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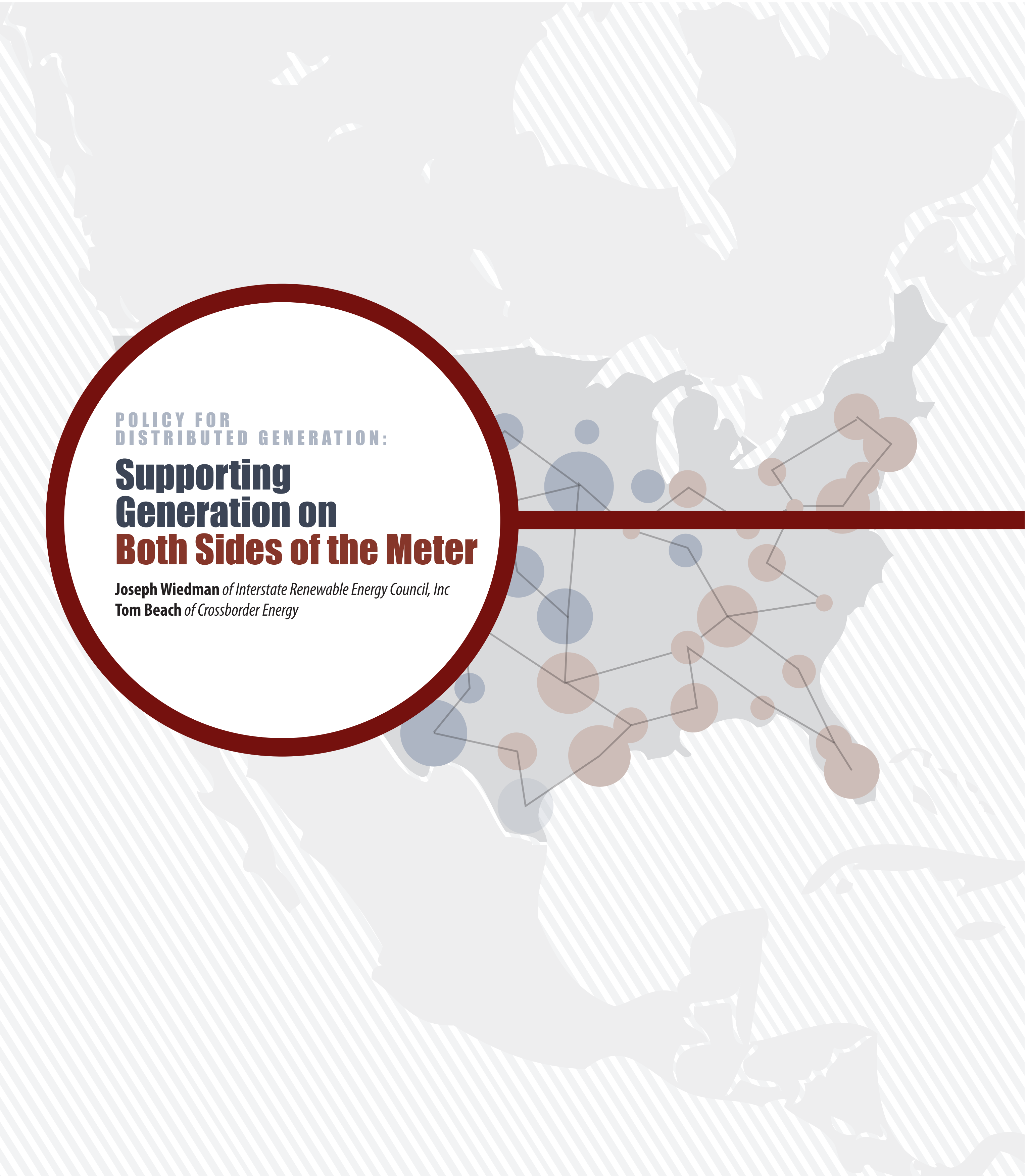

POLICY FOR DISTRIBUTED GENERATION:

Supporting Generation on Both Sides of the Meter

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EXECUTIVE SUMMARY

In today's era when consumers can buy solar panels at their local hardware store, it's clear that distributed generation is taking off. However, without concerted action, its growth may be hindered by legacy regulations designed for a different era. Clearing a path through this regulatory thicket is critical to ensuring a successful transition to a clean energy future. This report identifies specific actions that decision-makers at the local, state, and federal level can take to promote the continued expansion of distributed generation in both retail and wholesale markets.

The paper's recommendations fall into five major categories:

- **Net Energy Metering (NEM):** Energy consumers need a simple, certain, and transparent method for pricing the power that they supply to the grid. NEM has served this purpose well and should be continued so that the customers and suppliers of distributed generation (DG) systems know that this foundational policy will be available in the long-run. This report recommends that decision-makers address concerns over NEM through the same type of cost-effectiveness analyses that have been used for many years to assess other demand-side resources such as energy efficiency and demand response.
- **Shared Renewables:** Many energy customers do not have a rooftop suitable for the installation of solar panels or a yard large enough to site a wind turbine. Shared renewables programs can address this problem through the development of larger, centralized renewable generation projects, with the power output distributed to subscribers or community members using the existing distribution grid. This report recommends that shared renewables programs be developed so that all energy consumers are able to participate in clean energy markets.
- **Procurement of Wholesale DG.** Utilities can use DG to contribute to meeting their state's Renewable Portfolio Standard goals, to hedge against the risks of developing large-scale generation projects and to respond quickly to load growth. This report recommends that a variety of administrative or market-based pricing mechanisms be used to procure wholesale DG, with long-term contracts essential in order to allow these capital-intensive projects to be financed.

- **Interconnection Standards and Local Permitting.** Unduly burdensome interconnection requirements and poorly designed permitting processes both present major barriers to DG development. This report recommends widespread adoption of interconnection standards (based on best practices) along with improvements in the effectiveness and efficiency of the permitting process for DG as ways to remove these barriers to DG deployment while still ensuring safe and reliable installations.

- **Integrated Distribution Planning (IDP).** DG holds great promise as a means to reduce transmission and distribution costs, but this promise will be realized only if utilities integrate DG into their planning for delivery networks. IDP is a coordinated, forward-looking approach under which utilities plan in advance to upgrade or reconfigure certain circuits that are expected to have DG added in the near future, and make the associated costs known to the market with far more transparency than is common today.

Consumers will continue to demand access to distributed energy, and these policy recommendations can help clear the path.

INTRODUCTION

As part of ongoing efforts to better understand the extent to which renewable energy generation can meet United States energy demand, the U.S. Department of Energy sponsored the development of the Renewable Electricity Futures Study (RE Futures). Under this effort, RE Futures presented a deep analysis of the ability of commercially available renewable technologies - biopower, geothermal, concentrating solar power, photovoltaic solar power (PV), wind power (offshore and onshore) and new hydropower facilities - to meet U.S. energy needs under a wide range of scenarios with an extraordinary level of geographic, temporal and operational detail. The findings of RE Futures are compelling – renewable energy can meet 80 percent of U.S. energy needs by 2050 with technologies that are commercially available today on an hourly basis in every region of the country when these technologies are combined with a more flexible electric grid. Moreover, the cost of reaching this goal is in line with the costs shown in previous studies. RE Futures, thus, provides solid support for ongoing efforts on the policy front to remove barriers standing in the way of a growing penetration of renewable energy technologies.

Unfortunately, due to limitations in the models utilized in the study, RE Futures' analysis included only a fixed contribution of DG in the primary study of how renewable technologies can meet U.S. energy needs in the future.[1] Instead, the RE Futures analysis exogenously analyzed the penetration of distributed PV using the Solar Deployment System (SolarDS) model and then accounted for the results of that modeling within the net load that the RE Futures study analyzes. The RE Futures study did consider a scenario in which transmission deployment was constrained and that scenario resulted in increased utilization of DG. Unfortunately, the limitations of the models did not allow for exploration of future scenarios of the flexibility, opportunities and tradeoffs that DG resources offer in comparison to other, larger-scale options. For example, among its many potential benefits, DG can greatly reduce the need for some of the transmission upgrades modeled in the study. Additional benefits include:

- A shorter and less complex development path to bring new resources on-line.
- A closer match between supply and demand.
- Reduced environmental impacts.
- More resiliency and quicker recovery from outages than large-scale, central station generation.

Distributed generation also can enable customers and communities to invest much more directly in the transition to a renewable energy future. End-use customers can install DG to serve their own loads behind the meter. Companies and communities may be able to develop renewable DG at convenient sites and then deliver the electricity to multiple locations or to community members who subscribe to the output of the DG facility. Distributed generation can complement larger-scale renewable generation by encouraging diversity in resources and scale. Small-scale "micro-grids" can provide greater resiliency and more local control over electric supply without sacrificing the benefits of an interconnected grid. For these reasons and more, this paper lays out careful policies to enable DG to contribute significantly to an 80 percent renewable future, delivering fewer development risks, lower overall cost and greater system reliability.

The costs of renewable technologies continue to drop, particularly for solar photovoltaics (PV). A recent report produced for U.S. investor-owned utilities showed that distributed solar PV is already at grid parity for 16 percent of the U.S. retail electricity market, and that share is growing.[2] Similar growth has been seen in distributed PV in other countries, and in other DG technologies.[3] As a result, DG is becoming an essential and growing component of America's renewable energy future. Before 2005, only 79 megawatts (MW) of PV had been interconnected to the grid in the U.S. Yet just five years later, in 2010, 878 MW of PV capacity was installed and connected to the grid in just that year alone. Moreover, in 2011, grid-connected PV additions more than doubled again to 1,845 MW, bringing the total amount of PV to 4,000 MW by the end of the year. Collectively, this is a 500-percent increase in seven years.[4]

POLICIES FOR MAKING THE MOST OF DISTRIBUTED GENERATION

Smart policy support for distributed generation can help achieve a renewable energy future as cost-effectively as possible. To unlock DG's potential for growth and related benefits, this paper makes five policy recommendations to facilitate demand-side and wholesale DG deployment in a way that maximizes benefits to consumers:

1. **Net Energy Metering (NEM)**, which "runs the meter backwards" for utility customers who generate onsite power, has attracted significant retail customer investment in DG. For this reason, state governments should continue to support and expand it. States should address any concerns about NEM's impacts on non-participating ratepayers through the same comprehensive, data-driven cost-effectiveness analyses that are widely used to evaluate energy efficiency and other demand-side programs, as well as through rate design changes that more closely align retail rates with system costs.

2. **Shared renewables programs** should be developed so that the three-quarters of retail customers who currently cannot participate in on-site renewable energy programs can invest in DG.

3. **Wholesale procurement programs**, which allow utilities to buy and run DG, should be developed and expanded to provide for stable, cost-effective investment in wholesale DG, with an emphasis on siting DG in locations that can defer transmission and distribution (T&D) system infrastructure costs.

4. **State-level interconnection standards and procedures and local permitting processes** based on best-practices should be developed and maintained to support cost-effective DG development.

5. States and utilities should **incorporate realistic assumptions regarding DG in their T&D planning processes**, to ensure that the T&D benefits stemming from investment in DG are not lost to utilities and their customers, and to ensure that lower-cost DG opportunities are not ignored in planning the electric grid of the future. When developers, regulators and policymakers have a full sense of the costs and constraints of each option, DG can serve as an effective complement to large-scale renewables and bulk transmission.

1. NET ENERGY METERING

When a customer decides to install and interconnect on-site distributed generation (e.g. solar panels or a small wind turbine), net energy metering (NEM) allows that customer to receive a credit from the utility when on-site generation exceeds the customer's on-site load. Under NEM, the NEM participant earns credits for power exported to the grid, which is typically valued at the serving utility's full retail rate.[5] Often this is referred to as "running the meter backward" because the customer essentially offsets utility purchases of electricity for all generation produced on-site.

From the perspective of an electricity customer, this framework is simple and easy to understand at a conceptual level.[6] With respect to power exported to the grid, NEM also avoids the complexity and confusion of separate rates for the import and export of power. Finally, customers interested in distributed generation understand that NEM's design provides a hedge against future increases in their electricity rates because a NEM system will supply some or all of the customer's on-site energy requirements for a known price: either the upfront cost of the system or the known monthly lease or power purchase payments to the solar installer. Because of these factors, NEM has been a foundational element in the growth of behind-the-meter DG. In 2011, ninety-three percent of the grid-connected solar installations in the U.S. were net-metered, accounting for more than 3,000 MW-dc of new generating capacity.[7] Growth continued in 2012 such that there are now more than 290,000 net-metered systems operating across the U.S.[8]

RE Futures recognizes correctly that the market for distributed PV is highly sensitive to state and local regulatory structures and rate design policies.[9] Because NEM has supported successful growth of customer-sited DG, and, as discussed in more detail below, concerns about NEM can be addressed using well understood practices, public utilities commissions throughout the U.S. should adopt NEM policies based on best practices.[10]

Addressing concerns about net energy metering is vital

Strong growth in net-metered DG systems has raised concerns among some stakeholders, particularly utilities, about whether or not NEM results in a subsidy from non-participating customers to DG owners that participate in NEM programs. Utilities posit that NEM credits at the full retail rate fail to cover the costs for the grid services that NEM customers use, such as standby service or the use of the T&D system to accept exported power, or result in NEM customers avoiding the costs of social programs, such as low-income energy assistance, that other utility customers support. Since 2010, utilities have proposed several alternatives to address these concerns, most commonly advocating for imposing new charges on NEM customers or limiting the growth of NEM systems.

Because NEM plays such a critical role in the development of DG, addressing and resolving subsidy-related concerns is an important near-term policy challenge in the pursuit of continued deployment of behind-the-meter DG. Simply put, energy regulators need to assess the economic impacts of NEM on both DG customers and other non-participating ratepayers in a comprehensive, transparent and data-driven way. Fortunately, state regulators have years of experience doing this type of cost-effectiveness analysis in support of other demand-side programs (such as energy efficiency), and these analyses can be extended to NEM and to demand-side DG more broadly.[11, 12] Evaluating the costs and benefits of distributed energy resources, such as energy efficiency, demand response and behind-the-meter generation using the same cost-effectiveness frameworks will help ensure that all of these resource options are evaluated in a fair and consistent manner. See Appendix A and another paper in this series, The Role of Distributed Resources in a Renewable Energy Future, for details. These analyses are no less important if regulators decide to consider alternatives to NEM to value the output of DG facilities, as discussed in the next section.

Alternatives to NEM

Concerns about the impacts of NEM on non-participating ratepayers also have stimulated discussion and trials of alternatives to NEM. Discussed below are several alternatives that have received significant attention. While these policies may be viable options in certain circumstances, NEM remains a principal policy choice for the majority of jurisdictions.

- Feed-in tariffs (FITs). Over the last several years, a handful of U.S. utilities have experimented with a variety of "feed-in" tariff arrangements as a means of supporting development of DG resources.[13] Within these programs, payments to developers of DG resources have typically been cost-based with an eye towards setting payments at a level sufficient to spur development. FITs have been used widely in Europe, demonstrating clearly that FITs can stimulate development of large amounts of new renewable DG in short periods of time. Yet FITs have also produced significant new costs for other ratepayers.[14, 15] Perhaps as a result of the European experience, FITs in the U.S. have been limited. At the time of this writing, no state has adopted a FIT as a comprehensive alternative to NEM for behind-the-meter DG. Although a FIT with a long-term assured price can provide stimulus for investments in renewable DG, it does not provide the system owner with the hedge against future increases in utility rates that is available with NEM. Moreover, administratively setting the FIT payment rate can require regulators to make difficult decisions in order to set rates that achieve the right balance between the cost and the amount of renewable development desired. In an effort to streamline this process, some states have moved to establish market-based mechanisms to award FIT contracts to installers or developers who bid the lowest FIT price.[16]

- Austin Energy's value-based solar tariff. Since October 2012, Austin Energy, a municipal utility in Texas, has offered residential customers a new solar tariff that is based on a detailed model, developed by Clean Power Research (CPR), which calculates the long-term value of solar energy on Austin Energy's system.[17] The CPR valuation model includes avoided generation energy and capacity costs, fuel-cost hedging value and line loss and T&D capacity savings. The tariff pays a price for all of the customer's solar PV output, while the customer pays separately for power consumed at the standard retail rate. Thus, this structure is more akin to a feed-in tariff than to NEM. It differs from European feed-in tariffs in that it is based on the value of solar output to Austin Energy rather than on an estimate of solar PV costs. The solar tariff rate is revised annually,[18] so some stakeholders have argued that it may not provide an assured revenue stream or hedge value to support a customer's solar investment.

Over the next several years, there will be further tests in the U.S. market of whether these alternatives to NEM can be the basis for sustained growth of solar DG.

NEM in the long-run

Some stakeholders perceive NEM as appropriate only for a period of DG's infancy. Implicit in this perception are the assumptions that NEM provides an incentive for DG customers, and that, once this incentive is no longer necessary and DG penetration grows, NEM will need to be replaced by a more sophisticated valuation of DG. Without a doubt, there are more complex and targeted ways to value DG than NEM's retail rate credit, as illustrated by the Austin Energy value-of-solar tariff and various FIT programs. However, there are trade-offs: for a prospective customer looking to install a DG system to offset their load, these structures may not be viewed as simple or as certain as NEM. For example, requiring a DG customer to accept different prices for power exported to the grid and power consumed on-site could be a tough sell if the price offered for exported energy is viewed as arbitrarily low or transferring value of the investment to other utility customers. Moreover, alternatives have yet to demonstrate the same wide customer acceptance that NEM has achieved.

Most importantly, exploration of rate designs that better align rates with long-run costs can address cross-subsidy concerns while preserving the signal virtues of NEM for the DG industry and customers. Rate designs that are more closely linked to costs are likely to be desirable for other reasons, including providing accurate price signals to encourage energy conservation and to shift power use away from high-demand periods, both of which often are lower-cost steps that consumers should take before investing in DG. The central focus of NEM programs could also evolve in ways that address cross-subsidy concerns but still maintain the simplicity of NEM from the potential customer's perspective. For example, shorter netting periods – such as monthly or hourly instead of yearly – could be coupled with a payment for net excess generation at the end of the netting period. That payment could be set at a level that provides compensation to customers for the value of their energy investment to the grid. However, such a framework would require that compensation levels carefully and fully value the long run benefits that these demand-side systems bring to the grid, which is often not the case today. This outcome is important so that customers installing DG systems are fairly compensated for the value provided while non-participating customers are not paying for more than the value received. Such a framework would still allow a customer to avoid utility-purchased energy by consuming energy produced on-site which would leave NEM open to criticism that it is burdening non-participating customers due to this reduction in sales. However, this concern is more a function of current utility business models that rely on increased sales or infrastructure investments for revenue growth than a function of NEM policy. Evolution in utility business models to move away from the link between increasing sales and profitability will better align utility incentives with society's changing needs and preferences will be necessary to fully address this criticism.

It is also important to recognize that elimination of all cross-subsidies may not be feasible politically or desirable socially. It is commonly understood that retail rates are set based on social goals that may be more compelling to regulators than simple economic efficiency and cost causation. In many states, wealthy energy consumers typically subsidize their less wealthy neighbors, urban energy consumers subsidize rural consumers, residential energy customers are subsidized by commercial/industrial customers (or vice versa) and, in the case of California, coastal users subsidize users in the warmer central regions of the state. Increasing block rate design in California and other states to encourage reductions in consumption also can lead to cross-subsidies from higher energy users to lower energy users. Each of the cross subsidies that result from rates being set with underlying social goals in mind is not indicative of a problem with NEM, but rather a function of the social policies set by each state. This last point is important to remember: as customers are presented with more options and more freedom to manage their energy use and supply, all cross subsidies will need to be carefully examined to ensure they continue to result in the outcomes desired by society, which can often be in conflict.

Recently there has been significant attention to the possibility that the value of solar will decline at higher solar penetrations. Growth in solar DG, including behind-the-meter DG, will shift the electricity system's aggregate peak power demand to later in the afternoon or into the early evening, and wholesale solar will lower the market value of power on summer afternoons.[19] However, these studies have focused on achieving high renewable penetrations through adding only solar, such that there is a significant oversupply of resources to serve load in the daylight hours.[20] As a result, caution is advised on extrapolating these results to the RE Futures scenario of an 80 percent renewables penetration, which requires high penetrations of a wide range of renewable technologies, including significant amounts of resources other than solar, to meet the afternoon peak.

Undoubtedly, the value of solar and of other types of DG at high penetrations of renewables will be different than today, and will require rates to be revised periodically to align with changes in the value of power across the day, the week and the seasons. As rates change to reflect the evolving resource mix, customers seeking to invest in DG will adjust their investments in a way that continues to align costs with the benefits they receive from their investment. Ultimately, the game-changer in this regard is on-site storage. Even the availability of a few hours of storage per day would enable intermittent DG resources to focus their output on those hours when power is most valuable, even if those occur after sunset or when the wind is still. In addition, even modest amounts of storage will help to unlock the reliability and resiliency benefits of DG, by providing the ability to serve critical loads if a major storm disrupts grid service for an extended period. This will help to avoid experiences such as Hurricane Sandy, after which almost 1 GW of installed PV capacity in New Jersey could not operate because the grid was down.

DECISION-MAKER	RECOMMENDATION
PUCs	Adopt Net Energy Metering (NEM) based on best-practice policies identified in Freeing the Grid.[21]
PUCs, ISOs/RTOs, utilities	Evaluate NEM and distributed generation using the same cost-effectiveness framework used for other demand-side resources such as energy efficiency and demand-response. (See Appendix A for methodological suggestions.)
PUCs	Design retail electricity rates to align more closely with long-run marginal costs, including time-varying costs over the course of the day.

2. SHARED RENEWABLES

As described above, demand-side renewable energy programs, in particular NEM, have facilitated customer investment in renewable energy across the U.S., allowing homeowners and businesses to install on-site renewable energy systems and to generate their own electricity. Nevertheless, many residential and commercial consumers who are interested in supporting renewable energy cannot participate in NEM and other renewable energy programs that require a system to be located on-site. This may be because these consumers are renters, live or work in multi-tenant buildings and/or do not have adequate or appropriate roof space. In addition, some homeowners and businesses simply may not want to install renewable energy systems on-site. For example, a homeowner may live in an historic district where PV panels would be considered visually out of place. For these reasons, a recent report from the National Renewable Energy Laboratory (NREL) has estimated that only about one-quarter of U.S. households are able to install solar on their roofs.[22]

Shared renewables programs solve this issue by allowing a centralized system to serve these parties. By increasing the flexibility in the siting of a system, shared renewables programs allow new customers to participate in ownership of a renewable energy system and to receive the benefits from their investment. Such programs also allow renewable energy developers to tap a huge potential market. For example, if just 5 percent of U.S. households were to invest in a 3-kW share of a shared solar system — the size of a typical rooftop solar installation — it would result in more than 17,000 MW of additional solar capacity.[23] While still considered DG, shared solar systems often are larger than a typical rooftop system, and can benefit in lower installation costs due to economies of scale. Because well-designed shared renewables programs represent an opportunity to remove barriers to renewable energy growth, these programs should be expanded.

Defining shared renewables

Shared renewables programs refer to programs in which participants either own or lease panels, or purchase kilowatt-hour (kWh) blocks of generation from a particular system.[24] That is, participants have some sort of "interest" in a renewable generation facility or program from which they receive benefits via a check or a credit on their electricity bills. Because shared renewables programs provide participants with a direct benefit similar to what they might experience through NEM or other demand-side programs, these programs have proven to be popular where implemented. Solar installations power most shared renewables programs, but other types of renewable generation, such as wind, have made more sense for certain communities. [25]

Conversely, community-based renewables programs cover a relatively wider range of programs that facilitate investment in a DG facility located in or near a community — such as on a community center, a municipal property or a non-profit — if the facility is seen as benefiting the community. For example, Mosaic, a new company launched in 2011, relies on a crowd-funding model to finance community systems, and investors benefit through interest on their investment.[26] Other community-based programs have relied on a donation model, such as RE-volv (also founded in 2011), where interested participants donate to the construction of a renewable energy system in their community, sometimes receiving a tax deduction or a gift.[27] Community-based renewables programs have a long track record, especially in facilitating local investment in wind projects.[28]

Critical issues in developing shared renewables programs

Shared renewables programs tend to be developed in ways that respond to the particular needs and interests of their administrators and participants.[29] Thus, these programs are especially dependent on policy decisions by legislatures, state-level regulatory entities (such as public utility commissions), local governments and utilities' own governing bodies, such as a cooperative utility board. Each must address certain key issues, including the ownership of a system and the distribution of the benefits of participation.[30]

Ownership of the system: In some cases, the utility administering the program owns the community generation system.[31] In other cases, an individual or community organization may own the system. In still other cases, a program may allow for a third-party developer or multiple developers to own the systems. Finally, some programs provide for multiple ownership models. Flexibility in ownership models allows for innovative financing that can result in the lowest cost and most benefit to participants. Even so, at this writing, only 22 states and Washington D.C. allow third-party ownership of self-generation systems.[32] Prohibition of, or lack of clarity in, third-party ownership can serve as a barrier by limiting financing options.

Distributing the benefits of participation: For most programs, it makes sense to structure shared renewables programs in a form similar to familiar DG programs, distributing benefits via bill credits on participants' electricity bills. This method of distributing benefits is sometimes referred to as "virtual net metering" because the participant receives a credit on his or her utility bill, but the renewable energy system is not directly connected to the participant's meter. According to research from the Interstate Renewable Energy Council (IREC), about 80 percent of shared solar programs function this way. As with NEM, the most complex element of distributing shared solar credits is how to determine the appropriate value for the credit. Most programs today value the bill credit based on the utility's retail rate, similar to NEM bill credits. Some programs provide a modified retail rate-based credit that compensates the utility for certain things, like the use of its distribution grid and administration of the program. Recently, however, more utilities are considering bill credits based on the "value of solar" and other methodologies, as described above with respect to NEM.

Despite the implementation and policy challenges discussed above, shared renewables programs are emerging throughout the U.S., with more than thirty shared renewables programs operating as of 2012.[33] These programs can serve as models and useful resources for communities interested in developing their own programs.

DECISION-MAKER	RECOMMENDATION
PUCs, cities, counties, utilities	Adopt Shared Renewables programs using a bill credit mechanism. Enable flexible ownership models for shared renewables, including third-party ownership.

3. WHOLESALE PROCUREMENT PROGRAMS

Wholesale procurement programs allow utilities and system operators to buy DG directly, providing another means to accelerate a high-renewable electricity future and complementing retail programs including NEM and shared renewables.[34] Wholesale procurement policies are often part of a Renewable Portfolio Standard (RPS) implementation strategy. In some cases, RPS carve-outs for DG and/or solar inform the development of wholesale procurement programs; that is, wholesale programs can be designed to target particular distributed technologies or DG generally.[35] If implemented carefully, wholesale policies can create opportunities to locate DG projects where they maximize benefits to ratepayers while minimizing cost.

Existing wholesale procurement programs

States and utilities have a range of wholesale procurement mechanisms to use in implementing renewable procurement policies, each with its own set of challenges and benefits. Options include avoided-cost pricing, feed-in tariffs (FITs) and market-based procurement mechanisms, such as auctions and requests for proposals (RFPs). Each mechanism may be more or less attractive depending on the policy climate and the goals it is intended to achieve, but each can serve as a mechanism to support deployment of wholesale renewable DG.

- Avoided-Cost Pricing sets prices based on the energy and system costs that are saved when DG generation is added. The Public Utilities Regulatory Policies Act of 1978 (PURPA) first introduced the avoided-cost pricing mechanism.[36] PURPA originally required utilities to purchase electric generation from small power-production facilities, which include renewable energy facilities smaller than 80 MW, and cogeneration qualifying facilities (QFs) at a price equal to a utility's avoided cost. While PURPA's requirements have evolved over the years, many utilities continue to purchase QF output at avoided cost. For example, under its Small Customer Generator (SCG) Tariff, Duke Energy in North Carolina purchases the excess generation of certain eligible solar systems at avoided cost, as set by the state regulatory commission every two years.[37] Avoided cost-based prices have historically been too low to incentivize significant program participation, but several policy initiatives could change this. The first is that states could take advantage of a FERC decision from October 2010, which clarified that states may set technology-specific, "multi-tiered" avoided costs in cases where the state has a specific procurement goal for each technology.[38] The second is that the scope of avoided cost-pricing for DG QFs could be extended to include the avoided transmission and distribution capacity costs that result from using DG resources. QF pricing historically has been limited to avoided generation costs, even though many utilities calculate marginal transmission and distribution costs for use in rate design, and states such as California use avoided T&D costs in cost-effectiveness evaluations of DG and other demand-side programs.

- Feed-In Tariffs set prices based on the cost to the developer. FITs are similar to avoided cost mechanisms in that they obligate a utility to purchase power from eligible generators at administratively predetermined prices. In contrast to avoided cost prices, FIT pricing is intended to reflect a payment level that is viewed as necessary and sufficient to ensure that developers can build and operate a project with a reasonable profit. Thus, the price may be well above the cost of alternative resources. For this reason, U.S. jurisdictions that have established FITs have all imposed caps that limit FIT system deployment on the basis of installed capacity, total cost or allowable rate impacts. For example, Hawaii has a FIT for certain eligible renewable energy technologies, which is offered by the state's three investor-owned utilities: HECO, MECO and HECO.[39] Qualified projects receive a fixed rate, depending on technology and system size, over a 20-year contract. The program is capped at five percent of 2008 peak demand for each utility. Similarly, California has a FIT program for DG projects of three MW of smaller, which the California Public Utilities Commission (CPUC) recently modified in response to various pieces of legislation, although the new program is not yet in effect.[40] The FIT price under the California program will no longer be based on the all-in costs of a new gas-fired combined-cycle plant (as determined administratively by the CPUC), but instead will be set using an innovative market-based pricing mechanism called the renewable market-adjusting tariff (Re-MAT). The Re-MAT price will adjust up or down depending on the market demand for FIT contracts.[41] In addition, the FIT cap will increase to 750 MW statewide, split across investor-owned and publicly owned utilities.

- Market-Based Procurement Mechanisms: Unlike avoided-cost pricing and most FIT programs, market-based procurement uses competitive means, such as auctions and RFPs, to determine price levels. In short, a contract or contracts are selected largely based on best-available price, so long as the project meets the eligibility criteria of a program, which could include size, technology type or location and developer experience. Market-based programs may place smaller systems and emerging technologies at a disadvantage because administrative costs, such as the cost of submitting a bid, represent a larger percentage of project revenue than for larger PV projects. Nonetheless, there are some successful market-based programs that target DG procurement. For example, California's Renewable Auction Mechanism (RAM) covers renewable energy systems between three and 20 MW located anywhere within the three largest investor-owned utilities' service territories.[42] To date, California utilities have successfully implemented two of the four RAM auctions allowed by the CPUC, and are in the process of administering the third. The CPUC has not yet determined whether or not it will extend the RAM program after the fourth auction. California's investor-owned utilities also each have solar PV programs, which target solar DG through competitive solicitations.[43] Similarly, in Oregon, the Public Utilities Commission approved a market-based procurement pilot program for solar PV systems between 100 and 500 kW in capacity.[44] To date, two Oregon utilities, Pacific Power and Portland General Electric, have undertaken three rounds of RFPs as part of this program.

- Renewable Energy Credits (RECs) as part of a Renewable Electricity Standard:[45] Treatment of renewable energy credits produced by wholesale DG facilities is a complex, but important, consideration in designing successful wholesale DG programs. States have taken different approaches to using RECs to facilitate deployment of DG resources. Some states (e.g., Arizona, Colorado and New Jersey) allow DG facilities participating in their wholesale renewable energy programs to sell their RECs to a utility to meet identified solar and distributed generation requirements within their state-mandated RPS programs. Other states (e.g., California) require DG facilities to transfer RECs at no cost to a utility as a condition for participation in the state FIT program.

Critical components of wholesale procurement programs

Experience with existing wholesale procurement programs has demonstrated the importance of two critical program components: long-term program design and incentivizing location in higher-value areas. These two components can be integrated into a program using any of the mechanisms described above. When a wholesale program incorporates both of these components, it can facilitate a highly reliable, decentralized grid and allow for the avoidance of new transmission infrastructure.

Long-term program design

Wholesale procurement programs should provide for long-term investments, which are necessary to promote a stable market for capital-intensive renewable technologies. Successful wholesale procurement programs, such as California's Renewable Auction Mechanism, offer 10-, 15- or 20-year contracts to align payments with system lifetimes, making it easier for developers to finance and build renewable energy projects.[46]

Similarly, wholesale procurement policies should establish multi-year programs in order to avoid the regulatory uncertainty that can stymie investment by renewable energy businesses.[47] For example, Oregon's market-based procurement mechanism, even though it was considered a pilot project, was authorized for five years, from 2010 to 2015, at which point the Commission will reassess it. Assurance of stable policy support for renewable energy — in particular, the continued viability of wholesale procurement policies — sends an important market signal that supports investment in renewable DG resources.

Offering incentives to locate in higher-value areas

In addition to providing long-term support for wholesale renewable procurement, program designers should ensure that wholesale procurement programs prioritize higher-value DG. Distributed generation increases in value the closer it is to load, especially if it is sited on the same distribution system as the load it is intended to serve. It is critical to locate DG in this manner, as many of DG's benefits are location-specific and therefore are maximized when DG is near to the customers it serves.[48] When DG is sited strategically — such as on rooftops, parking lots and other hardscape areas or brownfield sites — it can put existing land and infrastructure to more productive use. At the same time, it can minimize the amount of virgin land and habitat that would otherwise be needed for power generation. On the retail side, NEM facilitates high-value on-site generation, and shared renewables programs can be designed to maximize locational value;[49] wholesale procurement policies should do the same.

Currently, most wholesale procurement programs do not prioritize development in higher-value locations because they typically allow participants to interconnect anywhere on the distribution or transmission systems. As a result, renewable energy developers do not take into account the costs of connecting in sub-optimal locations far from load, which may appear less expensive for other reasons (e.g., low land costs); instead, these costs are born, at least in part, by ratepayers. There are a variety of ways that a procurement program could realign incentives to encourage development in higher-value areas. For example, a program might provide an incentive payment for projects that locate in higher-value areas to reflect the added benefit of strategic siting. Interconnection policies also can incent wholesale projects to locate in higher-value areas, as described in more detail below.

Ensuring that wholesale procurement policies support higher-value DG would have the effect of creating DG "hot spots" in strategic locations that maximize the benefits of DG. As DG development increases and concentrates, it may put pressure on local DG permitting processes, which can sometimes be difficult to navigate or can become overwhelmed by high numbers of applications. Nevertheless, these "hot spots" may also be beneficial to utilities, enabling them to adjust their planning efforts to take advantage of concentrated DG. In addition, utilities could integrate energy storage or focus on demand-response programs in these higher-value DG areas to firm generation capacity.

DECISION-MAKER	RECOMMENDATION
PUCs	Set technology-specific, "multi-tiered" avoided costs to stimulate the DG market.
PUCs	Expand the scope of avoided cost pricing for qualified facilities to include avoided transmission and distribution capacity costs.
PUCs	Streamline bid processes for market-based procurement.
PUCs	Where there is a Renewable Portfolio Standard but no Feed-in Tariff, allow developers of DG facilities to sell Renewable Energy Credits to utilities.
PUCs	Design wholesale procurement mechanisms with long time frames (5-20 years), to support procurement of the output of new DG facilities.
PUCs	Incorporate locational value into wholesale procurement assessments via a locational marginal price adder or a location-specific interconnection incentive.

4. INTERCONNECTION STANDARDS AND LOCAL PERMITTING

The existing distribution system was built for a one-way power flow. As more on-site generation comes online, well-designed interconnection procedures are crucial to ensure safe and reliable operation of the distribution grid. However, the decision to study each individual generation system in depth must be balanced with the cost for utility staff time to review each application, the challenge of studying projects in series on a dynamic system, and the need for DG developers to have predictability, certainty and speed in interconnection. For these reasons, unduly burdensome study requirements and associated timeframes can pose significant hurdles to DG systems, particularly those in the 25 kW or smaller size range, and could present unacceptable costs to utilities and their customers with minimal safety or reliability benefits. To address these concerns, the Federal Energy Regulatory Commission (FERC) and many states have moved to adopt standards to govern the review of requests for interconnection that balance these concerns while removing barriers to DG deployment.

Adoption of best-practice interconnection procedures has been slower than adoption of net metering. Since 2000, FERC has adopted the Small Generator Interconnection Procedures (SGIP), and 32 states and Washington D.C. have adopted state jurisdictional interconnection procedures. Yet, according to state interconnection procedure ratings in Freeing the Grid, only eight states have earned an A for their interconnection procedures, and more than half have adopted interconnection procedures that grade at a C or below, or have not adopted statewide interconnection procedures.[50] This situation represents a serious barrier to continued deployment of DG. In addition, as discussed more fully below, even those states that currently achieve high grades will need improvements to ensure that the interconnection process is equipped to support higher penetrations of DG, particularly as the ratio of generation to load on distribution circuits increases.

Moreover, while much of the focus on removing barriers to DG deployment have focused on state-level efforts and activities at public utilities commissions, local jurisdictions have a crucial role to play in the deployment of DG within their permitting processes. Plan checks and inspections are an important part of ensuring safety and reliability of DG systems. However, there is a strong need to update permitting processes to ensure they are effective and efficient.

Reassessing the penetration screen for distributed generation

Most U.S. interconnection procedures use a set of technical screens, including a penetration screen, to identify which projects require an interconnection study and which can proceed on a faster track. As an increasing number of circuits in the country reach high penetrations of DG, more and more DG projects are failing the penetration screen. Thus, fewer projects are able to proceed quickly and more utility resources are tied up in the study process. In the near term, an update of the penetration screen to continue to allow for expedited review of small systems, while still maintaining a high level of safety and reliability, is important to keeping the interconnection process moving.

As the capacity of installed DG on a line increases, the possibility of unintentional islanding, voltage deviations, protection failures and other negative system impacts may increase.[51] To account for this possibility, most interconnection procedures apply a penetration screen that requires further study of a project if the new project would cause total generation to exceed 15 percent of the line section peak load. At the time this screen was originally drafted, few utilities were regularly collecting minimum load data, thus the 15 percent of peak load measurement was identified "as a surrogate for knowing the actual minimum load on a line section."[52] The screen is intended to approximate a limit of roughly 50 percent of minimum load.[53] In many cases, however, a full interconnection study is not required until the generation on a line exceeds 100 percent of minimum load. Thus, some states, including California and Hawaii, have adopted a modification to their penetration screen that allows projects that fail the 15 percent of peak load initial screen, but are below either 75 or 100 percent of minimum load, to interconnect without detailed study as long as they pass two supplemental screens that examine whether the interconnection raises potential power quality, voltage, safety or reliability concerns.[54] Two recently released studies from NREL support the viability of these approaches.[55] FERC, Massachusetts and Hawaii are considering a similar change. As other states experience higher DG penetration levels, it will be essential to consider this or a similar modification to their interconnection procedures.

Coordinate changes to interconnection and procurement

An update of the penetration screening method is the most critical near-term change for interconnection procedures, but a deeper evaluation of the role of the interconnection process as a whole will likely be needed, as the popularity of DG in certain markets is already resulting in penetrations that exceed minimum load on circuits in the U.S.[56] In particular, coordinated changes to the interconnection and wholesale procurement process can help maximize use of the existing infrastructure and result in greater system-wide benefits.

Increasing the transparency of the interconnection process can help to smooth the flow for both project developers and utilities. Creating system mapping tools and pre-application reports can provide valuable information to applicants, enabling them to select project sites with fewer potential interconnection issues and obtain a better understanding of the likely costs and interconnection time frames associated with chosen sites. This improvement should come in tandem with similar improvements to wholesale procurement programs, described above, that can drive projects to the lowest-cost, highest-value locations. These two policies in combination can reduce the number of applications for unviable projects, and can also help to maximize existing system capacity. In considering how to implement such changes, however, it is important to recognize the difference between rooftop solar projects designed largely to serve local load, and wholesale or shared renewables projects. Wholesale and shared renewables projects have greater flexibility in selecting sites, while rooftop customers have no choice in location. In addition, increasing transparency within the process itself, by adding clearly defined timeframes for each step in the process and an explanation of what the utility's analysis will include, can also help prevent backlogs in the interconnection queue.

While efforts to develop best-practice interconnection procedures have facilitated growth in DG to date, more needs to be done to ensure interconnection procedures are standardized nationally in order to further facilitate interconnection in a fair, safe and effective manner. Moreover, current procedures are not equipped to smoothly handle the volume of applications that could be submitted in high DG growth scenarios, nor are current interconnection procedures prepared to address the increasing number of technical issues that arise as higher penetrations of DG are reached. If the higher penetrations of DG shown to be feasible in RE Futures are to be undertaken, continued examination of interconnection standards will be necessary.

Enhancing and streamlining local permit processing

Much of the focus on enabling greater amounts of DG is centered on the actions of the public utilities commissions and the utilities. However, local governments and environmental regulatory agencies can also play a significant role in facilitating greater uptake of distributed generation by increasing the ease with which properly sited DG can obtain necessary permits for construction. Local governments, in particular, play a critical role in ensuring the safety and quality of solar installations on homes and businesses in the U.S. Without plan checks and inspections, it is possible that a number of faulty installations, which cause personal injury or property damage, could impair customer interest in renewable energy. Similarly, while ground-mounted DG creates fewer impacts than utility-scale installations, poor siting choices can also have significant land use and environmental impacts on communities.

With the importance of the review process in mind, there is a need for an update to the procedures for obtaining permitting review and approval to make them more effective and efficient. The most recent figures from the Department of Energy's SunShot Initiative indicate that improving permit review efficiency can result in system costs that are between 4 and 12 percent lower than in jurisdictions that have not adopted similar streamlining.[57] Tackling this issue is particularly challenging due to the sheer number of different permitting authorities that exist in the U.S. In addition to the public utilities commission in each state, there are over 20,000 municipalities and other authorities responsible for issuing permits to enable DG facility construction. Thus, the strategic approach has to involve widespread dissemination of well-developed models that can be easily adopted by other municipalities.

As the volume of DG increases, so will the number of permit applications that municipalities have to process. For example, the City and County of Honolulu processed an astonishing 16,715 PV permits in 2012, reviewing an average of 80 permit applications a day.[58] Even a small portion of this volume would easily overwhelm most jurisdictions. Thus, finding more efficient methods of review that do not undermine safety and quality can be in the municipality's interest. Approaches to permitting reform that can benefit both the municipal government and the installation community are most likely to be immediately appealing and successful.

Improved access to clear information about the permitting process and its requirements can enhance the quality of applications, and thereby reduce the back and forth that has burdened both installers and permit officials. Internal improvements in permit processing can include adopting expedited review for applications that meet pre-determined design criteria and new methods of scheduling permitting staff to enable faster application review and inspection. Moving the permitting process online can result in significant efficiency improvements but can require an upfront investment for cash-strapped municipalities. Finally, ensuring that inspectors and permitting staff, as well as the installation community, have sufficient training in DG technologies can enable more efficient review with high safety standards.[59]

DECISION-MAKER	RECOMMENDATION
FERC	Define a standard interconnection procedure.
PUCs	Adopt best-practice interconnection procedures.
FERC, PUCs	Enable systems that fail the penetration screen to interconnect without in-depth study if they pass additional screens examining their effect on power quality, voltage, safety, and reliability.
PUCs, Utilities	Create system mapping tools and pre-application reports to highlight the lowest-cost and highest-value locations for DG projects. Publish clear timelines for project development.
Municipal and local authorities	Improve and streamline permitting review and approval with the adoption of best practices

5. MOVING TOWARD INTEGRATED DISTRIBUTION PLANNING (IDP)

A central benefit of DG is the ability to avoid or defer the need for costly expansions of transmission and distribution infrastructure, but current utility business models tend to discourage planning that analyzes distributed generation's ability to defer T&D. Utility T&D planners alone have the information needed to make the decisions about whether DG can avoid T&D investments. But under the traditional U.S. model of utility ratemaking, utility profits are based on how much capital the utility has invested. This inevitably places pressure on the utility to minimize the potential for DG to reduce its spending program on T&D infrastructure. The utility's incentives are understandable, given a ratemaking structure that ties profits to the magnitude of T&D investments. Utility business models and regulatory frameworks will need to be reexamined in order to properly align utility incentives to take advantage of distributed generation's ability to defer or avoid T&D expansions or upgrades.[60]

Historically, utilities have planned for distribution system upgrades that accommodate growing or changing energy and power demand. Utility planners typically prioritize distribution system upgrades based on extrapolations of historical loads that may or may not include very small amounts of DG in the local area under study. But DG's exponential growth in some U.S. markets suggests that trending historical loads may not continue to provide a reliable picture of demand even a few years into the future.

Furthermore, under today's procedures, utilities study only pending interconnections, and circuits are upgraded to accommodate generation on a project-by-project basis. This approach has a number of potential downsides. First, it means the first project to trigger an upgrade pays the full cost, even if later generators also benefit. It also results in a slower interconnection review process because each project must be studied in sequence, and if a developer chooses not to proceed with an upgrade, it can sometimes result in a need to re-study projects further down in the queue.[61] This reactive approach also undermines the ability of the utility to provide incentives to DG to locate in the highest-value parts of the grid. It makes it very difficult, if not impossible, for utilities to pursue cost-effective upgrades to the distribution system to support anticipated levels of DG. In short, this approach provides no incentive for utilities to undertake system planning that can benefit both load and generation.

These historical inefficiencies in the treatment of DG can be addressed through more streamlined and coordinated approaches to distribution system planning and DG interconnection. One approach is for utilities to conduct forward-looking studies, and possibly even upgrades, for certain circuits that are expected to have generation added in the near future. This coordinated approach is known as "Integrated Distribution Planning" (IDP).[62] IDP requires a reconsideration of the traditional methods for financing interconnection studies and upgrades, but it makes more efficient upgrades and increased transparency possible. Hawaii and New Jersey have begun to implement this method as they see increasing pressure from high circuit penetrations.[63]

Emerging IDP methods under development generally use a two-step process to determine a circuit's capacity to host DG prior to a request for interconnection. The first step involves modeling to determine the ability of a distribution circuit to host DG. The second step coordinates distribution system planning with anticipated DG growth. In situations where anticipated DG growth exceeds a distribution circuit's hosting capacity, utility planners can identify additional infrastructure that may be necessary to accommodate the coming growth. The results of these proactive studies can be used to inform subsequent interconnection requests by determining, in advance, the precise level of DG penetration that can be accommodated without system impacts. At higher levels of penetration, utilities will have foreknowledge of any upgrades that may be required to maintain safety, reliability and power quality standards.

DECISION-MAKER	RECOMMENDATION
Utilities, ISOs/RTOs	Conduct forward-looking studies for circuits likely to achieve high penetrations of DG.
Utilities, ISOs/RTOs	Adopt Integrated Distribution Planning to compare DG and distribution system upgrades on an equal footing with each other, and with other demand- and supply-side options.

CONCLUSION

There is unlikely to be a single path to reach the goal of a U.S. electric grid that obtains 80 percent of its power from renewable resources. Distributed generation provides an essential piece of the puzzle, in conjunction with larger-scale renewable energy resources in remote areas where wind and solar resources are plentiful and there is adequate transmission capacity to bring energy from these facilities to load. In cases where land use concerns limit the ability of the renewables industry to site central station plants and the associated transmission in the remote areas, DG can and should be the primary alternative examined.

Individuals, communities and businesses are increasingly demanding DG. Harnessing this interest will require the development of smart, customer-focused policies that provide a stable and certain environment in which customers can make informed investments in DG systems, and incentives to encourage utilities to integrate DG resources into their planning on the same basis as investments in large-scale generation or the delivery infrastructure. Most importantly for the future, it will be easier to maintain momentum toward a high renewables future if a significant segment of electricity consumers have had the direct experience of procuring and producing their own renewable energy on their home, at work or in their local community.

On the wholesale side of the equation, stable, long-term policies are also necessary to incentivize participation by developers in utility DG procurement programs. Smaller-scale DG may compete with remote central station plants when avoided transmission and distribution costs are considered, and programs should be designed to offer the best solution over the long term, taking into account all the benefits DG can provide.

Adapting today's processes to accommodate DG growth will require both simple changes, such as the reassessment of penetration screens, and more fundamental reforms, such as a movement toward integrated distribution planning, and even a fundamental re-thinking of the role of the utility and the business models under which they operate. Making these changes requires recognizing that energy production is being fundamentally transformed and grid management will have to evolve along with it in order to maintain safety and reliability, provide DG systems with access to the grid and ensure that costs and benefits are fairly distributed amongst customers.

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ENDNOTES

1 DG is commonly understood to mean energy production facilities located within the distribution system with capacities of 20 megawatts (MW) or less. NREL did publish complementary analysis of the Sunshot Vision goals, which explore scenarios with higher contributions from DG. See Denholm et al (2013).

2 Kind, Peter, 2013. "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business." Edison Electric Institute. <http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf>

3 American Wind Energy Association, 2012. "2011 U.S. Small Wind Turbine Market Report." <http://www.awea.org/learnabout/smallwind/upload/AWEA_SmallWindReport-YE-2011.pdf>

4 Sherwood, Larry, 2012. "U.S. Solar Market Trends 2011." Interstate Renewable Energy Council. <http://www.irecusa.org/wp-content/uploads/IRECSolarMarketTrends-2012-web.pdf>

5 In some states, the export price under NEM is set explicitly at the utility's avoided cost, not at the retail rate; and in many states, avoided costs instead of retail rates are used to compensate DG customers if their production exceeds their on-site use.

6 The complexity associated with billing for net metering and how net metering credits are presented on customer bills can lead to confusion for participants in net metering programs. Billing simplification could help ameliorate these issues, but further research is needed to develop best practices in support of such simplification.

7 Sherwood, 2012. Figs. 2 & 6. Most NEM programs allow for a variety of renewable energy technologies. Solar PV generation today is the most prevalent DG technology, because PV is inherently modular and the broad availability of solar resources means that property owners may install distributed, behind-the-meter PV wherever there is a load and available sunny rooftop or open space.

8 Author correspondence with Larry Sherwood, Interstate Renewable Energy Council, April 15, 2013.

9 National Renewable Energy Laboratory, 2012. "Renewable Electricity Futures Study." Hand, M.M.; Baldwin, S.; DeMeo, E.; Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek M.; Sandor, D. eds. 4 vols. NREL/TP-6A20-52409. National Renewable Energy Laboratory. <http://www.nrel.gov/analysis/re_futures/>

10 Freeing the Grid, 2012. "Freeing the Grid 2013: Best Practices in State Net Metering Policies and Interconnection Procedures." Vote Solar; Interstate Renewable Energy Council. <http://freeingthegrid.org/> assigns letter grades to each state's net metering program, as assessed against NEM best practices. In 2012, sixteen states had adopted net metering programs that earned an A based on the design of their programs. However, eighteen states show low grades of a C or below, meaning those states' programs have program elements that represent serious departures from best practices, or they received no grade meaning they have no statewide net metering program or participation in the program by utilities within the state is voluntary.

11 For example, IREC has devoted significant attention to establishing a consistent and thorough approach to evaluating the costs and benefits of NEM. With the support of the Solar America Boards for Codes and Standards, IREC published A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering.

12 Keyes, Jason B.; Wiedman, Joseph F., 2012. "A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering." Interstate Renewable Energy Council. <http://www.solarabcs.org/about/publications/reports/rateimpact/pdfs/rateimpact_full.pdf>

13 Couture, Toby; Cory, Karlynn, 2009. "State Clean Energy Policies Analysis (SCEPA) Project: An Analysis of Renewable Energy Feed-in Tariffs in the U.S." NREL/TP-6A2-45551. National Renewable Energy Laboratory. <http://www.nrel.gov/docs/fy09osti/45551.pdf>

14 The German EEG charge that principally recovers the costs of the German renewable FITs now constitutes about 14 percent of the average residential electric rate in Germany.

15 Federal Ministry for the Environment, Nature Conservation and Nuclear Safety, 2013. "Development of renewable energy source in Germany 2011." Working Group on Renewable Energy-Statistics (AGEE-Stat). <http://www.erneuerbare-energien.de/fileadmin/Daten_EE/Bilder_Startseite/Bilder_Datenservice/PDFs__XLS/20130110_EEiZIU_E_PPT_2011_FIN.pdf>

16 "Renewable Auction Mechanism" California Public Utilities Commission, 2007. <http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm>

17 Rábago, Karl R., et al., 2011. "Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator." Austin Energy; Clean Power Research. <http://www.cleanpower.com/wp-content/uploads/090_DesigningAustinEnergysSolarTariff.pdf>

18 The Austin Energy solar tariff provides that "[t]he Value-of-Solar Factor shall initially be $0.128 per kWh, and shall be administratively adjusted annually, beginning with each year's January billing month, based upon the marginal cost of displaced energy, avoided capital costs, line loss savings, and environmental benefits." For more detail, see <http://www.austinenergy.com/About%20Us/Rates/pdfs/Residential/Residential.pdf>.

19 Mills, Andrew; Wiser, Ryan, 2012. "Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California." LBNL-5445E. Environmental Energy Technologies Division; Lawrence Berkeley National Laboratory. <http://eetd.lbl.gov/ea/emp/reports/lbnl-5445e.pdf>

20 The authors of the LBNL Report explicitly caution against drawing conclusions about the value of combinations of renewable technologies, which they plan to examine in a future study. LBNL Report, at 3 and 8.

21 The Vote Solar Initiative, et. al., Freeing the Grid, 7-8, Nov. 2012, available at <http://freeingthegrid.org>.

22 Denholm, Paul; Margolis, Robert, 2008. "Supply Curves for Rooftop Solar PV-Generated Electricity for the U.S." NREL/TP-6A0-44073. National Renewable Energy Laboratory. <http://www.nrel.gov/docs/fy09osti/44073.pdf>

23 "State and County Quick Facts." U.S. Census Bureau, 2013. <http://quickfacts.census.gov/qfd/states/00000.html>

24 In previous reports, IREC and other stakeholders have referred to shared renewables as community renewables or community-shared renewables. However, as the concept has matured, consensus has developed among stakeholders that use of "community" in describing the programs can create confusion, as stakeholders' perceptions of "community" are highly diverse. IREC has supported the move to describing programs as shared renewables and is adjusting references in documents it produces, including the ones cited in this paper, to that new nomenclature over time.

25 See <www.windustry.org>.

26 See <https://joinmosaic.com>.

27 See <http://www.re-volv.org>.

28 See <http://www.windustry.org>.

29 According to IREC's research, roughly half of the programs identified above are run by electric cooperatives, with the other half split between municipal utilities and investor-owned utilities.

30 IREC's Community Renewables Model Program Rules provide a good starting point for understanding issues relevant to community-shared solar. See <http://www.irecusa.org/2010/11/irec-releases-first-model-program-rules-for-community-renewables>. IREC also offers direct assistance to individuals and organizations looking to establish shared renewables programs. In addition, the U.S. Department of Energy has a useful Guide to Community Shared Solar for individuals and communities interested in establishing programs. See <http://www.nrel.gov/docs/fy12osti/54570.pdf>.

31 In the case of utility ownership, it is important that all system purchase costs, operation and maintenance costs, necessary investment returns, and other costs related to a utility-owned system are recovered from participants enrolled in the program and not non-participating ratepayers. This requirement ensures that non-participants do not bear costs for which they do not receive any benefits, and keeps a level playing field between utility offerings and offerings of other providers.

32 "3rd-Party Solar PV Power Purchase Agreements (PPAs)." DSIRE, 2013. <http://www.dsireusa.org/documents/summarymaps/3rd_Party_PPA_map.pdf>.

33 Information on shared solar programs can be found at http://sharedsolarHQ.org. The U.S. DOE also provides a list of programs at <http://apps3.eere.energy.gov/greenpower/markets/community_re.shtml>.

34 Fox, Kevin T.; Varnado, Laurel, 2010. "Sustainable Multi-Segment Market Design for Distributed Solar Photovoltaics." Interstate Renewable Energy Council. <http://www.solarabcs.org/about/publications/reports/market-design/pdfs/ABCS-17_studyreport.pdf>

35 Sixteen states and Washington, D.C., have created solar targets within their RPS programs, and nine states have created distributed generation procurement targets or allow utilities an RPS credit multiplier for customer-sited systems. See <http://www.dsireusa.org/documents/summarymaps/Solar_DG_RPS_map.pdf>.

36 "What is a Qualifying Facility?" Federal Energy Regulatory Commission, 2012. <http://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp>

37 Duke Energy Carolinas, LLC, 2012. "RIDER SCG (NC): Small Customer Generator Rider." <http://www.duke-energy.com/pdfs/NCRider-SCG.pdf>.

38 The FERC issued this order in response to a challenge of a California FIT designed specifically for small CHP projects. See Cal. Pub. Utils. Comm'n, 133 FERC ¶61,059, 2010.

39 DSIRE, 2012. Hawaii Incentives/Policies for Renewables & Efficiency." <http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=HI29F&re=0&ee=0>.

40 Cal. Pub. Utils. Code § 399.20. The CPUC approved the modified program rules in Decision (D.) 12-05-035, however it has not yet approved the utilities' revised tariffs or form contracts. Therefore, the new program is not yet active. For more detail on California's FIT, see California Public Utilities Commission, 2013. "Renewable Feed-In Tariff (FIT) Program." <http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/feedintariffs.htm>

41 California Public Utilities Commission, 2012. "Order Instituting Rulemaking to Continue Implementation and Administration of California Renewable Portfolio Standard Program." D. 12-05-035. <http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/167679.pdf>

42 California Public Utilities Commission, 2012. "Renewable Auction Mechanism." <http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm>

43 California Public Utilities Commission, 2010. "Investor-Owned Utility Solar Photovoltaic (PV) Programs." <http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Utility+PV+Programs.htm>

44 Oregon Public Utilities Commission, 2013. "Solar Photovoltaic Volumetric Incentive Program: Report to Legislative Assembly." <http://www.oregon.gov/puc/docs/010213SolarPilotProgramReport.pdf>

45 Renewable energy credits represent the renewable attributes of the energy produced by a renewable facility.

46 California Public Utilities Commission, 2012. "Resolution." Resolution E-4489. <http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/164684.pdf>

47 Weissman, Steven; Johnson, Nathaniel, 2012. "The Statewide Benefits of Net-Metering in California & the Consequences of Changes to the Program." Center for Law, Energy & the Environment; University of California, Berkeley. <http://www.law.berkeley.edu/files/The_Statewide_Benefits_of_Net-Metering_in_CA_Weissman_and_Johnson.pdf>

48 Wiedman, Joseph F.; Schroeder, Erica M.; Beach, Thomas R., 2012. "12,000 MW of Renewable Distributed Generation by 2020: Benefits, Costs and Policy Implications." Interstate Renewable Energy Council; Crossborder Energy. <http://www.irecusa.org/wp-content/uploads/Final-12-GW-report-7.31.12.pdf>

49 Colorado's community solar gardens program is a particular example. Under that program, community solar gardens (shared solar facilities) are required to be located within the same county as the participants being served by the facility. This geographic limitation helps ensure community solar gardens are located close to the load they serve.

50 The Vote Solar Initiative, et. al., Freeing the Grid, 7-8, Nov. 2012, available at http://freeingthegrid.org (fifteen states have yet to adopt adequate mandatory procedures, and an additional twelve states received grades of C or below).

51 Coddington, Michael, et al., 2012. "Updating Interconnection Screens for PV System Integration." NREL/TP-5500-54063. National Renewable Energy Laboratory. <http://energy.sandia.gov/wp/wp-content/gallery/uploads/Updating_Interconnection_PV_Systems_Integration.pdf>

52 California Energy Commission, 2003. "California Interconnection Guidebook: A Guide to Interconnecting Customer-owned Electric Generation Equipment to the Electric Utility Distribution System Using California's Electric Rule 21." <http://www.energy.ca.gov/reports/2003-11-13_500-03-083F.PDF>

53 See CEC Guidebook at 43; Interconnection Screens Report at 2 ("For typical distribution circuits in the U.S., minimum load is approximately 30 percent of peak load.").

54 *See* California Public Utilities Commission, Decision No. 12-09-018, Attachment A to Attachment A, Revised Rule 21 §§ G.2, Sep. 20, 2012. (Rule 21 Screen N and Supplemental Review Screens O and P); HECO has currently agreed voluntarily to move to 75 percent of minimum load. See <http://www.heco.com/vcmcontent/StaticFiles/pdf/20120918-easier2addsolar2roofs.pdf>. However, stakeholders have recommended that 100 percent of minimum load be the ultimate standard. See Reliability Standards Working Group Independent Facilitator's Submittal and Final Report, Docket 2011-0206, Attachment 4, Item b-4, pp. 12-13, Proposed Screen 12, Mar. 17, 2013; see also Interconnection Screens Report at 9-11; Kevin Fox, et al., Updating Small Generator Interconnection Procedures for New Market Conditions, pp. 22-24, Dec. 2012 ["Updating SGIPs"].

55 See Interconnection Screens Report, supra footnote 51; Updating SGIPs, supra footnote 54.

56 Campbell, Becky; Taylor, Mike, 2012. "2011 SEPA Utility Solar Rankings." Solar Electric Power Association. <http://www.solarelectricpower.org/media/257582/final%202011%20utility%20solar%20rankings%20report.pdf>
In 2008, 93 percent of the nation's total annual solar capacity was installed in the Western region. By 2011, however, Western states held only 61 percent of the nation's annual installed solar capacity, and only two California utilities were among the top ten for Cumulative Solar Watts-per-Customer (see figure 2).); Steve Steffel, PepCo Holdings, Inc., Advanced Modeling and Analysis, EUCI Presentation at Denver, CO, Nov.15, 2012 ("PepCo, Inc., the utility for many parts of southern New Jersey, has closed a number of its distribution circuits to further PV development because of high penetration levels.").

57 Wiser, Ryan; Dong, Changgui, 2013. "The Impact of City-level Permitting Processes on Residential Photovoltaic Installation Prices and Development Times: An Empirical Analysis of Solar Systems in California Cities." Environmental Energy Technologies Division; Lawrence Berkeley National Laboratory. <http://emp.lbl.gov/sites/all/files/lbnl-6140e.pdf>

58 Mangelsdorf, Marco, 2013. "Oahu's Solar Feeding Frenzy Continues." Honolulu Civil Beat. <http://www.civilbeat.com/voices/2013/01/25/18169-oahus-solar-feeding-frenzy-continues/>

59 Interstate Renewable Energy Council (2013). "Streamlining the Solar Permitting Process: Solar Permitting Best Practices." <http://www.irecusa.org/wp-content/uploads/Solar-Permitting-Best-Practices_Feb2013.pdf>

60 See America's Power Plan report by Lehr.

61 One solution to this is to adopt group-study processes for projects that are electrically related on a circuit. By studying the projects together, upgrade costs may be shared and the queuing issues can be mitigated, however the issue of drop-outs continues to be problematic.

62 Tim Lindl, Tim and Kevin Fox, "Integrated Distribution Planning Concept Paper." Interstate Renewable Energy Council (2013). <http://www.irecusa.org/wp-content/uploads/2013/05/Integrated-Distribution-Planning-May-2013.pdf>

63 See Reliability Standards Working Group Independent Facilitator's Submittal and Final Report, Docket 2011-0206, Attachment 4, Item b-7, Mar. 17, 2013. (Anticipated HPUC Order to Adopt PV Sub-Group Work Product as Part of Record); Steve Steffel, PepCo Holdings, Inc., Advanced Modeling and Analysis, EUCI Presentation at Denver, CO, Nov.15, 2012.

APPENDIX A: RATE DESIGN AND THE NET ENERGY METERING COST/BENEFIT CALCULATION

The first step in framing an assessment of the economics of Net Energy Metering (NEM) is to clarify the scope of the NEM transaction. In this regard, it is helpful to consider what would happen if a customer installed renewable distributed generation (DG) without NEM. In that case, federal law—the Public Utilities Regulatory Policies Act of 1978 (PURPA)[1]—would require the public utility to interconnect with the renewable DG system, allow the DG customer to serve the customer's on-site load and purchase excess power exported from the system at a state-regulated avoided cost price in a wholesale power transaction. The impact of NEM is only to change the price that the DG customer receives for its exports, from an avoided cost price to a bill credit set, in most cases, at the customer's retail rate. As a result, in evaluating NEM, the key question is whether this rate credit for exported power accurately reflects the value of that power, which the utility uses to serve other nearby loads.

Utilities in the U.S. routinely use sophisticated cost-effectiveness tests to evaluate demand-side energy efficiency and demand response programs.[2] It is important to evaluate the costs and benefits of DG as a demand-side resource, or to conduct a narrower analysis of NEM exports as one element of a DG transaction, using the same tests employed for energy efficiency and demand response programs. This promotes the consistent evaluation of all demand-side programs.[3]

Finally, it is critical that cost-benefit assessments of NEM, or of DG resources, should use long-term costs and benefits because renewable DG is a long-term resource with an expected useful life of 20-25 years. A long-term perspective is particularly important for assessing avoided transmission and distribution (T&D) costs. Although utility resource planners may consider DG in their integrated resource plans for future generation resources, DG is not well integrated into transmission or distribution system planning at most utilities, as discussed in more detail in the paper's section on integrated distribution planning. Yet standard regressions of long-term utility T&D investments as a function of peak demand—for example, in standard utility calculations of marginal T&D costs—show a close correlation between long-term T&D investments and peak demand. In the long-term, lower peak loadings on the T&D system will reduce investment-related T&D costs.[4] DG provides another tool to manage the growth of peak demand on the delivery system, such that long-term costs to expand transmission or substation capacity or to re-configure distribution circuits can be avoided.

In a ratepayer impact analysis of NEM, the principal costs are the retail rate credits that the utility pays for NEM exports. These credits are based on existing retail rates. The principal benefits of incremental NEM exports reflect the utility's avoided or marginal generation costs, in addition to the T&D benefits described above. If retail rates are based closely on the utility's marginal costs, then the impacts of NEM on non-participating ratepayers—positive or negative—will be minimized. However, rates typically are based on average or embedded costs, and as a result may depart, perhaps substantially, from marginal costs. The reasons for this departure from marginal cost-based rates are complex but often involve considerations such as universal access, equity, promotion of conservation and economic development. Furthermore, the centerpiece of the regulatory compact in the U.S. is providing the regulated utility with the opportunity to earn a reasonable return on its historical investments—a structure that naturally emphasizes rates designed on the basis of those historical, embedded costs. However, changes in retail rate design that move rates towards marginal costs represent one important avenue for addressing the ratepayer impacts of NEM.

For example, in states with significant low-cost base load generation, average rates tend to be well below marginal costs. In particular, retail rates often are much lower than the costs of the more expensive peaking power that are avoided by NEM exports from solar photovoltaics (PV). For example, in 2010, the Public Service of New Mexico (PNM) proposed a standby charge on new DG (mostly solar PV). The charge was based on the fixed T&D costs, which the utility alleged it would not recover from net metered DG. Analysis performed by the Interstate Renewable Electricity Council, however, showed that the benefits of this generation, based on PNM's own marginal costs[5], exceeded the lost revenues based on the utility's embedded cost rates for many customer classes, such that these classes should receive a standby credit rather than paying a standby rate.[6] The parties settled this case by supporting the utility's withdrawal of its proposal.

The opposite side of the coin is when rates are set artificially above marginal costs. The residential rate design for California's investor-owned utilities is an increasing block structure with four or five rate tiers. Since the 2000-2001 California energy crisis, increases to the rates for the first two tiers of usage have been limited by statute, resulting in very high, above-cost rates for usage in the two or three upper tiers. The CPUC conducted a cost-effectiveness evaluation of NEM in 2009, at a time when upper tier rates were close to their peak.[7] That study showed that NEM would result in a modest cost for non-participating ratepayers—a rate increase of 0.38 percent upon completion of the full build-out of the more than 2,500 megawatts of PV in the California Solar Initiative and its predecessor programs. Eighty-seven percent of this cost shift was the result of NEM in the residential market with these very steep tiered rates. Since 2009, the upper tier rates of California's three large investor owned utilities have dropped significantly, and statutory changes have allowed Tier 1 and Tier 2 rates to increase. The most recent cost-benefit analysis of NEM in the California market now shows that the net costs of residential NEM in California have dropped significantly, to the point that the costs and benefits are roughly equal—in other words, non-participating ratepayers should be indifferent to NEM.[8]

The results of cost-benefit evaluations of NEM will vary state-by-state, depending on rate structure, fuel costs, resource mix and other factors. However, in every case it is clear that the outcome is influenced significantly by retail rate design. The above examples show clearly that rate structures that more closely align rates with marginal costs (such as time-of-use rates for residential customers) result in reducing the costs of NEM for non-participating consumers, and that concerns with the cost-effectiveness of NEM can be addressed through standard cost-benefit analyses and rate design reforms.

More broadly, rate design will encourage customers to consider cost-effective forms of DG if rates provide customers with signals that reflect the long-term costs to provide service. In the long-run, few costs are truly fixed, and all utility facilities must be replaced. This suggests that economically efficient rates should use volumetric rate structures to the greatest extent possible, as customers have little ability to respond to rates that consist predominantly of fixed charges. Moreover, smart meter technology is now available, which allows all utility customers to be billed on a much more granular basis and which can provide consumers with more detailed feedback on their energy use. This will enable the broader adoption of precise and time-sensitive rate designs, replacing blunt instruments like the monthly maximum demand charge that are artifacts of older metering technology. A customer whose usage peaks at noon should not have to pay the same amount as another customer with identical peak usage, but whose peak coincides with the system peak at 4 p.m. Smart meter technology will not fulfill its promise unless it is accompanied by rate designs that are time- and usage-sensitive, providing customers with the information and ability to impact the amount, timing and costs of their electricity usage.

(Endnotes)

1 The PURPA requirements can be found in 18 CFR §292.303.

2 California Public Utilities Commission (2001). "The California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects." <http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF>

3 For example, due to NEM's more limited scope, an evaluation of the cost-effectiveness of NEM is a different inquiry than the assessing the costs and benefits of DG as a demand-side resource. Analyses of NEM are ratepayer impact measure (RIM) tests designed to assess the impacts of NEM on ratepayers who do not install DG, whereas assessments of the overall cost-effectiveness of DG as a resource typically will use broader, societal cost-benefit tests, such as the total resource cost (TRC) test, in addition to RIM tests.

4 Impact studies of large-scale DG programs such as the California Solar Initiative have shown that DG systems do reduce peak demands on both the transmission and distribution systems. *See* Itron, *2009 CSI Impact Evaluation Report*, at ES-17, at http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm; Itron, *CPUC Self-Generation Incentive Program—Sixth Year Impact Evaluation Report*, at 5-29 - 5-33 (Aug. 30, 2007), *available at* http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm.

5 PNM is the largest electricity provider in New Mexico.

6 See *Direct Testimony and Exhibits Of R. Thomas Beach On Behalf of the Interstate Renewable Energy Council in Support of Stipulation,* New Mexico Public Regulation Commission Case No. 10-00086-UT, at ¶¶ 13, 30 (Feb. 28, 2011).

7 California Public Utilities Commission (2010). "Introduction to the Net Energy Metering Cost Effectiveness Evaluation." <http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf>

8 Beach, R. Thomas, and Patrick G.(2013). "Evaluating the Benefits and Costs of Net Energy Metering in California." The Vote Solar Initiative. <http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf> This result is driven both by the reduction in upper tier residential rates in California since 2009 as well as by the higher avoided costs that reflect the fact that NEM exports are 100-percent renewable and will displace grid power that is 20-percent to 33-percent renewable.

APPENDIX B. ACRONYMS

AWEA	American Wind Energy Association
CEC	California Energy Commission
CPR	Clean Power Research
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
DG	distributed generation
FERC	Federal Energy Regulatory Commission
FIT	feed-in tariff
HECO	Hawaii Electric Company, Inc.
IDP	integrated distribution planning
IREC	Interstate Renewable Energy Council
ISO	Independent System Operator
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
MECO	Maui Electric Company, Ltd.
MW	megawatt
MW-dc	megawatts of direct current
NEM	net energy metering
NREL	National Renewable Energy Laboratory
PNM	New Mexico's largest electricity utility
PUC	Public Utilities Commission
PURPA	Public Utilities Regulatory Policies Act
PV	photovoltaics
QF	qualifying facility
RAM	Renewable Auction Mechanism

REC	Renewable Energy Credit
RE Futures	Renewable Electricity Futures study
Re-Mat	renewable market adjusting tariff
RFP	request for proposal
RPS	renewable portfolio standard
RTO	Regional Transmission Organization
SCEPA	State Clean Energy Policies Analysis project
SCG	Small Customer Generator
SGIP	Small Generator Interconnection Procedures
SolarDS	Solar Deployment System model
T&D	transmission and distribution