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Interconnection of Distributed Generation to Utility Systems:

Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues

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*Principal Author, Paul Sheaffer**

Distributed generation produces electricity at or near the place where it's used, and it typically interconnects to a utility's distribution system. This paper provides recommendations on technical requirements, procedures, and agreements for U.S. state-jurisdictional interconnections for distributed generation, focusing on systems 10 megawatts (MW) to 20 MW – an area that receives less attention by states than smaller systems. The paper also summarizes emerging issues that states may need to address in the future, such as modifying interconnection rules to better address high penetration of distributed generation and revising screening criteria that determine the level of system impact study conducted for a proposed interconnection.

Policies, regulations, and rules governing the interconnection of distributed generation may be established by state law and, for regulated utilities, may be established and enforced by the state public utility commission (PUC). The Federal Energy Regulatory Commission (FERC), however, may have jurisdiction over distributed generation interconnected at the distribution or transmission level if it involves sales for resale of electric energy in interstate commerce by public utilities.[1] For some distributed generation, energy and capacity is sold to utilities under provisions of the federal Public Utility Regulatory Policies Act (PURPA), which grants states broad authority for setting rates, interconnection, and other terms for Qualifying Facilities (QFs) – eligible renewable resources and cogeneration facilities.[2] Similarly, states have jurisdiction over interconnection of net-metered generators, although not all states have net-metering requirements.[3] Interconnection of distributed generation is covered by some type of state regulation in 42 states.[4] In the remaining states, requirements are set by each distribution utility, sometimes through PUC-approved tariffs. FERC has established interconnection procedures and agreements for distributed generator interconnections under its jurisdiction, for both "small" (up to 20 MW) and "large" (over 20 MW) systems.

States have adopted a variety of approaches for interconnection regulations for larger distributed generation. Some states' procedures do not address units larger than 2, 5, or 10 MW. Other states have no size limit in their rules, and larger distributed generation simply falls into the highest level of review – one of the recommendations in this paper. Among other recommendations are additional technical requirements for distributed generation larger than 10 MW, including exceptions, additions, and clarifications for Institute of Electrical and Electronics Engineers (IEEE) Standard 1547, such as active voltage regulation.

This paper first reviews treatment of 10 MW to 20 MW distributed generation units in model interconnection procedures. Next is an overview of current state-level procedures, agreements, and technical requirements. The paper then focuses on recommendations for state-level

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rules to address interconnection of distributed generation at the 10 MW to 20 MW level. The paper concludes with an overview of emerging interconnection issues that states will need to address in the future.

Model Interconnection Procedures

Interconnection rules have two primary objectives: 1) to preserve the safety, reliability, and service quality of electric power systems (EPS), and 2) to provide transparent and uniform technical requirements, procedures, and agreements to make interconnection as predictable, timely, and reasonably priced as possible. The following is a review of model procedures for distributed generation by the Mid-Atlantic Distributed Resources Initiative (MADRI) and the Interstate Renewable Energy Council (IREC). These model procedures include or reference technical requirements and model agreements. Both were initially developed in 2005 and originally addressed only state-jurisdictional facilities under 10 MW. In 2009, IREC updated its procedures to address systems up to 20 MW.

The MADRI procedures[5] benefited from the involvement of state regulators familiar with distribution system interconnections. The scope of the MADRI procedures includes systems under 10 megavolt amperes (MVA)[6] that are not interconnected under federal jurisdiction, such as the PJM Interconnection-domain. The procedures provide interconnection screening and review processes for three paths, or levels, spanning up to 10 MVA. MADRI provides a good overall structure for the interconnection review process, but does not address distributed generation over 10 MVA. The MADRI procedure framework using review levels forms the basis for many of the subsequently enacted state rules, such as those established by Pennsylvania, Maryland, the District of Columbia, and Oregon.

The IREC model procedures[7] originally developed in 2005 addressed state jurisdictional interconnections up to 10 MW. IREC's 2009 model interconnection procedures provide four review paths to include interconnection beyond 10 MW. Level 1 is for units 25 kilowatts (kW) or less, Level 2 is for units 2 MW or less, and Level 3 is for units between 2 MW and 10 MW. In addition to these size limits, additional qualification criteria apply for Levels 1 to 3. Level 4 is for all facilities that do not qualify for Levels 1 to 3, and thus addresses all sizes, including units over 10 MW.

The IREC Level 4 process addresses a number of key issues that can be barriers to interconnection if no transparent and uniform requirements are established:

- **Timeline.** The IREC process defines timelines and milestones from utility receipt of application to initial review by utility, the feasibility study agreement and findings, the impact study agreement and findings, the facilities study agreement and findings, and the interconnection agreement. The utility may waive any of these milestones.

- **Compliance With IEEE Standard 1547.**[8] The Level 4 process requires the utility to physically inspect the generating facility installation for compliance with IEEE Standard 1547 and specifies the utility's attendance at any commissioning tests. Upon completion of these inspection requirements, the utility notifies the applicant that the interconnection application is approved. The IREC Model Procedures suggest that IEEE Standard 1547 may be used as guidance for systems larger than 10 MW, even though the IEEE standard specifies its application to distributed generation 10 MVA or less.

- **Fees.** Fees are limited to $100 plus $1 per kW. For example, a 10 MW facility would be charged a maximum of $10,100. These fees do not include any utility charges for time spent on an interconnection study (those mentioned previously in "Timeline") or for utility facility upgrades.

- **Insurance.** The IREC model procedures specify insurance levels for units over 5 MW in the General Provisions section. The maximum insurance requirement is $3 million for non-inverter-based systems and $2 million for inverter-based systems.

- **Redundant Equipment.** The IREC model procedures require that the generating facility not be charged for any equipment that provides utility system protection that is already furnished with the certified facility equipment, such as equipment certified in conformance with Underwriters Laboratories (UL) 1741.[9]

- **Dispute Resolution.** The IREC model procedures recommend that the regulatory utility commission make complaint or mediation procedures available in the event of a dispute that the parties cannot resolve between themselves.

State Procedures, Agreements, and Technical Requirements for Interconnection

Most state-level rules for interconnection of distributed generation were established over the last decade. Before such rules, PUCs allowed each utility company operating within the state to develop and use their own rules or to treat interconnection applications on a case-by-case basis, with little or no transparency as to their requirements or decision-making process. Where utilities had published rules or "engineering requirements," there typically was broad leeway in what they could include. These engineering requirements primarily focused on technical requirements, but many of them also addressed procedural issues and contained applications and timelines. Some of these utility-developed requirements posed a significant barrier to distributed generation.

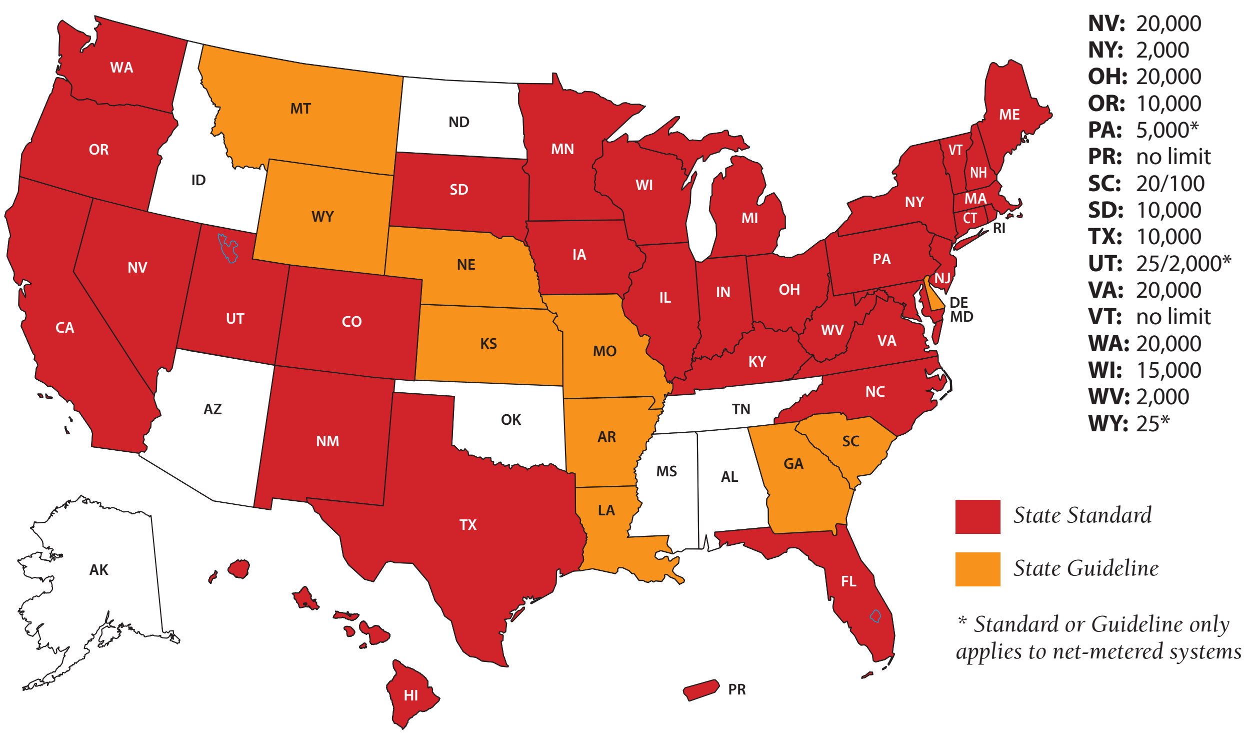
Today most state regulations do not address units larger than a certain size (see Figure 1). In these cases, interconnection requirements generally revert to utility-developed requirements.

Procedures

Procedures in state interconnection rules deal with the protocols of reviewing an application for a distributed generation interconnection and the process for the required studies to ensure the interconnection is safe, does not adversely affect power quality for other customers, and is compliant with the rules. The procedures detail the methodology the utility and applicant must follow. Most state rules include three or four levels of review, depending on the size and type of distributed generation and the

Figure 1. *Individual system capacity limits (in kW) covered by state interconnection policies today. Where limits vary by customer type, the first figure is for residential systems, the second figure is for non-residential systems. "No limit" indicates no stated maximum size for individual systems. State policies typically apply only to interconnections to investor-owned utility systems. Map prepared by IREC for the Database of State Incentives for Renewables & Efficiency, March 2011. Note: Oregon also has adopted standard interconnection procedures and agreements for systems over 20 MW.*

AR: 25/300*
CA: no limit
CO: 10,000
CT: 20,000
DC: 10,000
DE: 20,000*
FL: 2,000*
GA: 10/100*
HI: no limit
IA: 10,000
IL: 10,000
IN: no limit
KS: 25/200*
KY: 30*
LA: 25/300*
MA: no limit
MD: 10,000
ME: no limit
MI: no limit
MN: 10,000
MO: 100*
MT: 50*
NC: no limit
NE: 25*
NH: 100*
NJ: no limit
NM: 80,000



NV: 20,000
NY: 2,000
OH: 20,000
OR: 10,000
PA: 5,000*
PR: no limit
SC: 20/100
SD: 10,000
TX: 10,000
UT: 25/2,000*
VA: 20,000
VT: no limit
WA: 20,000
WI: 15,000
WV: 2,000
WY: 25*

characteristics of the grid feeder[10] on which it will be interconnected. In many cases, the levels are based on those established in the FERC or MADRI procedures.

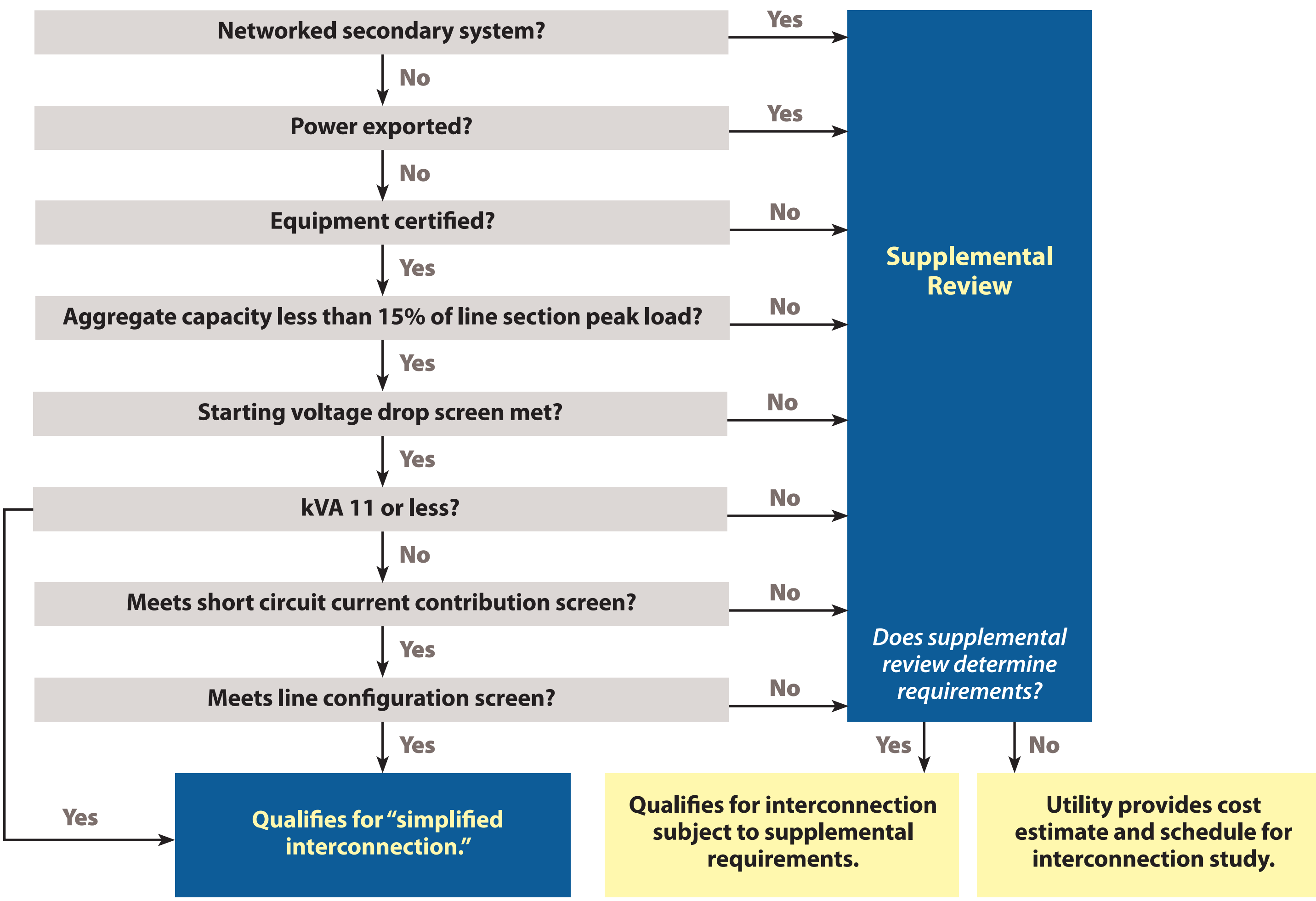
If the application does not pass the "technical screens" for a particular level, it moves up to the next level, with more stringent study requirements. These screens deal with issues like penetration of distributed generation on the feeder and other local grid parameters. Lower review levels allow for interconnection without a detailed impact study, although the screens themselves could be considered a simple impact study. Small (e.g., less than 10 kW), inverter-based distributed generation interconnected to radial systems are at the lower end (Level 1), with larger units and more complicated interconnections at the higher levels (Levels 2 to 4). Impact studies typically are required at the higher review levels, and always for Level 4. Figure 2 shows a simple screening process used in California to determine if an interconnection qualifies for the state's simplified interconnection process.

The higher review levels (Level 2 and beyond) typically involve the following steps for the review process:

- **Scoping Study.** The purpose of the scoping study (often a meeting) is to discuss the interconnection request and review existing studies.
- **Feasibility Study.** The feasibility study determines if there are obvious adverse impacts identified before additional studies are undertaken for the proposed project to continue in the process.
- **System Impact Study.** The system impact study identifies the electric system impacts that would

Figure 2.

Screening process to determine qualification for simplified interconnection[11]



result if the proposed distributed generation were interconnected without distributed generation project modifications or utility electric system modifications, focusing on the adverse system impacts identified in the feasibility study. System impact studies can include the following individual studies:

- Analysis of equipment interrupting ratings
- Distribution load flow study
- Flicker study
- Grounding review
- Power flow study
- Power quality study
- Protection and coordination study
- Short circuit analysis
- Stability analysis
- Steady state performance
- Voltage drop study

In some cases, other specialized system impact studies also are required.

- **Facilities Study.** The facilities study determines the specific utility equipment and changes necessary to complete the interconnection and the associated costs. This equipment will mitigate the adverse systems impacts caused by the distributed generation.

Equipment Certification Example

Interconnection equipment shall be deemed certified with establishment of the following:[12]

1. The interconnection equipment has been tested in accordance with the codes and standards shown below by any nationally recognized testing laboratory (NRTL) recogn ized by the United States Occupational Safety and Health Administration (OSHA) to test and certify interconnection equipment pursuant to the relevant codes and standards listed below.

   Codes and Standards
   IEEE 1547.1 Standard for Conformance Tests Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems; Underwriters Laboratories ("UL"), UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems.

2. The interconnection equipment has been labeled and is publicly listed by such NRTL at the time of the interconnection application.

3. The interconnection customer verifies that the intended use of the interconnection equipment falls within the use or uses for which the interconnection equipment is labeled, and is listed by the NRTL.

4. If the interconnection equipment is an integrated equipment package such as an inverter, then the interconnection customer shall show that the generator or other electric source being utilized is compatible with the interconnection equipment and is consistent with the testing and listing specified for this type of interconnection equipment.

5. If the interconnection equipment includes only interface components (switchgear, multi-function relays, or other interface devices), then an interconnection customer shall show that the generator or other electric source being utilized is compatible with the interconnection equipment and is consistent with the testing and listing specified for this type of interconnection equipment.

6. The interconnection equipment shall meet the requirements of the most current approved version of code and standard, as amended and supplemented at the time the interconnection request is submitted to be deemed certified.

7. Certified interconnection equipment shall not require further design testing or production testing, as specified by IEEE Standard 1547 Sections 5.1 and 5.2, or additional interconnection equipment modification to meet the requirements.

Procedures generally contain milestone schedules, stating how quickly the interconnection application will be reviewed and specifying a certain amount of time the utility and applicant can take to complete the above steps. Most procedures also include application forms the project developer completes.

Requirements for Certified Equipment. Many states require equipment to be compliant with certain standards or "certified" to qualify for some review levels. States define "certified" in slightly different ways – a typical requirement is shown in the accompanying text box.

Applications and Agreements

Standard application and agreement forms make the interconnection process more transparent. Most states have simpler, shorter application and agreement forms for Level 1 interconnection that is processed in an expedited fashion. Standard-form interconnection agreements may be included in the state interconnection rule, or utilities may be required to file such agreements with the state PUC consistent with the rules and any model agreement established in the rulemaking proceeding.

Technical Requirements

The Energy Policy Act (EPAct) of 2005 required state PUCs to consider the following standard:

> *Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services are* [sic] *offered shall promote current best practices of interconnection for distributed 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.*

As part of this process, many states that had not already incorporated IEEE Standard 1547 and UL 1741 as part of their rule did so. Using these standards as the technical requirements for state-level interconnection rules is becoming more common. Some PUCs have slight variations, stating clarifications, additions, or exceptions to the standard, but most simply use it unchanged.

IEEE Standard 1547 has the following limitation: "The criteria and requirements in this document are applicable to all distributed resource technologies, with aggregate capacity of 10 MVA or less at the PCC[13] [point of common coupling], interconnected to EPSs [electric power systems {grids}] at typical primary and/or secondary distribution voltages." IEEE Standard 1547 can be applied to larger distributed generation, however, and some states use it this way.

Most of the other standards in the IEEE 1547 series directly reference IEEE Standard 1547 and thus have the same size limitation, such as:

- IEEE Standard 1547.1 Standard for Conformance Tests Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems
- IEEE 1547.2 Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE initiated a standards development effort for some larger distributed generation interconnections titled *IEEE P1547.5, Draft Technical Guidelines for Interconnection of Electric Power Sources Greater than 10 MVA to the Power Transmission Grid.* This was to provide guidance regarding the technical requirements, including design, construction, commissioning acceptance testing, and maintenance/performance requirements, for interconnecting *dispatchable* electric power sources with a capacity greater than 10 MVA to the *bulk power transmission grid.* This effort has been languishing, however, and might not be further developed.

IEEE 1547.7 Draft Guide to Conducting Distribution Impact Studies for Distributed Resource Interconnection will describe criteria, scope, and extent for engineering studies of the impact on the grid resulting from the interconnection of a distributed resource or aggregate distributed resources. As part of this effort, many of the technical screens that are used in interconnection procedures are being reviewed. The result of this effort may be revised screening criteria that states could adopt.

IEEE is currently developing *IEEE Standard 1547.8, Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Standard 1547,* which will likely address systems larger than 10 MVA. IEEE Standard 1547.8 will recommend practices that apply to the requirements set forth in IEEE Standard 1547 and provide recommended methods that may expand the usefulness and uniqueness of IEEE Standard 1547 through the identification of innovative designs, processes, and operational procedures.

An IEEE Standard 1547.8 writing group is currently addressing recommendations for larger distributed generation, reviewing the base IEEE 1547 Standard to indicate what additional guidelines would be required for larger distributed generation.

State Practices for 10 MW to 20 MW Units

According to the *Freeing the Grid* study,[14] 16 states have no statewide interconnection standards for any size generating system.[15] Of the remainder, only 18 states specify interconnection standards or procedures for systems greater than 10 MW. The study gave 15 of those states passing grades of "C" or higher. A grade of "C" means that the study found requirements are:

> *…adequate for interconnection, but systems incur higher fees and longer delays than necessary. Some systems will likely be precluded from interconnection because of remaining barriers in the interconnection rules.*

The states that have standards or procedures for interconnection of systems 10 MW or larger and that earned a grade of "B" or higher are Maine, Massachusetts, Utah, Virginia, New Jersey, Illinois, California, Connecticut, North Carolina, New Mexico, and Nevada (listed from highest to lowest score).[16]

Six of the interconnection criteria the study used are most critical to distributed generation between 10 MW to 20 MW:

- Individual system capacity
- Breakpoints for interconnection review levels
- Timelines for processing applications
- Standard form agreement
- Insurance requirements
- Dispute resolution

When states were rescored based solely on these large system criteria, Massachusetts scored highest, with Maine also receiving a high score; Virginia, Connecticut, New Jersey, and Ohio scored somewhat favorably with some noted barriers or lack of strong points. The remaining 12 states with standards that cover larger systems fell below a "C" score based on the large system criteria alone. Although this re-ranking is far from conclusive, it provides useful information on best practices.

The appendix reviews interconnection practices, with a focus on distributed generation between 10 MW and 20 MW in the 11 largest states (based on population). The review also includes Oregon because it is viewed as having one of the best interconnection procedures in the country. Virginia, Connecticut, Maine, and Massachusetts also are reviewed because they ranked highest for interconnection practices for larger distributed generation.

Recommendations on best practices provided below are based on approaches used in the states listed previously and the MADRI and IREC model standards.

Recommendations for States – Technical Requirements, Procedures, and Agreements for Distributed Generation Greater Than 10 MW

States are taking different approaches for interconnection regulations for larger distributed generation. Some states' procedures do not address units larger than 2, 5, or 10 MW. Other states have no size limit in their rules, and larger distributed generation simply falls into the highest level of review. The highest level of review is not an expedited process and normally requires a scoping meeting, feasibility study, system impact study, and facilities study. The customer can decide not to interconnect at any step in this process. Typically, there are no, or minor, differences in the technical requirements for larger units. Most states have adopted IEEE Standard 1547 for all size ranges and review levels. After impact and facilities studies are completed, however, interconnection requirements tend to have more prescriptive requirements than in IEEE Standard 1547.

Of significance, most states limit their rules to distributed generation interconnected to distribution systems, although in fact the state has authority to regulate some distributed generation interconnected to transmission systems.

The following are recommendations for state-level interconnection procedures for distributed generation with a capacity between 10 MW and 20 MW, using criteria similar to the framework in the *Freeing the Grid* report.[17]

Rule Coverage

Many states have specified that their rules apply only to distributed generation interconnected to distribution systems. Some states have special interconnection requirements for net-metered systems, but typically net metering is capped at an individual unit capacity well below 10 MW.

State rules should apply to all distributed generation interconnected to distribution and transmission systems in which the interconnection is under state jurisdiction. The recommendations outlined in this paper can be used for systems connecting at either voltage level. If for some reason a state wants to limit its rules to units interconnected to distribution systems, the state can require that units interconnected to transmission systems follow regional system operator rules or FERC Small Generator Interconnection Procedures.

Breakpoints and Technical Screens for Interconnection Levels

The interconnection review process should have breakpoints, or "levels," with technical criteria, or screens, to determine if a distributed generation unit is eligible for the procedures at each level. FERC's Small Generator Interconnection Procedures, the MADRI and IREC model procedures, and most state interconnection rules have such provisions. For example, under the IREC Model Procedures, Level 1 is for units 25 kW or less, Level 2 is for units 2 MW or less, and Level 3 is for units between 2 MW and 10 MW. In addition to these size limits, there are additional technical qualification criteria, or screens, for Levels 1 to 3. If these criteria are met, Level 1 to 3 interconnections are eligible for expedited interconnection described in the procedures for these levels. Level 4 is for all facilities that do not qualify for Levels 1 to 3, and thus addresses all sizes, including distributed generation over 10 MW.

Larger distributed generation, including units over 10 MW, should fall into the highest review level. The highest review level does not contain technical screens.

Eligible Technology

Interconnection procedures for distributed generation from 10 MW to 20 MW should cover the full range of distributed generation technology types (e.g., inverter-based, induction machines, and synchronous machines). Almost all state rules are already technology-neutral, allowing for interconnection of all types of distributed generation. Some states only allow certain technologies for certain review levels (e.g., inverter-based for Level 1), but this type of restriction should not apply to the highest review level into which distributed generation over 10 MW would fall.

Individual System Capacity

Distributed generation interconnection procedures should not be capped at 20 MW. Units over 20 MW would likely require a dedicated feeder to the substation, but could be interconnected to some distribution systems as well as transmission systems. The highest review level should be a catchall for all interconnections that do not qualify for the lower levels. Systems greater than 10 MW would always be reviewed at the highest level, because they don't fit the requirements and screens for the lower levels. System capacity is generally defined as the aggregate total nameplate capacity interconnected at the point of common coupling. This is good practice and this language should be included in state rules.

Timelines

The review process typically involves a series of steps, with a timeline associated with each one. The lowest level review process, typically for smallest, certified units, has a fast-track, or expedited, process. As one moves up through the levels, the timelines become longer. The highest review level, which should apply to all units greater than 10 MW, plus other units that don't pass lower screens, should apply reasonable and explicit timelines similar to the following process:[18]

> *By mutual agreement of the parties, the scoping meeting, interconnection feasibility study, interconnection impact study, or interconnection facilities studies may be waived.*
>
> *Within 10 business days from receipt of an interconnection request, the utility shall notify the interconnection customer whether the request is complete. When the interconnection request is not complete, the utility shall provide the interconnection customer a written list detailing information that must be provided to complete the interconnection request. The interconnection customer shall have 10 business days to provide appropriate data in order to complete the interconnection request or the interconnection request will be considered withdrawn. The parties may agree*

19 MW system built for Xcel Energy in Colorado. Photo courtesy of SunPower Corporation.

to extend the time for receipt of additional information. The interconnection request shall be deemed complete when the required information has been provided by the interconnection customer or the parties have agreed that the interconnection customer may provide additional information at a later time.

A scoping meeting will be held within 10 business days, or other mutually agreed to time, after the utility has notified the interconnection customer that the interconnection request is deemed complete.

When the parties agree at a scoping meeting that an interconnection feasibility study shall be performed, the utility shall provide to the interconnection customer, no later than 5 business days after the scoping meeting, an interconnection feasibility study agreement, including an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.

When the parties agree at a scoping meeting that an interconnection feasibility study is not required, the utility shall provide to the interconnection customer, no later than 5 business days after the scoping meeting, an interconnection system impact study agreement, including an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.

When the parties agree at the scoping meeting that an interconnection feasibility study and system impact study are not required, the utility shall provide to the interconnection customer, no later than 5 business days after the scoping meeting, an interconnection facilities study agreement including an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.

An interconnection system impact study shall be performed when a potential adverse system impact is identified in the interconnection feasibility study. The utility shall send the interconnection customer an interconnection system impact study agreement within five business days of transmittal of the interconnection feasibility study report.

Before the interconnection facilities study is conducted, within five business days of completion of the interconnection system impact study, a report will be transmitted to the interconnection customer with an interconnection facilities study agreement that includes an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.

Upon completion of the interconnection facilities study, and with the agreement of the interconnection customer to pay for the interconnection facilities and upgrades identified in the interconnection facilities study, the utility shall provide the interconnection customer with a small generator interconnection agreement within 5 business days.

An interconnection customer shall have 30 business days, or another mutually agreeable time frame after receipt of *the small generator interconnection agreement, to sign and return the agreement. When an interconnection customer does not sign the agreement within 30 business days, the interconnection request will be deemed withdrawn unless the interconnection customer requests to have the deadline extended. The request for extension may not be unreasonably denied by the utility. When construction is required, the interconnection of the small generator facility shall proceed according to milestones agreed to by the parties in the small generator interconnection agreement.*

Queuing is an important aspect related to timelines, and it is especially important to larger distributed generation. When an interconnection request is complete, the utility assigns it a "queue position." The queue position of the interconnection request is used to determine the potential adverse system impact of the small generator facility based on the relevant screening criteria. If there are higher queued interconnection customers on the same radial line circuit or spot network, the utility evaluates the interconnection request by applying screens such as aggregate capacity requirements. If this requirement is exceeded, the utility notifies the customer and is not obligated to meet the timeline for reviewing the interconnection request until the utility has completed the review of all other interconnection requests that have a higher queue position and thus impact the aggregate capacity.

Once a large distributed generation unit is assigned a queue position, any other distributed generation in that queue would likely be delayed until all the studies on the larger distributed generation unit are completed, because the large distributed generation unit, by itself, will likely exceed the aggregate capacity screens.

A suggested change to the queue process is to allow very small distributed generation projects that are ready to proceed, but that are behind a large unit in the queue that is not ready to proceed, to move in front of that unit. Otherwise the lengthy impact studies for the large project would unnecessarily delay the small projects that require little time for review.

Application Fees

Most states' rules have an application fee, with a lower fee for Level 1 and higher fees for the higher review levels. For example, New Jersey's Level 3 systems (the state's highest level, with no cap on generator size) are subject to a $100 fee, plus an additional $2 per kW of capacity. The application fee for a 20 MW unit would be $4,100 under this system.

For distributed generators in the 10 MW to 20 MW size range, the recommendation is $100 plus $1 per kW of capacity, which matches the application fee in the highest-level review process under the IREC Model Procedures. These fees do not include study costs.

Engineering Charges

In almost all cases, interconnection of large distributed generation will require substantial facilities upgrades. The interconnection customer should be responsible for costs for all required interconnection studies and facility upgrades. A deposit of 50 percent of any study costs prior to starting any study is reasonable. If the utility incurs costs that it would otherwise be responsible for, the utility should pay for those costs. For example, the utility should pay to fix inaccurate distribution or transmission system diagrams or unknown configurations, and pay for planned upgrades such as protective equipment or utility facility upgrades such as reconductoring or transformer upgrades.

Standard Application Form

Distributed generation units larger than 10 MW, which will fall into the highest interconnection review level, should be able to use the same application form that is currently being used for the higher levels of review. Some slight variations may be required, however, because of the technical requirements recommended in this paper. For example, if technical requirements for monitoring equipment are different for larger distributed generation, the application form would require a better description of the equipment the customer intends to use for monitoring.

Standard Agreement Form

Typically, there is a short standard agreement for Level 1 interconnections and a more detailed standard agreement for Levels 2 to 4. Units larger than 10 MW should use a standard agreement form similar to the form for smaller units that are not eligible for the Level 1 interconnection process. As described later in this paper, however, new IEEE technical standards under development for systems larger than 10 MW should be incorporated into the agreement. Such sections should be clearly identified as applying only to units over 10 MW.

Insurance Requirements

Insurance requirements are reasonable for larger distributed generation units whose owners should be able to handle the additional cost. Some state interconnection procedures require that the distributed generation owner must have general liability insurance to cover an amount sufficient to insure against reasonably foreseeable direct liabilities, and this language is suitable for larger distributed generation. Most businesses that install larger distributed generation will likely have a general liability policy that can be amended to provide the protection needed, at an additional cost.

Dispute Resolution

Dispute resolution should be no different for small or large distributed generation units. The state can adapt its existing dispute resolution procedures or parties can use an independent third party with the costs shared 50/50 by the distributed generation developer and the utility.[19]

Equipment Certification

Most state interconnection rules place distributed generation units larger than 2 MW in the highest review level, even if they are certified. Units larger than 10 MW should be reviewed at the highest review level, whether or not the equipment is certified. In any case, certification by a nationally recognized testing laboratory of units larger than 10 MW is rare. States should include provisions for field certification of any size of distributed generation, however. Interconnection equipment is considered to be field-certified if within a previous period (typically 36 months) the utility approved it for use with the proposed facility and the utility has previously approved interconnection equipment identical to that being proposed.

Certification of a unit in the 10 MW to 20 MW size range may result in fewer types of individual impact studies required, and the utility should take this into account.

Network Interconnection (Spot, Area)

Interconnection rules should allow for interconnection of distributed generation units larger than 10 MW to spot[20] or area[21] networks in the highest review level. Large distributed generation units connected to spot or area networks would likely require substantial facilities upgrades to the grid.

External Disconnect Switch

The purpose of a manual, lockable disconnect switch is to ensure the safety of utility personnel when working on electrical lines. Distributed generation larger than 10 MW should require an isolation device that is readily accessible to the grid operator and lockable in the open position and that provides a visible break in the electric connection.[22] States require this type of equipment for interconnected distributed generation, except some states do not require it for some very small, inverter-based units.

Technical Requirements for Systems Over 10 MW

States should use IEEE Standard 1547 as the base requirement for distributed generation units larger than 10 MW and consider adding documented, transparent additional requirements. In particular, states should consider incorporating some of the noted exceptions, additions, and clarifications for IEEE Standard 1547 in PJM's Manual 14A,[23] Attachment E-1 for distributed generation units larger than 10 MW.

The IEEE group currently working on distributed generation larger than 10 MW for Standard 1547.8 has identified the following additional requirements that could be included in Standard 1547 to incorporate larger units.[24] Recommendations have not yet reached draft consensus, and thus this work is still in initial draft form. Many of these proposed new requirements draw from the PJM manual. States should review the final version of IEEE Standard 1547.8 when it is possible to consider incorporating into their rules these recommended practices for larger distributed generation. Based on typical IEEE document development cycles, the final version of this document will likely be completed in 2012. It will be available on the IEEE website.

The following is a summary based on the new requirements currently in the draft IEEE document.

Voltage regulation

Depending on the size of the distributed generation, relative to electric power system (EPS) strength, and location of interconnection, the generation unit may be required to provide or absorb reactive power, follow a voltage schedule to maintain an acceptable voltage profile on the grid, or do both. The distributed resource should not cause the grid service voltage at other locations to go outside the requirements of American National Standards Institute (ANSI) C84.1-1995, Range A.

Sufficient study of the grid EPS will have to be conducted to determine whether active voltage regulation or power factor control will be more appropriate. Such study may include steady-state power flow studies, transient machine response studies to check the effect of voltage changes due to sudden distributed resources changes (e.g., unexpected trip), and transient stability studies related to the surrounding power system.

Inadvertent energization of the Area EPS

The grid operator can allow the distributed generator to energize the grid under a written agreement with the grid operator. This variation from the IEEE Standard 1547 requirements could be used to create a micro-grid.[25] Guidance for intentional islanding can be found in IEEE Standard 1547.4.

Monitoring provisions

The grid EPS operator should monitor the distributed resource's connection status, availability, real power output, reactive power output, and voltage at the point of distributed resource connection. The monitoring shall be at the same frequency as other grid facilities.

Isolation device

A readily accessible, lockable, visible-break isolation device should be located between the grid and the distributed resource. The isolation device should be rated for the voltage and current requirements of the installation and can be located between the point of common coupling and the generator.

Area EPS faults

The standards should allow for different requirements under conditions mutually agreeable to the grid operator and generator. IEEE Standard 1547 requires the distributed generation unit to cease to energize the grid for all faults on the grid to which it is connected. In some cases, the grid operator may want large distributed generators to ride through the fault.

Area EPS reclosing coordination

The standards should allow distributed generation operation and protection to be fully coordinated with the grid under an agreement with the grid operator and operate outside IEEE 1547 standards under this agreement if needed. For example, increased reclosing time or the addition of synchronism check supervision to provide coordination may be used. Increasing the reclosing time in some cases could have an unreasonable impact on other customers, so other means, such as transfer trip or dead-line checking, can be used to insure isolation of the generator before automatic circuit reclose.

Voltage

Under agreement with the grid operator, other voltage ranges and clearing times can be established.

Frequency

The standards should allow for agreement with the grid operator to establish other frequency ranges and clearing times.

Reconnection to Area EPS

Verbal communication from the grid operator is required before returning the distributed generation to the system after it goes off-line due to a grid disturbance.

Harmonics

When multiple distributed generation units are operating at different points of common coupling on the same feeder, each distributed generator may meet the IEEE Standard 1547 current injection limit; however, the aggregate impact of the units could cause voltage distortion that would adversely impact other customers. The *aggregate* voltage distortion at each point of common coupling must not exceed IEEE 519 limits. If the limits described in IEEE 519 are exceeded, the distributed generation that is responsible for the adverse impact must take corrective actions to mitigate the problem.

Unintentional islanding

The unintentional islanding requirement of IEEE Standard 1547 can be met by transfer trip, distributed generation certified to pass an anti-islanding test, sensitive frequency and voltage relay settings, reverse or minimum power flow relay limited, or other anti-islanding means.

For distributed generation larger than 10 MW, the interconnection system should detect the island and cease to energize the grid within 10 seconds of its formation.

Area for Further Research – Impact Studies

State requirements for impact studies vary. Some states' requirements list exactly what studies need to be performed, others give recommendations, and still others say the utility should use "good utility practice" in determining what studies are needed. IEEE Standard 1547.7, under development, will likely give better guidelines on what studies are required for different situations based on the characteristics of the distributed generation and grid feeder. When this document is published, states should review it and consider modifying their rules to better stipulate exactly what impact studies are required.

Federal Procedures and Agreements for Small Generators

Interconnections that fall under federal jurisdiction are subject to standard procedures and agreements established by FERC. This includes any distributed generation that sells to wholesale markets, including units interconnected to distribution systems, although most FERC-jurisdictional distributed generation is connected to transmission systems. When such units are connected to the transmission system in organized markets, the interconnection is also governed by the regional transmission organization (RTO) or independent system operator (ISO) that runs the system. The accompanying text boxes provide a high-level review of the procedures and agreements for interconnections under federal jurisdiction.

New Issues That Should Be Addressed in Interconnection Regulations

IEEE Standard 1547 addresses the interconnection technical specifications and requirements and the interconnection test specifications and requirements. Most interconnection regulations were designed for low penetration of distributed generation. Some states, such as Hawaii and California, are starting to experience high distributed generation penetration in some areas. IEEE Standard 1547 does not address the impacts of high penetration levels of distributed generation on local and area EPS planning and operation. The IEEE Standard 1547 requirements apply at the point of common coupling, and don't consider effects of other distributed generation within the vicinity. Also, even small certified systems cannot pass some of the technical screens for lower levels of review

Example RTO Interconnection Requirements – PJM

PJM Interconnection is an RTO that operates a competitive wholesale electricity market and manages the high-voltage electricity grid for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM has developed its own interconnection procedures and agreements based on the SGIP requirements. FERC granted PJM's request to use a *pro forma* version of the FERC procedures. The PJM interconnection process uses a queue system to prioritize requests from developers to interconnect generating units to the system. Projects enter the queue and PJM and the interconnected Transmission Operator jointly study their impacts on the system. There are milestone requirements for feasibility, system impact, and facilities studies to identify impacts and required system upgrades.

Attachment E-1 of PJM's *Manual 14A: Generation and Transmission Interconnection Process* specifies technical requirements and standards for generators between 10 MW and 20 MW connecting to transmission systems. The standards are based on the core IEEE Standard 1547 requirements with changes and additions as required to address distributed generation larger than 10 MW. PJM provided additional clarification to Section 4.2.1 of the standard to assure that system protection requirements are compatible with the established reliability criteria used for transmission facilities. Attachment E-1 also notes other broadly vetted exceptions, additions, and clarifications regarding IEEE Standard 1547. PJM details 26 of these variations to clauses 4 and 5 of IEEE Standard 1547. The 26 variations include some that are applicable to all PJM members and some that are specified for only certain PJM members. Many of these variations to the standards are appropriate for interconnection to distribution systems as well, and were included in the recommendations in this paper for state interconnection procedures for distributed generation larger than 10 MW.

FERC Small Generator Interconnection Procedures and Agreement

FERC issued Order No. 2006 in 2005, Small Generator Interconnection Procedures (SGIP) and a standard-form companion document, the Small Generator Interconnection Agreement (SGIA). FERC established its final version of the SGIP and SGIA in 2006 through Order No. 2006-B.[27] The procedures and agreement set requirements for distributed generation no larger than 20 MW for FERC-jurisdictional interconnections in the U.S.[28]

Many model and state regulations are based on the SGIP or its general methodology, or on the MADRI procedures.

The SGIP include provisions for three levels of interconnection review and process:

1. *A 10-kW Inverter Process* for certified systems 10 kW or less
2. *A Fast Track Process* for certified systems no larger than 2 MW
3. *A Study Process* for all other systems no larger than 20 MW

The SGIP includes technical screens for the first two levels of interconnection, and if the screens are not met, the next higher review process may be used. The following is a review of FERC's SGIP using the criteria used by the *Freeing the Grid*[29] report to score states on indicators that unnecessary barriers have been removed for interconnection:

1. **Eligible technologies.** The SGIP includes all distributed generation technologies.
2. **Individual system capacity.** The SGIP includes distributed generation units up to 20 MW.
3. **"Breakpoints" for interconnection process.** There are three levels for review, including a fast-track process for small systems.
4. **Timelines.** The SGIP includes timelines for completion of each step of the review of an interconnection.
5. **Interconnection charges.** Processing fees vary by review level, and the customer pays for all required studies and facilities upgrades.
6. **Engineering charges.** The customer pays a deposit and all study costs and facilities upgrade costs.
7. **External disconnect switch.** The SGIP is silent on external disconnect switch requirements.
8. **Certification.** The SGIP applies IEEE Standards 1547 and UL 1741.
9. **Technical screens.** The review processes for Levels 1 and 2 include technical screens. If the screens are not met, the application may go to the Level 3 review process.
10. **Network interconnection (spot and area).** The SGIP allows for interconnection to spot networks for inverter-based distributed generation. All other interconnection to spot and area networks is not addressed by the SGIP.
11. **Standard form agreement.** The SGIA is the agreement used for Levels 2 and 3. Level 1 distributed generation interconnection abides by standard terms and conditions in the SGIP, but there is no standardized form.
12. **Insurance requirements.** Procedures for Level 1 interconnection simply refer to insurance requirements in the state's interconnection procedures. Levels 2 and 3 require insurance to cover all reasonable direct liabilities, and no cap is set.
13. **Dispute resolution.** The procedures require use of FERC's dispute resolution service. This service either assists the parties directly or selects another organization to resolve the issues. If third-party review is needed, the parties split the cost.
14. **Rule coverage.** The SGIP applies to all FERC-jurisdictional interconnections up to 20 MW.

in state rules if the feeder has high levels of installed distributed generation, making the interconnection process very difficult because it may have to be reviewed under the procedures specified for the highest level of review.

In addition, the introduction of smart grids will raise issues that may require changes to state interconnection rules. The smart grid should unlock additional benefits from distributed generation, including:[30]

- **Better handling of two-way electrical flows –** Distributed generators "export" power to the utility system when generation output exceeds any on-site load demand. That export makes it more difficult for the utility to provide voltage regulation and protective functions. Smart grid's monitoring and communications functions should make these tasks easier for utilities.

- **Easier deployment –** With near-real-time information provided by the smart grid, the utility system operator will have detailed reports on the current conditions of individual feeders and loads. That should allow for simpler interconnection studies – or no study at all if certain new screens are passed – for some applications.

- **Higher penetration levels –** With real-time knowledge of conditions on feeders and communications between the grid and distributed generations and loads, some utility operating practices could be modified to facilitate higher concentrations of distributed generation.

- **Dynamic integration of variable energy generation –** Smart grids will remotely monitor and report generation from distributed generations so automated systems and grid operators can dispatch other resources to meet loads.

- **Reduced downtime –** New inverter designs integrated with smart grids will allow distributed generation to detect operational problems on the utility system, such as faults, and continue operating during some of these disturbances.

- **Maintaining power to local "micro-grids" during utility system outages –** Smart grids could allow for the formation of intentional islands of distributed generation and loads that disconnect automatically when the grid is down and automatically resynchronize to the grid when conditions return to normal. Distributed generations within the micro-grid can then continue to produce electricity to serve customers and loads within.

- **Providing ancillary services –** Smart grid's built-in communications infrastructure will enable the grid operator to manage distributed generation to provide reactive power, voltage support, and other ancillary services under some circumstances.

Figure 3. *Potential smart grid benefits for distributed generation in the future, compared to operations today*

Distributed Generation (DG) as Smart Grid Evolves

Today

- Low penetration of DG
- Little or no communications between DG and the grid
- Detailed system impact studies needed for many applications
- DG meets IEEE Standard 1547
- Microgrid demonstrations

Mid-Term

- Increased penetration of DG
- Some interaction between DG and the grid – to respond to price signals, for example
- Interconnection standards and rules are updated
- More microgrids develop

Long-Term

- High penetration of DG
- DG can be monitored, controlled and dispatched by utility
- Easier interconnection
- DG rides-through some grid disturbances
- DG provides local voltage regulation and other ancillary services
- Microgrids are commonplace

Three 4.7 MW Mercury™ 50 recuperated gas turbine generator sets are at work at this landfill gas to energy facility in Agoura, California. Photo courtesy of Solar Turbines Incorporated.

IEEE Standard 1547.8, under development, will address some of these issues. States should monitor recommendations and guidance in IEEE Standard 1547.8 and, when available, modify interconnection rules appropriately.

Development and Enhancement of Technical Standards in the IEEE 1547 Series

IEEE Standard 1547.8 will provide recommended methods that may expand the usefulness and utilization of IEEE Standard 1547 through the identification of innovative designs, processes, and operational procedures. IEEE Standard 1547.8 will give recommendations for grid operators and distributed generation owners on what may be done when an application does not meet the requirements of IEEE Standard 1547. The following topics are under consideration for IEEE Standard 1547.8. Once IEEE Standard 1547.8 is approved, states should review the new guidelines and consider incorporating them into their interconnection rules, or reference the guidelines as recommended practice for applications that may extend beyond the 1547 requirements applied at the point of common coupling.[31]

IEEE Standard 1547 Clause 4.1.1 Voltage Regulation

This will include the new topic of operational integration and coordination of distributed generation exceeding the IEEE Standard 1547 requirements in order to allow distributed generators to provide voltage regulation or other grid operations support.

IEEE 1547 Standard Clause 4.1.6 Monitoring

This will include the new topic of recommended practices for two-way communications, expanding the baseline IEEE 1547 monitoring and controls requirements to likely include functions that provide the exchange of detailed information between the distributed resource and the grid operator.

IEEE Standard 1547 Clause 4.2 Response to Area EPS Abnormal Conditions

This will include new topics addressing operational integration and coordination of distributed resources to allow added value and technical support to help mitigate problems with the grid, to provide for alternate test methods for island detection, and to address multiple distributed resources, false trips of distributed resources, inability to detect an island, and related improvements.

IEEE Standard 1547 Clause 4.3 Power Quality

This will include the new topic of addressing multiple distributed resources, false trips of distributed resources caused by grid disturbances, inability to detect an island, and potential power quality issues.

New issues that are not addressed in IEEE Standard 1547 that may be addressed in IEEE Standard 1547.8 include:

Additional Data

The IEEE Standard 1547.8 work group is reviewing behavior of inverters, harmonic levels at various loads, influences of the energy source, static and dynamic data, and models used in system impact studies. This work may be used to develop best practices for more efficient system impact studies and to provide guidance to inverter manufacturers on what types of data utilities may need for models and studies.

Distributed Resource (DR) Facilities 10 MVA to 20 MVA

This section will give new technical guidelines for distributed generation in this size range. Additions, deletions, and clarifications to the base IEEE Standard 1547 requirements will be provided.

Optimizing Group Behavior of Multiple Distributed Resources; System Optimization

Distributed resources may, individually or in groups, directly enhance the performance of the grid. The potential for grid benefits from distributed generation is related to the unit's location, size, and operating characteristics along with the characteristics of the grid. This section will discuss how multiple distributed generation units can be integrated into the operation scheme of the grid itself.

Distributed Resource Required to See Faults; Clarification of Best Practices

The purpose of this section is to frame the discussion and examine ways of meeting the requirements or, if necessary, propose new definitions or specifications for the protection system that meet the intent (but not necessarily the exact requirements) of IEEE Standard 1547.

Review Levels and Screens

One of the most important issues related to state-level interconnection rules is the use of review levels and screening criteria to determine if a given application meets the technical requirements at that level. For most states, if an application does not pass one of the screens within a given review level, it is reviewed at the next higher level. In many of those cases, time-consuming and expensive impact studies are required. Utilities are sometimes given wide latitude in determining what individual impact studies should be performed and what tools are used to perform the studies. Companies usually have their own specific approach and often also use engineering judgment and long established rules of thumb.

Most state review-level criteria and screens are based on the FERC SGIP or MADRI procedures. As such, they tend to be based on a singular or over-simplified parameter. In some cases, these screens are a compromise between what the utilities and the distributed generation proponents wanted. There may be no definitive technical basis for the criteria level of the screen.

States should look to organizations like IEEE to develop better screening criteria to use in their rules and to determine what types of individual impact studies should be performed if a screen is not met.

IEEE Standard 1547.7

IEEE Standard 1547.7 will address some of the issues related to establishing more definitive methodologies and criteria levels and may develop a review process methodology based on technical criteria considering the characteristics of the distributed generation and the grid (as well as related technical considerations beyond the point of common coupling). States may want to review IEEE Standard 1547.7 when available and consider revising their methodology. A two-step process is a possibility, with a first set of criteria to determine if no further studies are needed that would allow for an expedited review process. If an application fails the first review, then a more detailed methodology would identify exactly what impact studies are required if a given criterion is not met. This may make the process more transparent, both for the grid operator to implement and for the distributed generation applicant.

For example, screening requirements concerning the propensity of distributed generation to cause the grid

One 15 MW Titan™ 130 SoLoNOx™ gas turbine generator set provides electricity and steam for this campus at Michigan State University. Photo courtesy of Solar Turbines Incorporated.

to operate in excess of its equipment ratings (e.g., rated current) under both normal and fault conditions in model rules, FERC rules, and state rules rely on the language in IEEE 1547.2:

> *Determine the maximum current contribution of the DR to the area EPS under both normal and fault conditions, and verify that, when taken in aggregate with all other generation on the distribution circuit, the DR will not cause any equipment on the distribution circuit to exceed a specified percentage of its short circuit interrupting or its withstand capabilities. The value used is commonly between 85% and 90%. For example, the Federal Energy Regulatory Commission used the concise value of 87.5% in its Small Generator Interconnection Order (see Federal Energy Regulatory Commission). This verification applies to all protection devices and equipment on the distribution circuit, including but not limited to substation breakers, fuse cutouts, and line reclosers. Proposals for installing DR on area EPS circuits already loaded beyond the specified threshold are not good candidates for simple impact studies.*

Because IEEE Standard 1547.2 does not state an exact requirement for this screen, FERC, model, and state rules have landed on various points between 85% and 90% for this value.

As another example, most rules have screens for distributed generation penetration that are in place with regard to propensity to create an undetected electrical island. IEEE Standard 1547.2 addresses the issue as follows:

> *For interconnection of a proposed DR with a radial distribution circuit, it is generally agreed that an undetected island cannot be created if the aggregated generation, including the proposed DR, on the circuit does not exceed 15% of the line section annual peak load as most recently measured at the substation. If the minimum line section load is known, 50% of that value could be used. A line section is that portion of the area EPS connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.*

IEEE Standard 1547.2 states that "it is generally agreed" that not exceeding 15% of the line section peak is an adequate requirement, but does not cite a technical study or calculation used to develop this screen. The standard also includes a requirement based on minimum load, but grid operators may not have this data available.

IEEE Standard 1547.7 will likely better address this technical screen and give states better technical criteria to use in their rules.

Solar America Board for Codes and Standards' Review of FERC's SGIP Screens

The Solar America Board for Codes and Standards recently published recommendations for updating the screens in the FERC SGIP, outlined below. This report addresses the SGIP fast-track screens and the capacity limit of the lowest review level (increasing it from 10 kW or less [inverter-based] to a larger capacity). As part of this work the Solar America Board surveyed 37 subject matter experts.

SGIP Screen 2.2.1.7: 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.

Recommendation: The 20 kW limit on the size of the aggregate distributed generation on a single-phase shared secondary should be revised so that it is stated in terms of a percentage of the transformer nameplate power rating serving the secondary. As an example, the New Mexico rules use 65% of the transformer nameplate rating as a screen.

FERC Screen 2.2.1.9: The proposed generation may not exceed 10 MW if interconnected to the transmission side of a substation transformer feeding the circuit in an area where there are known, or posted, transient stability limitations (e.g., three or four transmission buses from the point of interconnection).

Recommendation: The stability requirement should be rewritten for clarity. The current screen is too vague.

Photo courtesy of SunPower Corporation

FERC Screen 2.2.1.3: The interconnection of inverter-based generation may not facilitate an increase in aggregated inverter-based generation to the load side of spot network protectors that exceeds the smaller of 5% of a spot network's maximum load or 50 kW.

Recommendation: The screen should allow for interconnection to area networks in addition to spot networks. Many states allow for this. In addition, the limits on maximum capacity should be increased. Many states have screens that allow for larger generation on area and spot networks.

The report also recommended further study of the following screens to see if they should be updated.

FERC Screen 2.2.1.2: 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.

Potential Study: Further research is needed to determine if the current 15% limit on generating capacity related to circuit peak load could be increased, or if the limit should be based on circuit minimum load instead. Also, more research should be conducted to see if higher limits could be used for inverter-based generation.

The study also recommended further study to determine if the SGIP size limit for inverter-based systems should be increased from 10 kW. Many states also use 10 kW as the limit for their Level 1 review process.

If state rules use screens similar to those for which the Solar America Board for Codes and Standards recommended changes, states should consider similar modifications, as these are well-vetted suggestions. All of the recommendations are technically valid. They also would make interconnection easier for some customers, because more applications would be eligible for expedited review.

Conclusion

New technologies and standards will impact distributed generation interconnection in the future. Manufacturing of better inverters, smart grid deployments, and new IEEE 1547 Series standards are underway. States should review and update their interconnection technical standards, procedures, and agreements to align with updated best practices, emerging issues, and revised IEEE standards and recommended procedures.

States will also need to consider revising the screens within their rules as the smart grid capabilities are implemented and as better inverter-based systems are deployed. Both of these should lead to easier interconnection and allow additional distributed generation to be interconnected in an expedited fashion without having to perform detailed impact studies.

Potential owners of distributed generation also need to realize that just because their equipment is "1547-compliant" does not mean that it can be connected anywhere on the electric grid without causing system impacts. In some cases, even small 1547-compliant systems will cause impacts, require impact studies, and require the utility to install additional facilities or change operating practices to accommodate the new distributed generation.

Related Resources

The following are links to selected state, regional, and federal interconnection technical requirements, procedures, applications, and agreements, as well as links to relevant reports.

State Interconnection Rules

California. http://www.cpuc.ca.gov/PUC/energy/DistGen/rule21.htm

Connecticut. http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/a6ac34c9193a8f99852573a8006f661b/$FILE/030115RE01-120507.doc

District of Columbia. http://www.dcregs.dc.gov/Gateway/ChapterHome.aspx?ChapterNumber=15-40

Florida. http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=FL20R&re=1&ee=1

Georgia. http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=GA04R&re=1&ee=1

Illinois. http://www.icc.illinois.gov/downloads/public/edocket/228047.pdf and http://www.icc.illinois.gov/downloads/public/edocket/261072.pdf

Maine. http://www.dsireusa.org/documents/Incentives/ME15Ra.pdf

Massachusetts. http://www.env.state.ma.us/dpu/docs/electric/09-03/82009noiapb.pdf

Michigan. http://www.dleg.state.mi.us/mpsc/orders/electric/2009/u-15787_05-26-2009.pdf

New Jersey. http://www.dsireusa.org/documents/Incentives/NJ11Rb.htm

New York. http://www.dps.state.ny.us/Modified_SIR-Dec2010-Final.pdf

North Carolina. http://www.dsireusa.org/documents/Incentives/NC04R1.pdf

Ohio. http://codes.ohio.gov/oac/4901%3A1-22

Oregon. http://apps.puc.state.or.us/orders/2009ords/09-196.pdf and http://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=10-132

Pennsylvania. http://www.pacode.com/secure/data/052/chapter75/subchapCtoc.html

Texas. http://info.sos.state.tx.us/pls/pub/readtac$ext.ViewTAC?tac_view=5&ti=16&pt=2&ch=25&sch=I&div=2&rl=Y

Virginia. http://leg1.state.va.us/cgi-bin/legp504.exe?000+reg+20VAC5-314

Regional Documents and Model Rules

MADRI. http://sites.energetics.com/MADRI/pdfs/inter_modelsmallgen.pdf

PJM. http://pjm.com/~/media/documents/manuals/m14a.ashx

IREC Model Interconnection Rules. http://irecusa.org/fileadmin/user_upload/ConnectDocs/IREC_IC_Model_October_2009.pdf

Federal Documents

Federal Energy Regulatory Commission Small Generator Interconnection Procedures (FERC SGIP). www.ferc.gov/industries/electric/indus-act/gi/small-gen/procedures.doc

Federal Energy Regulatory Commission Small Generator Interconnection Agreement (FERC SGIA). http://www.ferc.gov/industries/electric/indus-act/gi/small-gen/agreement.doc

Reports

Network for New Energy Choices, *Freeing the Grid: Best and Worst Practices in State Net Metering Policies and Interconnection Procedures,* December 2010. http://www.newenergychoices.org/uploads/FreeingTheGrid2010.pdf

Solar America Board for Codes and Standards, *Updated Recommendations for Federal Energy Regulatory Commission Small Generator Interconnection Procedures Screens,* July 2010. http://www.solarabcs.org/about/publications/reports/ferc-screens/pdfs/ABCS-FERC_studyreport.pdf

Appendix

Review of Selected State Procedures

This is a review of interconnection practices for distributed generation larger than 10 MW in the 11 largest states (by population). The review also includes Oregon because it is viewed as having one of the best interconnection procedures in the country. Virginia, Connecticut, Maine, and Massachusetts also are reviewed because they ranked highest for interconnection practices for larger distributed generation in the *Freeing the Grid* report.

California

California's interconnection standards are outlined in Rule 21, which uses a screening process to determine the level of review process required for interconnected systems. The Initial Review Process is performed after the customer applies for interconnection, and if the system qualifies for a simplified process, no additional studies are needed. If the system does not pass the initial screening process, it goes through a Supplemental Review Process. After the supplemental process, systems may be permitted to connect to the grid through the simplified process, but with some additional requirements. If the proposed project fails one or more screens, the system is subjected to a full interconnection study, whose costs are determined by the utility and paid by the system owner. Larger distributed generation would almost always fail to pass one of these screens and would be subject to supplemental review. Rule 21 has provisions for certified equipment that is eligible for an expedited review, but approved equipment to date is much smaller than 10 MW. Rule 21's technical requirements for distributed generation installations are similar to those established in IEEE Standard 1547.

Rule 21 requirements apply only to distributed generation interconnected to distribution systems, and each of the three major utilities in California publishes its own version of Rule 21. Rule 21 model language was approved by the PUC and represents standardized interconnection language contained in the tariff booklets of California's three investor-owned utilities, Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. These rules are identical across the three utilities, with minor exceptions, such as slightly different Interconnection Agreements. Each utility's rule was approved by the PUC. Several California municipal utilities have also adopted interconnection rules similar to Rule 21.

Summary of Provisions for Systems Larger than 10 MW – California has no specified system capacity limit. For technical requirements, California generally follows the IEEE 1547 standard, except the state chose not to adopt the 10-MW limit, allowing Rule 21 to apply to the interconnection of units larger than 10 MW. These units may require a system stabilization function, and telemetering could be required for systems larger than 1 MW. California's procedures differ from other state procedures that have "review levels" and technical screens within the levels. In California, all requests enter at the same level, and additional study is required for those that don't pass the technical screens. The supplemental review in the California rule is different from the requirements for a scoping meeting, feasibility study, system impact study, and facilities studies typically found in other states with review levels. A supplemental review guideline document states what issues needed to be studied for distributed generation that does not qualify for expedited review.

Connecticut

In 2007 the Connecticut Department of Public Utility Control revised its interconnection guidelines for distributed energy systems. The guidelines apply to the state's two investor-owned utilities (Connecticut Light & Power and United Illuminating Company) and are modeled on FERC's interconnection standards for small generators, with some minor variations. As an example, customers are required to install an external disconnect switch and interconnection transformer, which are not required under FERC standards.

There are three levels of systems addressed in Connecticut's guidelines:

1. Certified, inverter-based systems no larger than 10 kW

2. Certified systems no larger than 2 MW
3. All other systems, no larger than 20 MW in capacity

Utilities were required to collaboratively submit a status report on the research and development of area network interconnection standards. Area network interconnection of distributed generation was not covered in the 2007 rules. Instead it is handled on a case-by-case basis to determine if the proposed generator can be safely interconnected. The status report was completed in 2009 and, as a result, area network interconnection is now allowed if the following criteria are met:

- The unit is a certified, inverter-based generator or it has inverter-based utility grade relays exclusively used in its design.
- The network primary feeders supplying the network to which the generation is connected are from the same electrical bus or from normally tied buses.
- The maximum generator size is limited to 50 kW at any location, to limit power flow through the cable limiters.
- Total aggregate generation interconnected to an area network is limited to 3 percent of the maximum network transformer-connected kVA with the feeder supplying the largest number of network units out of service, or a maximum of 500 kW, whichever is less.

Summary of Provisions for Systems Larger than 10 MW – Connecticut's interconnection guidelines apply to facilities of any size, with special provision for units larger than 20 MW. All systems larger than 5 MW require additional steps to ensure that the interconnection does not adversely affect the local distribution system. A special provision for units larger than 20 MW states that the rules can be used for any distributed generation interconnecting to the distribution systems, as feasible and appropriate, with longer timeframes allowed for the necessary reviews.

Florida

Florida's interconnection rules are for renewable distributed generation and have three review levels for which utilities must provide expedited interconnection procedures:

1. 10 kilowatts (kW) or less
2. 10 kW to 100 kW
3. 100 kW to 2 MW

Summary of Provisions for Systems Larger than 10 MW –The utilities may have their own rules for interconnecting systems larger than 10 MW, but there are no state requirements.

Georgia

Georgia's net-metering rules allow residential electricity customers with photovoltaic, wind-energy, or fuel cell systems up to 10 kW, and commercial facilities up to 100 kW, to connect to the grid. The total capacity of net-metered systems is limited to 0.2% of a utility's system peak demand from the previous year. There are no rules for systems larger than 100 kW. These rules apply only to interconnection to distribution systems.

Interconnected customers must comply with the relevant national standards, including IEEE 1547, UL 1741, and guidelines established in the NEC and National Electrical Safety Code. The Georgia Public Service Commission may eventually adopt additional safety, power quality, and interconnection requirements. Utilities are prohibited from requiring additional tests or liability insurance.

Summary of Provisions for Systems Larger than 10 MW – None.

Illinois

Illinois interconnection rules contain four levels of review for interconnection requests. The level of review is generally based on the system capacity, whether system components are NRTL certified, and the type of network connection. The following are the basic definitions for each tier:

Tier 1: Certified, inverter-based systems with a capacity rating of 10 kW or less

Tier 2: Certified systems with a capacity rating of 2 MW or less, interconnected to a radial distribution network or a spot network serving one customer

Tier 3: Non-exporting certified systems with a capacity rating of 50 kW or less interconnected to an area network, or certified, non-power-exporting systems with a capacity rating of 10 MW or less interconnected to a radial distribution network

Tier 4: Systems with a capacity of 10 MW or less not meeting the criteria for inclusion in a lower tier

Standardized interconnection agreements are available for all four tiers.

The Illinois Commerce Commission (ICC) adopted a separate set of rules for distributed generation facilities greater than 10 MW in capacity. The ICC rules require the utility to use relevant technical interconnection standards adopted by the applicable RTO. If the RTO does not have applicable standards, the utility and the interconnection customer negotiate modifications to IEEE Standard 1547 to address electric system and distributed generator conditions. From a procedural standpoint, the ICC rule is similar to the MADRI Level 4 review process.

Summary of Provisions for Systems Larger than 10 MW – Illinois has specific interconnection standards for facilities larger than 10 MVA in capacity. These standards apply the applicable regional transmission authority interconnection rules (those used primarily for interconnection to transmission systems) to distributed generation units greater than 10 MVA interconnected to distribution systems. If such standards don't exist, the parties negotiate adjustments to IEEE Standard 1547.

Maine

The Interstate Renewable Energy Council's 2006 Model Interconnection Procedures are the basis for Maine's interconnection guidelines, which were adopted in 2010. The procedures set four tiers of review for interconnection requests:

1. Certified, inverter-based facilities 10 kW or less
2. Certified facilities 2 MW or less
3. Non-exporting, certified facilities 10 MW or less
4. Any generating facility that does not qualify for the aforementioned levels of review and is not subject to FERC jurisdiction (The PUC order adopting the final interconnection rule, however, states that it only applies to interconnection to distribution systems.)

Technical standards are drawn from IEEE Standard 1547, IEEE Standard 929, and UL 1741. Insurance requirements differ depending on the size of the facility. All facilities with rated capacities greater than 5 MW must carry liability insurance with coverage of at least $2 million.

The state's rules limit interconnection to less than 10 MW in areas where there are known or posted transient stability limitations to generating units located in the general electrical vicinity.

Summary of Provisions for Systems Larger than 10 MW – Maine's interconnection guidelines are limited to systems smaller than 10 MW for Tiers 1, 2, and 3. Tier 4 systems can potentially be larger than 10 MW, but not in an area where there are known or posted system stability limitations. Additionally, the guidelines state that there will be no transmission line interconnections, and the generator cannot exceed the capacity of a customer's existing electrical service. Tier 4 procedures include a requirement for a scoping meeting, feasibility study, system impact study, and facilities study and are based on the IREC model.

Massachusetts

Massachusetts' interconnection standards apply to all distributed generation systems and to all customers of the state's investor-owned utilities (Unitil, NStar, National Grid, and Western Massachusetts Electric Company). The Model Interconnection Tariff includes provisions for three levels of interconnection to distribution systems.

Simplified interconnection procedures are used for inverter-based, single-phase systems less than 10 kW and three-phase systems up to 25 kW. There are no fees associated with the simplified interconnection approval process, and applications are processed within 15 days. For simplified interconnection to network systems, the aggregate capacity must be less than 1/15th of the customer's minimum electric load.

Larger distributed generators may still qualify for expedited interconnection, or they may have to undergo the standard interconnection review. Under expedited interconnection procedures, both the time frames and fees to complete the interconnection are limited. Fees are set at $3/kW of generator capacity, ranging from a minimum of $300 to a maximum of $2,500. Expedited provisions are for interconnections that pass a series of technical screens and are connected to radial distribution systems.

For large distributed generation systems, technical requirements are generally based on the IEEE 1547 and UL 1741 standards. A manual external disconnect switch may be required at the discretion of the utility (project-specific, not required in the tariffs).

The Massachusetts Clean Energy Center (MassCEC) developed an interconnection guide to help customers understand the interconnection process.

Summary of Provisions for Systems Larger than 10 MW – There is no size limit specified in Massachusetts' Model Interconnection Tariff, except for a 10-MW cutoff in areas where there are known or posted transient stability limitations to nearby generating units. Technical requirements are based on IEEE 1547 and UL 1741 standards. The utility performs an impact study and then determines, with good utility practice, what system modifications would need to be made to accommodate the distributed generation.

Michigan

The Michigan Public Service Commission's interconnection rules provide for the following interconnection categories:

- Certified, inverter-based systems less than 20 kW in capacity
- Systems greater than 20 kW but less than 150 kW
- Systems greater than 150 kW but less than 750 kW
- Systems greater than 750 kW but less than 2 MW
- Systems larger than 2 MW in capacity

Certified systems use equipment that has been certified by a nationally recognized testing laboratory to IEEE 1547.1 testing standards and in compliance with UL 1741. Utilities have some discretion in how they evaluate the requests. For instance, they are expected to provide their own technical screens, engineering, and operational requirements for the different categories of interconnection requests.

The rules do not require customer-generators to install an external disconnect switch, but utilities are free to make such a requirement. Utilities are prohibited, however, from establishing additional fees, requiring additional equipment or insurance, or making other requirements not specifically authorized by the standard rules.

Summary of Provisions for Systems Larger than 10 MW – Michigan's interconnection rules do not provide a limit for system capacity, so all units greater than 2 MW should be treated the same. The only size limitations are defined in relation to the local network's load. Systems interconnecting to a spot network circuit need to use a protective scheme ensuring that current flow will not affect network protective devices. Projects using only inverter-based protective functions are limited to 500 kW. The Michigan rules have different technical requirements according to size and types of generation, location of interconnection, and power export capability in the greater than 2 MW size range. The Michigan rules only apply to distributed generation interconnected to distribution systems.

New Jersey

New Jersey's interconnection standards apply to investor-owned electric distribution utilities but not to municipal utilities and electric cooperatives. The rules have been revised numerous times, resulting in a set of standards that includes the following basic provisions:

- All systems powered by Class I renewable energy resources are eligible. Class I resources include solar, wind, fuel cells powered by renewable fuels, geothermal technologies, wave or tidal action, landfill gas, anaerobic digester gas, and sustainable biomass.
- There are three levels of review procedures for applications, depending on size and certification:
  1. Inverter-based systems with a capacity rating of 10 kW or less
  2. Systems with a maximum capacity of 2 MW that are certified to meet IEEE 1547 and UL 1741 compliance standards
  3. Systems that do not qualify for either the Level 1 or Level 2 interconnection review procedures
- Utilities may not require Level 1 and Level 2 customer-generators to install additional controls or external disconnect switches that are not included in the equipment package, to perform or pay for additional tests, or to purchase additional liability insurance.
- Utilities are required to file interconnection reports with the Board of Public Utilities twice annually. Reports must list the total number of interconnected customers, the total generating capacity of

interconnected customers, and the total number of customers interconnected by Class I technology type.

- Interconnection to networks is permitted.

The New Jersey rules apply only to distributed generation interconnected to distribution systems.

Summary of Provisions for Systems Larger than 10 MW – There is no size limit for interconnection. Systems that qualify for Level 1 or Level 2 review (up to 2 MW) can qualify for an expedited review process. Level 3 is for interconnections that don't meet the Level 1 or Level 2 requirements, so systems larger than 2 MW are not eligible for the expedited review process. The Level 3 process includes an impact study to be conducted in accordance with good utility practice.

New York

New York's interconnection rules apply to systems up to 2 MW in capacity located in the service area of one of New York's six investor-owned utilities: Central Hudson Gas and Electric, Consolidated Edison (Con Edison), New York State Electric & Gas, Niagara Mohawk (dba National Grid), Orange and Rockland Utilities, and Rochester Gas and Electric.

Small systems up to 25 kW can go through a simplified process, whereas larger systems up to 2 MW generally use a more complicated process, including system impact studies. Certified, inverter-based systems from 25 kW to 200 kW are permitted to use the simplified process.

The New York rules apply only to interconnection to distribution systems.

Summary of Provisions for Systems Larger than 10 MW – There do not appear to be any rules for systems larger than 2 MW.

North Carolina

The North Carolina Utilities Commission's interconnection standards use a three-tiered interconnection process:

1. Systems up to 10 kW have a simplified interconnection process.
2. Systems larger than 10 kW and up to 2 MW can follow the "fast-track process."
3. Systems greater than 2 MW must follow the longer "study process."

Customer-generators are responsible only for the costs of upgrades and improvements directly associated with a system's interconnection, with these costs typically being determined by the utilities. The North Carolina rules apply to interconnection to both transmission and distribution systems.

Summary of Provisions for Systems Larger than 10 MW – North Carolina's standards apply to all interconnecting generators, with no limit on system size. Systems greater than 2 MW, however, require a detailed study; there is no simplified or expedited procedure. This process includes a scoping meeting, feasibility study, system impact study, and facilities study.

Ohio

Ohio provides three levels of review for the interconnection of distributed generation systems up to 20 MW in capacity:

1. A simplified review procedure applies to certified, inverter-based systems up to 10 kW that use renewable energy as a fuel. Systems must meet IEEE 1547 and UL 1741 standards.
2. An expedited review procedure applies to certified, inverter-based or synchronous systems up to 2 MW in capacity. Systems must meet IEEE 1547 and UL 1741 standards.
3. A standard procedure applies to inverter-based or synchronous systems up to 20 MW in capacity that do not qualify for Level 1 or Level 2 certification.

The Public Utilities Commission of Ohio has two application forms for interconnection: 1) a "short form" application for systems up to 50 kW in capacity, and 2) a standard application for all other systems. According to Ohio's interconnection rules, the point of interconnection cannot be on a transmission line.

Summary of Provisions for Systems Larger than 10 MW – Level 3 review is a catchall for systems that don't meet requirements for Levels 1 or 2 review. Ohio's Level 3 review is similar to what most other states have in their highest review levels, including a scoping meeting, feasibility study, system impact study, and facilities studies.

Oregon

The Oregon Public Utility Commission (PUC) adopted interconnection rules for net-metered systems for the two largest utilities in the state, Portland General Electric and Pacific Power and Light. The Oregon interconnection requirements are based on the MADRI model standard, with a few minor exceptions.

The PUC also established for all three investor-owned utilities interconnection procedures and standard-form applications and agreements for generator facilities up to 10 MW that are not net-metered (based on the MADRI model, with a few minor exceptions) as well as for systems greater than 20 MW (based on the FERC interconnection regulations for large generators). Interconnection regulations for distributed generation between 10 MW and 20 MW have not yet been established.

The interconnection procedures for generating facilities up to 10 MW employ four tiers of review: 1) lab-tested, inverter-based systems up to 25 kW, 2) systems up to 2 MW connected to a radial distribution circuits or spot distribution network and serving one customer, 3) non-exporting systems up to 10 MW, and 4) other systems. Systems in the first three tiers may not be interconnected to transmission systems. IEEE Standard 1547 requirements apply to all systems. The maximum application fee is $100 for Tier 1, $500 for Tier 2, and $1,000 for Tiers 3 and 4. There may be additional costs if an evaluation is required. The procedures for the first two tiers use the same interconnection standards as net-metered systems.

A unique aspect is that Oregon recognized field certification in addition to test laboratory equipment certification.

Procedures for interconnecting distributed generation units greater than 20 MW were established in April 2010 (Order No. 10-132). The procedures and agreement are based on FERC's Large Generator Interconnection Procedures and Large Generator Interconnection Agreement.

Summary of Provisions for Systems Larger than 10 MW – The Oregon PUC has established interconnection procedures and agreements for generating facilities up to 10 MW and separate requirements for units greater than 20 MW (based on FERC's Large Generator Interconnection Procedures and Large Generator Interconnection Agreement). Currently, there is a gap in the regulations – distributed generation between 10 MW and 20 MW is not covered by any of the requirements.

Pennsylvania

Pennsylvania's interconnection standards provide provisions for four levels of interconnection for generators up to 5 MW:

Level 1 interconnection: Certified, inverter-based systems up to 10 kW in capacity

Level 2 interconnection: Certified, inverter-based systems up to 5 MW in capacity that do not qualify or were not approved for Level 1 interconnection

Level 3 interconnection: Systems up to 5 MW in capacity that do not qualify or were not approved for Level 1 or Level 2 interconnection

Level 4 interconnection: Systems that do not qualify or were not approved for Level 1, Level 2, or Level 3 interconnection and that do not export power to the grid

Systems greater than 5 MW could presumably qualify for Level 4 interconnection if they are not power exporters.

There are technical screens and timelines for each level of interconnection. The IEEE 1547 and UL 1741 technical standards are used to evaluate all interconnection requests. Pennsylvania's standards allow a single point of interconnection for facilities with multiple generators, with limited interconnection to area networks. The rules apply only to interconnection to distribution systems.

Summary of Provisions for Systems Larger than 10 MW – Systems qualifying for Level 4 review could potentially be larger (up to 20 MW), but they may not export power to the grid. The Level 4 review is based on the MADRI model and has requirements for a scoping meeting, feasibility study, system impact study, and facilities studies.

Texas

The Public Utility Commission of Texas adopted interconnection standards in 1999 after the Texas Public Utility Regulatory Act of 1999 included a provision that all utility customers are entitled to have access to on-site distributed generation. The interconnection rules apply to distributed generation located at a customer's point of delivery, with a maximum capacity of 10 MW at the point of common coupling and an interconnected voltage of less than 60 kilovolts. Most of the Texas rules apply to all systems less than 10 MW, although there are specific requirements for distributed generation in four size ranges:

less than 10 kW, 10 kW to 500 kW, 500 kW to 2 MW, and 2 MW to 10 MW. Technical requirements differ from IEEE Standard 1547 – Texas has different criteria for voltage, frequency, harmonics, etc. Many of the screens in the Texas rules differ from those based on FERC's SGIP or the MADRI model.

Summary of Provisions for Systems Larger than 10 MW – None. The maximum capacity for interconnection at the point of common coupling is 10 MW.

Virginia

Virginia has one set of interconnection standards for net-metered systems less than 500 kW and another set of standards for all other systems. The rules for systems that are not net-metered were adopted in May 2009 and apply to all electric utilities operating in Virginia.

The FERC Small Generator Interconnection Procedures (SGIP) are the basis for Virginia's regulations. The state's interconnection procedures provide three tiers of review for interconnection requests:

1. Generating facilities smaller than 500 kW
2. Certified facilities no larger than 2 MW that do not qualify for the Level 1 process
3. Facilities no larger than 20 MW that do not qualify for the Level 1 or Level 2 process

Fees for interconnection requests increase with each level. A Level 1 request requires a $100 fee; a Level 2 request requires a $500 fee; and a Level 3 request requires the lesser of $1,000 or 50% of the estimated cost of the feasibility study.

Level 1 requests generally require an evaluation and no additional studies. Level 2 requests tend to require an initial review and possibly a supplemental review and facility modifications. Level 3 requests may include a scoping meeting, feasibility study, system impact study, and facilities study. There are standard forms for interconnection requests and agreements.

The State Corporation Commission specifies IEEE Standard 1547 as the technical standard of evaluation, and systems compliant with IEEE 1547, UL 1741, and the National Electric Code are considered to be lab-certified.

Summary of Provisions for Systems Larger than 10 MW – Virginia's interconnection regulations apply to generators up to 20 MW, but a utility may limit the interconnection capacity to less than 20 MW for distribution feeders, depending on the characteristics and potential for upgrading, as well as the nature of the loads and other generation on the feeder relative to the point of interconnection. As needed, a scoping meeting, feasibility study, system impact study, and facilities study are conducted prior to granting an interconnection request. Virginia's interconnection requirements include provisions for systems interconnecting to both the distribution grid and the transmission grid.

Endnotes

1 FERC does not have jurisdiction in Texas, Hawaii, or Alaska.

2 U.S.C. § 824a-3. State jurisdiction over PURPA Qualifying Facility (QF) interconnections applies only when a QF sells its full output to a directly interconnected utility pursuant to a PURPA-mandated purchase obligation and does not make any sales to a third party. See Florida Power & Light Company, 113 FERC P 61121, FERC Docket No. EL10-43-000 (Nov. 3, 2010). For QFs with a net capacity above 20 MW, FERC may relieve a utility from its mandatory purchase obligations under PURPA if certain market conditions are met.

3 Under net metering, the utility bills the customer for the net energy consumed during the billing period – the difference between the energy the customer consumes and the energy produced by an eligible generating system at the customer's site or, if allowed, at another customer-designated site.

4 National Renewable Energy Laboratory, *The Relevance of Generation Interconnection Procedures to Feed-in Tariffs in the United States,* 2010, www.nrel.gov/docs/fy11osti/48987.pdf.

5 Available at http://sites.energetics.com/MADRI/pdfs/inter_modelsmallgen.pdf.

6 MW is working power (also called actual power, active power, or real power). It powers equipment and performs useful work. MVA is apparent power and is the vectorial summation of MW and MVAR. MVAR is reactive power, which is electric power that establishes and sustains the electric and magnetic fields of alternating-current equipment and directly influences electric system voltage. Reactive power must be supplied to most types of magnetic (non-resistive) equipment and to compensate for the reactive losses in distribution and transmission systems. Reactive power is provided by generators, synchronous condensers, and electrostatic equipment such as capacitors.

7 Interstate Renewable Energy Council, *Connecting to the Grid 6th Edition 2009 – A Guide to Distributed Generation Interconnection Issues,* http://irecusa.org/wp-content/uploads/2009/11/Connecting-to-the-Grid-Guide-6th-edition.pdf.

8 IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems establishes criteria and requirements for interconnection of distributed resources with electric power systems and is used as the technical requirements for most state interconnection rules.

9 UL 1741 (Standard for Safety Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources). This UL test standard is used to confirm compliance with IEEE Standards 1547 and 1547.1. This standard covers inverters, converters, charge controllers, and interconnection system equipment intended for use in stand-alone or utility-interactive power systems. Utility-interactive inverters, converters, and interconnection system equipment are intended to be operated in parallel with an electric power system to supply power to common loads. UL 1741 is used to test equipment to ensure it is compliant with IEEE 1547 and 1547.1.

10 An electrical supply line and associated equipment that carries power from a substation through various paths that end at the customer transformer.

11 California Rule 21 Application Requirements, http://www.energy.ca.gov/distgen/interconnection/application.html.

12 District of Columbia Small Generator Interconnection Rules, http://www.dcregs.dc.gov/Gateway/ChapterHome.aspx?ChapterNumber=15-40.

13 The point where the local (customer's) electric power system is connected to the area electric power system (grid).

14 Network for New Energy Choices, *Freeing the Grid: Best and Worst Practices in State Net Metering Policies and Interconnection Procedures,* December 2010, www.newenergychoices.org.

15 The map on page 3 shows a slightly different number; it shows 18 states as having no standards or only guidelines. Another report states as many as 42 states have some type of state rule. Id. at FN 4.

16 In 2010 the Oregon Public Utility Commission adopted interconnection standards, procedures, and agreements for state-jurisdictional interconnections over 20 MW. See Docket UM 1401 at http://apps.puc.state.or.us/edockets/docket.asp?DocketID=15163. The Commission plans to take up the remaining gap (between 10 MW and 20 MW) in the future.

17 *Id.* at endnote 14.

18 Modified version of District of Columbia Small Interconnection Rules, which are based on the MADRI model. Some language that was in the MADRI model procedures but not included in the District of Columbia

Small Generator Interconnection Rules was added.

19 For an example of dispute resolution procedures for interconnection, see "Arbitration of Disputes" in Oregon Administrative Rules 860-082-0005, http://arcweb.sos.state.or.us/rules/OARS_800/OAR_860/860_082.html.

20 A section of the electric grid typically serving single large customers like a hospital or large office building. A spot network system consists of two or more wires that serve one customer so that when one wire is not working, the others can still provide power to the customer.

21 A section of the electrical grid typically found in major cities designed to provide high reliability to a group of customers. An area network system consists of multiple wires interconnected with each other and a group of customers. This provides multiple paths on which electricity can flow, to prevent loss of power if one piece of the network stops working.

22 See "Isolation device" under "Technical Requirements" below.

23 PJM Manual 14A, Generation and Transmission Interconnection Process, April 12, 2011, http://pjm.com/~/media/documents/manuals/m14a.ashx.

24 This represents the draft work of an IEEE Standard 1547.8 writing group as of February 2010. This group meets approximately every 6 months.

25 Micro-grids are intentional (planned) islands of distributed generation and loads that disconnect automatically from the grid during an electrical disturbance and automatically resynchronize to the grid when conditions return to normal. Micro-grids include equipment that safely supports the island.

26 "Organized power markets" refers to power markets with an Independent System Operator (ISO) or Regional Transmission Organization (RTO) that operates a regional energy market, capacity market, or both.

27 Under separate orders, FERC established procedures and agreements for generators larger than 20 MW.

28 Under the Federal Power Act, FERC has exclusive jurisdiction to regulate the rates, terms, and conditions of sales for resale of electric energy in interstate commerce by public utilities, including interconnection.

29 *Id.* at endnote 4.

30 Lisa Schwartz and Paul Sheaffer, "Is It Smart if It's Not Clean? Smart grid, consumer energy efficiency and distributed generation," Regulatory Assistance Project, March 2011, http://www.raponline.org/docs/RAP_Schwartz_SmartGrid_IsItSmart_PartTwo_2011_03.pdf.

31 IEEE Standard 1547.8 will cover a broad range of topics, some of which could impact state level interconnection requirements. An example is interconnection guidelines for distributed generation from 10 to 20 MVA. States should thoroughly review this standard once it is published.

32 Solar America Board for Codes and Standards, *Updated Recommendations for Federal Energy Regulatory Commission Small Generator Interconnection Procedures Screens*, July 2010, http://www.solarabcs.org/about/publications/reports/ferc-screens/pdfs/ABCS-FERC_studyreport.pdf.

33 Original review of each state's rules supplemented by a review of interconnection standards summaries at www.dsire.org.

34 By law, Oregon customers of Idaho Power adhere to Idaho net-metering rules.

35 Massachusetts Clean Energy Center, *Interconnection Guide for Distributed Generation,* http://www.masscec.com/masscec/file/InterconnectionGuidetoMA_Final(3).pdf.

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