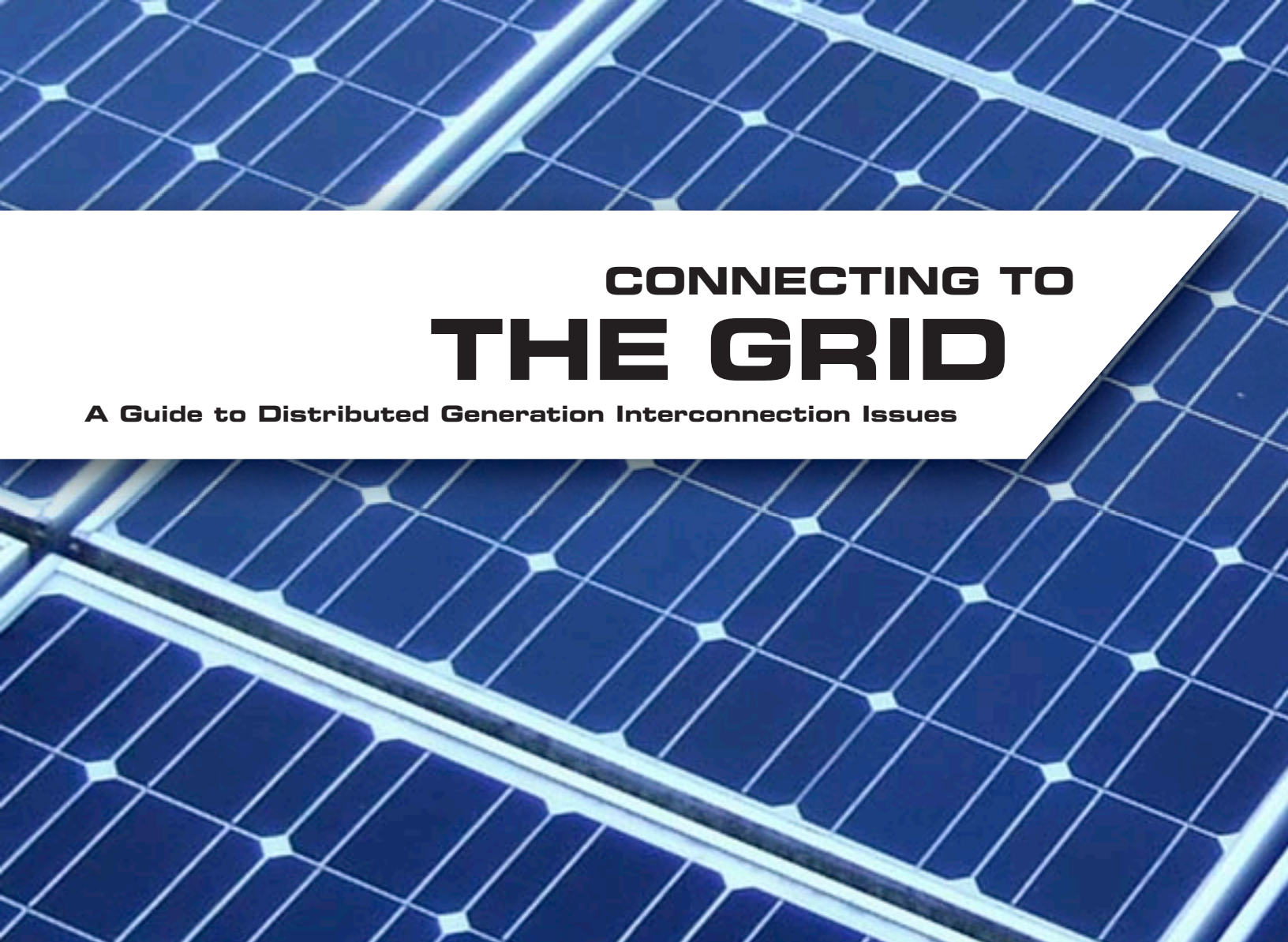




CONNECTING TO **THE GRID**

A Guide to Distributed Generation Interconnection Issues



6TH EDITION
2009

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Connecting to the Grid

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Sixth Edition
2009

by

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Preface to the 6th Edition

The swell of renewable energy installations shows no sign of diminishing in the near future. Despite growing demand for a cleaner, more reliable energy source, there remains a lack of uniform policies that allow renewable energy generators to connect to the utility grid. This fact significantly complicates renewable energy installations and has likely deterred the adoption of customer-sited distributed generation (DG).¹ Well-designed interconnection standards facilitate the deployment of renewables and other forms of DG by specifying the technical and institutional requirements and terms by which utilities and DG system owners must abide. To assist stakeholders in developing such standards, the Interstate Renewable Energy Council (IREC) published the first edition of *Connecting to the Grid* in 1997. Because distribution-level interconnection issues remain largely in the domain of the states, this guide is designed for state regulators and other policymakers, utilities, industry representatives and consumers interested in the development of state-level interconnection standards.

Because distribution-level interconnection issues remain largely in the domain of the states, this guide is designed for state regulators and other policymakers, utilities, industry representatives and consumers interested in the development of state-level interconnection standards.

Since the publication of the fifth edition, significant changes have swept across the technical and policy landscapes, both at the federal and state levels. A multitude of states has adopted interconnection standards for DG, sometimes in conjunction with implementing a new renewable portfolio standard (RPS) or expanding an existing RPS. Furthermore, there continue to be advancements as a result of the Federal Energy Regulatory Commission's (FERC) adoption of interconnection standards for generators up to 20 megawatts (MW) in capacity.²

The sixth edition of this guide addresses new and lingering issues relevant to all DG technologies, including net excess generation, third-party ownership, energy storage and networks. This publication also discusses IREC's model interconnection standards, updated in 2009 and published on the IREC Web site. IREC periodically revises its model procedures to incorporate the best practices developed at the state level. Recently, IREC has participated in interconnection rulemakings in Florida, North Carolina, Illinois, New York, South Dakota, Michigan, Kentucky, Colorado, Utah, California, Arizona, Virginia and New Mexico. While no single state has adopted comprehensive best practices, many states have added provisions that have led to an evolution of what defines best practices.

The authors wish to acknowledge the ongoing support of IREC and its consistent leadership in the interconnection field through its national *Connecting to the Grid* program. IREC has been a pioneer in interconnection and net-metering issues since 1997, when fewer than 20 U.S. states had implemented net metering, and the concepts of "DG" and "clean energy"

¹ In general, "distributed generation" (or "DG") refers to relatively small systems that generate electricity at or near the point of use.

² The FERC's Small Generator Interconnection Procedures (SGIP) include standard interconnection procedures, a standard interconnection agreement and screens. FERC governs all wholesale electricity transactions, even those involving systems connected at the distribution level. ([See FERC Order Nos. 2006, 2006-A, 2006-B and 2006-C.](#))

were neither widely recognized nor publicly appreciated. The authors would also like to express gratitude to the U.S. Department of Energy (DOE), which, through its involvement in the development of national standards and DG-testing facilities, has provided national leadership in addressing fundamental interconnection issues. The authors also wish to thank Jason Keyes, Kevin Fox, Joe Wiedman, Rusty Haynes, Michael Coddington, James Rose, Keith McAllister, Maureen Quinlan and Lauren Kirkpatrick for reviewing a draft of this publication and providing critical feedback.

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Executive Summary

Grid-tied renewable energy systems are quickly becoming a ubiquitous facet of the nation's utility landscape. Accelerated public interest in renewable energy in the United States has accompanied sustained, robust market growth of multiple distributed generation technologies over the last few years. At the same time, U.S. policymakers are working to address a number of pressing concerns related to the generation of electricity by conventional means, including aging infrastructure, grid congestion, electric rate increases, natural gas price volatility, climate change, diminished air quality and related public-health concerns, reliability issues, energy security and energy efficiency. While the full costs of conventional electricity generation are increasingly being recognized and internalized, the price of distributed, renewable-energy systems continues to decrease. As a result, many policymakers have recognized the need to facilitate investment in clean, customer-sited DG systems.

Net metering and interconnection policies are essential pieces of a supportive state-level regulatory policy framework addressing two important aspects of renewable energy development: whether a customer investing in renewable generation can unlock the full value of his or her investment; and how that customer will interconnect his or her generation system to the distribution grid. This guide introduces readers to the issues surrounding policy and technical considerations of grid-integrated, renewable energy development.

As of July 2009 net metering has been adopted by 42 U.S. states and is one of the most important policies for promoting growth in distributed renewable energy generation markets.

Interconnection standards vary widely from state to state, as do net-metering policies. The tradition among U.S. states of looking to other states (and to available models) for policy guidance is increasingly evident in these two areas because the issues are complex and technical. As a starting point, many states prefer to use model interconnection standards developed by IREC, the Federal Energy Regulatory Commission (FERC), the Mid-Atlantic Distributed Resources Initiative (MADRI), or highly effective rules developed by states like California.³

As of July 2009, net metering has been adopted by 42 states and is one of the most important policies for promoting growth in distributed renewable energy generation markets. To help states keep pace with these opportunities, IREC developed model net-metering rules that provide a compilation of current best practices adopted at the state level. IREC also developed this *Connecting to the Grid Guide* to provide general guidance regarding some of the important issues that play a key role in the development of robust net-metering policies, including the treatment of net excess generation (NEG), Renewable Energy Credits (RECs), third-party ownership of renewable generation systems, advanced metering infrastructure (AMI) and alternative billing options.

While most of the technical issues related to interconnection of distributed energy resources have been addressed through the development of national standards such as the Institute of Electrical and Electronics Engineers (IEEE) 1547 *Standard for Interconnecting Distributed Resources with Electric Power Systems*, there are many challenges associated with interconnecting distributed generation that lie in the policy and procedural arenas. One of the most significant challenges relates

³ Links to the FERC, IREC and MADRI interconnection models are included in the "References" section of this publication. A summary of California's Rule 21 is available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA21R&re=1&ee=1.

to the lack of consistency across state standards. Many states have adopted standards modeled on FERC's Small Generator Interconnection Standards (SGIP), which were issued by FERC in its Order 2006. As a result, there is greater consistency in employing a multi-level approach to system review depending on system capacity, generation type and location. Many states have also developed a standard agreement and concise application forms modeled on the FERC standard. However, despite a certain amount of unification brought about by FERC Order 2006, state interconnection standards remain fairly diverse in quite a number of respects.

The federal government has provided some degree of guidance to states on interconnection policy, and minimal guidance on net metering. The FERC Order 2006, adopted in May 2005, includes three levels of review for DG systems up to 20 MW in capacity. Although FERC's interconnection rules for small generators likely will have little impact on distribution-level interconnection (which is generally governed by states), the commission has stated that it hopes states will adopt its rules—with necessary modifications—to promote a more unified interconnection policy around the United States.

Most DG systems are installed, owned and operated by entities other than electric utilities, such as homeowners, businesses, farmers, manufacturers, nonprofits and government entities. Because the interconnection of DG challenges the century-old tradition of utility-owned centralized generation, it requires careful technical considerations and evokes new perspectives on ownership and control. This report covers several main aspects related to technical considerations: safety, power quality, national codes and standards, electrical inspectors and the North American Board of Certified Energy Practitioners' (NABCEP's) credentialing program.

Improved power quality increases the value of distributed generation. Relevant national technical standards, including IEEE 1547 and Underwriters Laboratories (UL) 1741, have been established and are amended or expanded as necessary to ensure that DG products and equipment, as well as interconnection practices, are safe. The value of national codes and standards to the interconnection process is immeasurable. Without standardized national documents, DG equipment manufacturers would be faced with the nightmare of developing separate devices and protection equipment to satisfy individual utility interconnection safety requirements.

While this guide does not discuss state-by-state activities in detail, IREC's *Connecting to the Grid* newsletter⁴ covers state, federal, local and international developments related to interconnection and net metering. This free monthly newsletter is published by the N.C. Solar Center at N.C. State University. In addition, the IREC *Connecting to the Grid* program Web site⁵ provides several additional public resources relevant to interconnection issues and net metering. These include:

- Model interconnection procedures
- Model net-metering rules
- Tables of states' net-metering and interconnection laws and guidelines
- Maps of states' net-metering and interconnection laws and guidelines
- A table of states' consideration of the Energy Policy Act (EPAct) proceedings related to interconnection and net metering

⁴ See <http://www.irecusa.org/index.php?id=33>

⁵ See <http://www.irecusa.org/index.php?id=31>.

IREC continues to work with state regulatory agencies to promote best practices for statewide interconnection and net-metering policies. Facilitating this process in the most efficient manner will translate into job creation, energy security, environmental benefits and technical innovation, among other important societal gains.

Additionally, the Network for New Energy Choice (NNEC) publishes an annual report, *Freeing the Grid*,⁶ which uses the best practices found in IREC's model rules for net metering and interconnection as a basis for grading the quality of each state's program. The report shows the evolution of individual state policies over the past three years, as states look toward using many of the elements contained in this guide.

⁶ The 2009 edition of *Freeing the Grid* is available at www.newenergychoices.org.

Distributed Generation Policy

1. NET METERING

Net metering is a low-cost and easily administered means of promoting direct customer investment in renewable energy.

Prior to the widespread adoption of net-metering policies, utility customers who generated excess on-site electricity generally had one option for receiving credit for the energy they exported to the utility grid. They would certify as a qualifying facility (QF) pursuant to the Public Utility Regulatory Policies Act (PURPA) and receive payment at a utility's avoided-cost rate for energy exports. This arrangement provided little incentive for customers to size a system above minimum on-site demand, given that there would be no assurance of adequate value for energy exported to the grid. A utility's avoided cost rate is often less than half the retail rate paid by the customer. Typically, avoided cost payment is an insufficient economic rationale for a customer to size an on-site generation system so that it will export energy—given that every kilowatt-hour exported would represent a financial loss to the customer. This results in an incentive for a customer to size his or her system such that it never exports electricity.

Beginning in the early 1980s, a handful of states, including Iowa and Minnesota, recognized that avoided cost rates may not provide a sufficient incentive to promote customer investment in distributed generation. To remedy this situation, these states became pioneers in adopting some of the first state net-metering policies.

Net metering is a low-cost and easily administered means of promoting direct customer investment in renewable energy. One of the major advantages of net metering is its simplicity; in many areas, customers can use their existing meter without any modification or additional equipment. Indeed, at its simplest, net metering allows for the flow of electricity both to and from a customer's premises through a single, bi-directional meter. At times when a customer's electricity generation exceeds the customer's electricity use, electricity supplied by the customer to the utility causes the meter to spin backwards, offsetting the electricity the customer must purchase from the utility at another time. In essence, the utility is essentially storing electricity in the same manner as would a battery back-up system.

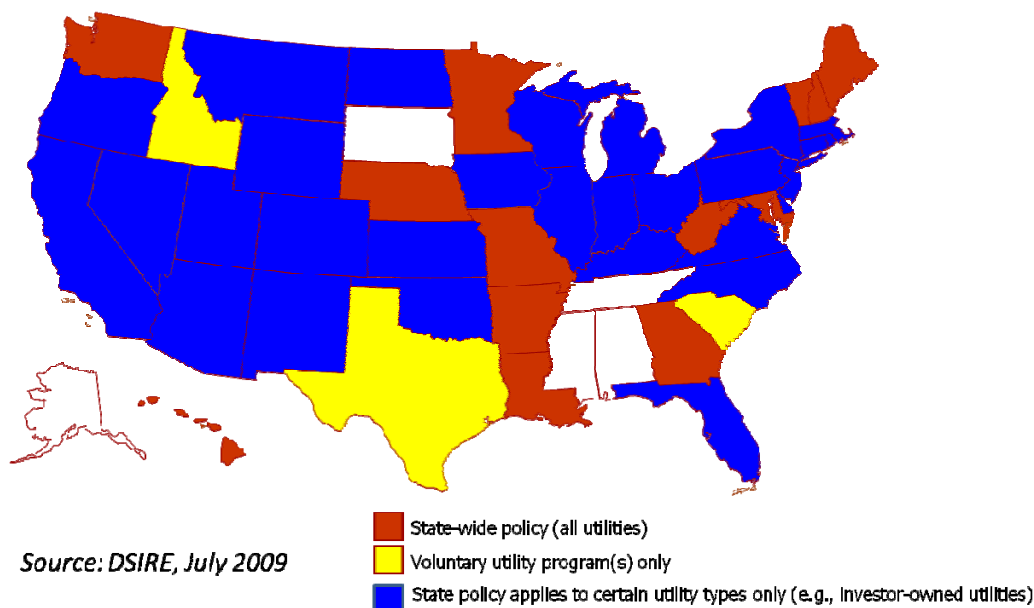
1.1 Net-Metering Basics

As of July 2009, 42 states had adopted net-metering policies; however, it is important to recognize that state net-metering policies vary in many significant ways. Typical variations include the types of technologies that are eligible for net metering; the types of customer classes that may enroll in net metering; the size of a system that can be net metered; the total aggregate generation capacity of systems that may enroll; the treatment of monthly and annual net excess generation; the types of utilities covered by a state policy (e.g. investor-owned utilities, municipal utilities, cooperatives, etc.); and the ownership of RECs.

Many states allow all customers to participate in net metering regardless of their rate classification. Although state net-metering policies typically apply to all investor-owned utilities, publicly-owned utilities (such as municipal utilities) and electric cooperatives are often able to develop their own policies. Some publicly-

owned utilities voluntarily offer net metering, but these policies may differ substantially from the policies that apply to investor-owned utilities within the same state.

Figure 1: Net-Metering Availability



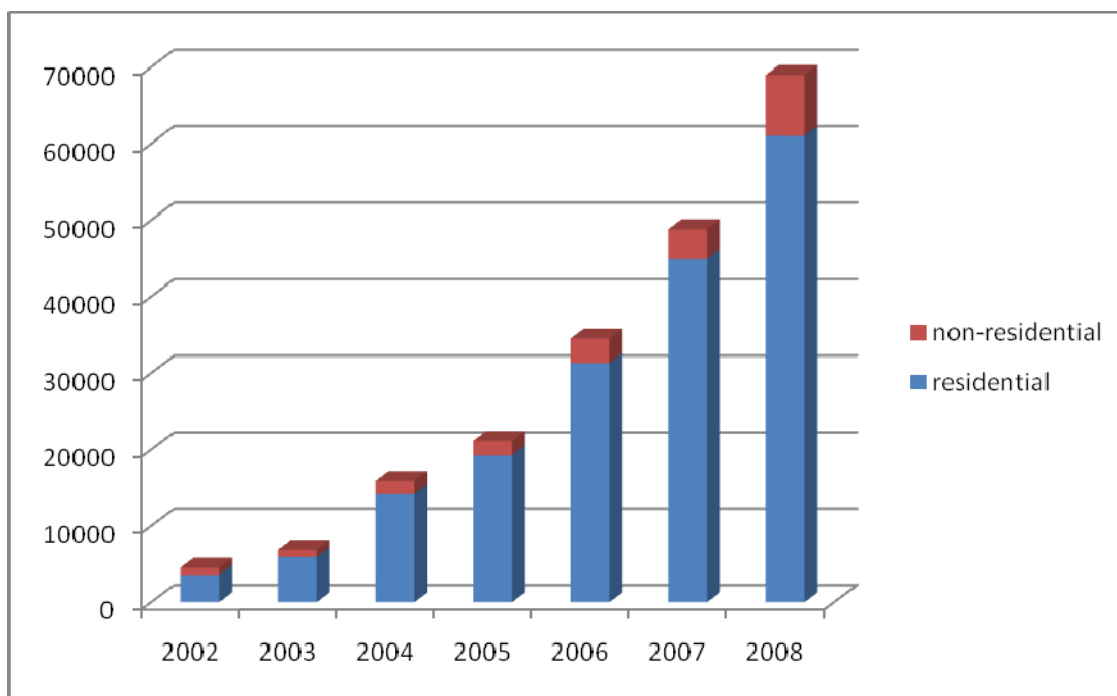
States often revisit and amend existing net-metering policies. In recent years, a number of states have reconsidered many such policies, prompted by requirements contained in the federal Energy Policy Act of 2005 (EPAct 2005), which required state regulatory authorities and nonregulated utilities to complete the consideration of a net-metering standard by August 2008. Although EPAct 2005 provided little guidance as to the specific aspects of net metering that states should consider, EPAct 2005 was useful in requiring states to re-evaluate existing standards. As a result, many states have considered the adoption of net-metering policies or made beneficial changes to existing policies.⁷

As customer investment in distributed generation flourishes, concerns have grown over the value net-metered systems offer to ratepayers. Proponents and opponents of net metering have hotly debated how to appropriately value the costs and benefits of net metering. While a discussion of these arguments falls outside the scope of this publication, it should be noted that relatively little information has been published regarding the costs and benefits of net metering to utilities, to net-metered customers, to non-net-metered customers and to the general public.⁸

⁷ A summary of these changes is provided in the January 2009 *Connecting to the Grid* Newsletter: <http://www.irecusa.org/index.php?id=33>

⁸ A Renewable Systems Interconnection (RSI) study, however, published in February 2008, provides an in-depth analysis of the value of photovoltaics interconnected to the utility grid. See http://www.solarelectricpower.org/docs/DoE.RSI.PV_value_analysis.2.08.pdf

Figure 2. Growing Number of Net-Metered DG Systems



Source: EIA Form 861 Database, IREC⁹

To help develop sound procedures, IREC has developed model net-metering rules for use by states. The IREC model rules incorporate the best practices of net-metering policies implemented by various states. These rules are updated periodically to reflect current trends. IREC's model has been influential in many states, including New Jersey, Colorado, Maryland and Pennsylvania. IREC's net-metering model includes these provisions:

- All renewable-energy powered systems are eligible, with no hard limit on system size. However, the model requires that a system be sized to meet a customer's on-site demand and not exceed a customer's service entrance capacity.¹⁰
- All customer classes are eligible.
- There is no limit on the aggregate capacity of net-metered systems.
- Excess kilowatt-hour credits are carried over to the customer's next monthly bill indefinitely.
- All utilities, including publicly-owned utilities and electric cooperatives, are included.
- Customers retain ownership of all RECs associated with their generation.
- Utilities may not charge customers special fees for net metering; net-metered customers should be treated no differently than customers who are not net-metered.

⁹ See <http://www.eia.doe.gov/cneaf/electricity/page/eia861.html> for data through 2007, 2008 data is extrapolated from research gathered for IREC's U.S. Solar Market Trends 2008 report, available at <http://www.irecusa.org>.

¹⁰ The service entrance capacity refers to the rating of the wires and equipment, in Amps, that connect a distribution line to a customer's property.

- Third-party ownership of net-metering systems is allowed.
- Customers with multiple meters on adjacent property may offset load on those meters with a single generation system.

Several of these issues, including net excess generation, REC ownership and new metering options, are discussed in greater detail below. IREC maintains an online state by state table that allows users to compare net-metering laws, regulations and utility programs by most of these criteria. In addition, the *Database of State Incentives for Renewables and Efficiency* (DSIRE)¹¹ provides detailed information on state laws, regulations and voluntary utility programs.

1.2 Specific Issues

Net Excess Generation

Net excess generation occurs when a renewable energy system produces more electricity over the course of a billing period than can be used onsite. Many net-metering policies allow customers to carry NEG forward to the following month on a kilowatt-hour (kWh) basis for up to 12 months. This arrangement is known as annualized net metering. In a handful of states, including Missouri and Nebraska, NEG is credited at the utility's avoided cost rate—as opposed to the utility's retail rate—and carried over to the customer's next monthly bill. This arrangement is obviously less favorable than annualized net metering to net-metered customers.

In some states with annualized net metering, if a customer has NEG remaining at the end of a 12-month period, the utility pays the customer for the excess kWh at the utility's avoided-cost rate. In other states with annualized net metering, any NEG remaining at the end of a 12-month period is granted to the utility with no compensation for the customer. Many states have a fixed annual period (i.e. the calendar year or June to May) after which accumulated NEG is either compensated or wiped out. New Jersey, however, allows customers to choose their own annualized period so that they may optimize the timing of their NEG reconciliation.

Renewable energy resources can be seasonal in nature, depending on the technology used. For example, a photovoltaic system may produce more electricity than a household consumes in the summer but less electricity than a household consumes in the winter. In this case, an annualized period would ideally begin at the start of the summer months so the NEG would carry forward and balance reduced system output in winter months. However, it is important to note that generalities about seasonal production may not hold true at every site and will vary among technologies.

Indefinite or perpetual NEG rollover is an easy way to account for variations among different system types and locations. Accordingly, a number of states have chosen to adopt indefinite rollover provisions for net-metering policies. As of July 2009, 11 states and the District of Columbia allow indefinite rollover of NEG with no monthly or annual settlement for net-metering credits.

Utilities may benefit from annualized or indefinite rollover provisions in net metering because they do not incur the administrative cost of paying customers for NEG on a monthly basis. Customers who produce NEG in a given month are usually required to pay the utility's basic monthly customer charge.¹²

¹¹ See <http://www.dsireusa.org>.

¹² Many states have safe-harbor clauses that prohibit net metering customers from being charged any additional fees, beyond the basic monthly fee, that other customers would not have to pay.

Ownership of Renewable Energy Credits

Renewable energy credits¹³ are the environmental (non-power) attributes of renewable generation. RECs allow these attributes to be unbundled or sold separately from the associated energy commodity. REC ownership has emerged as a critical policy and economic issue for DG system owners, utilities and regulators, especially in the wake of widespread state adoption of renewable portfolio standards (RPSs) in recent years.

States began to focus on REC ownership after FERC ruled in 2003 that RECs associated with renewable-energy generation by QFs under PURPA do not automatically convey to utilities.¹⁴ As of July 2009, 22 states had laws or rules that specified that net-metering customers are able to keep all or a portion of the RECs generated by on-site systems. A report titled *Renewable Energy Certificates: Background & Resources*, published by the EPA Clean Energy-Environment Technical Forum in 2008, details how states have approached REC ownership.¹⁵

REC ownership has emerged as a critical policy and economic issue for DG system owners, utilities and regulators, especially in the wake of widespread state adoption of renewable portfolio standards (RPSs) in recent years.

State renewable portfolio standards often create significant financial opportunities for consumers with net-metered renewable-energy systems. This is particularly true in states with standards that have specific procurement targets for distributed generation or solar photovoltaic systems. For example, PV system owners in Colorado have the opportunity to earn an up-front rebate of \$1.50 per installed watt in exchange for their system's REC production, based on a calculation of their expected electricity output.¹⁶ The RECs acquired by the utility may then be used to meet RPS procurement requirements; this arrangement provides value to a utility as well as to the customer investing in a renewable generation system. In states without such policies, there may be limited opportunities for owners of renewable-energy systems to sell RECs; opportunities for owners of very

small renewable-energy systems may be severely limited, as the transaction costs associated with REC sales may exceed the value of the RECs.

Third-Party Arrangements

Third-party financing is increasingly a preferred means of financing on-site renewable energy generation, particularly for commercial customers. Under these types of arrangements, a resident or business hosts a renewable system that is owned by a separate investor. Third-party financing arrangements are particularly beneficial for entities that cannot claim tax credits (such as governments, schools and nonprofits) and for entities that either lack initial investment capital to purchase a system or the desire to own and maintain a DG system. Under a third-party financing arrangement, an investor monetizes available incentives (e.g. tax credits, rebates and depreciation deductions). The investor then sells electricity produced by a system to a host entity at lower rates than the host customer may otherwise be able to benefit from, if the customer were to invest directly in the system.

¹³ RECs are also known as green tags or renewable energy certificates.

¹⁴ FERC 2003 Order Granting Petition for Declaratory Order, Docket No. EL03-133-000.

Available at: http://www.nmccae.org/federal/FERC_Order_on_RECs.pdf

¹⁵ See http://www.epatechforum.org/documents/2008-2009/10_21_08_RECs_Background-final.pdf

¹⁶ See DSIRE:

http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CO12F&re=1&ee=1

Third party financing mechanisms include both power purchase agreements (PPA)¹⁷ and leasing arrangements. With a PPA, the host agrees to purchase all the energy produced onsite. Any excess generation is typically subject to a net-metering arrangement between the host customer and a utility. With a leasing arrangement, the host agrees to pay a fixed monthly fee that is not directly based on the amount of on-site generation. *The Customer's Guide to Solar Power Purchase Agreements* (October 2008, Rarus Institute) provides a detailed explanation about the solar PPA model and how it compares with other financing options.¹⁸

Several states have specified that third-party arrangements are not considered as utilities by the state regulatory agency and are therefore not subject to regulation.¹⁹ Most net-metering rules do not yet address this issue.

Time of Use Metering

Many states, including California, New York, Virginia and North Carolina, allow customers who net meter to do so under a time of use (TOU) tariff. TOU metering allows customers to pay differentiated electricity rates based on the time of day they consume electricity. This differs from a flat rate arrangement, where even though rates may step up as a customer consumes more energy, the price does not vary according to the time energy is consumed. Whereas a flat rate for residential customers may be \$0.12 per kWh, the TOU rate for on-peak energy may be \$0.20 or more per kWh, and as low as \$0.03 per kWh for off-peak energy. In general, TOU metering is seen as a mechanism to better link customer consumption decisions with the actual price of generating the energy customers consume. For net-metered systems, the salient issue is how to net energy exported to the grid against energy procurement. Should on-peak exports only be counted against on-peak purchases or should a customer be able to apply an on-peak credit against an off-peak purchase?

TOU metering requires an electronic meter, which is fundamentally different from standard spinning electro-mechanical meters. Some TOU meters do not record electricity flows in both directions. As a consequence, there are generally two options for consumers who seek to take advantage of net metering and TOU metering simultaneously. The first option is to install a special electronic meter, or smart meter, that can measure energy flows in both directions and keep track of when those flows occur. However, these meters may cost up to \$300 or more and the customer often must pay for this expense and likely pay higher monthly fees. The second option, which has been adopted by New York, is to install a meter (in addition to the TOU meter) that only measures net flows to the utility. This second meter is not a TOU meter, so the generation recorded on it is allocated to the different rates based on expected time of PV output.

Depending on the structure of a TOU rate schedule, TOU metering may not make financial sense for a net-metered customer. In TOU schedules, weekends are normally considered off peak, so the calculation begins with two-sevenths (29%) of the electricity generated by a customer credited at the off-peak rate. TOU rates also may exclude holidays, weekday morning hours, and possibly even entire seasons from on-peak periods. Moreover, customers may also pay an extra monthly charge to go on a TOU schedule. Not only do TOU rates vary by season, but in some states, including North Carolina, on-peak credits can offset off-peak

¹⁷ PPA models include wholesale PPAs, where electricity is sold to utilities, and retail PPAs, where it is sold to non-utilities.

¹⁸ See <http://www.californiasolarcenter.org/sppa.html>.

¹⁹ As of the publication date of this report HI, CA, NV, OR, CO, MD, NJ and MA have ruled that PPAs are not subject to state regulatory jurisdiction.

use but not vice versa. Nevertheless, net-metered customers in North Carolina are required to take service under a TOU tariff if they wish to retain REC ownership.

Advanced Metering Infrastructure

Another consideration for customers looking to install distributed generation is the cost and availability of advanced metering technology that can accommodate TOU net metering. Such meters are typically designed for commercial and industrial accounts, and thus can be expensive for residential customers. However, some utilities have provided residential customers with TOU meters as part of a voluntary or mandatory TOU residential rate, and the cost of the meters is rate-based. There is increasing interest among utilities and some regulators in upgrading aging utility infrastructures with Advanced Metering Infrastructure (AMI) and smart grid technologies.

Recent interest in these topics has been further accelerated by activities at the federal level. Under Title XIII of the Energy Independence and Security Act of 2007 (EISA),²⁰ the U.S. Department of Energy established the Federal Smart Grid Task Force. Like EAct 2005 requirements that states consider adopting net-metering and interconnection procedures, EISA 2007 requires states to consider smart grid developments. A smart grid will act as a controlling mechanism for AMI and smart meters, which enable two-way communication between a utility and its customers.

A smart grid is envisioned to be a continuously upgradable network, capable of accommodating load growth and more efficiently managing power distribution. Smart grids will allow renewable energy systems to be integrated more effectively and safely into the distribution system and will allow utilities the ability to communicate with DG systems and disconnect them in a fault condition or power outage. In addition, a smart grid will be able to accurately measure, in real time, how much power is being produced by DG sources, allowing utilities to adjust their non-DG power production accordingly. This real-time communication ability could dramatically increase the effectiveness of renewable resources, decreasing utilities' need for supplemental generation plants. The concurrent development of advanced energy storage and plug-in hybrid vehicles could also help solve the challenge of renewable production intermittency.

Multiple Meter Billing Arrangements

Net metering has traditionally allowed a customer to use a single, on-site system to offset electricity purchases that flow through a single on-site meter. However, recently, several states have implemented expanded net-metering policies that allow groups of customers or single customers with multiple meters to use a single DG system to offset load on multiple meters at dispersed locations. These expansions allow a broader range of customers to invest in renewable DG systems, including those who have less than ideal sites for an on-site installation.

The most basic expansion is meter aggregation, which allows a customer with multiple meters, and therefore multiple utility accounts, to allocate net-metering credits from a central system to all their accounts. As of July 2009, Oregon, Washington, Rhode Island and Pennsylvania allow this sort of meter aggregation.²¹

²⁰ U.S. Public Law 110-140, Available at: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:h6enr.txt.pdf

²¹ See DSIRE net metering entries for OR, WA, RI, PA: www.dsireusa.org.

Shared-system net metering is a somewhat broader expansion. It allows groups of electric customers to jointly invest in a renewable energy system and use that shared system to offset energy consumption at the customers' individual properties. As of July 2009, Massachusetts, Vermont and Maine had adopted rules for shared-system net metering. New Jersey has a rulemaking process underway to consider a similar expansion.²² The broadest expansion is virtual net metering, through which customers with multiple, non-contiguous accounts produce energy at one location and have that energy offset consumption at multiple other locations. California, Pennsylvania and Rhode Island have adopted rules for virtual net metering.

2. INTERCONNECTION

The interconnection of distributed generation remains a significant regulatory issue because of the technical and procedural requirements needed to safely, reliably and efficiently interconnect a generating system to the electric grid. Moreover, it challenges the century-old tradition of centralized generation, which historically has been owned and operated by electric utilities. Before the development of certain national technical standards—including the IEEE 1547 and UL 1741 standards—and the adoption of interconnection rules and procedures by some states, electric utilities determined the technical and engineering requirements, and the policies, rules and terms governing the interconnection process for customers. In the absence of appropriate standards for residential-scale generators or small commercial-scale generators, many utilities simply applied existing interconnection procedures for qualifying facilities (QFs) under the federal Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA does not mandate special, simplified interconnection procedures for very small systems.

Interconnection procedures challenge the century-old tradition of centralized generation, which historically has been owned and operated by electric utilities.

In 2000, the National Renewable Energy Laboratory (NREL) published a study of barriers that generators encountered while attempting to connect to the grid. This 91-page report, titled *Making Connections: Case Studies of Interconnection Barriers and Their Impact on Distributed Power Projects*,²³ examined 65 DG projects ranging in capacity from 500 watts (W) to 26 MW. Barriers were documented through interviews with system owners, project developers and utilities, and were categorized as technical, business practice or regulatory. All but seven of the 65 project owners encountered at least one type of significant interconnection barrier. As a result, 16 projects were either abandoned entirely or reconfigured to serve only local loads as stand-alone systems. The NREL report was the first of its kind to address the problems associated with utility interconnection. The report stated that national leadership was needed to address interconnection of distributed generation.

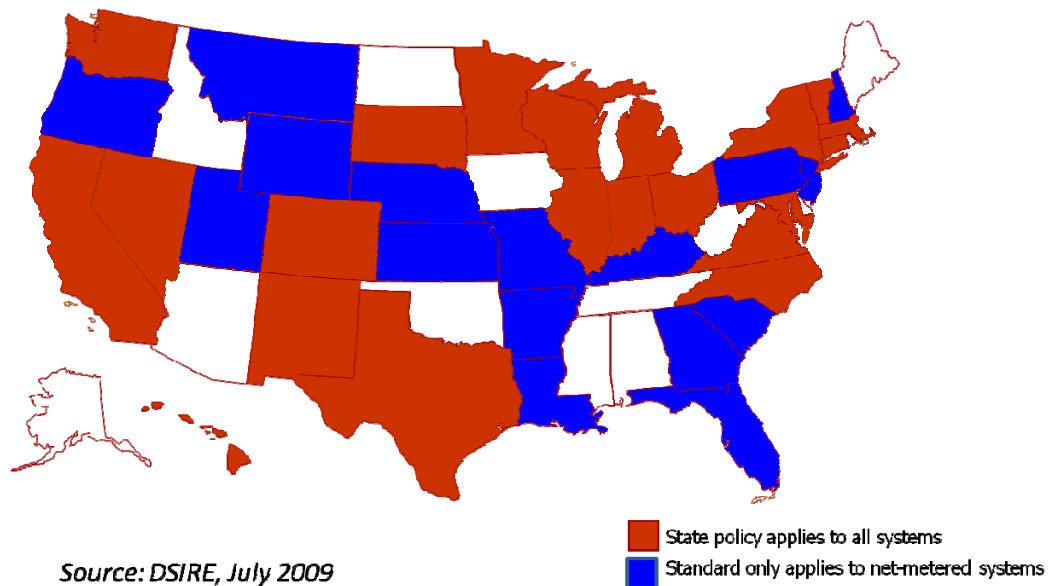
Realizing that interconnection difficulties existed for distributed generation systems, Congress enacted Section 1254 of EPAct 2005, which required state regulatory authorities and certain nonregulated utilities to complete the consideration of an interconnection standard based on the IEEE 1547 standard and current best practices. The mention of best practices was an indirect reference to the National Association of Regulatory Commissioners (NARUC)

²² See DSIRE net metering entries for MA, VT, ME, NJ: www.dsireusa.org.

²³ Available at: <http://www.nrel.gov/docs/fy00osti/28053.pdf>

Small Generation Resource Interconnection Procedures.²⁴ This requirement applied to nonregulated utilities so long as they had annual retail sales exceeding 500 million kWh. The deadline for concluding the consideration process was August 8, 2007. Thirty-one states adopted or amended their interconnection standards in some form or another during this time period. Whether or not these changes were a result of the EPC Act 2005 directive is not entirely clear. A number of these states may have simply recognized the value of distributed generation and would have set about to reform state policies regardless of encouragement from EPC Act 2005. Many states also enacted legislation requiring adoption of interconnection procedures. A number of states were already developing new standards, or revisiting existing standards when EPC Act 2005 was issued. In 2007, the U.S. DOE further encouraged state and non-state jurisdictional utilities to consider the several “best practices” in establishing interconnection procedures (See Appendix B).

Figure 3: Statewide Interconnection Policies



As of July 2009, 37 states and the District of Columbia had adopted interconnection standards. Sixteen of those states adopted standards that apply only to net-metered systems. Many of these state standards apply only to investor-owned utilities—not to municipal utilities or electric cooperatives.

The following sections provide a basic understanding of the relevant issues related to interconnection policy.

²⁴ These NARUC Procedures are no longer widely referenced because they have not been updated since 2003. They are available at: http://www.naruc.org/Publications/dgiaip_oct03.pdf

2.1 Model Interconnection Procedures

Prior to 2003, few states had comprehensive procedures for interconnecting distributed generation. For the most part, utilities had broad discretion to study the impact of an interconnection at a customer's expense. In addition, because few small generator interconnections were proposed, a lack of utility experience with these interconnections meant that the cost of the review process could overwhelm the cost of a system, particularly for modest residential-scale systems.

Six years later, the policy landscape is much different. Much of the content embodied in current state standards can be traced to the work done in developing four interconnection standards that later formed the foundation for many state efforts. These four model procedures are California's Rule 21 interconnection standard (CA Rule 21), FERC's Small Generator Interconnection Procedures (SGIP), the Mid-Atlantic Demand Resource Initiative Procedures (MADRI Procedures), and IREC's Model Interconnection Procedures (IREC Procedures). The remainder of this section discusses how these procedures came into existence and why they have since become templates for developing state interconnection procedures.

A lack of utility experience with interconnections meant that the cost of the review process could overwhelm the cost of a system, particularly for modest residential-scale systems.

California was among the first states to attempt a comprehensive rule for interconnecting distributed generation when it developed CA Rule 21 in 2000. In 2003, three critical events laid additional foundation for many of the interconnection procedures for distributed generation that exist today. First, IEEE finalized standard 1547 – the *Standard for Interconnecting Distributed Resources with Electric Power Systems*. This provided the basic technical requirements for interconnection. Second, FERC issued *Large Generator Interconnection Procedures* (LGIP) for interconnecting systems over 20 MW. The LGIP became the model for FERC's SGIP, which was adopted in 2005. And

third, NARUC finalized its *Small Generation Resource Interconnection Procedures* (NARUC Procedures). NARUC submitted its new procedures to FERC in the early stages of the docket that led to FERC Order 2006.

Despite being referenced in EPAct 2005, the NARUC Procedures are rarely reviewed by state regulators developing procedures. Instead, for various reasons the SGIP/SGIA, MADRI Procedures, CA Rule 21 and IREC Procedures are more commonly used, along with various state interconnection procedures. Nevertheless, the NARUC Procedures (and, to an extent, CA Rule 21) established a baseline of features that are now ubiquitous in state interconnection procedures. These include:

- Much of the application process
- Many of the technical screens used in current rules
- A fast-track process for generators that pass the technical screens
- A 20MW threshold
- A standard three-step structure for utility study of more complex generators (feasibility, impact, and facilities studies)
- Use of a standard form agreement between a utility and customer
- Reliance on IEEE 1547

FERC began to develop the SGIP in 2002. With extensive participation by utilities, regulators, renewable energy advocates, industry and government experts, FERC issued Order No. 2006 on May 12, 2005. Accompanying the SGIP in Order 2006 was the Small Generator Interconnection Agreement (SGIA), a standard form

agreement. Through subsequent orders, FERC developed its final version of the SGIP and SGIA on August 28, 2006, in Order 2006-B. The SGIP's significance rests in its application for large distributed generators, its widespread adoption and its function as a model for state procedures. For interconnection of distributed generators under a few megawatts, which is the vast majority of such interconnections, SGIP is rarely applicable since states typically have jurisdiction to oversee interconnections of such systems.

In November 2005, the utility commissions of Delaware, New Jersey, Maryland, Pennsylvania, the District of Columbia, the PJM Interconnection (the regional transmission organization for the states just listed) and various federal agencies (FERC, the Department of Energy and the Environmental Protection Agency) concluded work on the MADRI Procedures. These stakeholders developed their procedures as an alternative to the SGIP which came out six months earlier. It was not intended to be applied in its model form. Rather, the drafters intended that utilities and state regulators in the PJM Interconnection states would modify the new procedures and make them specific to peculiarities of local markets. Among the states in the PJM Interconnection, Pennsylvania adopted the MADRI Procedures in significant part; Maryland completed a rulemaking in June 2008 by adopting rules that improve upon the MADRI Procedures; and the District of Columbia initiated a rulemaking to consider similar rules. Delaware developed interconnection procedures with very low system capacity. New Jersey elected not to adopt the MADRI Procedures and instead developed what DG proponents consider to be one of the best state procedures in the U.S. Outside the PJM Interconnection region, the MADRI Procedures have been used in Illinois and Oregon. Utah and South Dakota are considering Oregon's improved version.

The IREC Procedures were initially developed in 2005, and were most recently revised in September 2009. The original intent of the procedures was to respond to EPAct 2005's call for states to consider adopting best practices by creating its own version of those best practices, as of late 2006. Coming at a later date than the other procedures discussed above, the IREC Procedures drew on SGIP/SGIA, the MADRI Procedures, the NARUC Procedures and the progressive rules developed in New Jersey. The IREC Procedures drew directly from the SGIP for its basic format, technical standards, application forms and the simplified agreement for interconnection of inverter-based systems no larger than 10 kW. The 2009 update of the IREC Procedures applies the simplified process for small inverter-based systems to systems no larger than 25 kW, and includes other stylistic and substantive revisions.

Although significant differences exist between the SGIP/SGIA, CA Rule 21, the MADRI Procedures, and IREC Procedures, their many commonalities establish a relative baseline of interconnection procedure essentials. Among the common elements of all four procedures are:

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

- Comprehensive coverage of issues such that utility discretion to create substantive additional rules is largely foreclosed

In October 2008, the Solar America Board for Codes and Standards issued a report titled, *Comparison of the Four Leading Small Generator Interconnection Procedures*, which provides a detailed look at the advantages and disadvantages of the four leading interconnection standards discussed above. Additionally, the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy and Office of Electricity Delivery and Energy Reliability issued a brief, two-page document in March 2007 listing best practices for DG interconnection.

2.2 Legal and Procedural Issues

Many of the barriers to interconnection have little to do with technical functionality or safety. Since the adoption of the national technical standards discussed in Section 3 of this document, states and utilities have been addressing technical issues in a satisfactory, uniform manner. At the very least, in many jurisdictions, the technical rules are clear to all parties involved. A substantial portion of the difficulties associated with interconnection now lie in the legal and procedural arenas.

If legal advice is necessary to interpret the paperwork required by a utility, then project costs rise, and plans are more likely to be abandoned.

This section describes some of the significant legal issues related to interconnection, including liability insurance and agreements between system owners and utilities. Procedural issues are then addressed, including:

- Utility practices and timelines
- Interconnection applications
- Expedited vs. study track procedures
- Fees and charges

State regulatory authorities develop procedural regulations, usually with input from interested stakeholders. In several states, including California and New Jersey, clear legal and procedural rules have greatly facilitated the interconnection process.

Insurance

The impact of liability insurance requirements depends on the size of a DG system. Additional liability insurance to cover systems greater than 100 kW installed at commercial or industrial facilities is generally not an issue because owners of such facilities likely already have sufficient liability insurance coverage (i.e., at least \$300,000 in coverage), or because the marginal cost of additional insurance is not prohibitive relative to a DG project's cost. Significantly, liability claims related to the malfunction of interconnected, customer-sited renewable energy systems are an extremely rare occurrence.

However, liability insurance has been a major battleground in developing of rules applicable to DG systems sited at homes or small businesses. Some states with interconnection standards require liability insurance for small systems as a means of protecting the utility and its employees from any accidents attributable to the operation of a customer's system. Because most homeowners already have liability insurance through a standard homeowner's insurance policy, a requirement to provide a reasonable amount of liability coverage usually does not

impact these system owners.²⁵ Many states with DG interconnection standards have prohibited utilities from imposing insurance requirements on customers beyond reasonable limits established by state regulatory commissions.

In several states, including California and New Jersey, clear legal and procedural rules have greatly facilitated the interconnection process.

Indemnity, another salient insurance issue relevant to DG interconnection, refers to security against or compensation for damage, loss or injury. In contracts between utilities and system owners, a utility frequently requires the system owner or other customer-generator to indemnify the utility for any potential damages as a result of operation of the installation. Indemnification requirements are somewhat redundant in states with liability insurance requirements. States that have specifically addressed indemnification in DG interconnection procedures usually require mutual

indemnification (as opposed to requiring indemnification of the utility by the system owner but not of the system owner by the utility).

Beyond the issues of limits of liability and indemnity, some utilities have sought to impose a requirement that the utility be listed as an additional insured on the customer's liability policy. In essence, this means a utility would be protected under the system owner's policy if the utility is sued in relation to the operation of the system. However, in most areas of the country, insurance companies have indicated that listing a utility as an additional insured is not even a possibility for residential insurance policies. As a result, some utilities have dropped this requirement. Where state regulatory authorities have examined the issue, the attempted requirement has been rejected.

Standard Agreements

In the process of developing interconnection procedures, most states choose to adopt a standard interconnection agreement in order to assure equal legal treatment of DG system owners across different utility service territories in the same state.²⁶ Standard agreements essentially make the interconnection process easier both for utilities and system owners. Even if a state adopts uniform interconnection rules with a clearly defined interconnection process, unreasonable contract terms that find their way into utility agreements can be fatal to DG projects when a standard agreement has not been developed or recommended.

The difference between larger DG installations (for commercial or industrial applications) and smaller systems (for residential or small commercial applications) is worth highlighting once again. Given the differences in scale and project application, two different model agreements are included in IREC's 2009 model interconnection rules.²⁷ For certified, inverter-based systems up to 25 kW in capacity, the agreement is included in the application as two pages of terms and conditions for interconnection. The second model agreement, which appears in IREC's model as Attachment 3, applies to all other systems.

Turning first to the smaller-scale installations, the two-page agreement serves as a first step to removing legal and financial barriers to the installation of grid-tied renewables. If a residential customer is forced to navigate and comprehend a pile

²⁵ Several states have specified that homeowners should carry at least \$100,000 in liability insurance (what is provided by most homeowner's insurance policies).

²⁶ One notable exception is New Jersey. Although New Jersey is widely considered to have excellent interconnection standards, it has not adopted a standard interconnection agreement (as of July 2009).

²⁷ IREC's 2009 model interconnection standards are available at www.irecusa.org/index.php?id=87.

of abstruse legal documents before a system may be installed, the customer is less likely to move forward with a viable project—even if the major technical issues have been settled. In other words, if legal advice is necessary to interpret the paperwork required by a utility, then project costs rise, and customers are more likely to abandon their plans.

The concise agreement for certified, inverter-based systems up to 25 kW not only simplifies the interconnection process, but also illustrates the importance of relying on national technical standards. Without wading into technical details, it is possible to state in a single sentence of a document that systems must meet the requirements established by UL, IEEE and the National Electric Code (NEC). Several states now use a one or two-page interconnection agreement for very small DG systems, especially for net-metered systems. Other states, including California, have developed a slightly longer document, but with the same intention of achieving simplicity.

Application Process

The discussion of procedural issues is commonly split between small-scale DG and larger DG systems because many of the issues involved are different. As illustrated previously in the discussion on interconnection models, however, interconnection procedures are often subdivided into different procedural tracks or levels to accommodate both small and large systems.

System owners seeking to interconnect under net-metering rules commonly complain first that they are unable to work with a utility representative familiar with net-metering and interconnection procedures, and second, that they encounter extensive delays in receiving necessary paperwork or in receiving approval after the paperwork is completed and submitted. Many utilities still do not have standard procedures for dealing with small DG interconnection, and most utilities do not have a designated individual to address interconnection requests by customers with smaller systems. It deserves mention that few utilities have directly used their control over interconnection procedures to discourage PV systems or other customer generation. However, by failing to facilitate a simple process for small systems, many have indirectly discouraged interconnection.

Effective interconnection procedures specify not only the procedural steps that must be taken, but also the amount of time allowed for each phase of the process.

State regulatory authorities have sought to remedy this problem by establishing timelines for the various steps of the process, and by requiring utilities to designate a representative or department to address customer requests for interconnection and net metering. Ideally, customers should be able to find all relevant information and submit interconnection applications online through utility Web sites.

Although the interconnection of smaller DG systems rarely warrants engineering studies, there may be a legitimate need to conduct detailed studies before a larger DG system may be approved for interconnection. It is critical to determine when such studies are necessary, as they can add significantly to project costs.

Effective interconnection procedures specify not only the procedural steps that must be taken, but also the amount of time allowed for each phase of the process. Timing can be critical, and exorbitant delays may arise if procedures do not include specific, reasonable time limits for each step. Such time limits require both the utility and the DG system owner to stay on track and communicate with one another as a project develops. Nearly all small-scale residential PV and other

renewable-energy systems will qualify for simplified, expedited interconnection in states that have adopted multiple levels of interconnection. For these systems, beyond processing an application, utilities may only need to perform a commissioning inspection, which many states make voluntary and at a utility's expense.

In states with multiple levels of interconnection, systems that do not qualify for simplified interconnection usually require a supplemental review. This process requires project owners or developers to submit to the utility more detailed information about a system. As a result of the supplemental review, a system could qualify for interconnection with limited system modifications, or the project could be subject to a full interconnection study. States usually have different requirements for determining if a full interconnection study is necessary. Interconnection studies are conducted by the utility after the system owner or developer has approved the cost and schedule quote.

In general, the more transparent and expeditious the application process is, the more likely interconnection applicants will be to successfully implement planned projects.

Fees and Charges

In addition to procedural barriers, smaller installations sometimes face substantial obstacles in the form of fees. Some utilities may impose a variety of fees on owners of small-scale systems, including permitting fees, interconnection fees and charges, metering charges and standby charges. Careful consideration of the propriety of any proposed fee is necessary because the imposition of even a modest fee can substantially alter the economics of smaller, grid-tied DG systems.

Prohibiting standby charges seems to be a prevailing trend among states modifying their net metering rules.

Interconnection-related fees and charges include initial engineering and inspection fees for reviewing a system. Historically, utilities have conducted inspections of individual generating facilities—no matter how small in size—and many charge the system owners for these inspections. Fees to inspect even small PV systems have been reportedly as high as \$900. However, fees for inspections could be eliminated or reduced with the more widespread recognition of relevant codes and standards such as NEC Article 690, IEEE 1547 and UL 1741.

Metering charges may be imposed when a second meter is installed for a DG system. Such charges typically range from \$4 to \$8 per month. These charges were more common before the widespread adoption of net metering in the United States. If a new meter is required for net metering, states have generally ruled that the utility must furnish the meter. A few states require the customer to either pay for the meter or to share some of the costs associated with the new meter and its installation. A second meter is often used to measure exported customer generation in states without net metering, and by customers who choose to pay for an additional meter in order to measure output for the purpose of selling RECs.

Standby charges have been established by utilities in some areas for customers with DG systems. Utilities argue that they are required to have capacity available to meet customer load in the event a customer's DG system fails. However, this logic is questionable for intermittent DG systems, especially for those using solar energy. In many parts of the country, solar energy systems reduce utility system load at the most opportune time, when the utility is experiencing peak demand

driven by cooling loads during a heat wave. For larger customers with separate energy and demand metering, standby charges for intermittent DG are particularly inappropriate. The customer's peak demand may only be modestly reduced; for instance, a customer with a solar energy system will still have significant demand after dusk. Typical standby charges for PV systems can be substantial, ranging from \$2 to \$20 per kilowatt of installed capacity per month. To ensure that this additional cost is not an obstacle to greater penetration of certain renewable technologies, at least 21 states as of July 2009 had prohibited standby charges and other such charges for customers with small-scale PV systems.²⁸ Prohibiting standby charges seems to be a prevailing trend among states modifying their net-metering rules.

Distributed Generation Technical Considerations

3. SAFETY, POWER QUALITY, CODES AND STANDARDS

Because utilities and DG system owners are concerned with safety, power quality and system reliability, technical details represent a critical component of the interconnection process. Three national standards and code-making bodies—the Institute of Electrical and Electronics Engineers (IEEE), Underwriters Laboratories (UL), and the National Fire Protection Association (NFPA)—have developed installation codes, functional requirements and test standards for DG equipment that will be connected to the grid.

This section first addresses safety and technical issues in general, and then offers a discussion of standards and codes, and how these can streamline the interconnection process. The goal is to familiarize the reader with these issues without plunging too deeply into technical detail.

3.1 Safety

Like any source of electricity, DG systems are potentially dangerous both to people and property. Therefore, much effort and care have been undertaken to minimize these inherent safety risks. Large industrial customers have been generating power onsite for as long as electricity has been used, but the trend toward interconnecting photovoltaic (PV) systems, microturbines and other relatively small DG systems to operate in parallel with the grid at residential and commercial locations is relatively new. The potential impact of DG on safety is a function of the type of DG system, its size (primarily in relation to the capacity and design of the utility grid to which the system is connected), and the amount and type of neighboring DG systems sharing the grid.

²⁸ California, Colorado, Delaware, Florida, Illinois, Kansas, Kentucky, Maryland, Missouri, Nebraska, Nevada, New Jersey, Ohio, Oklahoma, Oregon, Pennsylvania, Utah, Virginia, Washington, West Virginia and Wyoming all prohibit standby charges, according to the *Freeing the Grid* report for 2009.

Distinctions Among DG Systems

From a utility interconnection perspective, DG systems are generally classified by the type of generator²⁹ that interfaces the system to the grid: (1) solid-state or static inverters, (2) induction machines, and (3) synchronous machines. A substantial portion of renewable-energy systems produce grid-quality alternating current (AC) power using an inverter, and therefore are typically lumped together. Fuel cells also use an inverter interface, as do high-speed microturbines, despite the fact that they generate power through the rotation of a generator. As with some wind turbines, the high-frequency AC generated by microturbines is converted to direct current (DC) before being converted to grid-compatible AC power by the inverter.

Table 1: DG System Types and Characteristics

	Inverter	Induction Machine	Synchronous Machine
General Characteristics	Commonly current source-like (strictly, voltage regulated, current controlled) in grid-tied mode; voltage source in stand-alone mode, sometimes within the same unit. Low inertia (capable of very high-speed response).	Inherently current source; can be made to act as voltage source with external excitation. High inertia (relatively slow response).	Voltage source. High inertia.
Fault-Current Capabilities	Low (typically <1.2X normal current).	Medium (6X normal current).	High (10X normal current).
Power Quality	Total harmonic distortion and DC injection must be controlled; controllable power factor.	Low total harmonic distortion; power factor must be corrected.	Low total harmonic distortion; controllable power factor.
Examples	Fuel cells, PV, microturbines, some wind turbines	Some wind turbines, CHP	Solar thermal electric, diesel generators, traditional utility generators

Because inverters are power electronic devices, it is possible to incorporate safety and operational features into their controls, such as providing fail-safe designs that prevent the inverter from operating unless its protective functions are working properly. The upshot is that inverter-based and rotating generators are treated differently in the codes and standards, with properly designed and tested

²⁹ The IEEE 1547 technical standard uses the term "interconnection system" rather than "generator."

inverter-based devices requiring little (if any) additional external protection equipment.

While inverters are inherently very “controllable,” their use in utility applications has risen from a few thousand systems as of 2002 to over 69,000 systems by the end of 2008.³⁰ As technical interconnection issues were being debated through the mid- and late 1990s, attention was given to whether these devices needed the additional familiar protection relays used for rotating generators. Through the process of developing UL 1741 and IEEE 929, the predecessor to IEEE 1547, it was determined that these solid-state devices could be tested to assure that they could reliably provide standard utility protective functions (voltage and frequency trip), as well as additional safety features such as anti-islanding. The UL 1741 standard (*Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources*) addresses the electrical interconnection design of various forms of generating equipment. The IEEE 1547 and 1547.1 standards further improved upon those test procedures and applied the procedures to machine-based interconnection systems.

PV Power

Photovoltaic systems have special characteristics that warrant an individual discussion of the technology. Whereas output power can be increased or decreased by regulating the fuel source of a dispatchable generator, the output power of a PV system cannot increase beyond that allowed by instantaneous

The PV output profile over the course of a day generally coincides with load profiles in summer peaking locations.

sunlight intensity. Furthermore, a PV system’s output cannot be decreased without losing the energy that could have been generated. The PV output profile over the course of a day generally coincides with load profiles in summer peaking locations. However, without storage availability, PV systems provide no output for half of a 24-hour day or more, due to the absence of sunlight.

Furthermore, the majority of the national electric grid and our building electrical systems use alternating current (AC) electricity, but PV systems produce direct current (DC)

electricity, which has different characteristics than AC electricity. Therefore PV systems require different skills and techniques to safely install and maintain. Many electricians and electrical inspectors who do not regularly work with DC electricity may not have such skills. One difference is that many modern PV systems operate at 500 to 600 volts DC, which is a much higher voltage than the highest voltage (240 Volts AC) in most residential or commercial buildings. While the shock hazard of AC electricity is somewhat higher than that of DC electricity at equivalent voltages, the potential fire hazard of DC is greater than that of AC. Proper installation in accordance with the National Electrical Code (NEC),³¹ ensures proper control of potential hazards related to DC. In addition to the NEC, there are guides to the proper wiring of PV systems. Several entities, including the North American Board of Certified Energy Practitioners (NABCEP), PV manufacturers and inverter manufacturers offer training and installation guides.³²

³⁰ Sherwood, L., *U.S. Solar Market Trends 2008*, Interstate Renewable Energy Council, 2008. Available at: http://www.irecusa.org/fileadmin/user_upload/NationalOutreachDocs/SolarTrendsRepts/IREC_Solar_Market_Trends_Report_2008.pdf

³¹ See <http://www.nfpa.org/aboutthecodes/AboutTheCodes.asp?DocNum=70&cookie%5Ftest=1>.

³² For more information, see www.nabcep.org/pvresources.cfm. The PV Study Guide is an excellent resource for those planning to take the NABCEP Solar PV Installer Certification Exam.

However, not all grid-tied inverters require DC wiring. One PV product innovation is the AC module, which is a PV module with a built-in micro-inverter so that AC power leaves the module. While these characteristics have little impact on the utility interconnection discussion, a few relevant considerations are discussed below.

Because the general public values PV as a clean, renewable-energy source that should be encouraged, governments and some utilities offer a multitude of financial incentives to support PV deployment.³³ One significant incentive is net metering, which is discussed in detail in Section 1 of this guide. While net metering is a billing mechanism, the fact that net-metered systems export power to the utility distinguishes them from sources that are designed as non-exporting systems.³⁴ Power originating at a customer's facility and flowing back toward a substation may conflict with a radial distribution system designed for the opposite flow. For example, exporting DG causes a voltage rise instead of the expected drop wherever there is reverse power flow. Whether this action creates a problem depends on the circumstances, such as the total amount of exporting DG and the capacity (i.e., transformer size, wire length and size, etc.) of the distribution system. Export capability also means a DG system has the potential to power loads beyond the owner's facility, which raises the concern of unintentional islanding.

Islanding

Islanding refers to the condition of a DG generator continuing to power a location even though power from the utility is no longer present. Unintentional islanding is an issue of significant concern, discussion and research for DG systems. Islanding can occur at the customer level, such as when a hospital uses its emergency generators during a utility outage. Islanding may also occur at the utility level (e.g., when one section of a transmission system is isolated from another section for stabilization and load management). These are both examples of intentional islanding, a term that applies to systems that are designed, managed and approved for isolated operation.

Potential safety concerns occur when a customer-sited DG system that is not specifically designed and approved for intentional islanding operation fails to detect the loss of utility power and continues to energize an isolated section of the utility grid. Three primary concerns are related to the lack of utility control over unintentional islanding:

- Shock hazards for utility line personnel working on a line that may become unexpectedly energized;
- Damage to the utility's or customer's equipment resulting from a DG system operating outside of specifications; and
- Interference with automated distribution-system protection functions, such as reclosing.

Although line workers are trained to isolate, test, and either treat lines as live or ground all lines before working on them, these precautions do not alleviate all safety concerns because there are risks when these practices are not universally followed. For example, a small gasoline-powered generator³⁵ illegally plugged into

³³ *DSIRE* provides details on government and utility financial incentives for renewables, including PV. See www.dsireusa.org.

³⁴ There are several flavors of energy export to consider, related to the magnitude and duration of the export. "Inadvertent export" results when a DG system is unable to react to a sudden drop in load and generates some excess power while it reduces its output.

³⁵ These personal generators are typically synchronous machines designed to regulate voltage and frequency to the best of their ability. They are not designed to operate in parallel with other generators (and are typically destroyed if utility power is restored while

a wall outlet to allow a homeowner to turn on lights during a utility outage is potentially lethal to utility line workers, especially when transformed to distribution system primary-voltage levels. With the pressure to repair a damaged line—or multiple lines—and restore customer service, skipping just one step of the isolate, test and ground procedure could be fatal. Accordingly, without the proper safety procedures and equipment in place, a large number of DG systems scattered throughout a distribution system raises legitimate concerns for utility line workers. In response to these concerns, efforts have been made to ensure modern inverters contain anti-islanding mechanisms.

Grid-tied inverters monitor the utility line voltage and frequency continuously. When abnormal voltage or frequency conditions occur on the utility system, they shut themselves off quickly (or “cease to energize,” the phrase that appears in technical interconnection standards). Unintentional islands with inverters are very difficult to sustain because the inverter is not designed to regulate output voltage. Instead, these inverters produce current proportional to the available power from the prime power source. An islanding condition would require the source power to match real and reactive load conditions to sustain an unintentional island. With dynamic loads and a fixed power source, the natural tendency of the island is to shift outside the allowable voltage and frequency limits that would otherwise cause the inverter to trip. Extensive testing of inverters at Sandia National Laboratories, under a variety of laboratory-controlled, worst-case conditions, led to the development of specific islanding-detection (or anti-islanding) techniques and a generalized test procedure for evaluating the efficacy of any anti-islanding device. These and other anti-islanding techniques reduce the already low probability of inverter islanding, such that devices that pass this test are considered non-islanding. Informative discussions of islanding and anti-islanding inverters are included in the annexes to IEEE 929-2000³⁶ and in a report titled *Results of Sandia National Laboratories Grid-Tied Inverter Testing*,³⁷ which is one of the first studies published on this topic. Additionally, in 2003, R. A. Walling and N. W. Miller (GE) published a study which describes how DG can potentially support unintentional system islands on power system dynamics and how unintentional islanding can adversely impact power system performance at higher penetration levels.³⁸

Because induction generators only operate when the grid is operational, they can use similar anti-islanding techniques and are therefore evaluated using the same test procedure in IEEE 1547.1-2005. Synchronous generators are voltage-source devices designed to regulate voltage and frequency. The control systems of grid-connected synchronous generators must be designed to follow characteristics set by the utility grid. The conditions that would lead to a stable island are somewhat different than for induction machines and inverters, so different anti-islanding techniques may be employed. IEEE 1547.1-2005 provides an alternate test procedure to evaluate those techniques.

When natural gas, diesel or another relatively costly and readily dispatchable fuel is used to drive an induction-based or synchronous-based DG system, the cost of those fuels and the lack of incentives such as net metering provide an economic disincentive for exporting power to the utility. In such cases, it makes sense to incorporate special protective equipment to ensure that no power is exported (using what is called a reverse power relay) or that a minimum amount of power

they are operating), and may be able to provide power that is well outside the voltage and frequency specifications established by a utility.

³⁶ 929-2000 was withdrawn in 2006 in favor of IEEE 1547.

³⁷ See www.sandia.gov/pv/docs/PDF/viennaruss.pdf.

³⁸ See Distributed Generation Islanding – Implications on Power System Dynamic Performance, available at <http://www.electricdistribution.ctc.com/pdfs/Paper%20SPM%2002%20DG%20-%20Walling.pdf>

is constantly drawn from the utility (using an under-power relay). Because these relays eliminate the possibility of a DG system energizing equipment beyond the customer's facilities, the relays act to prevent unintentional islanding and are considered acceptable anti-islanding methods.

Transfer trip, a design element that provides an operate/disconnect signal over a dedicated communications line (or lines) from the utility, is another means of providing protection against unintentional islanding. However, the equipment, capital cost and monthly communications fees make this approach prohibitively expensive for small DG systems. While not a perfect solution, this design element is one that utilities are very familiar with and rely on for ensuring that DG systems—especially large and complex DG systems—respond properly to fault conditions.

Utility External Disconnect Switch

A utility external disconnect switch (UEDS) is a device that the utility uses to isolate a renewable energy system to prevent the DG source from accidentally sending power to the utility grid during routine or emergency maintenance. The UEDS is installed in an accessible location for operation by utility personnel. Utilities have historically treated customer-sited generation equipment connected to the grid with similar scrutiny as their large central power plants. Since there is a wide variety of generator types and installations, this approach may cause excessive interconnection requirements for small, inverter-based generating systems.

The National Electric Code® requires that grid-interactive inverters meet the safety and operational requirements of Underwriters Laboratories (UL) standard 1741 in addition to the interconnection requirements of Institute of Electrical and Electronic Engineers (IEEE) standard 1547-2003.

Largely because of these national standards, a trend appears to favor eliminating the requirement for a UEDS on small inverter-based systems. In 2007, two California utilities, Pacific Gas & Electric (PG&E) and the Sacramento Municipal Utility District (SMUD), voluntarily dispensed with the need for a UEDS on most inverter-based solar systems under 10 kW. In addition, Xcel Energy in Colorado recently announced that it will no longer require a UEDS on PV systems of 10 kW or less, as long as the system uses a UL 1741 certified inverter.

It is in large part because of national standards that there appears to be a trend in favor of eliminating the requirement for a UEDS on small inverter-based systems.

In 2008, two reports were published on this subject. The first was an NREL report titled *Utility-Interconnected Photovoltaic Systems: Evaluating the Rationale for the Utility-Accessible External Disconnect Switch*.³⁹ The report concluded that a

UEDS is not necessary for inverter-based systems under 10 kW. The second report was published by the Solar America Board for Codes and Standards: *Utility External Disconnect Switch: Practical, Legal and Technical Reasons to Eliminate the Requirement*.⁴⁰ The report concluded that half of all photovoltaic installations in the US in 2007 were installed *without* a UEDS. Additionally, the report showed that the operational histories of these systems demonstrate that a UEDS provides little, if any, additional safety, when PV hardware meets UL and IEEE standards and when the PV is installed in compliance with the requirements of the NEC.

³⁹ See <http://www.nrel.gov/docs/fy08osti/42675.pdf>

⁴⁰ Solar ABCs http://www.solarabcs.org/utilitydisconnect/ABCS-05_studyreport.pdf

These reports have proven influential. Over the past year, Florida and North Carolina⁴¹ both adopted interconnection standards that ensure customers with inverter-based systems under 10 kW will not have to pay an additional cost for installing a UEDS. New York additionally set the threshold at 25 kW for a UEDS and New Hampshire set it at 100 kW. This brings the number of states to eight that have waived the requirement for a UEDS on small inverter-based systems. California and Nevada prohibit the use of a UEDS for systems under 1 kW. However, this trend is not uniform. In 2008, Illinois required the use of a UEDS, even for the smallest systems.

3.1 Power Quality

Power quality is another technical concern for utilities and DG system owners. Power quality is analogous to water quality; just as municipal water suppliers and individual water wells must meet certain standards for bacteria and pollutant levels, utility power is consistently supplied at a certain voltage and frequency. In the United States, residences receive single-phase AC power at 120/240 V and 60 cycles per second (Hz). Commercial buildings typically receive either 120/240 V single-phase power or higher voltage (e.g., 120/208 or 277/480) three-phase power, depending on the size of the building and the types of loads in the building.

Each type of DG system has its own output characteristics based on the technology employed. Even systems that use inverters vary depending on the inverter design, the control algorithms and the characteristics of the input power source. Device-specific power-quality issues therefore are not addressed here.

The power factor can range from a low of zero, when the current and voltage are completely out of phase, to the optimal value of one, when the current and voltage are perfectly in phase.

Power quality is important because electronic devices and appliances are designed to receive power within a designated range of voltage and frequency parameters, and deviations outside those ranges can cause appliance malfunction or damage. Power quality problems can manifest themselves as extraneous lines on a television screen or static noise on a radio, which is sometimes noticed when operating a microwave oven or hand mixer.

Noise, in electrical terms, is any electrical energy that interferes with other electrical appliances. As with any electrical device, an inverter, which converts the DC power into usable AC power, can introduce noise that may cause interference. In addition to simple voltage and frequency ranges, discussions of power quality include characteristics of harmonics, power factor, DC injection and flicker.⁴² These are discussed in more detail below.

Harmonics generically refers to distortions in the voltage and current waveforms. These distortions are caused by the overlapping of the standard sinusoidal waveforms at 60 Hz with waveforms at other frequencies that are multiples of 60 Hz. Generally, a harmonic of a sinusoidal wave is an integral multiple of the frequency of the wave. Total harmonic distortion (THD) is a summation of all the distortions at the various harmonic frequencies.

⁴¹ Order Granting Motion for Reconsideration and Amending Generator Interconnection Standard, NCUC Docket No. E-100, Sub 101 (Dec. 16, 2008).

⁴² For a more detailed discussion of power quality, see ANSI C84.1 (voltage ratings), IEEE Std 519 (harmonics), IEEE Std 1453 (flicker) and the annexes of IEEE 929-2000.

Harmonics can be caused by non-linear loads (equipment), examples of which include power supplies for computers, variable speed drives and electronic ballasts. Traditional loads such as motors and incandescent light bulbs are linear loads, where there is a direct correlation between the voltage supplied and the current drawn by the device. Non-linear loads use solid-state devices, often with microprocessor controls, to switch current on and off. Current is drawn discontinuously and is not directly dependent on the voltage. When PG&E (an investor-owned utility) installed a 500-kW PV system in Kerman, California, in 1993, the neighbors across the street complained that their electric clocks were advancing by several extra minutes each day. Further investigation revealed a problem with harmonics filtering in the inverters. This problem was resolved fairly easily. Despite the large amount of discussion this topic generates, the number of documented problems caused by harmonics is relatively low even though various harmonic-producing loads are increasing. Modern interconnection requirements include limits on harmonic injection from DG systems, and devices evaluated to meet IEEE 1547.1 standards will have minimal harmonic impact.

Power factor (PF) is a measure of apparent power that is delivered when voltage and current waveforms are out of synch. Power factor is the ratio of true electric power, as measured in watts, to the apparent power, as measured in kilovolt-amperes (kVA). The power factor can range from a low of zero, when the current and voltage are completely out of phase, to the optimal value of one, when the current and voltage are perfectly in phase. Loads with motors, such as refrigerators and air conditioners, typically cause reduced (or lagging) power factor. The terms leading and lagging describe whether the current wave is ahead of or behind the voltage wave.

DC injection occurs when an inverter passes unwanted DC current into the AC (or output) side of the inverter. This action can be prevented by incorporating galvanic isolation through a transformer within the inverter design. The current trend in PV toward ungrounded arrays and un-isolated (i.e., transformerless) inverters, both of which are quite common outside the United States, raises new concerns regarding the potential for DC injection and what a reasonable limit should be. Un-isolated inverters must be more carefully designed to achieve balanced output, and potentially to provide highly accurate DC-sensing circuits. The IEEE 1547 limit of 0.5% of the inverter rated output current was originally derived for IEEE 929-2000, based on comfort levels of a sample of transformer manufacturers. During this process, it was determined that (1) most transformers could tolerate DC current up to 0.5% of the transformer rating without undue concerns related to core saturation, and (2) each inverter should be allowed to contribute a portion of the total allowable current based on its rating. This latter conclusion assumes that there would be DG system capacity equivalent to the transformer rating, and that the DC current from multiple inverters would be additive—two very conservative assumptions. DC injection is not an issue for rotating generators, which only produce AC power. The IEEE P1547.2 draft application guide to IEEE 1547 provides additional technical background and rationale for the DC injection and other 1547 requirements.

The term flicker was originally adopted as a reference to the visible flickering of an incandescent light bulb when subjected to voltage oscillations on a utility line. The perception of flicker is subjective, and depends on the magnitude and frequency of the voltage oscillations. A slow oscillation must be of higher magnitude in order to be as noticeable as a fast oscillation.

Voltage oscillations are caused by changes in the power drawn by a load or output from a DG system. A potential source of flicker from DG systems occurs during startup and shutdown, when there can be substantial changes in power. The synchronization requirement in IEEE 1547-2003 allows for a 5% voltage fluctuation, and tests are provided either to promote a low impact on voltage due to synchronization or to provide a measure of current flow into or out of the DG

during the synchronization process. However, it should be noted that the flicker requirement in IEEE 1547 is simply that the DG should not “create objectionable flicker for other customers.” IEEE 1547 does not address how this should be evaluated.

There are two problems in defining an objective flicker requirement. First, the actual voltage impact of a given DG system depends on both the level of DG current flow and the line impedance, so a unit may work fine in one application but cause problems in another. The measured current flow is used by utility engineers along with an estimate of the system impedance at the interconnection point in an analysis referred to as a flicker calc. The flicker calc evaluates the potential impact of a proposed induction motor, which can require significant amounts of in-rush current when starting, but it is readily applied to all other types of DG systems.

Even with this objective analysis, the requirement still comes down to the phrase “objectionable to other customers.” Whether or not a particular voltage fluctuation is objectionable is a function of the proximity of the DG to other customers and their sensitivity to flicker (e.g. sensitivity to light flicker or voltage fluctuations). Finally, a customer who finds the flicker objectionable must file a complaint with the utility before any action can be taken. Flicker is also an “in perpetuity” requirement, in that the complaint can be raised well after the system is installed and operational. If the local utility determines, through a flicker study, that the neighbor has a reasonable complaint, and that a DG system is the cause, then the DG system owner must address the problem.

Lastly, depending on their use and location, some DG systems are required to meet the electromagnetic emissions requirements described in Part 15 of the Federal Communications Commission (FCC) rules. FCC requirements and testing are intended to ensure that DG systems do not emit or conduct harmful interference with radio or television transmissions.

High Penetration PV

Significant cost reductions, a greater demand by mainstream consumers and increases in production of solar PV systems are driving dramatic growth in domestic installations. For example, in California, a number of homes are currently being built with PV systems as a standard feature. Moreover, programs such as DOE’s Solar Energy Technologies Program are aiming to make solar energy cost competitive with central generation power costs by the year 2015. As a result of this boom in PV deployment, the penetration levels of grid-tied renewable energy systems on individual feeders are beginning to push the current technical limitations enumerated in codes and standards such as IEEE 1547.

In the spring of 2007, the U.S. DOE launched the Renewable Systems Interconnection (RSI) studies⁴³ in an attempt to identify the research and development efforts needed to build and sustain a high-penetration renewable energy infrastructure. The RSI studies tested different levels of PV penetration, classifying them as low (5%), medium (10%) and high (30-50%). It should be noted that when the issue of grid penetration is discussed in these studies, it refers to the load on individual distribution feeder circuits, rather than the level of system-wide, or statewide, installed capacity. Almost all state and utility interconnection procedures allow expedited interconnection if penetration on a circuit is below 15% of line section peak capacity.

⁴³ See <http://www1.eere.energy.gov/solar/rsi.html>

One key finding of the RSI studies is that grid integration issues are likely to emerge much more rapidly than many analysts expect. In some regions of the United States, grid-integration-related barriers to future growth could emerge within the next five to ten years. The studies also found that current interconnection requirements need to evolve to accommodate future levels of increasing renewable deployment.

As a result of the RSI studies, the DOE initiated the Solar Energy Grid Integration Systems (SEGIS) program in early 2008. SEGIS is an industry-led effort to develop new PV inverters, controllers and energy management systems that will enhance distributed PV systems. As these technologies progress, utilities will be more equipped to accommodate increased deployment of PV on their distribution circuits. High penetration PV will likely also be much easier to facilitate with forthcoming advances in energy storage capabilities.

Energy Storage

Energy Storage (ES) is seen as one of the emerging technologies that can propel/support higher penetration levels of intermittent renewable resources, including PV. However, current regulatory policies are ill-suited to facilitate the deployment of ES onto the grid. Below is an overview of the issues and opportunities ES presents.

There are at least five potential locations on the grid that can accommodate ES:

- Customer sites
- Distribution substations
- Sub-transmission substations
- Transmission substations
- Generating stations

In some regions of the United States, grid-integration-related barriers to future growth could emerge within the next five to ten years.

Energy Storage can provide substantial value to the grid, but the value stream ES can provide is dependent on where it is sited. Because emerging ES technologies are still relatively expensive, capturing all available value streams is important in the economics of a project. Capturing all available value streams in one project, though, can prove challenging. Possible benefits based on location include:

1. Transmission level – voltage support, VAR source,⁴⁴ mitigation of transmission loading, etc.
2. Distribution level – power quality improvement, voltage support, load relief, load leveling, etc.
3. Customer sited – demand peak reduction, power quality, uninterruptible power supply, plug-in hybrid vehicles, etc. Customer-sited ES could also be aggregated similarly to demand response (DR) aggregation to provide grid-scale or market services.
4. Generation sited – operating reserves, arbitrage of energy prices (shifting of energy from low cost periods for delivery during higher cost periods) and other ancillary services.

⁴⁴ A VAR source, or reactive power compensation, provides voltage support for voltage sags and dips caused by rapidly-changing dynamic loads (i.e. large motors starts, industrial shredders or conveyors, etc.), or to provide power-factor correction. By reducing voltage fluctuations and managing reactive power flow, system stability and reliability are enhanced and capacity of the infrastructure is increased.

The U.S. DOE has embarked on a project to develop ES components and systems specifically designed and optimized for grid-tied PV applications. The project is called the Solar Energy Grid Integration Systems – Energy Storage (SEGIS-ES). Through SEGIS-ES, the U.S. DOE aims to conduct targeted research and development on applications most likely to benefit from a PV-storage system (*i.e.*, peak shaving, load shifting, demand response, outage protection, and development of microgrids).

As ES technologies become increasingly financially attractive across a broad range of locations and applications, policy makers will need to address regulatory barriers that may impede the deployment of ES onto the grid. For example, state interconnection standards are often ambiguous in their treatment of ES devices. Moving forward, it will be important to clarify whether interconnection standards apply to the interconnection of ES devices. It will also be important to address the eligibility of PV-integrated storage for state net-metering programs and to determine which utility retail rates are available to customers with PV-integrated storage. Policy makers will also need to address impediments to the integration of non-customer sited ES with distribution and transmission systems, including utility planning and procurement activities and issues related to utility cost recovery.

With the proper programs and policies in place, the prospect of plug-in hybrid electric vehicles (PHEVs) holds great promise. In addition to their function as clean transportation resources, PHEVs could provide many megawatts of storage and improve the overall functioning of the electrical power system, and there are already initial policies in place to make this happen. In 2009, Delaware became the first state to officially allow PHEVs to take advantage of net-metering-like credits for kWhs transferred to the grid.⁴⁵ Importantly, a high penetration of PHEVs could both encourage and benefit from a high penetration of intermittent renewable generation, such as PV and wind power, enabling a significant reduction in transportation-related foreign oil consumption. At present levels of PV penetration on the electrical grid, energy storage has not been a priority consideration. However, as PV prices decline and become comparable with prevailing electricity prices, the nation's electrical grid will benefit from the addition of energy storage technologies.

The major concern with interconnecting DG to a network focuses on the possible chance that a generator would export power onto the network, be detected by the network protectors, and “lock out” the network protector.

Electric Distribution Systems

Electric distribution circuits are typically of two types: radial circuits and secondary network systems (networks). Radial distribution systems are estimated to carry about 97% of the total electric load in the U.S. Radial systems are significantly less expensive than network systems, and are much simpler to plan, design, construct and operate. A radial distribution circuit exits the utility substation and passes through the system area with no lasting connection to other distribution circuits. Hence, radial distribution has one path between the customer and the substation and

power flows from the substation to the customer along this single path. One downside of a radial distribution circuit is that if the circuit is interrupted, it results in complete loss of power to the customer until the feeder is restored or the feeder is tied to an adjacent feeder.

Many larger metropolitan areas in the U.S. have network circuits with multiple distribution feeders and multiple service transformers. Networks are the most reliable type of distribution system, but are also the most complicated and

⁴⁵ See Delaware Senate Bill 153 (2009), available at <http://legis.delaware.gov/>.

expensive systems to distribute electric power. Networks provide continuity of service (reliability) far beyond that of a radial design. If an electric outage occurs on one circuit, power automatically re-routes itself through other circuits and customers rarely experience a power fluctuation or outage.

Networks are very expensive to install, maintain and operate, and for this reason, most utilities have not significantly expanded network service outside downtown areas. The purpose and operating principles of networks remain essentially the same since they were first installed in the early 1920s, which is to serve high-density loads at maximum reliability levels.

The key difference between a radial system and a network system is a device called a network protector. One of the primary purposes of a network protector is to isolate transformer and primary cable faults from the energized secondary, thus maintaining service and reliability. Network protectors are designed to open (that is, break the circuit) quickly when they detect back-feeding from the secondary (low voltage side, typically 120/208 volts) to the primary (typically about 12,000 volts). The major concern with interconnecting DG to a network focuses on the possibility that a generator would export power onto the network, be detected by the network protectors, and "lock out" the network protector. Most installed network protectors have not been designed or tested to operate with distributed generation.

Networks are divided into two distinct types known as area networks and spot networks. Area networks are multiple feeder systems meshed together through network transformers so that every low voltage secondary bus is supplied from a number of sources. Spot networks typically serve one building or one utility customer, and typically have only two or three feeders, transformers and network protectors. The most common network voltages are 120/208V and 277/480V.

IEEE Standard 1547-2003 does not currently provide for interconnection to an area network, but does provide for interconnection to a spot network under very specific and limited circumstances. IEEE is developing a recommended practice for interconnection of distributed generation to secondary networks. This project, known as IEEE P1547.6,⁴⁶ will be the standard for interconnecting distributed resources to distribution secondary networks. This standard focuses on the technical issues associated with the interconnection of area Electric Power System (EPS) distribution secondary networks with a local EPS having demand response generation. The standard provides recommendations relevant to the performance, operation, testing, safety considerations and maintenance of the interconnection. In this standard, consideration is given to the needs of the local EPS to be able to provide enhanced service to the DR owner loads as well as to other loads served by the network. Equally, the standard addresses the technical concerns and issues of the area EPS.

To clarify network issues and concerns, NREL published a technical report in July 2005 titled *Network Distribution Systems Background and Issues Related to the Interconnection of Distributed Resources*.⁴⁷ The purpose of this report is to identify the network specific interconnection issues for which test protocols should be developed, and to assist in the design of the test facility and development of test plans. The document also recommends criteria and requirements for interconnection of distributed generation with network systems.

To illustrate successful installations of PV systems on secondary network distribution systems NREL published a technical report in March 2009 titled *Photovoltaic Systems Interconnected Onto Secondary Network Distribution*

⁴⁶ See http://grouper.ieee.org/groups/scc21/1547.6/1547.6_index.html.

⁴⁷ See NREL/TP-560-38079 <http://www.nrel.gov/docs/fy05osti/38079.pdf> or search under <http://www.osti.gov/bridge> July 2005.

Systems - Success Stories.⁴⁸ The report addresses methodologies for interconnecting PV systems in larger metropolitan areas that are served by both area and spot networks. The main objectives of the report's six case studies were to record all interconnection requirements implemented by each local utility to interconnect each PV system to the area network or the spot network, and to evaluate the performance of these systems to date with respect to their integration with the electric utility.

The case studies demonstrate that PV systems connected to network distribution grids are not only feasible but that they are being successfully deployed. The studies also show that with implementation of properly designed controls, PV systems can operate safely, efficiently and reliably on network systems. Information provided in the report, and the methods used to control the generation, can also be applied to other DG systems.

Network interconnections have become an increasingly important issue, as shown by the fact that at least 15 US DOE Solar America Cities have some network service within their cities. However, network interconnections continue to be a challenging issue and some utilities do not allow DG interconnections to their networks. In what may herald a future trend, Consolidated Edison of New York, Inc. (ConEd), in an effort to reduce barriers to interconnection of customer-owned DG, has announced that inverter-based solar generators up to 200 kW may interconnect to the company's distribution network system without a detailed study.

In addition to the NREL study, the Solar America Board of Codes and Standards (Solar ABCs) will complete a review of the FERC Small Generator Interconnection Procedures (SGIP) screens. The goal of this task is to gather consensus agreement among subject matter experts in the field of small generator interconnections. Specifically, the study will review FERC SGIP Screen 2.2.1.3, that limits the aggregated inverter-based generation to the smaller of 5% of a spot network's maximum load or 50 kW, and will consider whether these limits should be raised.

In view of the NREL report on success stories, the ConEd allowance of inverter-based systems less than 200 kW, and the Solar ABCs pending report on FERC screens, it seems the prevailing trends support lowering barriers to network interconnections.

3.3 National Codes and Standards

The technical and safety issues discussed above are addressed in a number of national codes and standards related to the interconnection of DG systems. The value of these codes and standards to the interconnection process cannot be overstated. Without standardized national documents, DG equipment manufacturers would be faced with the nightmare of developing separate devices and protection equipment to satisfy individual utility interconnection safety requirements. With more than 3,000 utilities⁴⁹ in the United States, such a scenario would stymie DG development. Moreover, safety is enhanced when all parties adhere to nationally determined, certified codes and standards.

⁴⁸ NREL/TP-550-45061 <http://www.nrel.gov/docs/fy09osti/45061.pdf> or search under <http://www.osti.gov/bridge> March 2009.

⁴⁹ There are more than 3,273 utilities in the United States according to the Energy Information Administration.

A number of safety and code organizations have been instrumental in bringing about these standards. The primary organizations that publish interconnection codes and standards are the National Fire Protection Association (NFPA), Underwriter's Laboratory (UL) and IEEE (which once stood for Institute of Electrical and Electronics Engineers). Additionally, two federal labs – NREL and Sandia National Laboratories – work closely with the NFPA, UL, IEEE and the DG community on code issues and equipment testing. The labs are not responsible for issuing or enforcing codes, but they do serve as valuable sources of information on PV and interconnection issues.

IEEE 1547 Series

IEEE is a nonprofit, technical professional association with a worldwide membership. Among its functions, IEEE has created more than 800 active technical standards, with more than 700 in development. IEEE Standards Coordinating Committee (SCC) 21 on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage⁵⁰ has taken a leading role in addressing technical interconnection issues with the development of IEEE 1547-2003 and IEEE 929-2000 (which has since been withdrawn). SCC 23, a predecessor to SCC 21, developed IEEE Standard 1001-1988 (also withdrawn), a guide for interfacing dispersed storage and generation facilities with electric utility systems.

IEEE 1547 *Standard for Interconnecting Distributed Resources with Electric Power Systems* addresses the technical specifications for and testing of the interconnection of DG systems to the grid. The scope states: "This standard establishes criteria and requirements for the interconnection of distributed resources (DR) with electric power systems (EPS)."⁵¹ This document focuses on interconnection at the distribution level and is intended for systems up to 10

Without standardized national documents, DG equipment manufacturers would be faced with the nightmare of developing separate devices and protection equipment to satisfy individual utility interconnection-safety requirements.

megavolt-amperes (MVA). The standard's carefully worded "Purpose and Limitations" define what the document does and does not address, characterizing the requirements as "universally needed" and "sufficient for most installations," but noting that additional requirements "may be necessary for some limited situations."

The brevity of the scope is representative of the short 15-page standard (which at one point in draft form weighed in at more than 300 pages). The document is concise in part because the standard is strictly concerned with interaction at the point of common coupling—the interface point between a customer and a utility. The standard does not address the type, design or operation

of a DG system or of a utility system. Nor is the standard prescriptive, as it does not address how the requirements are to be implemented.

The other primary reason for the document's brevity is that IEEE 1547 is actually a series of standards, with 1547-2003 as the lead document addressing the core issues. During the numerous meetings and technical debates that marked the development of IEEE 1547, several important issues were left for further development in companion documents. Currently, eight documents in the IEEE 1547 series have been published or are under development:

⁵⁰ See <http://grouper.ieee.org/groups/scc21/index.html>.

⁵¹ An area EPS refers to the utility distribution grid, whereas a local EPS would be the electrical system at the DG owner's facility.

- IEEE Std 1547-2003 *Standard for Interconnecting Distributed Resources With Electric Power Systems*
- IEEE Std 1547.1-2005 *Standard for Conformance Test Procedures for Equipment Interconnecting Distributed Resources With Electric Power Systems*
- IEEE 1547.2 *Application Guide for IEEE 1547*
- IEEE Std 1547.3-2007 *Guide for Monitoring, Information Exchange and Control of Distributed Resources Interconnected with Electric Power Systems*
- IEEE P1547.4 *Draft Guide for Design, Operation and Integration of Distributed Resource Island Systems With Electric Power Systems*⁵²
- IEEE P1547.5 *Draft Technical Guidelines for Interconnection of Electric Power Sources Greater Than 10MVA to the Power Transmission Grid*
- IEEE P1547.6 *Draft Recommended Practice for Interconnecting Distributed Resources With Electric Power Systems Distribution Secondary Networks*
- IEEE P1547.7 *Draft Guide to Conducting Distribution Impact Studies for Distributed Resource Interconnection*

Utility interconnection requirements may be mandated by a state legislature, a state regulatory authority, the board of a publicly-owned utility or the board of an electric cooperative.

The 1547.1 conformance-test document provides detailed procedures for the tests and requirements defined in Section 5 of 1547-2003. It includes sections covering type tests (known as “design tests” in 1547) for verifying the suitability of a particular model, production tests performed on each unit manufactured, commissioning tests for evaluating a newly completed system, and periodic interconnection tests to assess ongoing interconnection system health.

The scope of 1547.2 is to provide technical background and application details to support the understanding of 1547-2003. This document, therefore, fills in much of the relevant background on various interconnection technologies and their relevant issues. It includes technical descriptions and schematics, applications guidance, and interconnection examples, and was approved in 2008. Standard 1547.3-2007 focuses on the functionality, parameters and methodologies for DG system communications and control.

Intentional islanding (discussed in section 3.1) was purposefully omitted by 1547 developers, to be addressed at a later date. P1547.4 encompasses the issues involved in integrating DG-islanding systems into the grid. The scope of the guide will include topics such as the ability to separate from and reconnect to part of the grid while providing power to the local island.

Whereas 1547-2003 is (somewhat arbitrarily) limited to interconnections of 10 MVA or less and is primarily intended for distribution-level interconnection, P1547.5 will provide guidelines for “interconnecting dispatchable electric power sources with a capacity of more than 10 MVA to a bulk power transmission grid.”

P1547.6 addresses interconnections to secondary network distribution systems. A secondary network (discussed in section 3.1) is a form of distribution system typically used in dense, high-load areas where electric reliability is critical. The term “secondary” is used because the network is formed on the secondary, low-voltage (i.e., 208-V or 480-V AC) side of the network transformers. This standard will define the technical requirements and tests for such interconnections. Draft guide P1547.7 will provide a described methodology to determine when

⁵² The “P” in front of an IEEE standard number indicates that the document is a project draft.

distribution system impact studies are appropriate, what data is required, how they are performed, and how the study results are evaluated.

Note that IEEE defines three types of guidelines: standards, guides and recommended practices. Both 1547-2003 and 1547.1-2005 are standards. These documents contain mandatory requirements and generally use the word "shall" in describing how the requirements are to be implemented. By contrast, P1547.2, P1547.3 and P1547.4 are guides, which are documents where approaches to best practices are suggested, but no clear-cut recommendations are made. The operative word in such documents is "may." Recommended practices, such as 1547.6, provide procedures and positions preferred by the IEEE. Here, the operative word is "should."

The use of IEEE standards (and most other standards) is voluntary unless mandated by a party. For example, an individual buying a piece of equipment can require that certain standards be used to test the equipment before a purchase is made. Utility interconnection requirements may be mandated by a state legislature, a state regulatory authority, the board of a publicly-owned utility or the board of an electric cooperative. Once mandated, the IEEE designation of standard, recommended practice or guide often loses its distinction, and in many cases, the "mays" and "shoulds" effectively become "shalls."

Significantly, the entire IEEE 1547 series was developed—and continues to be developed—in an open, collaborative process involving utilities, equipment manufacturers, national labs, end users and other individuals. The working group for the main 1547-2003 standard included nearly 350 official members and hundreds of additional interested parties. The balloting committee had an impressive 230 members, with nearly equal representation from electric users/utilities (35%), manufacturers/producers (31%) and general interest (35%, e.g., consultants, testing labs). The remaining 4% were government representatives. The IEEE 1547 standard is available for purchase from IEEE.

IEEE 929-2000 (withdrawn)

Prior to the completion of IEEE 1547, IEEE 929-2000 (*Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*) was the definitive interconnection document. While 1547 covers all DG technologies and addresses much larger systems and grid impacts, IEEE 929 was strictly an inverter document and technically only addressed PV applications. In the 1980s, IEEE published ANSI/IEEE Std 929-1988, *IEEE Recommended Practice for Utility Interface of Residential and Intermediate Photovoltaic (PV) Systems*. This document addressed the basic issues of power quality, equipment protection and safety. Extensive revisions led to the final version, IEEE Std 929-2000, which was approved by IEEE in January 2000, replacing the 1988 version.

It was the intent of IEEE 929-2000 to meet all legitimate utility concerns with safety and power quality so that there would be no need for additional requirements in developing utility-specific guidelines, especially for systems of 10 kW or less. In addition to being an enforceable standard, 929-2000 was also intended to be an informative document and still serves as an excellent primer on PV interconnection issues. While the standard itself is only about 12 pages, it contains informative annexes with nearly 20 pages of background information on islanding, distribution transformers and manual disconnects.

IEEE 929 was withdrawn in 2006 in lieu of 1547, which, with a larger, more diverse working group, refined and expanded the 929 tests and requirements. IEEE 929 covered all relevant issues related to PV interconnections but was only a

recommended practice—not a standard—and thus did not carry the same weight within the IEEE context.

UL 1741

Underwriter’s Laboratory is a private, nonprofit organization that has evaluated products, materials and systems in the interest of public safety since 1894. UL has become the leading safety testing and certification organization in the United States; its label is found on products ranging from light sockets to inverters. Although UL writes the testing procedures, other organizations may perform the actual testing and listing of specific products. In addition to the UL testing labs, Intertek, the Canadian Standards Association (CSA) and TUV Rheinland of North America are recognized listing (testing) agencies. The U.S. Occupational Safety and Health Administration (OSHA) maintains a complete list of nationally recognized testing labs (NRTLs) and which tests these labs are qualified to perform.⁵³

Local building inspectors look for a listing mark (such as UL, ETL or CSA) that provides assurance that installed equipment has been tested and verified to meet the proper requirements. The NEC requires all equipment used in an electrical installation to be “examined for safety.” The NEC does not specifically require that all equipment be listed, although some equipment, including utility-interactive inverters used in PV systems and fuel cells, are required to be listed.⁵⁴ Most inspectors are likely to require either that components be listed or that qualified test results be presented. Without a listing mark, additional on-site third-party testing is usually required. For large DG systems, the cost of on-site testing for each installation is factored into the system cost, resulting in minimal adverse impacts on the project relative to the overall project budget. However, for smaller DG systems, the cost and complexity of on-site testing can sink a planned project. Accordingly, the option to have smaller system components listed, and avoid additional requirements and testing, is extremely beneficial to manufacturers of smaller DG system equipment.

Development of UL 1741 began in the mid-1980s in order to provide test requirements for PV inverters and charge controllers. UL 1741 was ultimately published in May 1999, following parallel development with the revised IEEE 929, and was further updated in 2001 and 2005.

Table 2: UL 1741 Development

Version	Published	Title
1 st Edition	May 1999	<i>Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems</i>
1 st Revision	Jan 2001	<i>Inverters, Converters and Controllers for Use in Independent Power Systems</i>
2 nd Revision	Nov 2005	<i>Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources</i>

⁵³ See www.osha.gov/dts/otpc/nrtl.

⁵⁴ Curiously, the NEC requires neither inverters used with other energy sources nor machine-based DG to be listed.

The title changes noted in Table 2 reflect the expanding scope of UL 1741, which now addresses all forms of distributed generation, including inverters for PV, microturbines, wind turbines, fuel cells and control equipment for synchronous and induction generators. Until 2001, UL 1741 was strictly an inverter-focused document that only addressed PV systems. Concurrent with the development of IEEE 1547 and 1547.1, UL 1741 expanded its scope. The committees developing the two documents worked closely together to ensure the documents were in synch. All utility interaction tests were removed from the current edition of UL 1741 and replaced with a simple reference to IEEE 1547.1.

As of July 2009, PV inverters still comprise the majority of listed DG equipment intended for utility interconnection. However, UL 1741 has been successfully applied to inverters used with other systems such as wind turbines, fuel cells and microturbines, and it now provides tests and processes to list single and multi-function relays and controllers for machine-based DG systems.

Finally, unlike the IEEE standards discussed here, UL 1741 covers more than just grid-interconnection issues. Organizationally, UL was originally established as a fire and product safety test facility. Thus, in addition to utility-compatibility issues, the scope of 1741 includes electric shock hazards, fire hazard and mechanical hazards. UL 1741 also covers stand-alone devices, such that equipment can be UL 1741 listed but not listed for utility-interactive operation. UL 1741 evaluations also address some ancillary equipment used for PV systems, such as battery charge controllers and combiner boxes used on the DC side of a PV system.

National Electrical Code Article 690

The NFPA, which publishes the NEC (or NFPA 70), is the principal U.S. organization that addresses electrical equipment and wiring safety. The NEC, a standard for the safe installation of electrical wiring and equipment, is now 780 pages long and is the most detailed of any NFPA code or standard. The NEC applies to homes and other public and private buildings and installations, but not to the power lines or generators operated by utilities. By contrast, the National Electrical Safety Code (NESC), published by IEEE, addresses equipment on the utility side of the meter.

An entire section of the NEC—Article 690 “Solar Photovoltaic Systems”—pertains to PV. While interconnection to the utility grid receives mention, this section emphasizes descriptions of components and proper system wiring and protection. One key NEC requirement states that all equipment must be tested. Furthermore the code requires utility-interactive inverters to be listed—a certification process that includes testing—by a recognized listing agency. To meet this requirement, PV systems will typically use a UL 1741-listed inverter.

It is important to note that the NEC is legally mandated in most states and in many large cities. Therefore, by extension, the requirement for listed components is also a legal requirement.

Article 690 also addresses utility disconnect switches. The code requires that PV systems have both DC disconnects (for the PV power source) and AC disconnects (for the inverter output). In many inverter models, these disconnects are built into the inverter. However, the AC disconnects required by the NEC frequently do not satisfy utility disconnect requirements because they may not provide a visible separation, may not be lockable, and are mounted at the inverter, where they may not be accessible to utility personnel.

PV systems were first given the status of a “special equipment” article in the NEC in 1984. Although revisions are continuously made to this article, it has remained largely intact. The NEC is updated on a three-year cycle; the 2008 edition is the most recent.⁵⁵ To help system designers and installers with specific NEC issues, the Southwest Technology Development Institute at New Mexico State University and Sandia National Laboratories publish a guide with recommended practices based on the NEC.⁵⁶ This guide provides practical information on how to design and install safe, reliable and code-compliant PV systems.

Building and electrical codes are often changed at the national level. After a national standard or code is amended, state and local authorities may choose to adopt the changes at their own discretion. Some jurisdictions purposely remain one or more revisions behind the latest version to illustrate local autonomy. Local jurisdictions also frequently impose rules that are stricter than national codes require. For example, certain jurisdictions require sprinkler systems for fire protection in residences. No national building code requires sprinkler systems for residences, but some local codes supersede the national code.

Solar America Board of Codes and Standards⁵⁷

The U.S. Department of Energy created the Solar America Board of Codes and Standards (Solar ABCs) as one of the major projects of its Solar America Initiative (SAI). The intent was to create a central organization to improve the responsiveness, effectiveness and accessibility of solar codes and standards for U.S. PV stakeholders at all levels.

The Solar ABCs identifies current issues, establishes a dialogue among key stakeholders, and catalyzes appropriate activities to support the development of codes and standards that facilitate the installation of high quality, safe PV systems. It serves as a centralized repository for such documents, regulations and technical and 'best practices' materials. It makes all materials and information easily accessible to the public.

The Solar ABCs works through the following types of panels:

- Coordination Activity Working Panels enable communication and planning across the different codes and standards-setting bodies to develop and modify uniform solar codes and standards, as deemed necessary.
- Implementation Activity Panels provide communication, outreach and training for PV stakeholders to facilitate adaptation and implementation of solar codes and standards.
- Study Panels conduct short-term activities of an immediate nature to analyze issues important to developing PV codes and standards. The Solar ABCs Steering Committee uses Study Panel results to set priorities for future work. For example, the Local Codes Study Panel investigates and deals with critical issues on local codes related to the installation of PV systems, including permitting, fees, liability insurance, solar access, solar rights, ordinances, statutes, community codes, covenants and restrictions (CCRs), condominium regulations and other related issues.

One report with recommendations is already complete. It is titled *A Comprehensive Review of Solar Access Law in the United States*.⁵⁸ Two further

⁵⁵ See

<http://www.nfpa.org/aboutthecodes/AboutTheCodes.asp?DocNum=70&cookie%5Ftest=1>

⁵⁶ See http://www.nmsu.edu/~tdi/PV=NEC_HTML/pv-nec/pv-nec.html

⁵⁷ This section is taken largely from the Solar ABC's website at <http://www.solarabcs.org/>

⁵⁸ See <http://www.solarabcs.org/solaraccess/>

reports with recommendations are under development: *Expedited Permitting*⁵⁹ and *High Wind Loads and Model Code*.⁶⁰ The Local Codes Study Panel is lead by the Florida Solar Energy Center (FSEC) and Interstate Renewable Energy Council (IREC), with direct assistance from the North Carolina Solar Center (NCSC).

4. ELECTRICAL INSPECTORS

Electric utilities and DG system owners have an obvious interest in assuring that interconnected DG systems operate safely. Electrical and building inspectors share this interest in safety, and in many jurisdictions they play an important role in allowing projects to go forward. While reports of inspectors' unfamiliarity with smaller, customer-sited DG systems have waned, concerns remain that an inspector could disapprove systems simply because the inspector does not fully understand the system design or technology. At the center of this issue is the fact that inspectors have local autonomy. Though they follow the codes to the best of their abilities, local inspectors are not bound to national codes and, in most cases, are not bound by state codes either.

Most city or county inspection departments look to the NEC for guidance on electrical inspection work. Since Article 690 of the NEC addresses in detail how PV systems should be wired for safety, any inspector can review this document to gain an understanding of how to assess an installation. If a PV installation has not been installed according to NEC requirements, then the code official has full authority to prevent the system from operating. Furthermore, an inspector is not obligated to approve a system that is installed in compliance with the NEC if the inspector documents appropriate concerns. Until the code official is satisfied, the system remains dormant.

Most problems begin when a system owner fails to brief a code official properly on the installation. Expressing concern to a code official about the issues the official is trained to assess can help ensure a smoother inspection process. In most cases where inspectors are unfamiliar with PV systems, the system installer should explain the system and its operation to the inspector. In general, it is beneficial to provide electrical inspectors with drawings and wiring diagrams. An installer should furnish an inspector with a complete set of simple plans in addition to the diagrams that come with the equipment.

4.1 NABCEP Functions

The North American Board of Certified Energy Practitioners (NABCEP) exists to support the renewable energy and energy efficiency industries, professionals, and stakeholders in developing and implementing quality credentialing and certification programs for practitioners.

NABCEP's credentialing program is for solar electric and solar thermal installers who possess the combination of training and experience required to sit for the certification exam. Individuals who pass the exam earn certification as PV or Solar Thermal Installers. NABCEP Certificates are valuable because they ensure that a practitioner's knowledge and skill have been documented and validated in

⁵⁹ See http://www.solarabcs.org/index.php?option=com_content&view=article&id=71-fasterpermitting-&catid=37&Itemid=63

⁶⁰ See http://www.solarabcs.org/index.php?option=com_content&view=article&id=73-highwindloads&catid=37&Itemid=63

a psychometrically defensible independent process. The NABCEP PV Installer Certification is ANSI/ISO/IEC 17024 accredited.⁶¹

It is important to note that NABCEP Certification is not a professional license issued by a government agency, and does not authorize a certificant to practice. NABCEP certificants must comply with all legal requirements related to practice, including licensing laws. The certifications are voluntary and the professionals who choose to become certified demonstrate their competence in the field and their commitment to upholding high standards of ethical and professional practice.

NABCEP also administers an Entry Level PV Knowledge (EL) examination. To pass the EL exam, an individual must demonstrate a basic knowledge of PV systems. Entry-level job seekers often use this exam, and the passing score validation is often used by entry level job seekers to show they have sufficient knowledge to begin a closely supervised job.

⁶¹ Full details of the requirements for NABCEP's Certification Programs can be found at www.nabcep.org.

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Appendix A: List of Acronyms Used

AC: Alternating Current
ANSI: American National Standards Institute
CHP: Combined Heat and Power
CSA: Canadian Standards Association
DC: Direct Current
DG: Distributed Generation
DOE: U.S. Department of Energy
DR: Distributed Resources
DSIRE: Database of State Incentives for Renewables and Efficiency
EERE: U.S. Department of Energy Office of Energy Efficiency and Renewable Energy
EPA 2005: Energy Policy Act of 2005
EPS: Electric Power System
FERC: Federal Energy Regulatory Commission
Hz: Hertz
IEEE: Institute of Electrical and Electronics Engineers
IREC: Interstate Renewable Energy Council
kVA: Kilovolt-Ampere
kW: Kilowatt (1 kW = 1,000 W)
kWh: Kilowatt-Hour
MADRI: Mid-Atlantic Distributed Resources Initiative
MVA: Megavolt-Ampere
MW: Megawatt (1 MW = 1,000 kW)
NABCEP: North American Board of Certified Energy Practitioners
NARUC: National Association of Regulatory Utility Commissioners
NEC: National Electric Code
NEG: Net Excess Generation
NESC: National Electrical Safety Code
NFPA: National Fire Protection Association
NREL: National Renewable Energy Laboratory
NRTL: Nationally Recognized Testing Laboratory
OE: U.S. Department of Energy Office of Electricity Delivery and Energy Reliability
OSHA: U.S. Occupational Safety and Health Administration
PF: Power Factor
PUC: Public Utilities Commission
PURPA: Public Utility Regulatory Policies Act of 1978
PV: Photovoltaic
QF: Qualifying Facility
RPS: Renewable Portfolio Standard
SCC: Standards Coordinating Committee (for the Institute of Electrical and Electronics Engineers)
THD: Total Harmonic Distortion
TOU: Time of Use
UL: Underwriters Laboratories
V: Volt
W: Watt

Appendix B: U.S. DOE's Best Practices for Distributed Generation



March 15, 2007

DISTRIBUTED ENERGY INTERCONNECTION PROCEDURES BEST PRACTICES FOR CONSIDERATION

The U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) and Office of Electricity Delivery and Energy Reliability (OE) recognize the importance of electric utilities adopting procedures for implementing interconnection requirements that allow for simple connection of distributed energy technologies to the electric grid. Promoting distributed interconnection furthers Administration policy of modernizing our nation's electric grid and can be accomplished in a manner that is fair to interconnecting generators, utilities, and ratepayers.

Section 1254 of the Energy Policy Act of 2005 (EPAct) requires each State regulatory authority for its jurisdictional electric utilities (and non-State regulated utilities), to have commenced consideration by August 8, 2006 of whether to require interconnection service to any consumer the utility serves who has on-site generation, and to complete its determination by August 8, 2007. The service is to be based on the Institute of Electrical and Electronics Engineers Standard 1547 for the Interconnecting Distributed Resources with Electric Power Systems. Several States have already established interconnection procedures, while other organizations have developed model procedures.

Although EERE and OE do not endorse the model interconnection procedures of any single external organization, EERE and OE do encourage State and non-State jurisdictional utilities to consider the following "best practices" in establishing interconnection procedures:

- First and foremost, EERE and OE note that EPAct requires that agreements and procedures for interconnection service "shall be just and reasonable, and not unduly discriminatory or preferential." As such, generators and utilities should be treated similarly in terms of State requirements.
- Create simple, transparent (1- or 2-page) interconnection applications for "small generators" (equal to or less than 2 MW), as noted in the FERC Order 2006.
- Standardize and simplify the interconnection agreement for "small generators" and, if possible, combine the agreement with the interconnection application.
- Set minimum response and review times for interconnection applications. Provide expedited procedures for certified interconnection systems that pass technical impact screens.

- Establish small processing fees for “small generators”, otherwise the interconnection request must be accompanied by a deposit that goes toward the cost of the feasibility study, per FERC Order 2006.
- Set liability insurance requirements commensurate with levels typically carried by the respective customer class.
- Require compliance with IEEE 1547 and UL 1741 for safe interconnection.
- Avoid overly burdensome administrative requirements, such as obtaining signatures from local code officials, unless such requirements are standard practice in a jurisdiction for similar electrical work.
- Develop administrative procedures for implementing interconnection requirements on a statewide basis through a rulemaking or other appropriate regulatory mechanism for state-jurisdictional utilities to apply uniformly to all regulated electric distribution companies in the State. Where practical, State interconnection administrative procedures should reflect regional best practices and be comprehensive in scope. Administrative procedures should also be transparent to both small generators and electric distribution utilities.