17. Encourage Clean Distributed Generation

1. Profile

"Distributed generation" (DG) is a widely used term that has been defined and interpreted in significantly different ways across federal, state, and local jurisdictions. For the purposes of this document, we use DG to refer to generating facilities with a rated capacity of 20 megawatts (MW) or less that are interconnected to a distribution system (i.e., not directly connected to transmission lines). Most DG is not owned by the distribution utility, but it is possible that some DG will be partially or fully owned by a utility in some places. Solar photovoltaic (PV) DG systems are prominent today and thus DG is assumed by some to be limited to PV, but the use of the term "DG" in this chapter is intended to encompass all DG technologies that contribute to reducing greenhouse gas (GHG) emissions in the power sector. This definition includes generating systems using PV, wind, biomass, anaerobic digestion, geothermal, fuel cell, and efficient combined heat and power (CHP) technologies.[1,2]

DG investment is on the rise because the cost of DG is declining and the value of DG to the electricity system, consumers, and society is increasing. The cost of DG is declining at different rates for different technologies, and for a variety of reasons. The cost of fuel cells and CHP systems fueled by natural gas has declined because the cost of the fuel itself has declined. Economies of scale and technological advances have reduced the cost and improved the efficiency of most DG technologies in recent years. Public support for clean energy has also created a favorable policy environment at the federal level and in many states that has led to favorable interconnection rules, tax treatments, incentive payments, and tariffs in the places where the respective policies apply. In addition, the value of DG to customers, the electric system, and society is rising because environmental and public health concerns have translated into a consumer preference for clean, distributed energy resources; severe weather events have revealed the value that DG can add to grid security and grid resiliency; and grid modernization is providing opportunities for DG and other customer resources to provide additional energy, capacity, and ancillary service values.

At the same time, DG is encountering headwinds in some states. Some consumer advocates are concerned that Net Energy Metering (NEM) may impose customer cross-subsidies and some utilities are concerned that NEM constitutes a subsidy to PV adopters. The validity of this claim depends on valuation studies being conducted to assess the costs and benefits created by PV adoption. In addition, some utilities allege that DG resources (especially distributed PV systems) impose electric system operational impacts that cause incremental costs. The validity of this claim depends on system studies that investigate high-penetration DG impacts. Both of these assertions are being investigated in a number of states by public utility commissions (PUCs).

The effects of decreasing costs and increasing value have been especially dramatic for PV DG. Over the last six years PV installed capacity in the United States has jumped from 1 gigawatt (GW) to 3 GW as module costs dropped from about \$4 per Watt (W_{DC}) to about \$1/W_{DC} and the installed cost of small systems dropped from about \$9/W_{DC} to about \$5/W_{DC}.[3] Although cost reductions for new installations of other DG technologies have not been as dramatic, some technologies are experiencing significantly improved

1 For the purposes of this document, we exclude consideration of distributed diesel generators, as this technology does not significantly contribute to power sector emissions reductions and may in some cases lead to increased emissions.

2 CHP technologies are discussed in detail in Chapters 2 and 3. In this chapter, references to CHP are limited and focus on smaller, distributed CHP systems.

3 Barbose, G., Darghouth, N., Weaver, S., & Wiser, R. (2013, July). *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012.* LBNL-6340E. Berkeley, CA: Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf.

economics. For example, distributed CHP system operating costs have taken a favorable turn with natural gas prices declining (more than two-thirds of CHP systems in the United States are fueled by natural gas) and the costs of anaerobic digesters and wind turbines have continued to decline.

The policy tools used by federal and state governments to encourage DG have been important to increasing clean DG deployment. The federal government has established favorable investment and production tax credits. Most states have adopted favorable NEM policies and some states have implemented incentive programs for some DG technologies that provide direct incentive payments to adopters. In addition, some states allow clean DG to count toward Renewable Portfolio Standard (RPS) requirements, some states have established Feed-In Tariffs (FITs) and Value of Solar Tariffs (VOSTs) to complement or replace NEM, and some states are broadening the ability of DG resources to participate in energy, capacity, and ancillary service markets. Some states have also passed regulations or laws that allow new business models for delivering DG services such as third-party leasing, on-bill financing, and virtual net metering or community solar programs. Taken together, the suite of policy programs is transitioning clean DG from a technology in which few benefits are formally recognized or compensated toward a future in which the full range of clean DG benefits to the electric system and to society are becoming recognized and compensated.[4]

Clean DG adoption indirectly reduces GHG emissions by reducing the need to dispatch (operate) fossil-fueled generation resources that emit GHG, and by displacing the future need for incremental fossil-fueled generation resources. In addition, clean DG has line loss reduction and reserve requirement reduction benefits that further increase the GHG reduction benefit. As grid modernization takes hold in states, clean DG and other customer resources will be able to provide services that have historically been provided exclusively by fossil fuel generation technologies and thus the GHG reducing potential of clean DG will increase over time.

2. Regulatory Backdrop

Most of the significant regulatory issues associated with DG are issues of energy/economic regulation rather than air pollution/environmental regulation. Both types of regulation are discussed here.

Overview of Energy Regulation

The regulatory framework for clean DG consists of a mix of federal and state energy legislation and regulations, as well as state PUC orders. The topics addressed in this complex framework include state and federal tax provisions and incentive programs, business model policies, interconnection rules, utility tariffs, and utility procurement policies. As explained in Chapter 16, the Federal Energy Regulatory Commission (FERC) has nearly exclusive jurisdiction and fairly broad authority to regulate wholesale electricity transactions in the United States, whereas retail energy transactions are generally the purview of state governments.[5]

Tax Provisions, Incentive Programs, and Business Model Policies

Many state governments and the federal government have provided tax treatments and incentive programs that benefit DG adopters. Financial incentives for clean energy technologies are addressed in Chapter 6 and are not repeated in this chapter, except to underscore that these policies can dramatically alter the costs and benefits, and thus the deployment, of DG.

Some state governments have also developed "business model" policies that affect the interaction between potential DG developers and the incumbent utility. Examples that have had an impact on DG deployment include allowing on-bill financing (i.e., financing of DG systems through the customer's electric bill), allowing customers to lease DG systems from nonutility third parties, and authorizing virtual net metering programs for community solar projects.[6] Each of these business model options has

4 Favorable tax treatment and other financial incentives for clean energy technologies are addressed in Chapter 1, and specifically for CHP in Chapter 3. RPS policies are addressed in Chapter 6. Capacity markets are discussed in Chapter 19.

5 For a more detailed and nuanced discussion of this complicated subject, refer to: The Regulatory Assistance Project. (2011, March). *Electricity Regulation in the US: A Guide*. Available at: http://www.raponline.org/document/download/id/645.

6 Traditional net metering policies are discussed later in this chapter. There is no standard terminology at this time for "virtual net metering" or "community solar." Different terms are used by states for variations on similar (but not always identical) concepts. Generally speaking, the business model we refer to here is one in which the output of a DG system, almost always a PV system, is credited against the electric bills of more than one metered account.

the effect of facilitating financing for DG projects. The "community solar" business model further allows for economies of scale in building DG systems, it allows for optimal siting of DG systems, and it allows customers who can't install a system on their own property to benefit from DG.[7]

Interconnection Rules

Historically, almost all of the components of the electric grid have been designed, installed, and operated by utilities in a very carefully coordinated way to ensure electric reliability. The installation of DG systems introduces a new and unplanned-for complexity. Whereas customers historically were one-way receivers of energy from the grid and their demand for electricity was fairly predictable, we now see two-way flows of electricity to and from customers with DG, and the quantities have become harder to predict. Unless safeguards are in place, the variability and relative unpredictability of power flows to and from DG customers could potentially lead to voltage instability, power flow or reactive power problems, or other challenges to reliable utility service.

Electric utilities are responsible for ensuring that any generating facility connected to the grid will not jeopardize the safety of utility employees or the public and will not impair the reliability of service. To meet that obligation, utilities establish standards and procedures that third parties must satisfy before interconnecting new resources with the grid. The details of those utility standards and procedures must conform to federal and state interconnection regulations.

The FERC has jurisdiction over interconnections to the high-voltage interstate transmission system. States have jurisdiction, usually exercised by the PUC, over interconnections to the lower-voltage utility distribution system. In this chapter, we have defined DG to include only resources that connect to a distribution system, so our discussion of interconnection will be limited to state requirements.[8]

The interconnection standard adopted in most states is based on a version of the Institute of Electrical and Electronics Engineers' (IEEE) standard IEEE 1547 that was updated in 2004. This version of the standard does not address the very specific types of impacts that may result when there are high levels of DG adoption in concentrated areas of the distribution system. This older version focuses on disconnecting PV systems when grid conditions become stressed. Ironically, this approach can exacerbate system reliability problems rather than relieve them. In states like California, where higher levels of DG adoption are occurring, a revised standard is already in effect that addresses these problems.[9] Standard IEEE 1547 is also in the process of being updated (as of July 2014) to reflect the capabilities of new technologies and to address situations that arise in higher DG penetration situations, and it is expected that states will begin adopting the new version of IEEE 1547 later in 2014.[10] Interconnection of very small systems usually does not require the utility to perform a special study of safety and reliability issues, but larger DG systems may have unique local electric system impacts and thus these larger systems are often required to pay for a system impact study. Sometimes the DG investor must incur additional costs necessary to protect the electric system as a condition of interconnecting.

Utility Tariffs

Policies governing the design of tariffs are perhaps the most important aspect of the DG regulatory framework. In the context of electric utilities, a "tariff" is a package of standard rates (prices) and terms of service that is

7 A complete discussion of business model issues specifically for PV can be found at: Bird, L., McLaren, J., Heeter, J., Linvill, C., Shenot, J., Sedano, R., & Migden-Ostrander, J. (2013, November). *Regulatory Considerations Associated With the Expanded Adoption of Distributed Solar.* National Renewable Energy Laboratory and The Regulatory Assistance Project. NREL/TP-6A20-60613. Available at: http://www.raponline.org/document/download/id/6891.

8 Although excluded from our discussion of DG, it is worth noting that the FERC has promulgated Small Generator Interconnection Procedures and a Small Generator Interconnection Agreement that govern the interconnection of generators with a rated capacity of less than 20 MW directly to the high-voltage interstate transmission system.

9 In California this standard is called Rule 21.

10 One aspect of interconnection that is being updated is the specifications for inverters that convert Direct Current (DC) power from the DG unit into Alternating Current (AC) power that is used on the grid. Revised standards will take intelligent inverters into account. Intelligent inverters allow the system operator to monitor the DG system's power production and allow the electricity from the DG unit to be controlled more flexibly.

applicable to a defined group of customers.[11] Customers who install a DG system will generally require a special kind of tariff to account for the fact that the customer is generating electricity and not merely purchasing electricity. As a practical matter, the terms of these tariffs can either encourage or discourage the deployment of DG. The regulatory structure governing tariffs consists of both federal and state requirements.

In most cases, electric utilities are required by federal law to provide service to customers who choose to install DG. Pursuant to rules authorized by the Public Utility Regulatory Policy Act of 1978 (PURPA) and promulgated by FERC, utilities must offer to sell electric energy to and purchase electric energy from "qualifying small power production facilities" and "qualifying cogeneration facilities" at rates that are just and reasonable to the utility's customers and in the public interest, and non-discriminatory toward qualifying facilities (QFs). With respect to this "purchase obligation," regulators may not require utilities to offer to purchase energy at rates in excess of the utility's "avoided costs" (i.e., "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the QF or QFs, such utility would generate itself or purchase from another source").[12]

There are some instances in which utilities do not have to meet this federal purchase obligation. This happens if a small power production facility or cogeneration facility has nondiscriminatory access to wholesale markets for the sale of electric energy and capacity. The FERC's current rules establish a rebuttable presumption that facilities with a rated capacity of 20 MW or less do not have nondiscriminatory access to markets, and a rebuttable presumption that facilities greater than 20-MW capacity do have nondiscriminatory access in five of the seven US wholesale electricity markets: the Midcontinent ISO, PJM Interconnection, New York ISO, ISO New England, and Electric Reliability Council of Texas.[13,14] Furthermore, FERC rules require each utility to offer standard rates for purchases from all QFs with a design capacity of 100 kilowatts (kW) or less.[15] The FERC gives utilities discretion on whether to offer standard rates or to individually negotiate rates for purchases from QFs larger than 100-kW capacity, but state laws and regulations may further limit that discretion. These federal requirements are summarized in Table 17-1.

In summary, utilities have an obligation in almost all

Table 17-1

Summary of Utility Purchase Obligation Under PURPA and FERC Rules

Rated Capacity of QF Generator	Location of QF Generator	Utility Purchase Obligation?
≤100 kW	Any	Yes, at standard rates
100 kW to 20 MW	Any	Yes (rebuttable by utility), but not necessarily at standard rates
>20 MW	Midcontinent ISO PJM New York ISO ISO New England Electric Reliability Council of Texas	No (rebuttable by QF)
	Everywhere else	Yes, but not necessarily at standard rates

11 In jurisdictions that allow for competition in the provision of retail electric services, contracts between a non-utility provider and its customers are also relevant to this discussion. For simplicity, the remainder of this chapter uses "tariffs" to refer to either a tariff or a similar contractual arrangement for electric services.

12 The question of how to interpret and calculate avoided costs is a contentious one and is beyond the scope of this document.

13 A rebuttable presumption is an assertion that is presumed by the FERC to be true unless and until a party comes forward to prove it is not true. The burden of proof falls on the party asking the FERC to override the presumption. The FERC's rationale for these two rebuttable presumptions is explained in Order No. 688 (Docket No. RM06-10-000). The 20-MW dividing point in FERC rules is the primary reason this chapter limits the term "distributed generation" to generating facilities with a rated capacity of 20 MW or less.

14 For a map showing the territories served by these markets, refer to the ISO/RTO Council at http://www.isorto.org/Images/IRCmap.png.

15 The FERC rules for small power production facilities are codified at 18 C.F.R. §§CFR 292.

cases to offer to purchase energy from DG systems. For the smallest DG systems, including almost all residential and commercial customer PV systems, utilities must offer standard rates for purchasing energy from the customer. However, federal law and regulations leave ample discretion to states and utilities on the details of how they will fulfill the PURPA purchase obligation. The issues that states and utilities grapple with are not whether utilities should have to buy energy from DG systems, but under what terms and at what prices.

In practice, customers who own QFs generally have three options for selling the energy or excess energy that they generate:

- Accept an *ex ante* administratively determined tariff or standard offer contract offered by the customer's utility. (For the reader's convenience, we consider standard offer contracts to be a type of tariff.) The customer accepts a standard price (which may be fixed or variable) and other standard terms previously established by the utility that are identically applicable to all similarly situated customers who choose to accept the tariff.
- Enter into a Power Purchase Agreement with a utility or wholesale electricity trader. Some of the terms of the agreement may be predetermined by regulators, whereas others, including the price, are negotiated between the buyer and seller on a case-by-case basis.
- Sell directly into an organized wholesale electricity market, if located where such a market exists. The price the generator receives will be determined by market forces and will vary over time and place based on market supply and demand conditions.

The second and third options listed above are not generally realistic choices for owners of DG systems, so the remainder of this discussion focuses on common ways of implementing the first option.

- **NEM Tariffs –** A NEM tariff bills the customer, or provides a credit to the customer, based on the net amount of electricity consumed during each billing period (i.e., the kilowatt-hour [kWh] difference between electricity consumed and electricity produced). Provisions are made for periods in which the net amount consumed is negative (production exceeds consumption). NEM does not require separate metering of consumption and production. NEM is also referred to more simply as "net metering." NEM is being challenged by consumer advocates and utilities in some states based on the assertion that the value of DG to the electricity system is less than the compensation that NEM adopters receive, thus constituting a cross-subsidy from non-adopters to adopters. A number of state PUCs are testing this assertion. Determining whether PV adopters are undercompensated or overcompensated requires a comprehensive valuation study that takes all relevant sources of cost and benefit into account.
- **Standard Offer Contracts –** A standard offer contract or tariff pays the customer for all of the electricity he or she generates under terms that are different from the customer's tariff for purchasing energy. This kind of tariff requires separate metering of consumption and production. If the price the utility pays the customer is set at or below the utility's avoided costs of procuring energy and capacity from unspecified (or least-cost) resources,[16] the tariff will satisfy PURPA requirements and might be considered a "PURPA tariff." But some states and utilities have established special tariffs for specified sources like renewable DG systems. These special tariffs come in several forms, with the FIT being the most recognizable, and more recently a variation on standard offer contracts called a VOST. The state experiences with FITs and VOSTs are discussed later in this chapter.

Utility Procurement Policies

As noted in Chapter 16, some states have adopted procurement policies that require regulated utilities to procure specified amounts of electricity specifically from DG resources as part of a broader RPS. These RPS "carve out" or "set aside" policies have a fairly direct impact on DG deployment because they create a differentiated market for electricity from DG.

16 Various states have interpreted the term "avoided cost" differently in PURPA implementation, with some states setting standard offer contracts based on short-run avoided cost and some based on long-run avoided cost. Short-run avoided cost implies the PURPA qualifying resource is not displacing utility generation in the long term, and thus it should only be paid for providing short-term energy. States adopting long-run avoided cost compensation are asserting that the PURPA resource will displace or defer a future generation addition.

Air Pollution Regulations

As noted in Chapter 6, some of the "clean" generating technologies (e.g., PV and wind) do not emit any air pollution and are not directly subject to air pollution regulations. Other technologies, including some that are applicable to DG, are considered clean because they emit fewer GHGs, but they do emit other air pollutants and may be subject to emissions limits and control requirements, as well as permitting, monitoring, recordkeeping, and reporting obligations. These topics are covered in a general way in Chapter 6 and need not be repeated here. It is worth noting, however, that because DG systems are smaller in size than utility-scale systems, they will generally have lower annual emissions (although potentially higher instantaneous or hourly emissions rates), and they are more likely to be exempt from air pollution regulations.

Chapter 6 also notes that in the Clean Power Plan proposed by the Environmental Protection Agency (EPA) in June 2014 (a.k.a. the proposed "111(d) rule," because it is based on authority under Section 111(d) of the Clean Air Act), the EPA proposed GHG emissions guidelines with emissions rate performance goals for each state that are based on assumed levels of zero-emissions resource deployment. When determining compliance with the goals, states will be allowed to add megawatt hours (MWh) of generation from zero-emissions resources to the MWh of generation from affected sources to get an "adjusted" carbon dioxide emissions rate in pounds per MWh. This formula for compliance determinations has ramifications for DG, specifically, because the output of small DG systems is not always metered. If states wish to include the output from non-metered DG systems in their plans for compliance with the performance goals, they will need to develop a method for estimating or calculating the MWh of output that can meet the EPA's standards for approvable plans. A number of states received American Recovery and Reinvestment Act funding to deploy advanced metering and some additional states with higher levels of PV adoption are implementing advanced metering requirements. In these states the metering of small systems will become routine. In states without advanced metering, statistical approaches can be proposed or air directors might collaborate with PUC officials to consider advanced metering requirements. Alternatively, the EPA could address the issue of non-metered DG in the final rule and relieve states of this burden.

3. State and Local Implementation Experiences

As noted in the previous section, states vary considerably in the policies they have adopted with respect to business models, interconnection, tariffs, and utility procurement policies for DG. The state experiences with these policies are summarized in the sections below and in Figures 17-1 through 17-7, along with the impact that some of these policy choices appear to have had on DG deployment.

Business Model Policies

Most public utilities operate as state-authorized monopolies within a designated service territory. In areas of the country that have not implemented retail competition, this means that the laws preclude other parties from selling power directly to customers. States are finding that they can accelerate the deployment of DG, especially PV systems, by authorizing new business models that allow third parties to install DG systems on customers' premises for the customers' benefit. This helps projects get financed, lowers installation costs, and expands opportunities to more customers. States vary in whether they allow this kind of third-party arrangement, as shown in Figure 17-1. Some states welcome third-party ownership (TPO), some effectively preclude it, and most states are somewhere in between with no explicit law or policy that encourages or precludes TPO. In the states authorizing TPO, air regulators can expect to see higher DG penetration levels, all else being equal. In the states without an explicit policy, air regulators will have to work with PUCs and legislatures to address ambiguities of TPO if they want to use TPO of DG as part of a GHG reduction or state 111(d) compliance plan.

In recent years, TPO of residential PV systems has become the norm in the states that have the highest levels of PV deployment. Examples of this phenomenon are indicated in Figure 17-2 for four states: Arizona, California, Colorado, and Massachusetts. These states ranked second, first, eighth, and sixth, respectively, at the end of 2013 in total installed PV capacity, suggesting that TPO can be a significant accelerator of deployment.[17]

17 GTM Research. (2013). *US Solar Market Insight Report: Q3 2013.* Produced for Solar Energy Industries Association. Available at: http://seia.us/1nnAjVq.

Figure 17-1

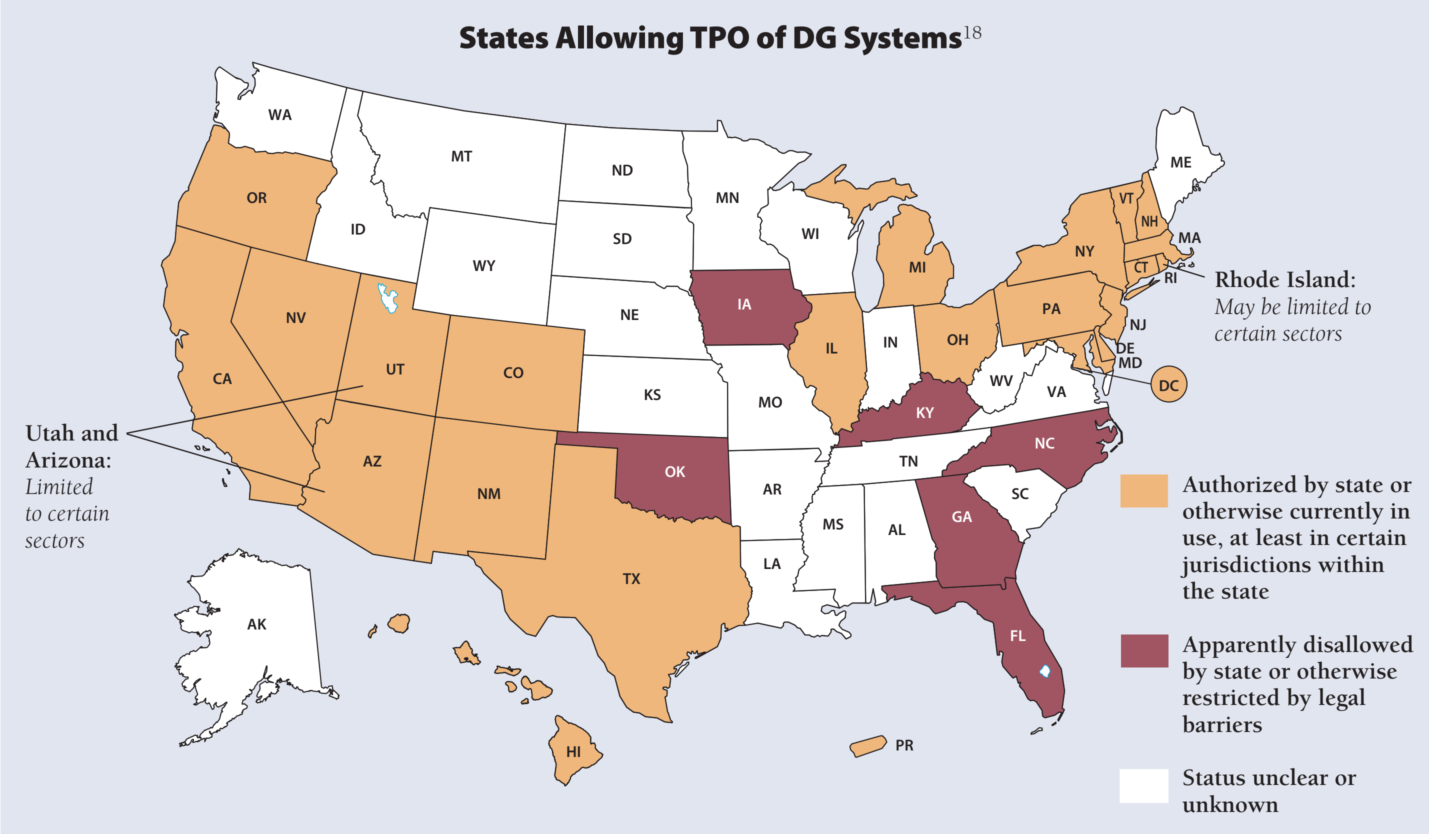
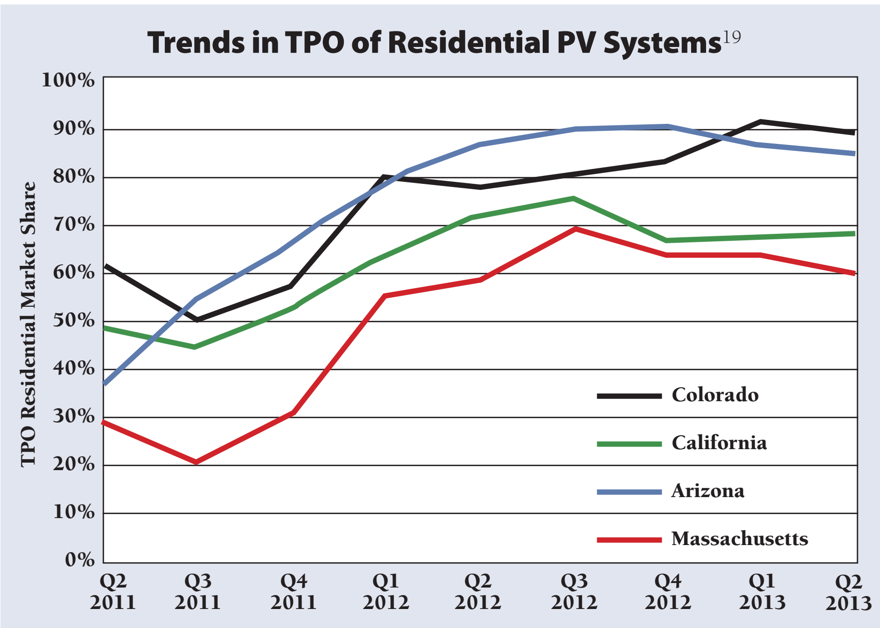


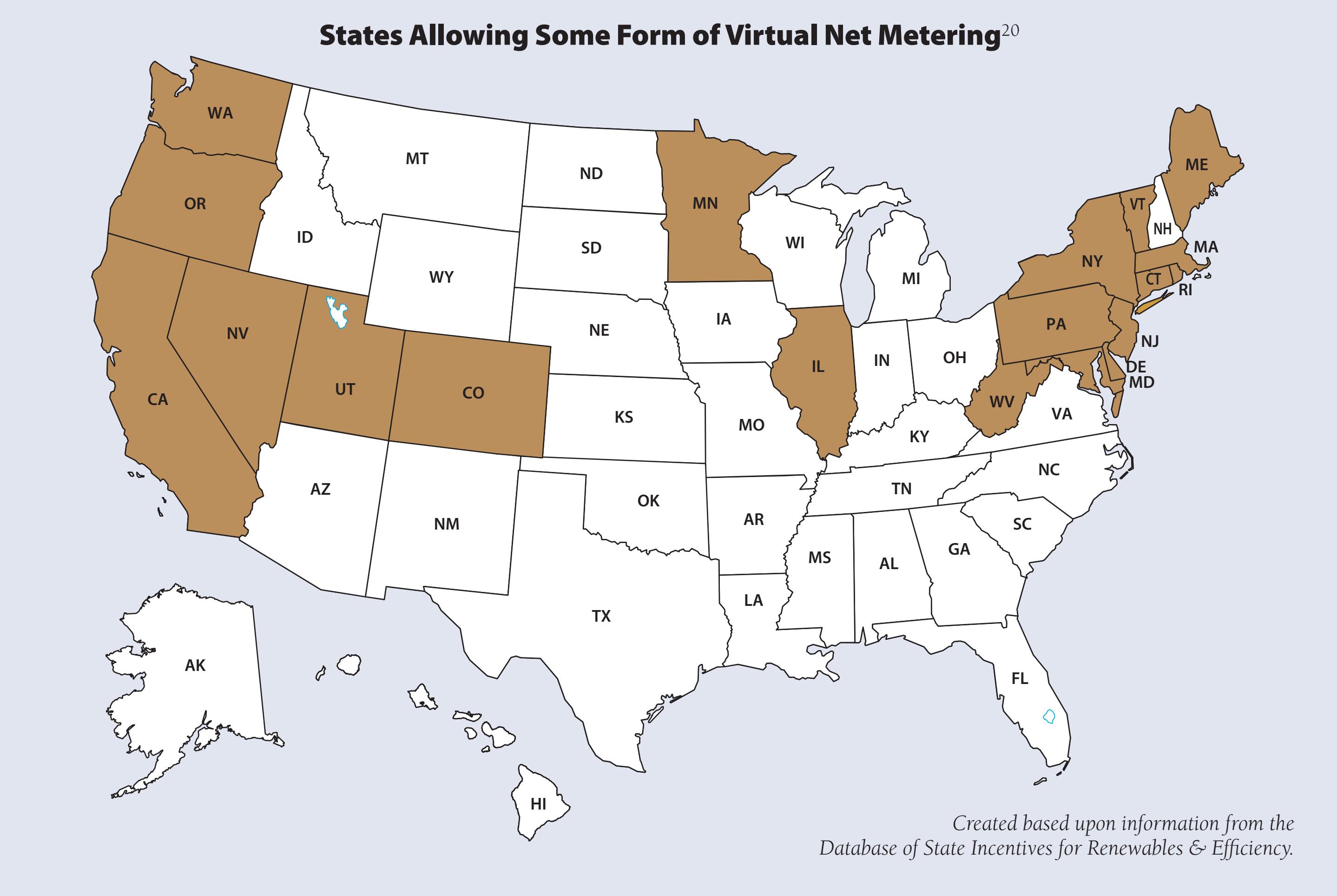
Figure 17-2



18 Based on data from: North Carolina State University. (2014). *Database of State Incentives for Renewables & Efficiency (DSIRE)*. Available at: www.dsireusa.org.

19 Solar Energy Industry Association. (2013). *Market Insight Report, Quarter 2, 2013.* Available at: http://www.seia.org/research-resources/solar-market-insight-report-2014-q2

Figure 17-3



Another business model option that makes DG more affordable and practical for customers is to allow virtual net metering (a.k.a. community solar, group net metering, or solar gardens). This option essentially allows customers to "buy a share" of a DG system, and then apply their share of the system output to their electric bill just as a net-metered customer who has an onsite DG system would. The states that have authorized some form of virtual net metering or community solar policy are indicated in Figure 17-3.

Interconnection

Forty-three states have adopted standard interconnection rules for DG systems. As noted earlier, these state interconnection policies are typically based on IEEE Rule 1547, but the size of the DG system covered by those policies varies, as summarized in Figure 17-4. Where state interconnection rules do not exist or where utility responsiveness to interconnection requests is nonexistent or excessively slow, the DG investor has more uncertainty about what it will take to get interconnection approval from their utility, and that uncertainty can delay projects or add to project costs. Improvements to state interconnection policies can thus play a role in supporting increased levels of clean DG deployment. Policies in Oregon, Virginia, Connecticut, Maine, and Massachusetts have been cited by at least one source as representing current best practices among the states.[21]

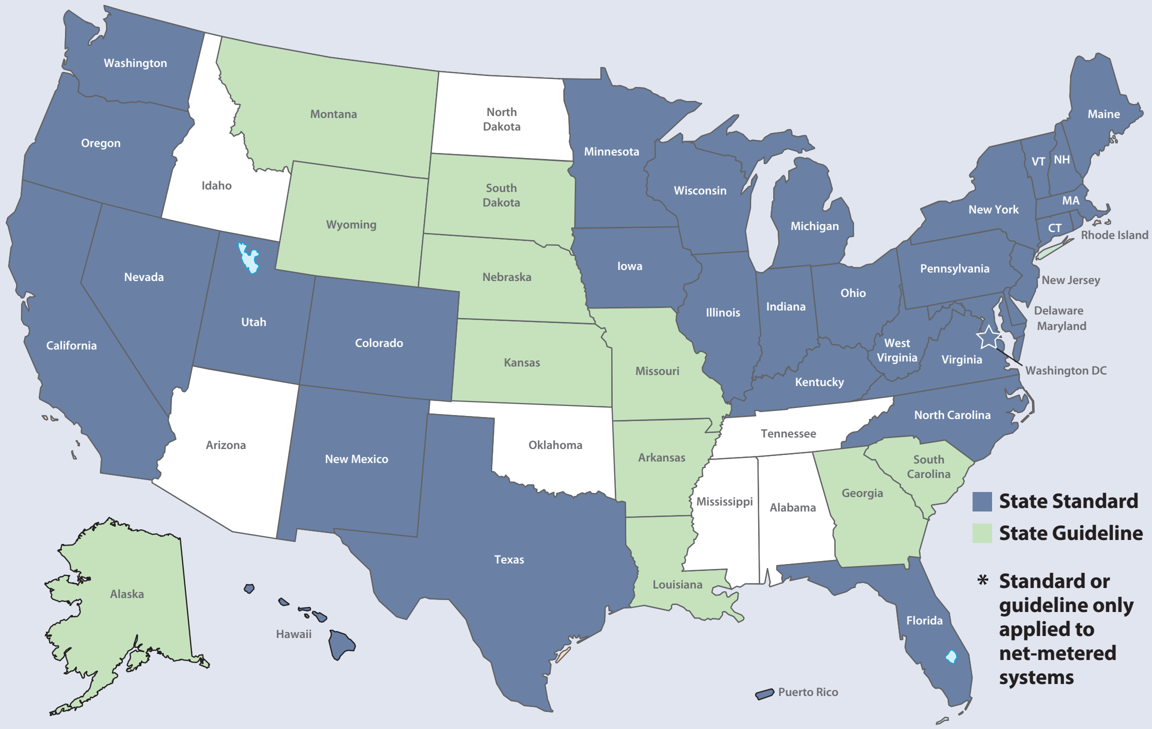
20 Linvill, C., Shenot, J., & Lazar, J. (2013, November). *Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6898.

21 Sheaffer, P. (2011, September). *Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues.* Montpelier, VT: The Regulatory Assistance Project, page 7. Available at: http://www.raponline.org/document/download/id/4572.

Figure 17-4

States With Interconnection Standards or Guidelines[22]

43 states plus Washington DC and Puerto Rico have adopted an interconnection policy.



Alaska: 25 kW*
Arkansas: 25/300 kW*
California: No limit
Colorado: 10,000 kW
Connecticut: 20,000 kW
Delaware: 20,000 kW*
Florida: 2,000 kW*
Georgia: 10/100 kW*
Hawaii: No limit
Illinois: No limit
Indiana: No limit
Iowa: 10,000 kW
Kansas: 25/200 kW*
Kentucky: 30 kW*
Louisiana: 25/300 kW*
Maine: No limit
Maryland: 10,000 kW
Massachusetts: No limit
Michigan: No limit
Minnesota: 10,000 kW
Missouri: 100 kW*
Montana: 10,000 kW
Nebraska: 25 kW*
Nevada: 20,000 kW
New Hampshire: 1,000 kW
New Jersey: No limit
New Mexico: 80,000 kW
New York: 2,000 kW
North Carolina: No limit
Ohio: 20,000 kW
Oregon: 10,000 kW
Pennsylvania: 5,000 kW*

Notes: Numbers indicate system capacity limit in kW. Some states limits vary by customer type (e.g., residential versus non-residential) "No limit" means that there is no stated maximum size for individual systems. Other limits may apply. Generally, state interconnection standards apply only to investor-owned utilities.

Rhode Island: No limit
South Carolina: 20/100 kW
South Dakota: 10,000 kW
Texas: 10,000 kW
Utah: 20,000 kW
Vermont: No limit
Virginia: 20,000 kW
Washington: 20,000 kW
Washington DC: 10,000 kW
West Virginia: 2,000 kW
Wisconsin: 15,000 kW
Wyoming: 25 kW*
US Territories:
Puerto Rico: No limit

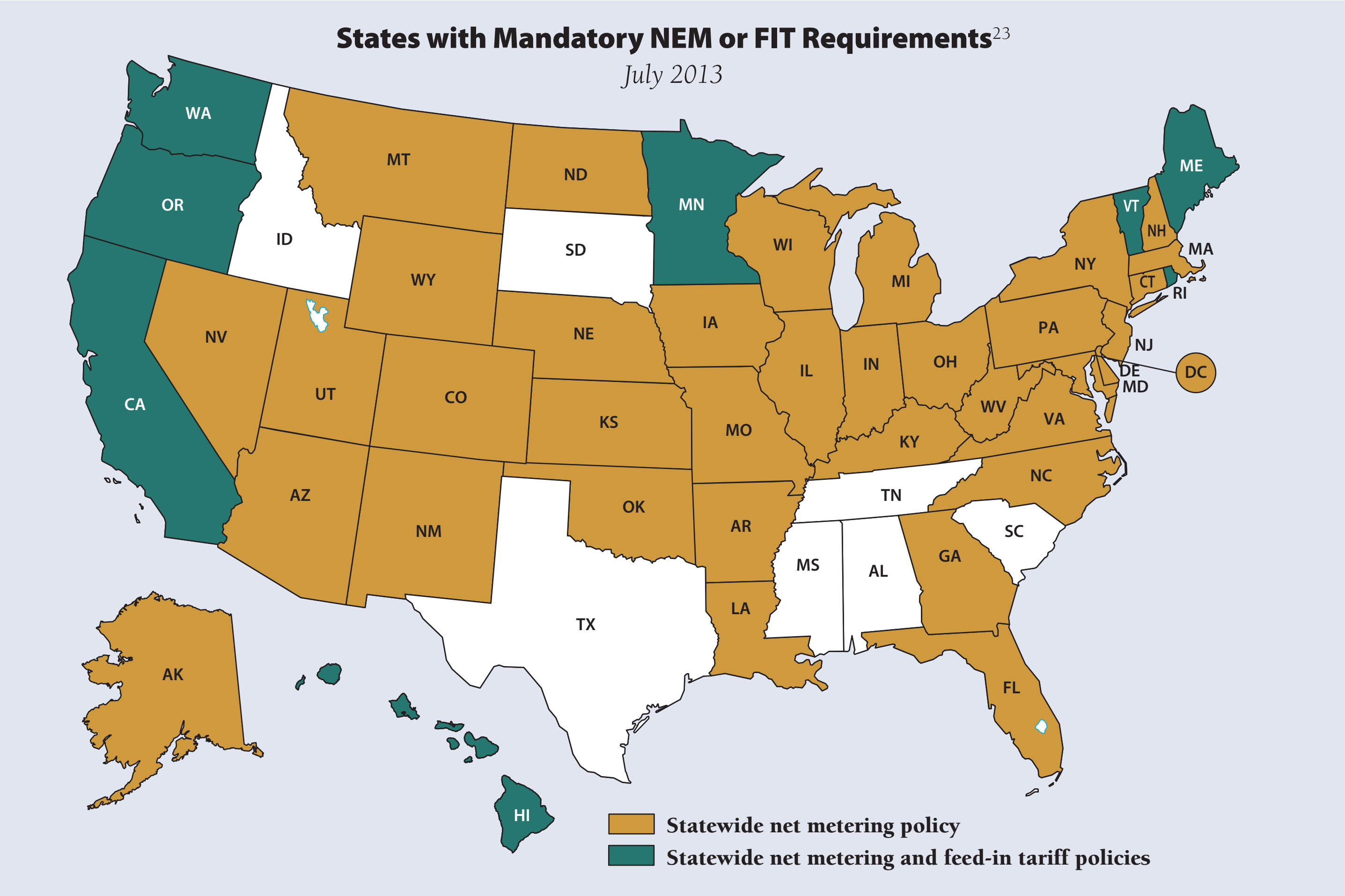
Utility Tariffs

Most states have adopted a policy requiring utilities to offer NEM tariffs for customers who have DG, as shown in Figure 17-5. The figure also indicates that relatively few states have adopted policies requiring utilities to offer FITs. What is not obvious from the figure is that there is considerable variation in these state policies on a number of key tariff design issues that influence the deployment of DG. To be more specific, these state policies vary in terms of whether they cover some or all types and sizes of utilities; the types and sizes of generating systems that are eligible for the tariff; the maximum amount of generating capacity that utilities must enroll under the tariffs; and the basis for rates and compensation. With respect to NEM tariffs, the key variable for rates and compensation is the treatment of net excess generation (i.e., what happens when the customer generates more electricity than he/she consumes during a billing period). For FITs, the key variable is the price paid to the customer for each kWh of generation.

There is little doubt that NEM tariffs in particular are a driving force for the deployment of DG in the United

22 North Carolina State University. (2014). *Database of State Incentives for Renewables & Efficiency (DSIRE)*. Available at: www.dsireusa.org.

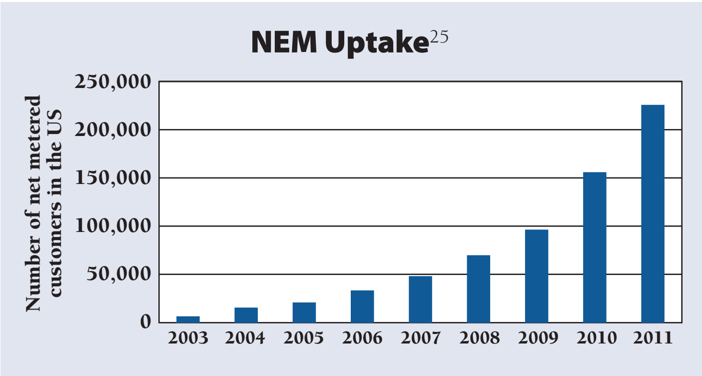
Figure 17-5



States. Figure 17-6 summarizes the number of customers enrolled under NEM tariffs. In 2003, fewer than 7000 customers in the entire country were net metered. In 2005, the federal Energy Policy Act of 2005 created a new requirement for states to formally consider (but not necessarily adopt) NEM tariffs. Less than ten years later, the number of net-metered customers had grown to more than 225,000, a thirtyfold increase. In terms of capacity, the same data show that 2688 MW of generating capacity was enrolled in NEM tariffs at the end of 2011.[24]

NEM tariffs have been especially popular as an option for customers owning PV systems. The US Energy Information Administration found that 97 percent of the customers under NEM tariffs in 2011 had PV systems, representing 93 percent of the total net-metered capacity. Furthermore, the Solar Electric Power Association estimates that as of the end of 2012, 99 percent of installed PV systems in the United States were on NEM tariffs, totaling approximately 3.5 GW

Figure 17-6



23 Supra footnote 20. Information in the figure was compiled by the authors from DSIRE data: North Carolina State University. (2014). *Database of State Incentives for Renewables & Efficiency (DSIRE)*. Available at: www.dsireusa.org.

24 These data are from US Energy Information Administration statistics. Available at: http://www.eia.gov/.

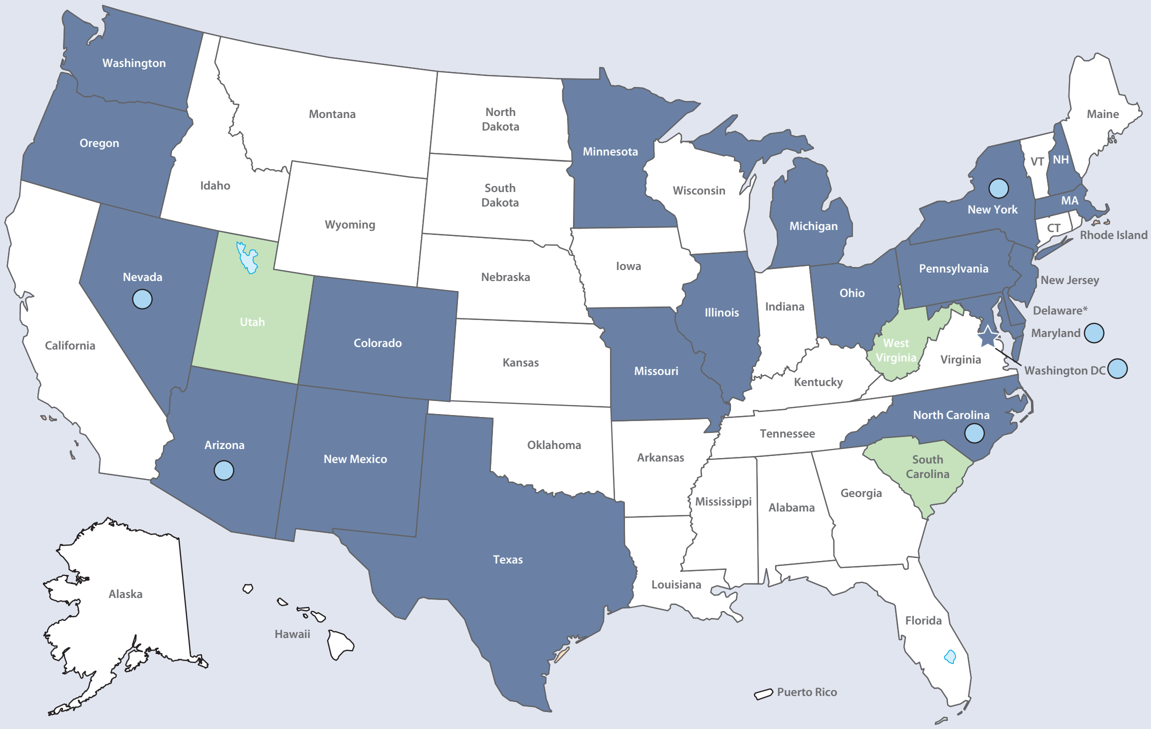
25 Supra footnote 20. Information in the figure was compiled by the authors from data published by the US Energy Information Administration (2013).

Figure 17-7

States With Solar or DG Provisions in Their RPS Policies[28]

23 states plus Washington DC have a renewable portfolio standard with solar or distributed generation provisions.

Arizona: 4.5% DG by 2025.
Colorado: 3.0% DG by 2020. 1.5% customer-sited by 2020, various multipliers
Delaware: 3.5% PV by 2026; 3.0 multiplier for PV*
Illinois: 1.5% PV by 2026. 0.25% DG by 2026
Maryland: 2% solar by 2020
Massachusetts: 400 MW PV by 2020
Michigan: 3.2+ multiplier for solar-electric
Minnesota: 1.5% solar by 2020. 0.15% PV DG by 2020
Missouri: 0.3% solar-electric by 2021
Nevada: 1.5% solar by 2025; 2.4+ multiplier for PV
New Hampshire: 0.3% solar-electric by 2014
New Jersey: 4.1% solar-electric by 2028
New Mexico: 4% solar-electric by 2020. 0.6% DG by 2020
New York: 0.58% customer-sited by 2015
North Carolina: 0.2% solar by 2018
Ohio: 0.5% solar-electric by 2026
Oregon: 20 MW solar PV by 2020; 2.0 multiplier for PV
Pennsylvania: 0.5% PV by 2021



Renewable portfolio standard with solar/distributed generation (DG) provision
Renewable portfolio goal with solar/DG provision
Standard or guideline only applied to net-metered systems

* *Delaware allows certain fuel cell systems to qualify for the PV carve-out*

South Carolina: 0.25% DG by 2021
Texas: 2.0 multiplier for non-wind (non-wind goal: 500 MW by 2015)
Utah: 2.4 multiplier for solar-electric
Washington: 2.0 multiplier for DG
Washington DC: 2.5% solar by 2023
West Virginia: Various multipliers

of capacity.[26] This suggests that more than 1 MW of new PV systems enrolled in NEM tariffs in 2012 alone.

There are fewer examples of FIT policies and consequently fewer data available on the impact of those policies. Anecdotal evidence suggests that the uptake of FITs is strongly dependent on the price paid for customer-generated electricity; different prices are necessary to encourage deployment of different types of DG resources; and uptake of FITs can be rapid when the prices are set high enough to attract investment.[27]

One important innovation in utility tariffs for DG is the VOST. The VOST concept borrows from both NEM tariffs and FITs. It was first introduced by Austin Energy in 2012. It sets the compensation for solar energy produced by DG systems at the value that the energy provides to the utility system. The utility customer buys all of its energy from the utility under a regular tariff, but the customer's bill is then credited with the value of solar produced and exported to the grid. It is like a FIT in that the customer sees a specified price for generation and pays a standard rate for consumption, but it is like a NEM tariff in that the customer's bill is credited for the value of generation. (The customer isn't actually paid for generation.) Several

26 For more information, refer to http://www.solarelectricpower.org/media/51303/sepa-top-10-executive-summary_final-v2.pdf.

27 Supra footnote 20. Information in the figure was compiled by the authors from data published by the US Energy Information Administration (2013).

28 Supra footnote 22.

other states are examining a VOST approach. Most notably, Minnesota recently adopted a VOST that utilities can propose as an alternative to offering NEM tariffs.

Utility Procurement Policies

Another category of support for DG can be found in the inclusion of carve-outs or set-asides for DG within state RPS programs. Figure 17-7 shows how DG is or is not allowed to participate in RPS programs around the country. Inclusion of clean DG in RPS or other clean energy standards is thus another tool in the 111(d) implementation tool kit.

The state of New Jersey offers one example of the significance of having a solar carve-out in a state RPS policy. As Figure 17-7 indicates, New Jersey has one of the most ambitious solar/DG provisions of any state. New Jersey was also one of the first states to adopt this policy approach. Over time, the RPS policy has been a strong driver for distributed PV deployment, and as a result New Jersey ranked third among the states in total installed PV capacity at the end of 2013.[29]

4. GHG Emissions Reductions

The inherent potential of clean energy *technologies* to reduce GHG emissions is addressed in detail in Chapter 6 and need not be repeated here. But DG systems differ from utility-scale, central station generation in one important respect that affects GHG emissions. Because DG systems produce electricity closer to where it is consumed, far less electricity is lost (or none is lost at all) in the transmission and distribution system than occurs when central station generation is delivered to customers. To the extent that the central station generators emit GHGs, reduced line losses equate to reduced emissions. In this way, a kWh of DG can reduce the GHG emissions associated with greater than 1 kWh of system-supplied electricity.[30]

5. Co-Benefits

The co-benefits associated with clean energy technologies, including solar and wind energy, are detailed in Chapter 6. Here we only note some of the co-benefits that are unique to clean DG, or significantly different for DG than for utility-scale installations.

The two most significant differences with DG (compared to utility-scale investment in clean energy) are that the generation is sited coincident with customer load (in nearly all cases), and the customer invests all or most of the capital to build a resource that provides system benefits. The significance of the first point is that DG, by generating electricity where it is used, reduces the amount of electricity that is unavoidably lost in the electric transmission and distribution system. The significance of the second point is that customers usually only invest in DG when it makes economic sense for them to do so, and this guarantees that the participating customer benefits from DG in ways that it might not benefit from utility-scale investments in clean technologies. For example, the customer investing in DG will expect its energy bills to decrease, whereas bills may or may not decrease as a result of utility-scale investment in the same technologies.

Clean DG is sometimes compared to energy efficiency because both are customer-focused, customer-driven, voluntary options, and they possess many of the same potential benefits. Although some of the co-benefits of efficiency are not applicable to clean DG, other co-benefits are arguably greater for clean DG than for efficiency. For example, some sources of clean DG have a greater potential to provide electric system services that protect the reliability, resiliency, and security of the grid.

The full range of co-benefits that can be realized by encouraging or incentivizing clean DG is summarized in Table 17-2.

29 Supra footnote 17.

30 Although most of the benefit of DG comes from displacing utility-scale fossil-fueled generation with inherently lower-emitting forms of generation, it is possible that in some cases well-placed fossil-fueled DG could produce some emissions reduction benefits by virtue of avoided line losses. Clean DG would, of course, provide far more emissions reduction benefit than fossil-fueled DG, all else being equal.

Table 17-2

Types of Co-Benefits Potentially Associated With Clean DG	
Type of Co-Benefit	**Provided by This Policy or Technology?**
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Maybe
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	Yes
Avoidance of Uncollectible Bills for Utilities	Yes
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Maybe – DG may allow utilities to avoid infrastructure investments, but at high penetration levels additional investments in infrastructure may be necessary to manage variable generation and power flows
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes – interconnection rules are designed to prevent DG from compromising reliability, but in some ways DG can enhance reliability
Displacement of Renewable Resource Obligation	Yes
Reduced Credit and Collection Costs	Yes
Price Suppression Effect	Yes
Other	

6. Costs and Cost-Effectiveness

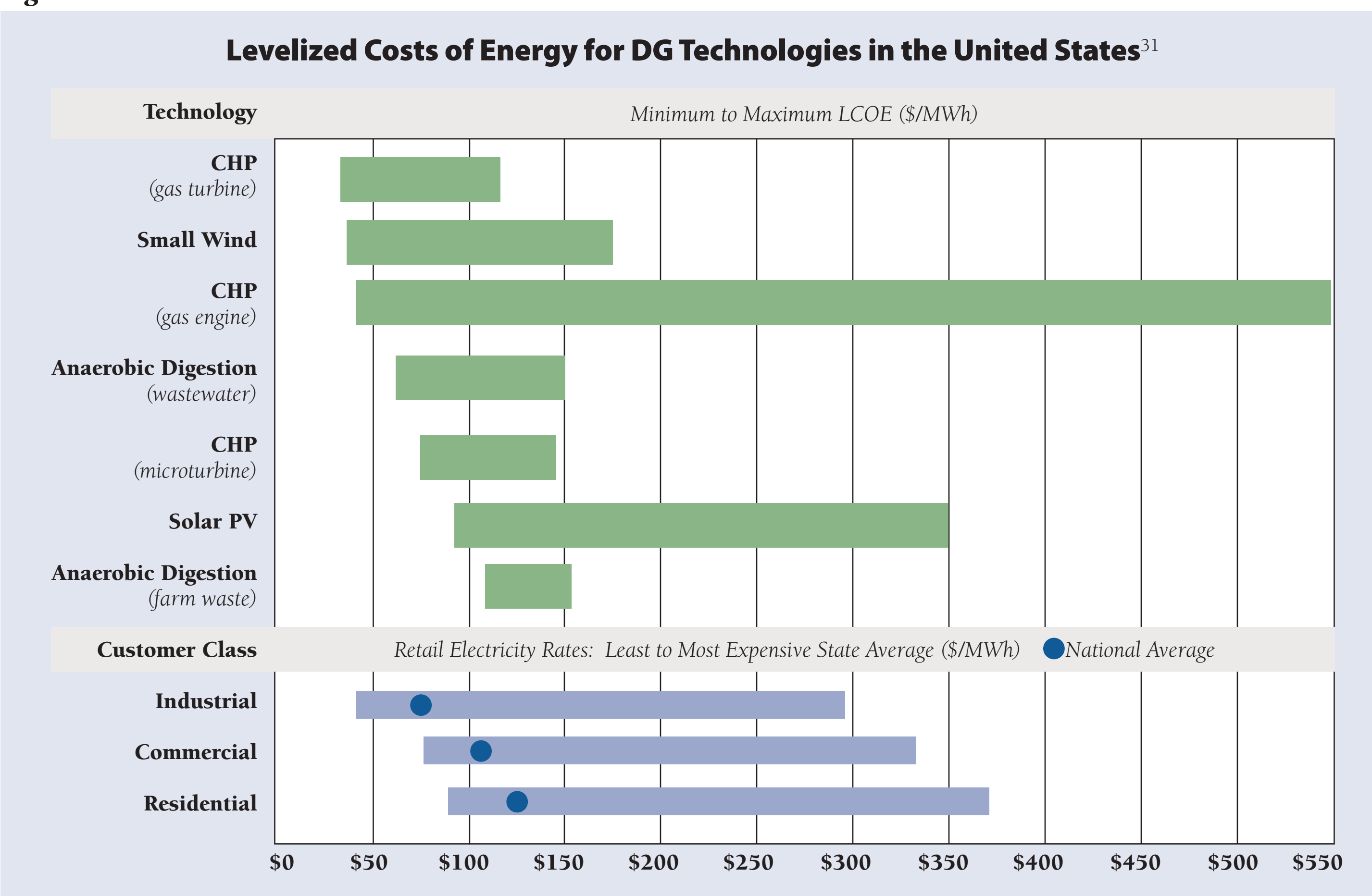
As explained in Chapter 6, the concept of levelized costs of electricity (LCOE) was created to facilitate comparisons of the costs of different electric generation technologies. LCOE reflects the average cost of producing each unit of electricity over the life of a typical generator. LCOE estimates include consideration of all costs (including capital, financing, operations and maintenance, and fuel costs) and the amount of electricity produced from a particular type of generation.

When utility-scale investments are made by electric utilities or independent power producers, LCOE data can be useful for evaluating generating technologies to get the best value out of limited capital. The investing entity will compare the costs of different technologies to each other, and to expected wholesale power prices, before deciding whether an investment could be a good choice for consumers (in the case of a utility) or profitable (in the case of an independent power producer).

When DG investments are made by customers, LCOE values can be different than for utility-scale investments in the same technologies, and the values can have a different significance. When customers invest in DG, they don't compare the LCOE of all of the different technologies to wholesale prices. Instead, they compare the LCOE of their realistic DG options (in some cases, solar PV being the only realistic option) to their expected costs as a retail electricity customer. In other words, the customer wants to know if generating electricity will save them money compared to buying power at retail rates.

Figure 17-8 shows the LCOE for selected DG technologies as compared with retail electricity rates. The chart indicates that some forms of clean DG are currently competitive with national average retail rates, especially for the more expensive residential customer rates. And all of the selected

Figure 17-8



31 Supra footnote 20. LCOE data in the figure are based on: Bloomberg New Energy Finance. (2013, August). *Small Distributed Power Generation in the United States – Is It Competitive?* (Subscription required). Retail rates data were compiled by the authors from data published by the US Energy Information Administration (2013).

DG technologies can be competitive with retail rates in the right circumstances – wherever the LCOE (which can vary based on geography and other factors) is less than the retail rate (which varies geographically and by customer class).

It is also interesting to compare the LCOE data presented here in Figure 17-8 to the LCOE data included in Figure 6-7 in Chapter 6. The comparison is imprecise because the studies were conducted with different assumptions, but the comparison does convey the general notion that some clean DG technologies appear to be cost-effective even when compared to utility-scale investments in fossil and renewable generating technologies. In making these comparisons, one should remember that the value of clean DG includes some avoided cost benefits (e.g., deferred transmission investment) that can be significantly different or nonexistent for utility-scale investments in generation capacity. It is equally important to recognize that the cost and value of DG vary by location and so it is not accurate to say that all clean local DG adds incremental value relative to utility-scale, central station generation.

7. Other Considerations

Like energy efficiency, DG leads to reduced retail electricity sales. Concerns are sometimes raised that this in turn creates the need for an increase in retail electric rates to ensure stable revenues for utilities. For clean DG adopting customers, any increase in rates needs to be evaluated in light of the net reduction in the participants' electricity bill. For non-adopting customers, any possible rate increase arising from reduced revenues needs to be evaluated in the context of a comprehensive study of sources of cost and value for DG. For example, can the cumulative effects of DG avoid or significantly delay capital investments in the power grid that would have been paid for by customers, including customers without DG? The Rocky Mountain Institute examined how the sources of cost and value have been computed for solar PV systems in 15 recent studies.[32] These studies indicate that accounting for the utility's "lost revenues" is one of a number of impacts that can affect the calculation of benefits and costs of PV DG to non-adopting customers. The studies indicate that the results are dependent on the terms of DG tariffs, and that one cannot make a universal statement that increasing DG penetrations either hurt or benefit nonparticipating customers. Similar conclusions were reached by Keyes and Rábago in a separate publication.[33] But even in those situations in which nonparticipating customers may be harmed, tariffs can be amended to ensure that participants, nonparticipants, and utility shareholders can pay for and be compensated fairly for the services they receive or provide to others.[34]

Clean DG that is targeted to meet temporal or geographic needs of the electric system can be highly cost effective, even as DG penetration increases. So programs that can target clean DG deployment to provide energy at high-cost times, receive energy at low-cost times, and provide energy services locationally to meet reliability challenges (like local frequency support or reactive power) should be considered. The ability of DG to provide these high-value services will be enhanced as the electric grid modernizes and smart inverters and bidirectional flow meters become standard. These grid enhancements increase the "visibility" of customer generation to the grid operator and allow the customer resources to become more fully integrated into grid operations. Furthermore, these enhancements also allow DG to be "islanded" and operate in parallel to the grid. This is especially important for improving grid resiliency. The grid may experience problems while islanded generation continues to produce electricity for local demand.

Distributed energy storage technologies are often paired with DG to enhance the value of DG to the customer and the grid. Batteries are, of course, the best known of these storage technologies, but other options such as flywheels and compressed air systems are now commercially available. Storage systems allow the customer to use the electricity produced by their DG system at different times than when it is generated, but they also offer potential solutions to some of the challenges of integrating large

32 Hansen, L., & Lacey, V. (2013, September). *A Review of Solar PV Benefit and Cost Studies, 2nd Edition.* Rocky Mountain Institute. Available at: http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

33 Keyes, J., & Rábago, K. (2013, October). *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation.* Interstate Renewable Energy Council, Inc. Available at: http://www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf.

34 For a detailed examination of tariff design issues for DG, refer to: Supra footnote 20.

amounts of DG into the utility system. Storage systems can smooth out the variation in the amount of electricity exported and imported by a customer who has DG over the course of a day, making grid integration and utility system planning easier and further facilitating the use of DG to provide energy services.

Clean DG installations also have the benefit of providing small incremental additions to capacity (e.g., in 5-kW or 5-MW increments) that defer or obviate the need for large, lumpy investments in central station fossil generation (e.g., in 250-MW increments). These DG installations can be operational in a matter of months, whereas utility-scale investments typically require multiple years for planning, permitting, and construction. The matching of changes in load with changes in supply has long been an inherently imprecise exercise where large incremental generation facilities get built in advance of the need for the full capacity of the resource. Thus, consumers are paying for capacity they do not need for some time until load growth catches up with capacity. This "lumpy" nature of generation investment is not present with DG. DG installations happen in small increments, so they have the potential to better match need with resources than large lumpy investments. This value of clean DG is often captured in an estimate of the benefits to all consumers of deferring the need for new generation capacity, transmission capacity, or distribution system capacity. As clean DG constitutes a larger proportion of the resource mix, the value paid to DG will have to be refined to reflect the evolution of system benefits it provides. Some of these impacts are positive, for example, obviating the need for a new large generation facility, and some are negative, for example, creating the need for local distribution system investment that would not have been necessary but for the growth of DG.

More extensive treatments of all of the issues discussed in this section can be found in the recent literature on DG.[35]

8. For More Information

Interested readers may wish to consult the following reference documents for more information on encouraging or incentivizing clean DG:

- Barbose, G., Darghouth, N., Weaver, S., & Wiser, R. (2013, July). *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012.* LBNL-6340E. Berkeley, CA: Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf.
- Bird, L., McLaren, J., Heeter, J., Linvill, C., Shenot, J., Sedano, R., & Migden-Ostrander, J. (2013, November). *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar.* National Renewable Energy Laboratory and The Regulatory Assistance Project. NREL/TP-6A20-60613. Available at: http://www.raponline.org/document/download/id/6891.
- Bloomberg New Energy Finance. (2013, August). *Small Distributed Power Generation in the United States – Is It Competitive?* Subscription newsletter and proprietary data service.
- Costello, K. (2014, June). *Gas-Fired Combined Heat and Power Going Forward: What Can State Utility Commissions Do?* National Regulatory Research Institute. Available at: http://www.nrri.org/documents/317330/16dd1f89-c8ec-44db-af73-7c6473a3ef09.
- Hansen, L., & Lacey, V. (2013, September). *A Review of Solar PV Benefit and Cost Studies, 2nd Edition.* Rocky Mountain Institute. Available at: http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

35 See the following, for example: Bird, L., McLaren, J., Heeter, J., Linvill, C., Shenot, J., Sedano, R., & Migden-Ostrander, J. (2013, November). *Regulatory Considerations Associated With the Expanded Adoption of Distributed Solar.* National Renewable Energy Laboratory and The Regulatory Assistance Project. NREL/TP-6A20-60613. Available at: http://www.raponline.org/document/download/id/6891. Hansen, L., & Lacey, V. (2013, September). *A Review of Solar PV Benefit and Cost Studies, 2nd Edition.* Rocky Mountain Institute. Available at: http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue. Linvill, C., Shenot, J., & Lazar, J. (2013, November). *Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6898.

- Keyes, J., & Rábago, K. (2013, October). *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation.* Interstate Renewable Energy Council, Inc. Available at: http://www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf.
- Linvill, C., Shenot, J., & Lazar, J. (2013, November). *Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6898.
- North Carolina State University. (2014). *Database of State Incentives for Renewables & Efficiency (DSIRE).* Available at: www.dsireusa.org.
- Selecky, J.,Iverson, K., & Al-Jabir, A. (2014, February). *Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States.* Prepared by Brubaker & Associates, Inc. and The Regulatory Assistance Project for Oak Ridge National Laboratory. Available at: http://www.raponline.org/document/download/id/7020.
- State and Local Energy Efficiency Action Network. (2013, March). *Guide to the Successful Implementation of State Combined Heat and Power Policies.* Available at: https://www4.eere.energy.gov/seeaction/system/files/documents/see_action_chp_policies_guide.pdf.

9. Summary

Clean DG technologies are cost-competitive in some states today and are becoming increasingly competitive as technology costs decline, technology performance improves, grid modernization better allows the potential value of local DG to be captured, and state policies toward DG evolve.

Improvements in interconnection policies, effective tax and incentive policies, state policies preferring clean energy sources such as RPS policies, and the terms and conditions of DG tariffs and contracts can each contribute to increasing the deployment of clean DG. NEM, FIT, and VOST tariffs, virtual NEM policies such as community solar and solar gardens, third-party leasing and on-bill financing, best practice standby rates, and evolution of markets to allow clean DG to more fully participate in providing energy, capacity, and ancillary services can each contribute to increasing clean DG adoption.

Clean DG displaces the need for some fossil fuel-based, central station generation and thus can contribute to GHG reductions and 111(d) compliance. Most forms of DG also reduce other air pollutant emissions. The benefits of clean DG are amplified to some extent by the fact that DG avoids most or all of the transmission and distribution line losses that are associated with central station generation. DG systems can also be deployed in much smaller increments than utility-scale, central station generation, which reduces the risk and expense of developing more capacity than utility customers need. DG penetration is still small today almost everywhere, but higher levels of PV adoption will present challenges to utility revenues and electric system operations when penetrations become substantially higher. Fortunately, there are utility business model adaptations that can address utility revenue sufficiency in the face of high DG adoption and there are electric system improvements (e.g., smart inverters and improved DG visibility) that can address the reliability challenges.