. While generally not adopted in a useable form by states, non-exporting generator provisions have compelling logic. That logic is that, all else being equal including generator size, it should be easier to evaluate a generator that does not feed power back to the utility grid than it is to evaluate a generator that does export power. This one provision could open a market for systems over 2 MW that would be subject to costly and time-consuming studies under most procedures.

"Recognizing the value of the MADRI Procedures' simplified approach to non-exporting generators, the IREC Procedures adopted this innovation and unlike the MADRI Procedures, made the provisions non-discretionary for utilities."

For most timelines and application fees, the IREC Procedures looked to the New Jersey rules that continue to be more accommodating to industry. Seeing no evidence that these timelines and fees were leading to rate impacts or reliability concerns in New Jersey, IREC adopted those procedures as best practices in its current procedures.

Based on field experience for distributed generation, particularly solar arrays, IREC adopted two provisions to expand markets and lower costs where it did not appear that safety or reliability would be affected. First, interconnection to spot networks and area networks is allowed to reach the lesser of 10% of minimum annual load or 500 kW, which is far beyond the allowable levels in most state procedures. The authors are not aware of any incident or study indicating that network reliability would be impacted at these modest levels, indicating that the levels are appropriate. However, network connections are a contentious topic and some alternative such as a non-exporting requirement for larger systems may be part of an appropriate solution.

Regarding the external disconnect switch, IREC took the position taken in New Jersey rules that there is no need for the switch and it should therefore never be required at a customer's expense. There has not been compelling evidence that these switches are used or necessary, so IREC's Procedures prohibit utilities from requiring a disconnect switch. The conclusion of a 2008 study by the National Renewable Energy Laboratory was that the switch was unnecessary for systems under 10 kW, while not discounting its usefulness for larger systems.

Beyond the NNEC grading criteria, the IREC Procedures have a direct style and a shorter length that allows new users to grasp the rules quickly. The IREC Procedures were used extensively in Colorado and an earlier version of the IREC Procedures was the basis of New Jersey procedures. In addition, the IREC Procedures are the basis of comments filed by IREC in dozens of states, with the result that many provisions have been adopted in state procedures.

Literature review

As this analysis is largely a point-by-point review of four interconnection procedures, most of the literature review relates directly to discussion of the procedures by the bodies that developed them.

For the SGIP/SGIA, there is a complete record of comments filed in the docket leading to FERC Order Nos. 2006, 2006-A and 2006-B. In the final orders, each provision in the SGIP/SGIA is discussed at length, including party positions and resolution of the issue at stake. Among the filings in order No. 2006 is the NARUC Procedures, which was also reviewed for the discussion of its influence on all but CA Rule 21.

For CA Rule 21, California Public Utility Commission (CPUC) orders and proceedings were reviewed, along with the very approachable and informative California Interconnection guidebook, *A Guide to Interconnection Customer-owned Electric Generation Equipment to the Electric Utility Distribution System Using California's Electric Rule 21*.

For the MADRI Procedures, the MADRI website listed in the references section of this paper provides presentations at all of the meetings leading to the development of the procedures. As well, the procedures themselves contain extensive commentary regarding party positions on various issues.

Finally, the authors represent IREC in state interconnection rulemakings and have the benefit of access to the developers of the IREC Procedures and the individuals who have shaped opinions leading to those procedures, including Jane Weissman, Chris Cook, Rusty Haynes, and Tom Starrs. Comments filed in various proceedings by Mr. Cook were particularly useful background material.

Material of a more generalized nature reviewed for this paper includes the 15-page IEEE 1547 standard that provides a foundation for all of the procedures herein, along with UL 1741 (Underwriter Laboratories' Standard for Innerters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resurces) *Connecting to the Grid* (5th Ed., 2007) by Rusty Haynes and Chuck Whitaker provided useful material on technical requirements for interconnection in particular.

Analysis

The sixteen NNEC grading criteria used in *Freeing the Grid* (2008) are reviewed below, with a description of how each of the four procedures performed under each criterion.

1. Eligible Technologies

All four procedures cover a full range of technologies, not just renewables. The SGIP facilitates interconnection of any "devise for the production of electricity." CA Rule 21 covers interconnection of all devices that convert "mechanical, chemical, or solar energy into electrical energy." The MADRI Procedures encompasses interconnection of Small Generator Facilities and defines that term as equipment rated at 10 MVA or less, with no restriction on eligible technologies. The IREC Procedures open with the statement that there are four review paths for interconnection of customer-sited generation without providing technology-based restrictions.

Under the NNEC grading, failure to encompass all technologies results in negative points. It would be needlessly duplicative to have separate rules for renewable energy generators and non-renewables. All four procedures received a score of zero, the highest score.

2. System Capacity

The SGIP covers facilities with a maximum rated capacity up to 20 MW. CA Rule 21 does not establish a specific size limit and therefore receives the maximum score of zero. The MADRI Procedures set a cap of 10 MVA, which acts as a lower cap than 10 MW if reactive power is also produced. The IREC Procedures set a 10 MW cap.

NNEC changed its scoring in 2008 to set the SGIP's 20 MW cap as the highest score (zero), with -0.5 attributed to procedures using a 10 MW cap. The IREC and MADRI Procedures each receive this small deduction. In former editions, *Freeing the Grid* did not have a deduction for procedures with a 10 MW cap. In future editions, a further credit for applicability to systems over 20 MW may be enacted to ensure that there is not a gap in state and federal procedures that leaves larger "qualifying facilities" without an applicable standard.

In practice, systems over 10 MW are likely to interconnect on transmission lines, meaning the SGIP would likely be applicable. However, if such systems certify as qualifying facilities and their full output is sold to an interconnected utility, state interconnection procedures apply regardless of the size of the generator and regardless of whether the interconnection is to a transmission or distribution line. In addition, FERC has declined jurisdiction over transmission-line interconnection of at least two generators in excess of 10 MW. Thus, limiting state interconnection standards to systems of a particular size may create a gap between state and federal interconnection rules.

3. Breakpoints

The SGIP includes three alternative procedures for evaluating an interconnection request depending on the size of a proposed system. NNEC scoring awards one point for four or more procedures based on system size or other features, awards zero points for having three procedures, deducts a point for only having two procedures, and deducts two points for having only one procedure.

The SGIP's Level 1, a "10 kW Inverter Process," is available for inverter-based systems under 10 kW that either meet certain codes, standards, and certification requirements stated in the SGIP or are determined safe to operate by an interconnecting utility after it has reviewed the design for or tested a facility (SGIP § 1.1.1 and Attachments 3 & 4). Level 2, a "Fast Track Process," is available for facilities no larger than 2 MW that meet the same list of codes, standards, and certification requirements or that are determined safe to operate, but Level 2 applicants need not be inverter-based. Both the 10 kW Inverter Process and the Fast Track Process evaluate systems using a series of technical screens (SGIP § 2.1 and Attachment 5). The main distinction between the 10 kW Inverter Process and the Fast Track Process, besides the inverter requirement for the small systems, is that the 10 kW Inverter Process uses a simplified application and interconnection agreement. Level 3 is a four-step "Study Process" that is available for facilities up to 20 MW that do not qualify for the Fast Track Process or the 10 kW Inverter Process. The Study Process includes a scoping meeting, feasibility study, system impact study, and facilities study (SGIP §§ 1.1.1 & 3.1).

In contrast to the SGIP, CA Rule 21 applies the same evaluation process regardless of the size of a proposed generator. The process starts with an initial review, which applies eight screening criteria to determine whether a generating facility qualifies for a simplified interconnection (CA Rule 21 (C)(1)(c)). Failure to pass a screen does not mean that a generating facility cannot be interconnected; it only means that further review is necessary. Although a system of any size could qualify for a simplified interconnection, the screens favor systems that are small compared to on-site load and systems that are not expected to export power. In fact, facilities under 11 kVA take an abbreviated path through initial review by automatically satisfying three of the eight screens applied during initial review (CA Rule 21 (I)(3)). If an initial review determines that a proposed generating facility can be interconnected by means of a simplified interconnection, a utility will provide a customer with a written description of the interconnection requirements and an executable interconnection agreement (CA Rule 21(C)(1)(c)(2)).

If a CA Rule 21 interconnection request fails the initial review screens, a utility may perform a supplemental review to determine whether (i) the failure may be inconsequential to the safe operation of the distribution system, (ii) a minor alteration to the proposed interconnection will address the failure, or (iii) an interconnection study is needed. Under the first two of these outcomes, a simplified interconnection may still be appropriate. If, however, a supplemental review reveals that a proposed generating facility cannot be interconnected to a utility's distribution system by means of a simplified interconnection or that significant upgrades to the utility's distribution system will be required to accommodate the generating facility, the utility will need to perform an interconnection study (CA Rule 21(C)(1)(d)). If an interconnection study is needed, an applicant will be provided an estimate of the cost and time necessary to complete the study. The applicant may either authorize the study or cancel the application. Cancellation may be preferable if the cost of interconnecting appears too high. Recognizing that CA Rule 21 provides a simplified procedure and a standard study process in practice, CA Rule 21 is given a score of -1.

The MADRI Procedures have four levels for interconnection review. Like the SGIP, there is a simplified procedure for small, certified, inverter-based generators (MADRI Procedures § 4). The list of certification codes and standards is the same between the two, and the MADRI Procedures' 10 kVA breakpoint is the same as a 10 kW breakpoint for generators operating at unity-power factor (the usual case for solar arrays). The MADRI Procedures' Level 2 review process is restricted to inverter-based systems, excluding rotating generators that are allowed under the SGIP Fast Track Process (MADRI Procedures § 5.1.1 and comment following). This is a major limitation of the MADRI Procedures, as it forces all rotating generators into a study process that will involve longer timelines, utility discretion, and study costs. For generators over 2 MVA, a study process similar to the SGIP process is provided as Level 3 (MADRI Procedures § 6).

The MADRI Procedures also include a Level 3A that gives utilities broad discretion to allow interconnection of non-exporting systems no larger than 50 kVA to an area network or no larger than ten MVA to a distribution circuit (MADRI Procedures § 7). While the concept of simplified rules for interconnection of non-exporting generators is very positive, the fact that the utility has complete discretion makes the provisions unattractive to potential developers of generating facilities. Without certainty, developers will not take the first exploratory steps. For area network interconnections, the utility may pay for a study and deny the application if it determines "in its sole discretion" that there are potential adverse impacts of the interconnection (MADRI Procedures §§ 7.3.2.2 & 4.2). For non-exporter interconnection to distribution circuits, the procedures are only used "by mutual agreement" of the utility and the customer (MADRI Procedures § 7.4).

While the MADRI Procedures appear to have four levels and thereby deserve a score of 1 because they have one more breakpoint than the SGIP, it is the authors' opinion that MADRI Procedures are no better than the SGIP in this area. Level 3A is ineffective because it is entirely discretionary and Level 2 is restrictive in comparison with the SGIP because it excludes rotating generators, so overall, the MADRI Procedures are awarded a zero, equal to the SGIP.

The IREC Procedures have breakpoints for certified inverter-based generators no larger than 10 kW, a Level 2 fast track process for certified systems no larger than 2 MW, and a Level 4 study process for systems no larger than 10 MW, mirroring the SGIP. In addition, the IREC Procedures allow interconnection to area networks under Levels 1 and 2 (IREC Procedures §§ e, f & g), and they contain a Level 3 process for non-exporter interconnection to area networks and distribution circuits that is functional. For exceeding the scope of the SGIP tiers and introducing functional non-exporter rules, the IREC Procedures receive two points under the NNEC grading for this criterion.

The intent of this criterion is not to count up the number of levels and compare that to the three tiers in the SGIP. The point of having levels is to carve out as many types of interconnection as possible that can be approved without further study if quantifiable screens are met. For instance, any of the procedures discussed here could be improved by moving their first level cap to more than 10 kW, as several states have done. Likewise, utility discretion to pursue studies at the customer's cost will hinder market development and should be avoided unless necessary.

4. Timelines

Under all of the procedures reviewed in this paper, interconnection requires the completion of a series of steps, each having an associated timeframe. The NNEC grading criteria assigns a point to state interconnection procedures that establish overall timeframes that are shorter than the SGIP and subtracts a point if timeframes are longer. The SGIP requires an interconnecting utility to make reasonable efforts to meet all timeframes established for completing an interconnection unless the interconnecting utility and interconnection customer agree to a different schedule (SGIP § 4.1). If an interconnecting utility cannot meet a timeframe, it must notify the interconnection customer, explain the reason and provide an estimated time by which it will complete the applicable interconnection procedure.

Under the SGIP 10 kW Inverter Process and the Fast Track Process (§§ 1.3, 2.2 & Attachment 5), a utility has three business days after receiving an interconnection request to notify an interconnection customer that a request has been received and ten business days to notify an interconnection customer if a request is complete or incomplete. Within 15 business days of notifying an interconnection customer that an interconnection request is complete, a utility must perform an initial review using the screens in SGIP and notify the interconnection customer of the results. Within five business days of that determination, if a proposed interconnection passes the screens or is determined to be safe, reliable, and compliant with applicable standards, the utility must provide the interconnection customer an executable interconnection agreement.

The SGIP study process is lengthier and more detailed (§ 3 & Attachments 6, 7 & 8). Within ten business days of receiving a complete interconnection request, a scoping meeting must be held, unless otherwise mutually agreed by the parties. No later than five business days after the scoping meeting, a utility must provide an interconnection customer with either a feasibility study agreement or a system impact study agreement. Within 30 business days of an interconnection customer's agreement to conduct a feasibility study, the feasibility study must be completed and the feasibility study report transmitted. If a feasibility study shows no adverse system impacts and no additional facilities are needed, an interconnecting utility must provide an executable interconnection agreement within five business days. If a feasibility study shows the potential for adverse system impacts, the interconnecting utility must provide a distribution system impact study agreement within 15 business days of transmittal of the feasibility study report. A distribution system impact study must be completed and transmitted within 30 business days of a system impact study agreement being signed, and a transmission system impact study must be completed and transmitted within 45 business days if required. Once a required system impact study(s) is completed, within five business days, the interconnecting utility must prepare a system impact study report and send it to the interconnection customer along with a facilities-study agreement. A facilities study must be completed and transmitted within 45 business days of the receipt of a facilities study agreement if system upgrades are required and within 30 business days if no system upgrades other than interconnection facilities are required. After the facilities study is completed, within five business days the interconnecting utility must provide the interconnection customer with an executable interconnection agreement.

CA Rule 21 earns no points in this category. Under CA Rule 21(C)(1), within three business days of an initial request, a utility must provide sample agreements, an application, technical information, a listing of certified equipment, initial and supplemental review fee information, applicable tariff schedules, and information on metering requirements. The utility has ten business days from receiving an application for interconnection to acknowledge receipt and state whether the application is complete. If the application is complete, absent "extraordinary circumstances," a utility must complete its initial review within ten business days and complete a supplemental review, if required, within 20 business days. Generating facilities that qualify for net metering are normally accommodated no later than 30 business days following a utility's receipt of a completed, net energy metering application, including all supporting documents and required payments; a completed signed net metering interconnection agreement, and evidence of the applicant's final inspection clearance from the governmental authority having jurisdiction over the generating facility (CA Rule 21(C)(2)(d)).

The MADRI Procedures match the SGIP timelines for Level 1 generators (§ 4.4) but adds at least an additional two weeks to the Level 2 application process, depending on holidays. Recall that the MADRI Procedures restrict Level 2 to inverter-based systems, so the review process should generally be simplified in comparison to the review to be done under the SGIP. First, the MADRI Procedures add five business days to the review of a completed application (§ 5.4.5) and then add an extra five days to the end of the process to send a completed agreement (§ 5.4.7). As well, the MADRI Procedures do not require notice within three days of receipt of an application, as the SGIP does, so a lost application can go undetected for roughly two weeks from the date it was sent, and the applicant will have to begin anew unless proof of mailing is available (§ 5.4.2.1).

The study process of the MADRI Procedures' Level 3 is slightly longer than the SGIP process. Rather than requiring a scoping meeting within ten days, as the SGIP does, the MADRI Procedures call for a ten-business-day review to determine whether the application is complete and ten more days to schedule the scoping meeting. (§ 6.3) This stretches the time for an initial meeting from two to four weeks if there are no holidays. Timelines for the feasibility, impact, and facilities to be conducted by the utility are provided in separate agreements and are similar to the SGIP timeline. For its slower timelines in Levels 2 and 3, the MADRI Procedures lose a point under the NNEC grading.

The IREC Procedures generally adopt the aggressive but achievable timelines used in New Jersey. For Level 1, it provides that the utility has three days to notify an applicant that an application has been received and an additional ten days to review the application (§ f). This is three days longer than the SGIP process, which has these events occurring simultaneously. However, the utility is required to send a customer a completed agreement within three days of successful completion of the review, which is two days shorter than the SGIP, so the IREC Procedures take one additional day when compared to the SGIP for Level 1.

For generators up to 2 MW, IREC's Level 2 process is slightly faster than SGIP (§ g). There are three extra business days for notice that the application is complete, the same 15-business-day review period but just three business days for notice that the application has been approved. This approval notice period is seven business days shorter than the SGIP process.

For generators subject to the IREC study process, the timelines are quite similar to the MADRI Procedures, with twenty days to a scoping meeting and the same study timelines provided in the study agreements. As noted, this is a slightly slower process than the SGIP has. IREC's timelines receive one point in *Freeing the Grid* (2008), because there is a faster timeline for Level 2, which is the level most likely to have the majority of installed capacity.

A helpful provision that would be worthy of a 0.5 point credit, but is not included in *Freeing the Grid* (2008) or any of the procedures reviewed here, would be a requirement that utilities accept online applications and provide instant notification of receipt. Given that electronic communication is ubiquitous, there is no reason to build mailing costs and delays into the application process or to create a process that extends time periods in the event of lost applications.

5. Interconnection Charges

The SGIP requires a non-refundable processing fee of $100 for the 10 kW Inverter Process and $500 for the Fast Track Process (SGIP, Attachment 5 and § 2.4). If a supplemental review is required at the end of the Fast Track process, the interconnection customer must pay the actual costs of conducting the supplemental review. NNEC grading awards one point for interconnection charges lower than FERC's, negative one point for charges higher than FERC's, two points for waiver of fees for net metered systems, and negative three points for fees that are double FERC's level.

CA Rule 21 interconnection fees are slightly higher than SGIP's only in the cases of systems over 1 MW or non-solar, non-net-metered systems under 1 MW (CA Rule 21(C)(1)(d)). For these systems, an initial review fee of $800 must be included with an application, with fifty percent of this fee returned to an applicant if an application is rejected by a utility or is withdrawn. If supplemental review is required for these systems, an applicant must pay an additional $600 (CA Rule 21(C)(1)(c)(3)).

Despite CA Rule 21 fees for the special cases discussed above, CA Rule 21 receives two points from NNEC because generators eligible for net energy metering are exempt from paying fees, including for any necessary studies, and solar-powered generating facilities up to 1 MW that do not sell power to the grid are also exempt from these fees in almost all cases (CA Rule 21(C)(1)(d)). Regarding these non-net metered systems, the California Public Utilities Commission stated that, "CalSEIA has made a persuasive argument that solar distributed generation installations under 1 MW impose negligible interconnections costs on the utility system; therefore, we will waive up to $5,000 in interconnection fees for solar distributed generation up to 1 MW" (CPUC Decision No. 01-07-027, 2001, p. 70).

The MADRI Procedures explain in the preamble that its process "deliberately does not prescribe levels for application fees" to allow individual jurisdictions to settle appropriate fees based on their circumstances. The procedures do state that fees for Level 1 applications are to be "nominal," but they do not settle on a number. Given the utility discretion to set fees, the MADRI Procedures loses a point on this criterion.

The IREC Procedures sets application fees of $20 for Level 1, $50 plus $1/kWh for Level 2, $100 plus $1.50/kWh for Level 3 (non-exporters), and $100 plus $2/kWh "as well as charges for actual time spent on the interconnection study" (§§ f, g, h & i). While IREC's scaled fees will end up costing the customer slightly more for systems near the top of the Level 2 and 3 ranges, it is better for the lower end of those ranges and superior for Level 1. For that reason, the IREC Procedures received a point in this category.

6. Engineering Charges

If an interconnection request is submitted under the SGIP Study Process, an interconnection customer must deposit the lesser of 50 percent of the estimated cost of performing a feasibility study or $1,000 (§ 3.3.2 and Attachment 6). Additional deposits, without limitation, may be required if a system impact study or facilities study are required (§ 3.3.2 and Attachments 7 & 8). Ultimately, an interconnection customer is responsible for paying all costs of performing a feasibility study, system impact study, and facilities study (SGIP attachments 6, 7 & 8). An interconnection customer is also responsible for paying the cost of all interconnection facilities and distribution system upgrades needed to accommodate an interconnection (SGIA §§ 4.1, 4.2). If transmission system upgrades are necessary, an interconnection customer is initially responsible for payment but is repaid through transmission access charge credits (SGIA § 5.2).

CA Rule 21 requires interconnection customers to pay for all costs reasonably incurred by a utility in reviewing, studying, and testing an interconnection (CA Rule 21(E)(2)). However, CA Rule 21 exempts generators that are eligible for net metering from paying the cost associated with interconnection studies and distribution system modifications (CA Rule 21(E)(2)(b) & (C)(1)(d)). CA Rule 21 also waives interconnection study fees of up to $5,000 for solar generating facilities with a capacity up to 1megawatt (MW) that do not sell power to the grid. (id.). For all other systems, applicants are responsible for all costs associated with installing interconnection facilities and all costs reasonably incurred by a utility in providing, operating, or maintaining distribution system modifications required solely for the interconnection of the applicant's generating facility. Payment requirements are contained in an interconnection agreement. Under NNEC grading, California receives a point for its waiver of fees for net metered systems and its $5,000 waiver for solar systems of 1 MW or less that do not sell power to the grid. The authors contend that such favorable allowances could justifiably be worth more than a single point.

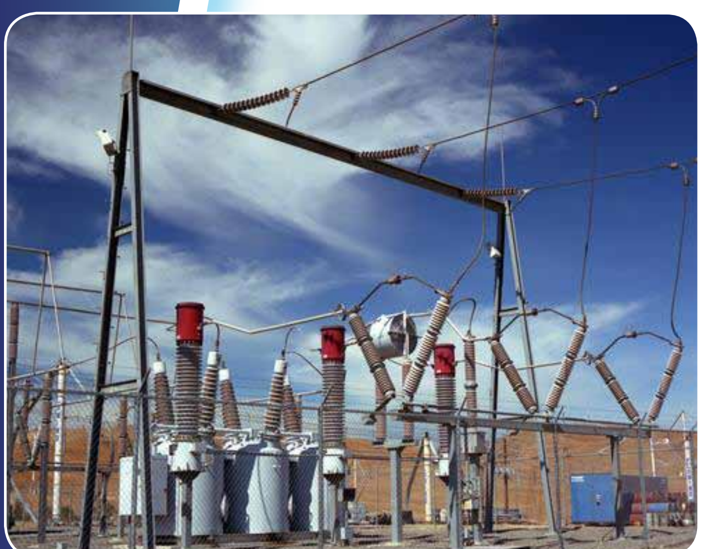
The MADRI Procedures have the same basic provisions for engineering fees that SGIP has (MADRI Procedures § 6 and Appendices 3, 4 &5). For matching the SGIP, a score of zero is allotted. To its credit, the MADRI Procedures do contain a deposit limit for each interconnection study while the SGIP only has a deposit limit on the feasibility study (MADRI Procedures Appendices 3, 4 &5). However, this does not significantly limit payments for the studies, just the timing of payments. Such provisions are helpful and should be considered for half-point awards in the future.

The IREC Procedures has the same study deposit caps proposed by MADRI and caps engineering costs at $100/hr (§ j), which was enough to earn a point. However, CA Rule 21 received the same score for policies that are far more generous to applicants; it would be appropriate to have further gradation for this criterion in the future, rather than having a single step from zero points to one point.

7. External Disconnect Switch

Given the exposure that this issue has had through a recent NREL study and a concurrent Solar ABCs study, the rationale for prohibiting an external disconnect switch requirement is not discussed here. NNEC awards one point for prohibiting the requirement, awards no points for ignoring the issue (as the SGIP does), deducts a point for leaving the requirement up to utilities, and deducts two points to procedures that require the switch. In 2008, the NNEC scoring for this criterion changed to award half a point credit for prohibiting a switch requirement for Level 1 installations, where the usefulness of the switch is the most suspect and the economic impact of requiring a switch is the most acute.

The SGIP does not require or prohibit an external disconnect switch for any size system, but it does direct 10 kW Inverter Process customers to check with the interconnecting utility before submitting an application to determine whether disconnection equipment is required (§ 4.0). The 10 kW Inverter Process also specifies that an interconnecting utility must have access to a disconnect switch if one is required.



CA Rule 21 does not require the use of an external disconnect switch, but an interconnected utility may require an interconnection customer to furnish and install a manually operated external disconnect switch, or comparable device. (CA Rule 21(D)(1)(d)). Only systems under 1 kW are exempt from this requirement and may not be required to install an external disconnect switch (CA Rule 21(D)(1)(d)). Given that the rule has a limited prohibition against the switch and two California utilities have dropped the requirement for certain small residential systems, CA Rule 21 appears to be at least as helpful as the SGIP on this issue on balance, and therefore receives a zero.

The MADRI Procedures leave installation of an isolation device entirely up to utilities at the customers' expense (§ 3.6.8). This provision results in a lost point and is clearly less progressive than CA Rule 21.

The IREC Procedures prohibit utilities from requiring a disconnect switch (§ j(5)). For that, it is given a point in the NNEC grading scheme.

In practice, the vast majority of installed systems are under 10 kW. As well, the referenced studies conclude that the disconnect switch is unnecessary for these small systems, but do not take firm positions on the usefulness of the switches for larger systems. Therefore, it may be appropriate to give full credit for elimination of the requirement for systems under 10 kW in the future.

8. Certification

All four procedures receive at least a score of zero on this criterion, meaning that they apply the IEEE 1547 (Standard for Interconnecting Distributed Resources with Electric Power Systems) and UL 1741 (Inverters, Converters, and Controllers used in Independent Power Systems) without significant modification. CA Rule 21 deviates from IEEE 1547, but these deviations are minor enough that CA Rule 21 is not penalized. The three explicit CA Rule 21 deviations relate to spot networks, protection from electromagnetic interference, and utilization of a higher system cap (CA Rule 21 uses a 20 MW cap while IEEE 1547 is limited to 10 MW)(CA Rule 21(D)), and some technical specifications are rewritten with the stated intent of maintaining conformity with IEEE 1547 (CA Rule 21(A)). In addition, UL 1741 certification alone is not sufficient in California, although a cumbersome review process eventually finds that virtually all UL 1741 certified equipment is certified for use in California. This needless administrative hurdle and the IEEE 1547 deviations could be acknowledged with a point deduction, but are not. It may be appropriate to adjust the CA Rule 21 scoring in the future. Instead, CA Rule 21 earns a point for self-certification provisions to allow the same type of unlisted generator to be installed in multiple locations without repetitious studies. The MADRI Procedures reference such an approach but do not require it, and therefore are scored the same as the SGIP, receiving a zero. The IREC Procedures have no self-certification provision and receive a zero as well.

9. Technical Screens

The SGIP applies a series of technical screens to interconnection requests that qualify for either the SGIP 10 kW Inverter Process or the Fast Track Process. If an interconnection request passes these screens, it must be approved (§ 2.2.2). If an interconnection request fails the screens, it must be studied under the SGIP Study Process, unless an interconnecting utility determines that a facility may be interconnected safely, reliably, and within power quality standards despite having failed the screens.

The SGIP applies the following technical screens (§ 2.2.1):

- The point of interconnection must be on a segment of the distribution system that is covered by the interconnecting utility's Open Access Transmission Tariff.
- If the interconnection is to a radial distribution circuit, the interconnection may not facilitate an increase in aggregated generation on the circuit that exceeds 15% of the line section annual peak load. A line section is a portion of an interconnected utility's electric system bounded by automatic sectionalizing devices or the end of a distribution line.
- The interconnection may not assist in contributing more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.
- The proposed interconnection may not cause any distribution protective devices and equipment or interconnection customer equipment to exceed 87.5% of the short circuit interrupting capability.
- The proposed interconnection must use the correct type of interconnection to the primary distribution line given the type of electrical service provided to the interconnecting customer.
- If the proposed generation is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the new generation may not exceed 20 kW.

- If the proposed generation is single-phase and is to be interconnected on a center tap neutral of a 240-volt service, its addition may not create an imbalance between the two sides of the 240-volt service of more than 20% of the nameplate rating of the service transformer.
- The proposed generation may not increase the generation interconnected to the transmission side of a substation transformer feeding the circuit where the interconnection customer proposes to interconnect above 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).
- The proposed interconnection may not cause the interconnecting utility to construct facilities on its system.

NNEC grades state interconnection procedures by determining whether they have adopted the SGIP screens. A state interconnection procedure receives no points for adopting the SGIP screens and loses one point for a partial adoption of the SGIP screens. State procedures lose two points if no screens are used or the screens are left to utility discretion. NNEC assesses penalties if more conservative screens are used and bonuses if a state drops one or more SGIP screens that do not affect safety.

CA Rule 21 passes all interconnection requests through eight screens to determine whether they qualify for a simplified interconnection. If all the screens are passed, the generating facility qualifies for simplified interconnection. If a proposed interconnection fails any of the screens, the interconnection request proceeds to a supplemental review. Because the screens applied under CA Rule 21 differ from the SGIP screens, CA Rule 21 loses a point for this criterion.

Given that CA Rule 21 screens were developed and implemented well before the SGIP was adopted and most distributed generation is installed based on the CA Rule 21 screens, it is fair to ask why Rule 21 loses a point for this criterion. Moreover, CA Rule 21 screens appear to have some advantages over the SGIP screens. For example, there is no screen in CA Rule 21 related to exceeding the equipment interrupt rating, or limiting distributed generation on a shared secondary to 20 kW. In the SGIP, the 20 kW limit is in the aggregate, in CA Rule 21, it is per applicant. These advantages would appear to justify a reevaluation of the CA Rule 21 scoring for this criterion and perhaps a broader examination of the FERC screens to determine whether they may be improved upon.

The MADRI Procedures and the IREC Procedures have very similar provisions, adopting and improving upon the SGIP screens. Both adopt all of the screens listed, except the first SGIP screen that relates to FERC jurisdictional facilities and therefore would not be applicable in state procedures. Both the MADRI and IREC Procedures use a shortened version of the SGIP screens for Level 1 review. And both adjust the fourth screen slightly to state that the proposed interconnection may not cause any distribution protective devices and equipment or interconnection customer equipment to exceed 90% of the short-circuit interrupting capability, rather than 87.5% as the SGIP does. Several states have adopted this cutoff. For simplifying the SGIP screening process, both the MADRI and IREC Procedures receive a point.

10. Spot Network Interconnection

Networks are characterized as either area networks that may supply several city blocks, or spot networks that typically serve a single customer. Both use multiple transformers in an interconnected electrical network circuit to improve reliability. The SGIP requires facilities interconnecting to the load side of spot network protectors to use an inverter-based equipment package. The facility, together with other inverter-based generation, may not exceed five percent of a spot network's maximum load or 50 kW, whichever is less (§ 2.2.1.3).

Although CA Rule 21 addresses spot network connections, if a generating facility will interconnect to an area or spot network, it does not qualify for a simplified interconnection under CA Rule 21 and a supplemental review is required (CA Rule 21(I)(3)(a)). CA Rule 21 does not adopt IEEE 1547 Clauses 4.1.4.2 (Distribution Secondary Spot Networks), which is being studied for inclusion in a subsequent version of the rule (CA Rule 21(D)). CA Rule 21 receives no points for spot network interconnection, comparable to the SGIP, though a study process is required in California. Deduction of points is reserved for rules that prohibit spot network interconnection, and the cost of any necessary study is borne by the utility for net metered systems, so there is little impact on the customer generator in these typical cases.

The MADRI Procedures follow the approach of the SGIP and allow inverter-based generators to interconnect so long as aggregate generation on the network does not exceed the lesser of five percent of the spot network's maximum load or 50 kW (§ 5.3.2). As ever, matching the SGIP gets a score of zero.

The IREC Procedures allows aggregate inverter-based interconnection on a spot network of up to five percent of the spot network's peak load, without adding the 50 kW limitation. As many spot networks experience peak loads far in excess of one MW, this lifts the allowed spot network interconnection substantially while still maintaining a low threshold in percentile terms. For this, IREC is awarded two points in the NNEC grading.

The topic of spot and area network interconnections is being investigated by the National Renewable Energy Council and others, and results of these investigations may change the scoring of network provisions in the future. Yet, the authors conclude that with no evidence of network-interconnected systems causing harm, it is reasonable to assume that some process can be developed to allow fast-track review of such systems.

11. Area Network Interconnection

Major metropolitan areas such as New York and Chicago are served by area networks, which increase reliability and reduce outages in high-density load areas by using several primary feeders suitably interlaced through an area in order to achieve acceptable loading of transformers under emergency conditions and to provide a system of extremely high service reliability.

The SGIP does not address area network interconnections. CA Rule 21 addresses area network connections, however, only to the extent necessary to determine that a generating facility that interconnects to an area network does not qualify for a simplified interconnection under Rule 21 (CA Rule 21(I)(3)(a)). This allowance does not make interconnection to area networks any more feasible than it is under the SGIP, and CA Rule 21 is not awarded points. Generally, NNEC does not award a point for this criterion if studies are required because such a provision makes small systems uneconomic. CA Rule 21's requirement that utilities assume interconnection study costs for net metered systems would appear to facilitate area network interconnections, but it is still possible that the studies will determine that costly system upgrades are necessary to interconnect a system.

The MADRI Procedures have an extended process with utility discretion to permit area network interconnections of up to 50 kVA in the aggregate (§ 7.3). The utility may study the interconnection at its own cost and determine "in its sole discretion" that the interconnection will cause adverse system impacts. With that level of uncertainty, the MADRI Procedures are not credited with any substantive improvement in the ease of making area network interconnections. However, the MADRI Procedures could be modified to allow area network interconnections.

Finally, the IREC Procedures do allow area network interconnection up to the lesser of 10% of minimum area network load or 500 kW (§ e(2)). The procedures are awarded two points for this, though scoring for this criterion will be reviewed in the future based on the results of studies related to area network interconnections.

12. Standard Form Agreement

In Order 2006, the FERC established a standard Small Generator Interconnection Agreement (SGIA) that must be signed by an interconnection customer and interconnected utility after a proposed interconnection has been successfully evaluated under either the Study Process or the Fast Track Process. The SGIA describes the legal relationships of the parties, including who pays for equipment modifications to the interconnecting utility's system to accommodate the interconnection. There is no separate agreement for interconnections evaluated under the 10 kW Inverter Process. Instead, customers with generators under 10 kW agree to abide by certain terms and conditions when they submit an application under the 10 kW Inverter Process.

California utilities have three to five different interconnection agreement forms each, which vary depending on whether the applicant is a utility customer or a third party. All utility agreements are CPUC-approved. Simple interconnections use simple forms, which is an improvement over the SGIP approach of using a lengthy document. Also, the third-party ownership model has become the leading way to finance larger commercial solar arrays, so it is helpful to have standard forms that address this type of ownership. Despite its positive aspects, CA Rule 21 gets a score of zero due to the burden of having so many contracts rather than just a few with statewide application.

The MADRI Procedures adhere to the basic format of the SGIP for its forms without simplification or added complexity and is given a score of zero. The IREC Procedures adopt the standard agreement from the NARUC Procedures for interconnections that will not require upgrades to the utility's system. Without that complexity, the agreement is a straightforward six-page contract, rather than the 34-page SGIA. For this, IREC is given a point.

13. Insurance Requirements

The SGIP 10 kW Inverter Process requires parties to follow all applicable insurance requirements imposed by the state in which the point of interconnection is located. (SGIP, Attachment 5) Insurance requirements for other SGIP interconnections are contained in SGIA Article 8. Under those requirements, an interconnection customer must maintain general liability insurance of an amount sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. An interconnection customer of sufficient credit-worthiness may self-insure for such liabilities.

CA Rule 21's insurance provisions are scattered among multiple standard forms. PG&E, the largest utility in the state, provides that owners of net metered solar and wind systems under one megawatt and over 30 kW are only required to obtain insurance if they fail to abide by any of the operational, safety or legal requirements that they commit to do under their interconnection agreement (PG&E Form 97-978). Insurance is not required at all for net metered solar and wind systems up to 30 kW (PG&E Form 79-1101). In general, insurance is required for other generators. In short, insurance is not mandated automatically for most systems, so CA Rule 21 receives a point for its insurance provisions.

The insurance provision in the MADRI Procedures' standard agreement encourages the customer to carry adequate insurance, but do not require it (Appendix 7, Article 7).

Such a provision recognizes the relatively low risk involved and the likelihood that the customer has adequate liability insurance already without requiring utility oversight. Such a provision gets the maximum score of one. The IREC Procedures have a similar provision in their standard agreement and also receive a point (Attachment 5, Section 13).

14. Dispute Resolution

The SGIP provides a dispute resolution process (§ 4.2). If a dispute is not resolved within two business days after receipt of written notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute. The DRS assists the parties in either resolving the dispute or in selecting an appropriate dispute resolution venue. Parties split the cost of paying a neutral third-party arbiter. If neither party seeks assistance from the DRS, or if an attempted dispute resolution fails, either party may pursue legal action. An identical dispute resolution procedure is contained in Article 10 of the SGIA.

CA Rule 21 also establishes procedures to be followed in the event of a dispute. Under this process, disputes must be reduced to a writing that contains the facts of the dispute and a request for relief (CA Rule 21(G)(2)). Within 45 calendar days of a dispute letter being sent, authorized representatives must meet and attempt to resolve it. If a resolution is not reached within 45 calendar days, either party may request to continue negotiations for an additional 45 days; make a written request to the CPUC Chief Administrative Law Judge for mediation; or request mediation from an outside third-party mediator with costs shared equally between the parties. If the parties cannot resolve the dispute within 90 calendar days of a dispute letter being sent, the dispute must be submitted for resolution under the CPUC's Rules of Practice and Procedure Applicable to Customer Complaints. Due to the long delay–up to 90 days–between dispute occurrence and resolution, NNEC assigns a zero to CA Rule 21 for this criterion, indicating that CA Rule 21 provides for an administratively burdensome resolution process. The CPUC also provides an informal dispute-resolution process through its Consumer Services Division. Small disputes can be resolved through this process in as little as a few days. In many cases, this may offer a quicker dispute resolution process than the one provided for in CA Rule 21. Balancing these factors, CA Rule 21 is awarded zero points, equivalent to the SGIP/SGIA.

The MADRI Procedures' version of dispute resolution is an agreement that the parties will attempt to resolve disputes promptly, equitably, and in a good faith manner (§ 8.1). While most disputes can be settled by following such counsel, this does not adequately address how the parties are to handle disputes that will not settle on their own. On this point, the MADRI Procedures are given a zero for not addressing dispute resolution.

The IREC Procedures allow regulators to appoint a technical master with binding authority to resolve technical disputes (§ k(1)). The concept is that typical technical disputes related to interconnection have modest sums at stake and the parties would benefit from a prompt answer from an expert in a day rather than a thoughtful resolution by an arbiter in a month and accompanied by a sizeable cash outlay. The IREC Procedures receive two points on this issue.

15. Rule Coverage

In 2008, NNEC added a criterion for the extent of applicability of a state rule. Procedures applicable to all utilities within a state receive a point while procedures only applicable to investor-owned utilities receive no points. This new criterion is intended to credit certain states for having broadly applicable rules. For this criterion, the SGIP does not fit comfortably as the standard against which others are compared. By definition, its score is set at zero, though the SGIP applies to all FERC-jurisdictional interconnections, including certain interconnections on public utility transmission and distribution lines. However, as noted earlier, state procedures are nearly always applicable rather than the SGIP.

None of the procedures reviewed here call for statewide coverage, and state procedures typically determine the reach of state interconnection rules based on the jurisdiction of the state utility commission. The level of jurisdiction over municipal utilities, co-operatives, and public utility districts varies from one state to the next. CA Rule 21 only applies to the state's investor owned utilities, so it receives a score of zero. Likewise, since the IREC and MADRI Procedures are silent on this point, they receive zeros.

16. Miscellaneous

All but CA Rule 21 use the basic format of the SGIP/SGIA, and the authors consider this uniformity a useful benefit because industry and utilities are already familiar with the federal procedures. As a result, CA Rule 21 receives a point deduction for being significantly different in structure from the SGIP. The other three procedures receive scores of zero.

Conclusions

A summary of the grading of each of the four procedures is provided below, with a table provided at the end of this section. Recommendations based on this review are provided in the analysis section.

NNEC grading of the SGIP

The NNEC grading methodology is based on the SGIP, with scores of zero for every criteria and a "C" grade overall. In some cases, the SGIP sets the high bar, in many cases it is the average, and for some criterion, the SGIP is surpassed by many state rules.

The SGIP sets a reasonable standard for system capacity, accommodating interconnection of systems up to 20 MW. In practice, there is rarely a need for state procedures above 10 MW, so NNEC only deducts half a point for rules that have an upper limit of 10 MW capacity (larger systems typically will interconnect with FERC-jurisdictional transmission lines, so state procedures need not cover these larger systems). The SGIP's applicability to all technologies is the standard, though some states restrict interconnection procedures to only certain renewable technologies.

In several categories, a handful of state procedures exceed the SGIP, though most state procedures lag behind or are at the SGIP level. For example, timelines for review of systems has been shortened in some states, spot network interconnections are more widely accepted, and area networks are permitted (they are not discussed in the SGIP). External disconnect switches are not addressed in the SGIP, but are not required by utilities in New Jersey or Rhode Island or for certain small systems in California and Florida.

In other categories, the SGIP is routinely exceeded by state procedures. Application fees established by the states are generally lower, the dispute resolution process in the SGIP is regularly found to be inferior to state processes, state standard form agreements are often considered friendlier than the SGIP's agreement (the SGIA) and insurance is often prohibited at some level in state procedures (it is not required or prohibited in the SGIP).

From the standpoint of large system developers, investors and installers, the SGIP's "C" grade is superior in one way to state procedures with the same grade. That one clear superiority is that the SGIP is already thoroughly understood and interpreted. An investor or developer considering a project in a state with few large distributed generators has to investigate the state's procedures carefully to be sure there are no provisions that might delay or block a proposed project. For installers, a consideration in entering a new state is whether the interconnection procedures are substantially different from those existing in states in which the installer already practices. As a broad generalization, national adoption of the SGIP, or any procedures, would be one of the most effective ways to allow the industry to mature and grow.

Note that interconnection scores for the SGIP/SGIA in Freeing the Grid (2008) are set at zero for each criterion, but totals for all state scores are adjusted by 7.5 to make the scores comparable to scores for net metering rules. Thus, the SGIP/SGIA has a total score of 7.5 despite having a score of zero for each criterion.

NNEC grading of CA Rule 21

The score for CA Rule 21 has increased since the 2007 edition of *Freeing the Grid*. Minor refinements in NNEC's grading methodology and reevaluation of CA Rule 21 increased the rule's score, reflecting its friendly provisions regarding interconnection costs for net metered systems and its prohibition of an external disconnect switch for very small systems. It scores two points higher than the SGIP, achieving a grade of "B,"placing it among the top eight state procedures in *Freeing the Grid* (2008).

CA Rule 21 now scores the same as the SGIP on the issue of external disconnect switches. California leaves it to utility discretion to determine whether an external disconnect switch should be required for most systems, which would result in California losing a full point for this criterion. However, California is one of only a few states that exempts the smallest systems, those under 1 kW, from being required to install an external disconnect switch, and PG&E, the state's largest utility, has used its discretion to decide not to require the switch for most residential systems. The SGIP does not take a position on the switches, which tends to leave the issue entirely up to utilities. In comparison, CA Rule 21 seems just as favorable, and therefore its score was increased from the score awarded in 2007, and arguably, CA Rule 21 deserves at least a modestly positive score for this criterion.

Also, California's Rule 21 had previously received no additional points for waiving or lowering application and study fees for net metering eligible applicants. Although NNEC grants a point for fixed engineering fees and CA Rule 21 effectively fixes these fees for most applicants at zero because fees are waived for net metered systems up to 1 MW, the lack of fixed fees for other systems resulted in a penalty score of minus one point in 2007. Given that most systems are likely to be net metered, and the no-cost provision is an especially favorable version of a fixed fee, CA Rule 21 is now awarded a score of zero. Arguably, CA Rule 21 deserves a modestly positive score for this criterion as well.

CA Rule 21 does fail to adopt IEEE 1547 entirely, for which a point deduction is arguably justified, but its digressions from IEEE 1547 do not appear to be substantial.

NNEC grading of the MADRI Procedures

In many respects, the MADRI Procedures follow the direction taken by the SGIP/SGIA and therefore score a zero on many criteria. As discussed, the SGIP/SGIA scores of zero is the high score in eligible technologies and system capacity, so the MADRI Procedures are in good company on these points. Like most state procedures and the SGIP, the MADRI Procedures have very limited allowance for network connections, and therefore do not get credited under NNEC's grading for area and spot network interconnections. Its forms and agreements are not substantially different from the SGIP/SGIA's forms and agreements, and the MADRI Procedures take no new direction regarding system certification or technical screens, remaining tied with the federal procedure on those points as well. The MADRI Procedures score 1.5 points below the SGIP/SGIA, receiving a low "C."

The MADRI Procedures improve upon the SGIP/SGIA with respect to insurance provisions, which are addressed by not requiring customers to carry special insurance for their generators or to add special provisions to their insurance policies. Also, the MADRI Procedures can fairly be considered superior to the SGIP/SGIA with regard to its adoption of a fourth tier for review, which it titles Level 3A rather than Level 4. Level 3A covers non-exporting generators, and while it is not mandatory for utilities to approve these generators if they pass the stated screening process (and therefore receives no credit in scoring), at least the innovative approach is included.

In four respects, the MADRI Procedures fall short of the SGIP/SGIA. First, they force all non-inverter based generators to seek approval through a study process at applicant's cost, which will impact the economics of many otherwise viable applicants proposing rotating generator technologies.

The second, shortcoming of the MADRI Procedures is that they require the external disconnect switch (referenced as an isolation device). The MADRI Procedures provide half a page on the requirement, describing how and where the switch can be installed for small generators, all of which could simply be deleted based on the apparent lack of need for disconnect switches on smaller generators at all.

Third, the MADRI Procedures allow cost-based application fees without specifying actual amounts. Cost-based fees will result in very high fees for the earliest customers of a particular utility while the utility learns how to analyze interconnections, and cost-based fees give utilities little incentive to reduce costs. On the issue of costs, it should be noted that the MADRI Procedures do set upper limits on required deposits for interconnection studies for larger generators, which is a substantive improvement over the SGIP/SGIA.

Fourth, the MADRI Procedures also fall short of the SGIP/SGIA with respect to dispute resolution procedures. The only requirement is that the parties attempt to resolve disputes "promptly, equitably and in a good faith manner." Disputes can happen and any complete agreement states that the parties will first make a good faith effort and provide what happens if that does not work. The MADRI Procedures do include specific useful procedures in comments by the Solar Energy Industries Association and others, but these are not included in the MADRI Procedures themselves.

NNEC Grading of the IREC Procedures

As noted, the NNEC concurs with IREC's view about what constitutes best practices on most points, and IREC assisted NNEC with its development of *Freeing the Grid* (2008). Thus, the fact that the IREC Procedures receive an "A" grade under the NNEC criteria is not surprising. In the end, it is up to regulators to determine whether the NNEC criteria are appropriately conceived and weighted. While the IREC Procedures would almost certainly allow greater penetration of distributed generation than other procedures, without loss of reliability or safety, some argue that the procedures shift costs from interconnection customers to ratepayers. While IREC debates that point, cost allotment is not settled.

Shortened timelines mean that utilities have to plan to have available engineering staff to meet the demand to review applications that arrive in any given week. Low application fees mean that utilities will not recover completely for installation types it is reviewing for the first time. Fixed engineering rates may not be sufficient in future years. Not requiring insurance entails a minute risk that the utility will suffer damages and not be compensated. And more systems means less utility sales, spreading fixed costs over fewer kW hours. On all of these points, the IREC Procedures are awarded a high score, and IREC argues that this is justified by the benefits of distributed generation.

The benefits of distributed generation include environmental benefits of renewable energy and efficient fuel use of combined heat and power systems, lowering of utility peak demand and delay of the need for transmission and distribution system upgrades, and reduced rates for those customers who installed systems. It is up to regulators to set the balance between these benefits to ratepayers and the costs that they might incur due to reduced electricity sales.

On technical issues, the IREC Procedures receive points for what some might say are relaxed standards. Not requiring an external disconnect switch and allowing up to 500 kW on a typical area or spot network are examples. IREC counters that these positions do not entail any loss of safety or reliability based on the unlikelihood of anything going wrong using those criteria, especially given that no utility appears to have ever suffered damages anywhere in the country. Still, regulators continue to face the assertion that relaxing these provisions results in greater risk, and there is no adequate way to prove that the risk is very low.

Finally, IREC adopts a dispute resolution process that earns it credit under NNEC grading for putting binding authority regarding technical disputes in the hands of a technical master, if the utility's regulators have approved the technical master. This seems appropriate for small matters that do not justify resolution through arbitration or court. However, for very large systems, the amount in dispute could be sizeable.

Table 2. Grading of Interconnection Procedures

Criterion	NNEC Maximum	SGIP/ SGIA	CA Rule 21	MADRI	IREC
1. Eligible Technologies	0	0	0	0	0
2. Individual System Capacity	0	0	0	-0.5	-0.5
3. Breakpoints	2	0	-1	0	2
4. Timelines	1	0	0	-1	1
5. Interconnection Charges	2	0	2	-1	1
6. Engineering Charges	1	0	1	0	1
7. External Disconnect Switch	1	0	0	-1	1
8. Certification	1	0	1	0	0
9. FERC Technical Screens	1	0	-1	1	1
10. Spot Networks	2	0	0	0	2
11. Area Networks	2	0	0	0	2
12. Standard Form Agreement	2	0	0	0	1
13. Insurance	1	0	1	1	1
14. Dispute Resolution	2	0	0	0	2
15. Rule Coverage	1	0	0	0	0
16. Miscellaneous	0	0	-1	0	0
Score (with 7.5 pts added)*	**26.5**	**7.5**	**9.5**	**6**	**22.0**
Grade	**A**	**C**	**B**	**C**	**A**

* *NNEC adds 7.5 pts to each state's interconnection score in order to bring the point range for interconnection scores in line with the scores assigned to net metering rules, which NNEC also grades.*

Recommendations

The authors' primary recommendation is that utility regulators use a familiar starting point for the development of interconnection rules. Any of the four procedures discussed here can serve as a suitable starting point, although the authors favor the IREC Procedures. The procedures considered here have been extensively vetted and field tested, while unique procedures are likely to have unanticipated pitfalls. More importantly, the procedures reviewed here all contain key features that are critical for any successful interconnection rules. These features include broad applicability, capacity limits of at least 10 MW, breakpoints, standard form agreements, and limited insurance requirements.

As regulators develop rules starting from a selected standard, each NNEC criterion should be considered and regulators should either adjust the standard they are using to maximize the NNEC score or articulate why they are choosing an alternative approach. With respect to safety and reliability issues, regulators should consider that the SGIP/SGIA, CA Rule 21, and the MADRI Procedures were developed before most of the existing solar facilities in the United States had been installed. The caution in those procedures with respect to network interconnections, disconnect switches, and non-exporting generators are almost certainly overstated. The dispute resolution procedures in those procedures should be updated as well, to reflect the need for a technical master to address technical issues promptly.

With respect to criterion related to cost causation, regulators should consider whether or not there are offsetting benefits that justify applying a particular cost to ratepayers generally. In the zeal to properly account for cost causation, regulators can inadvertently create a significant impediment to interconnection of distributed generation at all. Utility costs to review the earliest applicants will be much higher than average review costs as thousands of generators come on line. Forcing the earliest applicants to bear all of the utility review costs will deter some, if not many, of those early applicants. Given the various benefits of distributed generation, the very small cost per ratepayer to set up utility programs is properly attributable to ratepayers generally.

Finally, beyond the NNEC criteria, the authors recommend that regulators strive to achieve the somewhat conflicting goals of simplicity and comprehensiveness. All else being equal, short rules are better than long rules, self-contained rules are better than rules spread over multiple documents, fixed timelines are better than targets, and penalties for utility non-compliance are better than no penalties.

To summarize, distributed generation is far more likely to be deployed if developers and utility customers can easily discern what the costs of interconnection are and how long the approval process will take. While regulators have a challenging task in formulating interconnection procedures, the benefits of implementing functional procedures are substantial.

References

NNEC's *Freeing the Grid* (2008)

Network for New Energy Choices (2008). *Freeing the Grid*. October. Retrieved 22 October 2008 from http://www.newenergychoices.org.

Procedures reviewed in this paper

California Public Utilities Commission (1999). *California Rule 21* (CA Rule 21). October. Retrieved on 5 July 2008 from http://www.energy.ca.gov/distgen/interconnection/california_requirements.html.

Federal Energy Regulatory Commission (FERC) (US) (2005). *Small Generator Interconnection Procedures* (SGIP) *and Small Generator Interconnection Agreement* (SGIA). Established by FERC Order No. 2006. Washington DC, May 12. Retrieved 5 July 2008 from **http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.**

Interstate Renewable Energy Council (IREC) (US) (2006). *The Model Interconnection Standards and Procedures for Small Generator Facilities (*IREC Procedures). Retrieved 5 July 2008 from www.irecusa.org/fileadmin/user_upload/ConnectDocs/IC_Model.pdf.

The Mid-Atlantic Demand Resource Initiative (MADRI) (US) (2005). *MADRI Small Generator Interconnection Procedures* (MADRI Procedures). Retrieved 5 July 2008 from www.energetics.com/madri/pdfs/inter_modelsmallgen.pdf.

Other procedures and standards

Federal Energy Regulatory Commission (FERC) (US) (2003). *Large Generator Interconnection Procedures (LGIP) and Large Generator Interconnection Agreement (LGIA)*. Established by FERC Order No. 2003, Washington, DC, July 24. Retrieved 5 July 2008 from http://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen.asp.

Institute of Electricians and Electrical Engineers (IEEE) (2003). *IEEE 1547–Standard for Interconnecting Distributed Resources with Electric Power Systems (IEEE 1547)*. Industry Standard. Retrieved 5 July 2008 from http://grouper.ieee.org/groups/scc21/1547/1547_index.html.

The National Association of Regulatory Commissioners (NARUC) (US) (2005). *Small Generation Resource Interconnection Procedures (NARUC Procedures).* Retrieved 5 July 2008 from www.naruc.org/resolutions/interconnection.pdf.

Reports and other publications

BEW Engineering (BEW) (2005). *Letter Report to the Office of Clean Energy, New Jersey Board Public Utilities (BEW Letter Report).* Nov. 26. Retrieved 5 July 2008 from http://www.energetics.com/madri/pdfs/inter_NJBPULetterReport.pdf.

California Energy Commission (CEC) (2003). *California Interconnection Guidebook: A Guide to Interconnecting Customer-owned Electric Generation Equipment to the Electric Utility Distribution System Using California's Electric Rule 21, P500-03-083.* September. Retrieved 5 July 2008 from http://www.energy.ca.gov/distgen/interconnection/guide_book.html.

California Energy Commission (CEC) (2005). *California Electric Rule 21: Supplemental Review Guideline.* August. Retrieved 5 July 2008 from http://www.energy.ca.gov/distgen/interconnection/guideline.html.

Interstate Renewable Energy Council (IREC) (US) (2007). *Connecting to the Grid: A Guide to Distributed Generation Interconnection Issues.* 5th Edition. Retrieved 5 July 2008 from http://www.irecusa.org/fileadmin/user_upload/ConnectDocs/IC_Guide.pdf.

National Renewable Energy Laboratory (NREL) (2008). *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch*. Technical Report No. NREL/TP-581-42675. January. Retrieved 5 July 2008 from http://www.nrel.gov/docs/fy08osti/42675.pdf.

Oregon Public Utility Commission (Oregon PUC) (2005). *Distributed Generation in Oregon: Overview, Regulatory Barriers and Recommendations.* Report. February. Retrieved 5 July 2008 from http://www.puc.state.or.us/PUC/electric_gas/dg_report.pdf.

Pacific Gas & Electric Company (PG&E) (2005). *Rule 21–Generating Facility Interconnections.* CPUC Sheet Nos. 23678-E to 23736-E. Effective September 21. Retrieved 5 July 2008 from http://www.pge.com/tariffs/pdf/ER21.pdf.

Solar Electric Power Association (SEPA) (2008). *Residential Photovoltaic Metering and Interconnection Study.* Report No. 01-08. March. Retrieved 5 July 2008 from http://www.solarelectricpower.org/docs/SEPA%20_%20Report_Final%20March%206.2.pdf.

US Department of Energy (U.S. DOE) (2008). *Renewable Systems Interconnections.* Executive Summary of research. Report. February. Retrieved 5 July 2008 from http://www1.eere.energy.gov/solar/solar_america/pdfs/42292.pdf.

Legislation, statutes, regulations and administrative issuances

California Public Utilities Commission (CPUC) (2002). *Opinion Interpreting Public Utilities Code Section 2827.* (CPUC Decision No. 02-057). March 21. Retrieved 5 July 2008 from http://docs.cpuc.ca.gov/published/FINAL_DECISION/14191-03.htm.

California Public Utilities Commission (CPUC) (2001). *Order Instituting Rulemaking into Distributed Generation.* (CPUC Decision No. 01-07-027). July 12. Retrieved 5 July 2008 from http://docs.cpucca.gov/published/FINAL_DECISION/8823.htm.

California Electric Commission (CEC) (updated regularly). *DG Equipment Currently Certified Under Rule 21.* Available at http://www.energy.ca.gov/distgen/interconnection/certification.html.

Energy Policy Act of 2005 (EPAct 2005). Pub. L. 109-058. Retrieved 31 July 2008 from http://www.epagov/oust/fedlaws/publ_109-058.pdf.

Federal Energy Regulatory Commission (FERC) (US) (2003). *Order No. 2003, Standardization of Generator Interconnection Agreements and Procedures (Order No. 2003)*. Washington D.C., July 24. FERCStats. & Regs. 31,146. Retrieved 5 July 2008 from http://www.ferc.gov/industries/electric/indus-act/gistnd-gen.asp.

Federal Energy Regulatory Commission (FERC) (US) (2005). *Order No. 2006, Standardization of Small Generator Interconnection Agreements and Procedures* (Order No. 2006). FERC Stats. & Regs. 31,180. Washington, DC, May 12. Retrieved 5 July 2008 from http://www.ferc.gov/industries/electric/indus-act/gismall-gen.asp.

Federal Energy Regulatory Commission (FERC) (US) (2005). *Order No. 2006-A, Standardization of Small Generator Interconnection Agreements and Procedures–Order on Rehearing (Order No. 2006-A).* F.E.R.C. Stats. & Regs. 31,180. Washington, DC, November 22. Retrieved 5 July 2008 from http:/www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.

Federal Energy Regulatory Commission (FERC) (US) (2005). *Order No. 2006-B, Standardization of Small Generator Interconnection Agreements and Procedures–Order on Clarification* (Order No. 2006-B). F.E.R.C. Stats. & Regs. 31,221. Washington, DC, November 22. Retrieved 5 July 2008 from http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.

Public Utility Regulatory Policies Act of 1978 (PURPA) (US). Pub. L. No. 95-617, 92 Stat. 3117. Codified at 16 U.S.C. §2621. Retrieved 5 July 2008 from http://www.law.cornell.edu/uscode/.

Solar America Board for Codes and Standards

www.solarabcs.org