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Designing Distributed Generation Tariffs Well

Fair Compensation in a Time of Transition

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List of Acronyms and Abbreviations

AMI	Advanced Metering Infrastructure
CHP	Combined Heat and Power
CPP	Critical Peak Pricing
DG	Distributed Generation
EIA	(U.S.) Energy Information Administration
EPACT	Energy Policy Act of 2005
FERC	Federal Energy Regulatory Commission
FIT	Feed-In Tariff
IOU	Investor-Owned (electric) Utilities
kW	Kilowatts
kWh	Kilowatt-Hour
LCOE	Levelized Cost of Energy
LRAM	Lost Revenue Adjustment Mechanisms
MECO	Maui Electric
MW	Megawatts
MWh	Megawatt-Hour
NEM	Net Energy Metering
O&M	Operations and Maintenance
PAC	Program Administrator Cost (Test)
PCT	Participant Cost Test
PUC	Public Utility Commission
PURPA	Public Utility Regulatory Policy Act of 1978
PV	Photovoltaic
QF	Qualifying Facility
REC	Renewable Energy Credit
RIM	Ratepayer Impact Measure (Test)
RPS	Renewable Portfolio Standard
RTP	Real-Time Price
SCT	Societal Cost Test
TOU	Time-Of-Use (Pricing)
TRC	Total Resource Cost (Test)
UCT	Utility Cost Test

Executive Summary

Customer resources are playing a significant and growing role in the power sector. A number of factors have combined to produce significant increases in distributed generation (DG) adoption in the United States recently, including improving economics as a result of improved technology cost and performance, lower gas prices, and favorable policy environments in many states. Energy efficiency and demand response resources have become accepted as the most cost effective resource in many states and the scope of services these resources provide is expanding as electricity markets and institutions catch up with information, communications and electric control system capabilities. Add to these the possibilities for storage and it seems clear that the quantity and scope of the services that customer sited resources will provide is becoming a cornerstone in the power sector of the future.

Given the central role of customer side of the meter resources, regulators need to be proactive in ensuring that they are fairly compensated. Failure to recognize the value of services provided will impede their maturation, lead to unnecessary investment in redundant resources and thus impose unnecessary costs on all electricity customers. At the same time, the electricity grid will continue to provide important services to customers, and regulators will need to ensure that utilities are adequately compensated for these services. From a theoretical perspective, it appears that we are heading toward a point where the exchange of service will be at least a two way transaction. Introduce the role of third party aggregators and intermediary service providers and we appear to be trending toward what some have called a transactive energy economy.

A series of trends are leading towards a more transactive economy. For instance, many customer resources in many regions have already established themselves as cost effective resources that can provide valuable services to the power sector. Communications and electric system control technologies will continue to prod evolution and innovation in the power sector, and a time will come where markets, institutions and regulators will figure out how to align institutional capabilities and regulation with the underlying capabilities of all resources. There is tremendous uncertainty regarding how and when we will collectively learn how to take advantage of the tremendous opportunities that technology offers. In short, we are in a time of transition where we can see the two-way and multi-party transactive future but we still live with legacy infrastructure and legacy institutions.

The regulator's challenge in this time of transition is to support policies that use the legacy systems wisely while nurturing the evolution of the systems that will facilitate the transition to a far more efficient, environmentally benign transactive electricity sector. This paper is intended to help regulators in managing that transition with respect to nurturing the development of the distributed energy resource sector. The fundamental principle we address is that of fair compensation.

The achievements on the customer side of the meter are an economic, policy and marketing success story for many, but the reality is that this success story is not celebrated in all corners. Some utilities have expressed concern that DG adopters are undermining the financial foundation of the electric system. They argue that DG is failing to pay its fair share for its use of (and the ongoing dependence of its owners on) the electric grid. DG developers and advocates argue that the value being provided to the electric system exceeds the cost that ratepayers contribute, and so, if anything, they are being under-compensated for the services they provide. And some consumers argue that they are unfairly subsidizing DG adopters.

Regulators charged with protecting the public interest by fairly balancing the interests of stakeholders and consumers are listening and asking whether the compensation established when penetration of DG was relatively low remains appropriate at higher penetration levels. Regulators are looking for the well-designed tariff that compensates DG adopters fairly for the value they provide to the electric system, compensates the utility fairly for the grid services it provides, and charges non-participating consumers fairly for the value of the services they receive.

The purpose of this paper is to communicate regulatory options in this time of transition. We encourage regulators to think ahead and make decisions that support a more transactive energy future. But we understand that these forward looking decisions have to be made with the legacy system we have to work with today. Thus we start by considering DG tariffs for distributed energy resources less than 20 megawatts that we have today and ponder what regulators should consider as they weigh the benefits, costs and net value to stakeholders and society as a whole in setting the terms of these tariffs.

We focus on the tariffs we have to work with today because we believe that implementing these tariffs well is the most realistic option for many places in the country. We then introduce the idea of a two way distribution tariff with full recognition that implementing such an innovative tariff may not be possible in some places because the legacy institutions and metering technology have not caught up with the technological opportunities, but also with full hope that regulators will be considering the transition to a more transactive energy economy as they use the tools in their hands today.

The primary focus of the paper is on designing tariffs that ensure fair compensation for clean, distributed energy resources ranging from solar photovoltaic to combined heat and power resources. This focus should not be construed to be a concession that interconnection rules and other system charges such as standby rates are not important. To the contrary, addressing all barriers to beneficial DG is important but this document is focused on tariffs to keep the scope manageable. We include specific recommendations on implementing net energy metering (NEM) and feed-in tariffs (FIT) in the paper but in this executive summary we will focus on the overarching recommendations we have for regulators as they seek to implement tariffs that embody fair compensation in this time of transition.

Recommendations for Regulators

1. **Recognize that value is a two way street.** Customer side of the meter resources like DG, energy efficiency, demand response and storage are resources that produce value for the electric system. The electricity grid offers valuable services to DG customers and it will continue to do so for the foreseeable future. Customers, the utility and third party participants in exchanges should all be fairly compensated for the services they provide each other with due consideration of the full range of benefits and costs associated with each service delivered.
2. **DG should be compensated at levels that reflect all components of relevant value over the long term.** The DG resource provides a broad range of services and values and should be fully compensated for those values. This means including avoided energy and capacity cost, as well as the avoided generation, distribution, and transmission, avoided line losses, avoided price and supply risks associated with renewable, non-fossil resources and all other utility system benefits identified in Section 2. It should be recognized that the placement of DG in the network may avoid more or less future costs depending on the specific location.
3. **Select and implement a valuation methodology.** DG resources provide utility system benefits and non-energy benefits. There are many sources of benefits and costs that should be accounted for to fully value a DG resource. The regulator should decide on a methodology and implement the methodology consistently so that DG resources are fairly valued and the presence of any potential inequities can be judged objectively.
4. **Remember that cross-subsidies may flow to or from DG owners.** Regulators should remain objective and allow for the possibility that the value provided to all customers by DG may be greater than the costs incurred to support the presence of DG tariffs. Conversely, regulators should be open to the possibility that non-participating customers may be getting less value from DG than they are paying to support those tariffs.
5. **Don't extrapolate from anomalous situations.** Some places, like southern California, have very high tail block electricity rates which are far in excess of long run marginal costs of service. Problems that have arisen in that situation, or any other relatively anomalous situation, should not be used to drive policy or tariff solutions in states with completely different situations. Regulators should build policies, regulations and tariffs that recognize the characteristics of their state and the utility in question. See Bird, et al. (2013) for a list of questions that regulators can ask stakeholders to diagnose the characteristics of their specific context.

6. **Infant-industry subsidies are a long tradition.** Land grants to railroads were used to encourage construction of infrastructure in the 1800s. Air mail contracts helped launch commercial air service. Military contracts helped subsidize the development of semiconductors. At some point an industry becomes mature, and should compete without subsidies, but regulators should be mindful that financial assistance to prove up promising new industries is a long-established practice.
7. **Remember that interconnection rules and other terms of service matter.** The focus of this paper has been on tariffs but that does not mean that interconnection rules and other terms of service, like standby charges are not important. To the contrary, DG should have fair and open access to the grid at non-discriminatory terms and rates, and regulators should ensure such access through administered rules and incentive programs. Incentive programs for utilities to move their open access beyond established rules to "best in class" open access innovation should be considered by regulators.
8. **Tariffs should be no more complicated than necessary.** Remembering Bonbright (1961): Tariffs should be practical. Tariffs should be simple, understandable, acceptable to the public, feasible to apply, and free from controversy as to their interpretation. Established tariffs like the NEM tariff have the virtue of being simple and relatively well-understood. At the same time, NEM tariffs are a blunt instrument and their inherent imprecision should be acknowledged. The alternatives, however, may be too complex for consumers to fully understand. In weighing the policy, regulation and tariff options possible for DG one should keep in mind both the virtue of simplicity and the virtue of adequate precision as one deliberates on fair compensation.
9. **Support innovative business models and delivery mechanisms for DG.** Leasing and aggregation of loads for NEM have been game changing approaches that have significantly supported solar PV uptake in Colorado, California and elsewhere. These approaches support cost-effective deployment of DG policy and should be encouraged. They make it possible for lower-income consumers and even renters to participate in DG development. For a more complete discussion of business model approaches for solar PV see Bird, et al. (2013).
10. **Keep the discussion of incentives separate from rate design.** In seeking to identify a rate design that provides fair compensation across the board, regulators should keep separate any discussion of specific incentives to support a specific technology. Rate design should be about fair compensation for value of services provided and fair allocation of the costs to reliably operate the system. If policy makers feel for any reason that additional incentives are warranted, those incentives should be added in a transparent manner that does not distort or obscure the assessment of fair compensation.
11. **Keep any discussion of addressing the throughput incentive separate.** Accounting for utility lost revenues associated with declining utility load may be an issue that regulators want to address. There are regulatory treatments like decoupling that can effectively address that concern. But the discussion of addressing the throughput incentive and rate design for DG tariffs should be considered separately.
12. **Consider mechanisms for benefitting "have not" consumers.** With current financing mechanisms, low-income consumers will not be likely investors, owners, or even hosts to renewable energy resources. Ensuring fair compensation for the value of electric services provided will protect low income customers from being over-charged, but any incentives implemented with ratepayer funds to support any DG technology will end up primarily in the pockets of relatively wealthy customers who can afford to invest capital in DG or who have a high enough credit rating to qualify for leasing contracts. Since low income customers contribute to the revenue pool that supports incentive payments, it is fair for them to benefit from at least a pro-rata portion of their contribution toward these payments. Regulators can support programs such as group NEM that make use of these funds to offer benefits directly to lower income consumers, and they should choose programs that demonstrate the greatest benefit per dollar invested. These will often be energy efficiency programs and perhaps demand response programs and hot water storage programs, but less often renewable energy programs.

While the urgency to address compensation of distributed solar PV is highest in those states where its penetration is highest, trends of declining PV installed cost and increased customer choices suggest that these matters will come to most if not all regulatory commissions sooner or later. The principles we enunciate here are intended to guide regulators as they evolve their DG tariffs to address the concerns being heard from different corners today as well as to position the power sector to take advantage of the best new technologies as they become available. The over-riding principle we suggest is one of fair compensation: fair compensation for all who provide power sector services, fair compensation for the value delivered for services provided, fair compensation so that customers are not over-charged for the services they receive, and fair compensation so that valuable services will be compensated and grow as customer preferences and technological capabilities evolve.

Introduction

Improvements in distributed generation (DG) economics, increasing consumer preference for clean, distributed energy resources, and a favorable policy environment in many states have combined to produce significant increases in DG adoption in the United States. The entry of a new class of third-party providers of solar through leasing arrangements has added to the growth in demand. This has been especially true for customer-sited solar photovoltaic (PV) systems in the United States. Distributed PV cost reduction has been dramatic. The price of PV modules has dropped from about \$4/W_{DC} to about \$1/W_{DC} over the last six years. Residential and small commercial system installed costs have dropped from about \$9/W_{DC} to almost \$5/W_{DC} over the same period.[1] During this same time period the quantity of distributed PV installed has increased from well less than 1 GW to over 3 GW. In some regions DG is on a path to materially contribute to the resource mix.[2]

While adoption rates of other DG technologies have not increased as dramatically as adoption rates for PV, other technologies are experiencing favorable economics that could lead to increased adoption, and concerns over energy security and grid resilience suggest that these additional sources of DG could gain further momentum. Combined heat and power (CHP) distributed 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). The costs of other DG technologies such as anaerobic digesters and wind turbines also continue to decline.

Technology improvements, lower costs, and increased consumer demand for cleaner sources have resulted in increased market acceptance. Although this sounds like an economic, policy, and marketing success story, it is not celebrated in all corners. Some utilities have expressed concern that DG adopters are undermining the financial foundation of the electric system. They argue that DG is failing to pay its fair share for its use of (and the ongoing dependence of its owners on) the electric grid. Indeed some consumer advocates express concern that net-metered DG adopters are being subsidized by customers who cannot afford to become adopters themselves. Because bundled rates typically include distribution system costs, costs that exist with or without the deployment of DG systems, net energy metering (NEM) customers sometimes make no contribution toward those costs. Either the company must go uncompensated or those costs must be covered elsewhere in rates. More broadly, consumer advocates want to ensure that non-participating consumers are not unfairly subsidizing distributed generators. DG advocates counter that the value provided by distributed systems goes beyond the benefits provided to the adopter alone. These advocates argue that all of the value provided to consumers and the utility should be counted, including all avoided generation, distribution, and transmission costs, all reduced line loss benefits, and a number of non-energy benefits.

Regulators charged with protecting the public interest by fairly balancing the interests of stakeholders and consumers are listening and asking whether the compensation levels they established when penetration of DG was low remains appropriate at higher penetration levels. Regulators are also concerned with identifying and quantifying all benefits and costs associated with DG installation so that the net cost or benefit to non-adopting consumers and the utility are fairly considered. Fair interconnection rules and non-tariff barriers are also important for regulatory attention, but this paper focuses on translating fair valuation of distributed resources and grid services into fair tariffs.[3]

In order to fairly assess the DG debate, one must first be clear about what DG is and understand the DG tariffs in effect today. The paper begins by defining terms

1 Barbose et al., 2013.

2 Bloomberg New Energy Financie, 2013.

3 For a good discussion of interconnection issues see DOE SEE Action Report, 2013.

and current tariffs carefully. Section 2 then enumerates what regulators should consider as they weigh the benefits, costs, and net value to DG adopters, non-adopters, the utility, and society as a whole. Section 2 concludes by emphasizing the importance of aligning the tariffs, tariff conditions, and ratemaking treatments (such as decoupling and incentives) with the valuation methodology that best promotes fairness and the public interest in the context of the State and utility under consideration. Section 3 offers DG rate design and ratemaking options for regulators to consider. The section concludes with recommendations for fairly implementing tariffs and ratemaking treatments that promote the public interest. This paper does not seek to address all issues important to the DG discussion today. For example, while we do address the need to reduce solar soft costs to levels seen in places like Germany, we are not evaluating the needs of the DG developers to create a financially stable developer industry and we are not addressing the whole range of barriers like ease of interconnection and reasonableness of standby rates. Each of these issues deserves to be addressed. Indeed, as we continue to discuss regulation and the power sector of the future these issues, along with the tariff issues we address here, will be important.

Section 1: Distributed Generation 1.0

"Distributed generation," the focus of this paper, is a widely used term that has no universally accepted definition. Public utility regulation is a highly decentralized function in the United States, and DG – like so many terms – has been defined and interpreted in significantly different ways across federal, state, and local jurisdictions. But for the purposes of this paper, we will use a simple and practical interpretation of DG that is grounded in relevant federal statutes and regulations. We will define DG to refer to generating facilities with a rated capacity of 20 megawatts (MW) or less that are interconnected to the distribution system (i.e., not directly connected to high voltage transmission lines) but are not owned by the distribution utility.

The Utility "Purchase Obligation"

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 the Federal Energy Regulatory Commission (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 nondiscriminatory toward qualifying facilities. 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 qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source").[4]

Under federal law, a "small power production facility" is a generating facility of 80 MW or less whose primary energy source is renewable (hydro, wind, or solar), biomass, waste, or geothermal resources.[5] In order to be considered a *qualifying* facility (QF), a small power production facility must meet all of the requirements in FERC rules for size, fuel use, and certification.[6] A "cogeneration facility" is a generating facility of any size or primary energy source that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy. In order to be considered a QF, a cogeneration facility must meet FERC requirements for operation, efficiency, use of energy output, and certification.[7] In today's terminology, cogeneration facilities are more commonly called "combined heat and power" (CHP) facilities.

There are some instances in which utilities do not have to meet their federal purchase obligation. This happens if a small power production facility or cogeneration facility

4 The question of how to interpret and calculate avoided costs is somewhat beyond the scope of this section. It is not straightforward, despite the statutory language, and has been extensively debated and litigated. In response to a petition from the California Public Utilities Commission, FERC issued a clarification in 2010 of how it interprets avoided costs. Refer to 133 FERC ¶ 61,059 (2010) (October 21 Order Granting Clarification and Dismissing Rehearing). This FERC order provides a good summary of many of the current issues and numerous references to relevant case law. A basic discussion of avoided cost approaches is provided in Section 2.

5 There are some very limited exceptions. Certain small power production facilities designated under section 3(17)(E) of the Federal Power Act (FPA) (16 U.S.C. § 796(17)(E)) are exempt from the size limitation.

6 Refer to 18 C.F.R. §§ 292.203(a), 292.203(c) and 292.204 for size and fuel use requirements, and to 18 C.F.R. § 292.207 for certification requirements.

7 Refer to 18 C.F.R. §§ 292.203(b) and 292.205 for operation, efficiency, and use of energy output requirements, and to 18 C.F.R. § 292.207 for certification requirements.

has nondiscriminatory access to wholesale markets for the sale of electric energy and capacity. 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 U.S. wholesale electricity markets: the Midcontinent ISO, PJM Interconnection, New York ISO, ISO New England, and Electric Reliability Council of Texas.[8,9]

Furthermore, the FERC rules require each utility to offer standard rates for purchases from all QFs with a design capacity of 100 kilowatts (kW) or less.[10] 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. Federal requirements are summarized in Table 1.

Options for Fulfilling the Purchase Obligation

Federal law and regulations leave ample discretion to states and utilities on how to fulfill this purchase obligation. The issues they grapple with are not whether utilities should have to buy energy from distributed generators, but under what terms and at what prices. In practice, customers who own DG 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.[11] (For the reader's convenience, we will 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.

Table 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

8 A rebuttable presumption is an assertion that is presumed by 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 FERC to override the presumption. 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 paper limits the term "distributed generation" to generating facilities with a rated capacity of 20 MW or less.

9 For a map showing the territories served by these markets, refer to the ISO/RTO Council at http://www.isorto.org/site/c.jhKQIZPBImE/b.2604471/.

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

11 Throughout most of this paper, we will use the term "utility" as shorthand for all types of load-serving entities, including investor-owned utilities, publicly owned utilities, cooperatives, and competitive retail electric service providers. Where the distinctions are important, we will use more specific terminology.

- 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 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.

This paper focuses on the first option. There are two basic approaches to designing tariffs for customer-owned generation. Although there is a great amount of variation across jurisdictions in the terminology that is used, we define these two approaches as follows:

- **Net Energy Metering Tariff.** 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 as "net metering."
- **Standard Offer Contract.** 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 sources,[12] we will call this a "PURPA tariff" for reasons explained below. If the price the utility pays the customer exceeds the utility's avoided costs of procuring energy and capacity from unspecified sources, we will call the standard offer a feed-in tariff (FIT).

In addition to establishing a purchase obligation, PURPA created federal ratemaking standards for electric utilities. These standards were later amended by the Energy Policy Act of 2005 (EPACT) to add a specific ratemaking standard for NEM:[13]

"**Net metering**. Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term "net metering service" means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period."

PURPA and EPACT require state regulators to consider, but not necessarily adopt, a net metering standard.

Net Energy Metering Tariffs

Under a NEM tariff, a customer is billed by his or her utility or load-serving entity based upon net electricity consumption (i.e., the amount consumed minus the amount generated). For example, if the customer's system generated 1,000 kWh during a billing period, and the customer consumed 1,200 kWh during the same period, the customer will be billed for 200 kWh of purchased electricity (1,200 kWh minus 1,000 kWh). Net consumption can be measured either with a single meter that measures net energy and is capable of counting forward or backward, or with separate metering of the customer's generation and consumption and a mathematical calculation of the net value computed by the utility. The ability to use one meter represents the virtue of simplicity that characterizes NEM in many states.

NEM policies vary from state to state. First, and most obviously, is the variation in whether such a tariff is offered at all. Beyond that fundamental question, even where NEM is offered the details of the tariff can vary substantially in several respects. The most common and significant variations are:

- **Applicability of State Policies to Different Utilities.** NEM policies in some states apply to investor-owned electric utilities (IOUs) only,

12 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. For additional discussion on this point refer to Section 4.2 of Lazar and Colburn, 2013.

13 Refer to 16 USC 2621(d) for the current version of federal law with respect to ratemaking standards, as amended.

whereas in other states the policies apply to different combinations of IOUs, member-owned electric cooperatives, and publicly owned (e.g., municipal) electric utilities. Note that individual utilities that are not required by a state statute or state public utility commission (PUC) policy to offer NEM tariffs may elect to do so.

- **Eligible Technologies.** Despite the fact that the PURPA ratemaking standard required consideration of NEM for all forms of DG, in practice most states and utilities have more narrowly specified the technologies that are eligible for NEM tariffs. Fossil-fueled generators, including CHP systems and diesel generators, are eligible for NEM only in a small number of states.
- **Project Caps.** Almost all NEM tariffs include a maximum limit on the size of eligible DG systems, expressed either as a fixed limit on the rated capacity of the system or a limit relative to the customer's annual electricity consumption. These "project caps" sometimes vary from one customer class to another or from one resource type to another. For example, IOUs regulated by the State of Kansas limit NEM eligibility to residential systems with a rated capacity of 25 kW or less, whereas commercial and industrial systems of up to 200 kW capacity are eligible. In Wisconsin, all IOUs and municipal utilities must offer NEM for projects of up to 20 kW capacity, but some IOUs have been ordered to offer a higher cap (100 kW) for renewable energy projects.
- **Program Caps.** Many states and utilities have adopted caps on the total amount of DG eligible for enrollment under NEM tariffs. Program caps on NEM tariffs may be expressed as an absolute amount of installed capacity (e.g., 1,500 MW in Maryland) or as a percentage of the utility's peak load (e.g., five percent in Missouri).[14]
- **Treatment of Net Excess Generation.** NEM tariffs vary widely in terms of what happens when the customer's generation exceeds consumption during a billing period. In some jurisdictions (e.g., Arkansas and Montana), the value of this net excess generation is forfeited by the customer to the utility. In a few other jurisdictions (e.g., Georgia and Minnesota), the utility makes a cash payment to the customer for the value of the excess generation, which is typically calculated based on the utility's PURPA avoided cost rate. But in most jurisdictions, credits for net excess generation may be rolled over indefinitely from one billing period to the next. This can be especially helpful for customers who own PV systems that produce significant excess generation in the longer daylight of summer months but produce less than the customer's consumption in other months. Finally, some tariffs place a time limit (e.g., 12 months) on how long a credit for net excess generation can be applied to the customer's bill. At the end of the designated time period, the utility may retire the value of the credit or make a cash payment to the customer, again typically at a PURPA avoided cost rate.
- **Allocation of Renewable Energy Credits (RECs)**. State policies and individual utility tariffs also vary in the ways they treat REC ownership under NEM arrangements.[15] Most state policies grant ownership of any RECs created under a NEM tariff to the customer, or do not specify who owns the RECs. A few states (e.g., New Mexico) grant REC ownership to the utility or require

14 States report varying reasons for establishing program caps. These include uncertainty about a quantity or aggregated capacity of NEM projects that will materially affect system operation or reliability, awareness of quantity or capacity limits and a desire to stay below them, and concerns about limiting utility revenue erosion.

15 In 29 states, the District of Columbia, and two territories, some or all utilities are obligated by state policy to source a portion of the electricity they sell to retail customers from renewable resources. Furthermore, many of these state Renewable Portfolio Standard (RPS) policies have distinct provisions for customer-sited generation or solar power that supplement other RPS requirements. In addition to any such mandatory obligations, many utilities sell renewable energy or "green power" at a premium price to customers who ask for such service. Almost all of the RPS policies and green power transactions are built upon a system that issues a REC to the generator for each megawatt-hour (MWh) of qualifying renewable generation. In states that have distinct provisions for customer-sited generation or solar power, eligible generators may receive a special kind of REC (e.g., a solar REC or SREC) that is more valuable than a normal REC, or they may receive more than one ordinary REC for each MWh of eligible generation. Utilities must own and annually retire a number of RECs equal to their compliance obligation and green power sales. Most state policies also allow RECs to be traded through bilateral arrangements or on open markets.

sharing of the RECs between the customer and the utility. Where REC ownership is not specified in state policy, it may or may not be specified in an individual utility's tariff. Some states also require customers to transfer RECs to the utility if state or utility subsidies were used to support the installation of the system.

- **Meter Aggregation**. Nearly 20 states have adopted policies that allow for the aggregation of multiple meters under a NEM tariff. States vary in what they allow. Generally speaking, the output of a single generator is allocated to all of the participating meters and netted against the consumption measured on those meters as with other NEM tariffs. In the most limited form, meter aggregation applies only to a single customer who has a generator and multiple meters on the same property. In the broadest form, meter aggregation applies to a generator that may be owned by a utility, one or more customers, or a third party, the output of which is allocated to the meters of multiple participating customers on multiple properties (that need not be contiguous). This sort of arrangement is sometimes referred to as "group," "community," "neighborhood," or "virtual" NEM or aggregation.

A summary of these policy attributes for the states that have adopted NEM policies can be found in the online appendices for this document.[16]

Feed-In Tariffs

When a utility offers a FIT, it essentially offers to enter into a long-term power purchase agreement, under standard (non-negotiable) terms and conditions, with any customer who meets specified eligibility criteria. In this paper we distinguish a FIT from a PURPA tariff by further stipulating that a FIT offers the customer a price that exceeds the utility's avoided costs of purchasing unspecified energy and capacity.

Most FITs are structured in such a way that the utility agrees to pay the customer a fixed price for every kWh the customer generates over the duration of the contract. An alternative, less common structure is one in which the customer is offered a fixed premium for every kWh that is added to a base price that is more variable. For example, the "Cow Power" FIT offered by Green Mountain Power in Vermont offers to pay a guaranteed premium of four cents, over and above a PURPA avoided cost price that may vary over time, for every kWh of electricity generated from biogas systems on farms. Under either a fixed price or a fixed premium FIT structure, the customer continues to *purchase* electricity under a separate retail tariff.[17]

Eight U.S. states have FIT policies, some of which do not apply to all types of utilities. FITs are also offered by a relatively small number of utilities that are not subject to a state policy. But in any event, most U.S. utilities do not offer FITs. And even where FITs do exist, the policies vary from state to state and the tariffs vary from utility to utility in some significant ways. We've already discussed how FITs vary in terms of whether they are expressed as a fixed price or a fixed premium. Beyond that fundamental difference in tariff structure, the most common and significant areas of variation in FITs are:

- **Applicability of State Policies to Different Utilities**. As with NEM policies, FIT policies can be established either by a state legislature or by a state PUC and may apply to different combinations of IOUs, electric cooperatives, and municipal electric utilities.
- **Eligible Technologies**. The DG technologies that are eligible for a FIT vary from one jurisdiction to the next, and are noted in each policy. For example, the State of Oregon requires IOUs to offer a FIT for solar PV systems only. In contrast, the Hawaii PUC has ordered IOUs to offer FITs for solar thermal, PV, landfill gas, wind, biomass, hydroelectric, geothermal, municipal solid waste, small hydroelectric, tidal energy, wave energy, and ocean thermal systems. California's FIT policy similarly applies to many technologies, but CHP facilities are only eligible if they are sized to the facility's thermal load and meet certain efficiency requirements.
- **Project Caps**. As implemented in the United States, each FIT includes a maximum limit on the rated capacity of eligible systems.

16 Online appendix is available at: http://www.raponline.org/document/download/id/6897. The Database of State Incentives for Renewables & Efficiency (DSIRE), http://www.dsireusa.org/, is also an excellent resource on this topic.

17 We will not discuss the retail tariff under which the FIT customer purchases electricity from the utility, but a critically important issue for many CHP facilities is the level of the standby rates that the utility charges. Standby rates are intended to compensate the utility for any costs associated with preparing for contingencies in which the CHP unit is unable to generate at a normal or expected level, as well as the costs of providing any supplemental power that the customer requires beyond what the CHP unit can produce. See Selecky et al., 2013 for an evaluation of the standby rate issue.

- **Program Caps**. FIT programs in the United States also have program caps, but there is some variability in how the caps are expressed. The typical formulation is that a FIT will be offered until the total aggregated amount of capacity enrolled reaches some maximum rated capacity. In order to encourage diversity in customer participation, policymakers sometimes impose multiple caps that are applied to different combinations of utility type, customer class, generating technology, or project size. The State of California offers an example not just of the typical formulation for program caps, but also of how multiple caps may be applied simultaneously. California's FIT legislation requires IOUs and municipal utilities to offer FITs until 1,000 MW of new capacity is enrolled across the state. But within that overall cap, there are separate program caps for IOUs (collectively) and municipal utilities (collectively); for bioenergy and all other eligible resources; and for different technologies within the bioenergy category.[18]
- **Basis for Determining Prices**. The prices paid to customers under a FIT can be determined through either of two procedural methods:
  1. The most common method historically has been for the utility or the PUC to set FIT prices through an administrative process, such as a normal tariff proceeding. In some of these jurisdictions, FIT prices are based primarily on estimating the generator's costs. If, for example, the cost of generating electricity from biogas on a dairy farm averages 12 cents per kWh, the FIT rate for biogas might be set at or around 12 cents. In some other jurisdictions using an administrative process, FIT prices are based on a premium added to the utility's PURPA avoided cost rates or a market rate, or based on the value of the output to the wider electric grid, irrespective of the generator's costs. For example, a FIT might be set at a rate equal to the utility's PURPA avoided cost rate *plus a premium* of two cents per kWh.[19] Because it is fairly standard for utilities to be granted ownership of any associated RECs as part of a FIT transaction, the estimated value of the RECs to the utility (for RPS compliance, for trading, or for sale under a "green power" program) may be explicitly or implicitly factored into these administratively determined prices or premiums.
  2. An entirely different procedural method for setting FIT prices is to use a competitive procurement process. With this kind of method, the utility establishes all of the terms and conditions of the FIT except the price and then solicits price bids from potential participants through a Request for Proposals or a reverse auction.[20] In the United States, there appears to be a trend toward this kind of process. Competitive procurement methods were recently adopted in California, Maine, Oregon, Rhode Island, and Vermont.[21]

  Regardless of the method used to set prices (administrative or competitive), it is common for a state or utility FIT policy to have multiple categories of eligible systems, each receiving a different rate or premium. This is to be expected, because the generator's costs, the utility's avoided costs, and the system value of DG all vary with the generating technology, system size, and location.
- **Rate Stability/Adjustments.** FITs are structured to provide the participating customer with stable terms and conditions, including the rate or premium paid, over a long period of time. FIT policies vary in terms of how long that period lasts, but 5 to 20 years is the norm in the United States. A few U.S. jurisdictions have also adopted a rate adjustment

18 A much less common formulation for program caps is to limit participation based on the total amount of energy sold under the tariff, or the total incremental cost paid by the utility. For example, some Wisconsin utilities have offered FITs with the program cap expressed as a percentage (0.5 percent or 0.25 percent) of retail kWh sales from the prior calendar year.

19 If the rate were set exactly equal to avoided costs, with no premium, it would be what we call a PURPA rate rather than a FIT.

20 A reverse auction is an auction in which the bidders offer a price at which they are willing to sell electricity, rather than a price at which they are willing to buy. The utility selects the lowest priced bids that meet its procurement needs. In some cases, all accepted bids are granted a "clearing price" (i.e., the price offered by the most expensive accepted bid).

21 When prices are set through a competitive process, they could conceivably end up at a price that is less than the utility's avoided costs for unspecified energy and capacity. Technically, using the terminology we have adopted for this paper, the resulting tariff would thus be a PURPA tariff rather than a FIT.

policy called "degression," in which the FIT rates offered to newly participating customers decline over time in a predictable fashion. This means that each customer enjoys stable terms and conditions for the duration of his or her own contract, but a customer who enrolls today will be paid a higher price than one who enrolls in the future. An example of degression can be found in the FITs offered by the Los Angeles Department of Water and Power. Los Angeles Department of Water and Power announced before it launched its FIT program that it would reduce the base price paid to participating customers by one cent per kWh after total enrollment reached 20 MW, and reduce it by one more cent each time another 20 MW of capacity was enrolled in the program.[22]

A summary of these policy attributes for the states that have adopted FIT policies and for a sampling of the FITs offered by individual utilities can be found in the online appendix for this document.[23]

Although this paper is not intended to represent a precise or thorough treatment of legal issues raised by FITs and NEM, it is worth noting in brief that there has been a great deal of confusion and some litigation in the United States regarding the legality of FITs.[24] PURPA explicitly prohibits states from ordering utilities to purchase energy from QFs at state-specified rates that exceed the utility's avoided costs. Superficially, this would seem to prohibit FITs, which by our definition offer the customer a price that *exceeds* the utility's avoided costs.

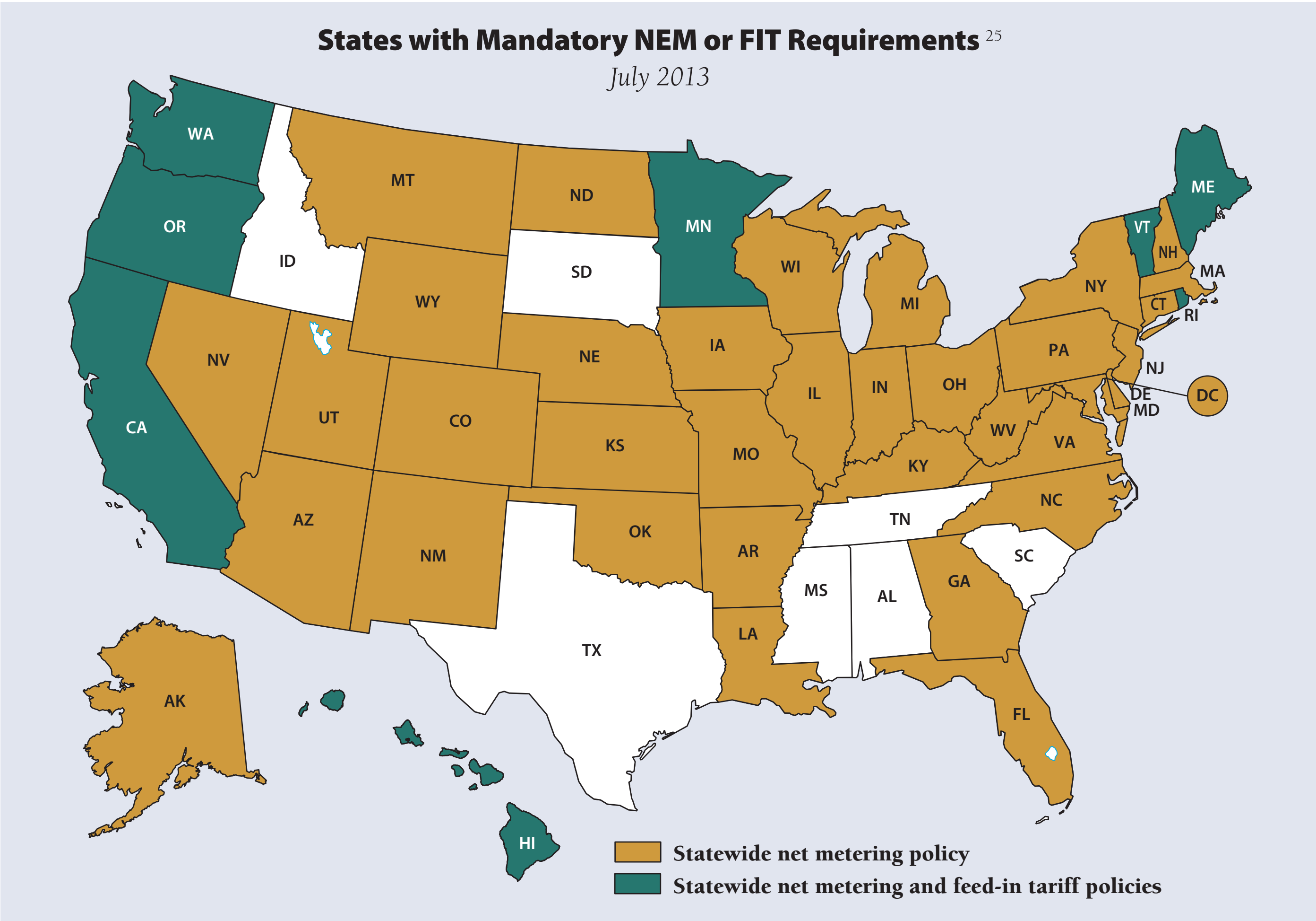
22 Outside of the United States, some FITs also include an automatic adjustment to the rate based on inflation. The authors are unaware of any U.S. jurisdiction that has adopted this policy option.

23 Online appendix is available at: http://www.raponline.org/document/download/id/6897. Here again, the Database of State Incentives for Renewables & Efficiency (DSIRE), http://www.dsireusa.org/, is another excellent resource.

24 For a detailed discussion of legal issues, refer to Hempling et al., 2010.

25 Based on information compiled in the Database of State Incentives for Renewables & Efficiency (DSIRE), http://www.dsireusa.org/.

Figure 1



However, states have adopted a variety of approaches to reconcile this apparent contradiction. These approaches include allowing utilities to voluntarily offer FITs at a price decided by the utility; allowing market actors rather than the state to determine FIT prices through a FIT auction mechanism; defining the character of power obtained through renewable energy FITs as different in substance than "avoided cost" power; and using taxpayer or voluntary "green power" customer money rather than general ratepayer money to pay for any FIT costs above the utility's avoided costs.

Net Energy Metering and Feed-In Tariffs in the United States Today

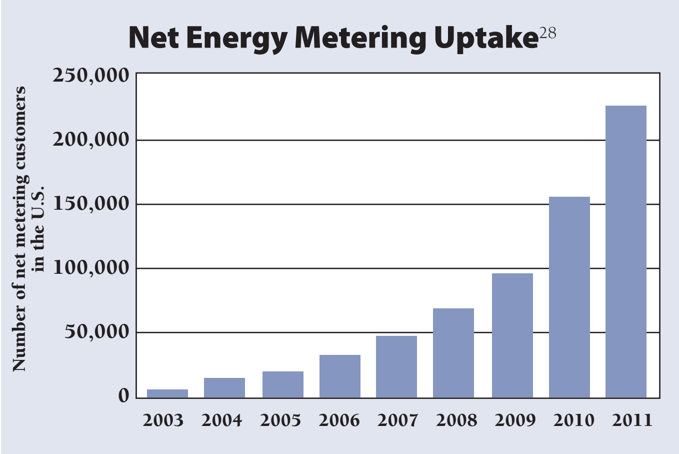
Even though implementation of the federal ratemaking standards in PURPA was not mandatory, legislatures or PUCs in nearly all states have implemented NEM requirements for some or all types of utilities. FITs, on the other hand, have been extremely widely adopted internationally but are still far less common than NEM tariffs in the United States.[26] Figure 1 indicates the states that have adopted mandatory NEM or FIT policies. Note that these state policies do not necessarily apply to all utilities in each state, and some utilities offer NEM or FITs even in the absence of a state mandate.

The fact that most NEM and FIT policies include program caps suggests that these tariffs have been implemented by states and utilities not as a way to procure the lowest cost system resources, but rather as a policy mechanism to accelerate the deployment of renewable generation and DG or to support the maturation of infant industries. Judged on that basis, both types of tariffs have proven to be quite successful.

Figure 2 summarizes the number of customers enrolled under NEM tariffs. In 2003, prior to the enactment of EPACT and the creation of a federal NEM standard, fewer than 7,000 customers in the entire country were net metered. Less than ten years later, that number had grown to over 225,000 net-metered customers, a thirtyfold increase. In terms of capacity, the same data show that 2,688 MW of generating capacity was enrolled in NEM tariffs at the end of 2011.[27]

NEM has been especially popular as an option for customers owning PV systems. The EIA report 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

Figure 2



were on NEM tariffs, totaling approximately 3.5 GW of capacity.[29] This suggests that more than a MW of new PV systems enrolled in NEM tariffs in 2012 alone.

An important innovation that has emerged in the NEM space is Community Aggregation NEM. Community Aggregation NEM offers apartment dwellers and those who do not have roofs amenable for solar to share in distributed solar investment, and thus it opens participation in NEM to a much larger segment of the population. See the text box on Community Aggregation for NEM on the following page for more on this innovation.

The EIA has not collected similar comprehensive national data on FIT enrollment. Anecdotal evidence for the uptake of FITs in specific jurisdictions can be found from a variety of utility regulatory filings, press releases, and utility or PUC reports. This evidence suggests that FITs, where they are offered, can be at least as popular with customers as NEM tariffs and that FITs have supported the deployment of a more balanced mix of

26 In fact, according to REN21, Renewables 2013 Global Status Report, "FITs are the most widely adopted renewable power generation policy... As of early 2013, 71 countries and 28 states/provinces had adopted some form of FIT." Some foreign jurisdictions have developed creative and innovative variations on the two basic FIT structures described in this paper, but this paper is focused only on FITs in the United States and does not attempt to capture all of those alternatives.

27 U.S. Energy Information Administration, 2011.

28 Based on U.S. Energy Information Administration, 2011.

29 For more information, refer to http://www.solarelectricpower.org/media/279520/sepa-top-10-executive-summary_final-v2.pdf.

Community Aggregation for Net Energy Metering

Many states (shown in Figure 3) have adopted policies that allow for the aggregation of multiple meters under a net metering tariff.

Advocates for meter aggregation point to several benefits that this kind of policy provides to participating customers, including:

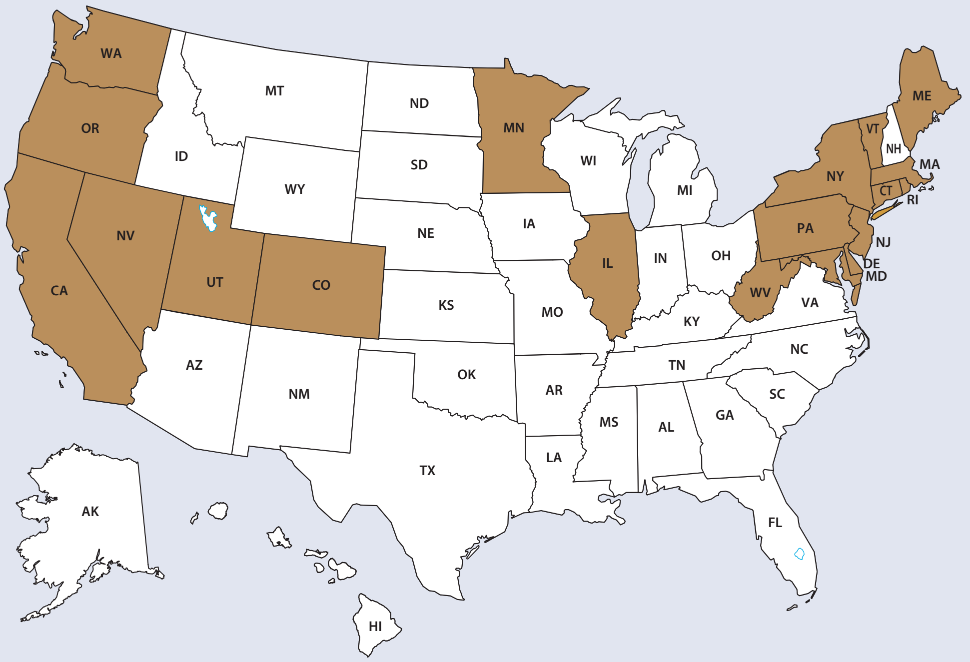
- Aggregation allows more customers to potentially benefit from net metering. Customers who rent a property normally can't install DG, but they might be able to "buy a share" of the output of a generator and apply it to the home or commercial space they are renting. Similarly, customers who own a property that is ill suited for DG (e.g., they can't install PV because their roof is shaded) can also participate and benefit.
- Larger DG systems can be installed that may benefit from economies of scale. For example, the cost of installing a 20-kW PV system on one property will generally be less than the cost of installing two 10-kW systems on separate properties.
- DG can be sited in optimal locations instead of always having to site it on a single participating customer's property. For example, an aggregation of commercial customers could site a wind turbine on the property of the one customer who has the best wind profile, such that the output is much greater than would be the case if each customer sited a smaller generator on their own property. Or alternatively, a generator serving multiple net metering customers could be sited in a location where it alleviates (rather than exacerbates) a distribution system operational problem.

Detractors of meter aggregation policies point to the same concerns that arise with NEM in general, some of which can be exacerbated by aggregation. Although these policies will tend to promote even greater deployment of DG, they will also further erode utility kWh sales and, at least in the short term, increase the pressure to raise rates. In addition, these policies can potentially encourage the deployment of higher capacity variable energy resources that add to the utility's challenge of balancing load, managing the distribution system, and providing reliable service.

Where meter aggregation is allowed, the costs and benefits of DG under a NEM tariff can be significantly different, especially from a participating customer's perspective. However, from the utility's and non-participants' perspectives, the changes won't always be as significant, assuming that other restrictions and caps in the policy are unchanged. If a state allows meter aggregation but has a NEM program cap, then aggregation might change who participates and how much they individually benefit without changing the cumulative amount of DG deployed or the impact on the utility and non-participants. Policymakers considering aggregation need to recognize that the design of the policy and ensuing tariffs will shape whether meter aggregation benefits all stakeholders or benefits some at the expense of others.

Figure 3

States Allowing Meter Aggregation for Net Energy Metering



resources than NEM tariffs.[30] One of the most consistent themes relating to FITs is that they are often launched with relatively modest program caps, and then reach full enrollment in relatively short amounts of time. For example:

- Gainesville Regional Utilities reached the initial 4-MW annual program cap for its solar FIT in just three weeks; annual caps have also been reached in subsequent years.
- Long Island Power Authority nearly fully subscribed its 50-MW FIT program in the first year it was offered; and
- Northern Indiana Public Service Corporation approached the 30-MW program cap for its FIT after just two years.

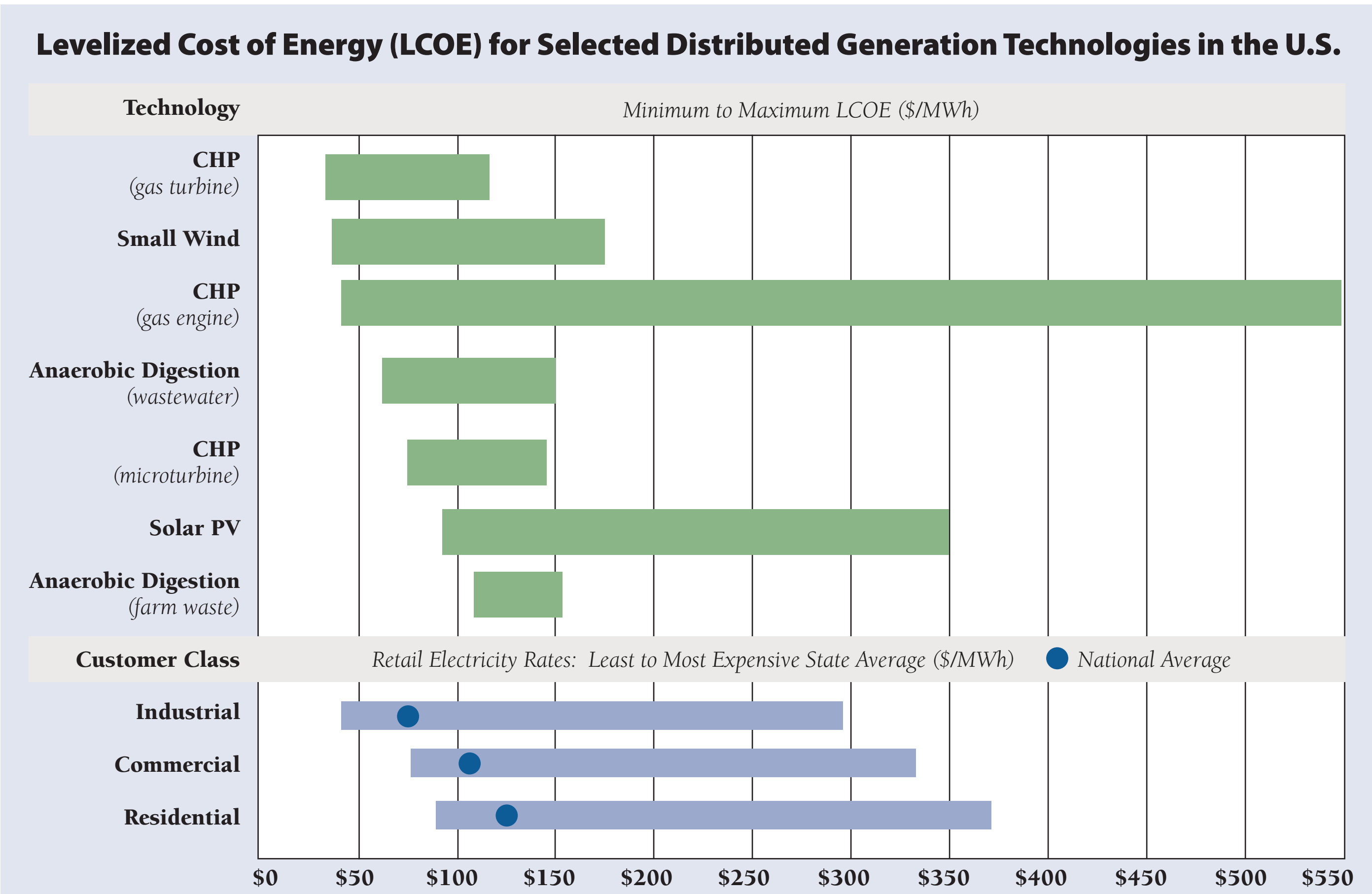
30 For example, a 2010 status report on the FITs offered by Wisconsin utilities found that PV systems represented just 15 percent of the installed capacity enrolled in FITs, while biogas and wind systems represented 71 percent and 14 percent, respectively. See Public Service Commission of Wisconsin, 2010. http://psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=143806.

Section 2: Benefits, Costs, and Valuation Perspectives

The electric power industry looks very different today than it did in 1978 when PURPA created the purchase obligation that provided the first real impetus for DG. To begin with, the costs of DG have declined dramatically. This is reflected in the "levelized cost of energy" (LCOE), a common metric for comparing generation costs of different technologies.[31] In many cases, the LCOE for DG technologies is now close to or even less than the retail cost of delivered electric power, as indicated in Figure 4. The decline in solar PV has been especially dramatic in the last few years, as shown in Figure 5, and there are reasons to believe that prices will continue to decline in the United States. Feldman et al. report that the installed cost of solar PV in the United States is more than double the installed cost in Germany and they attribute the disparity to differences in "balance of system" costs.[32]

At the same time, we are seeing several forms of

Figure 4



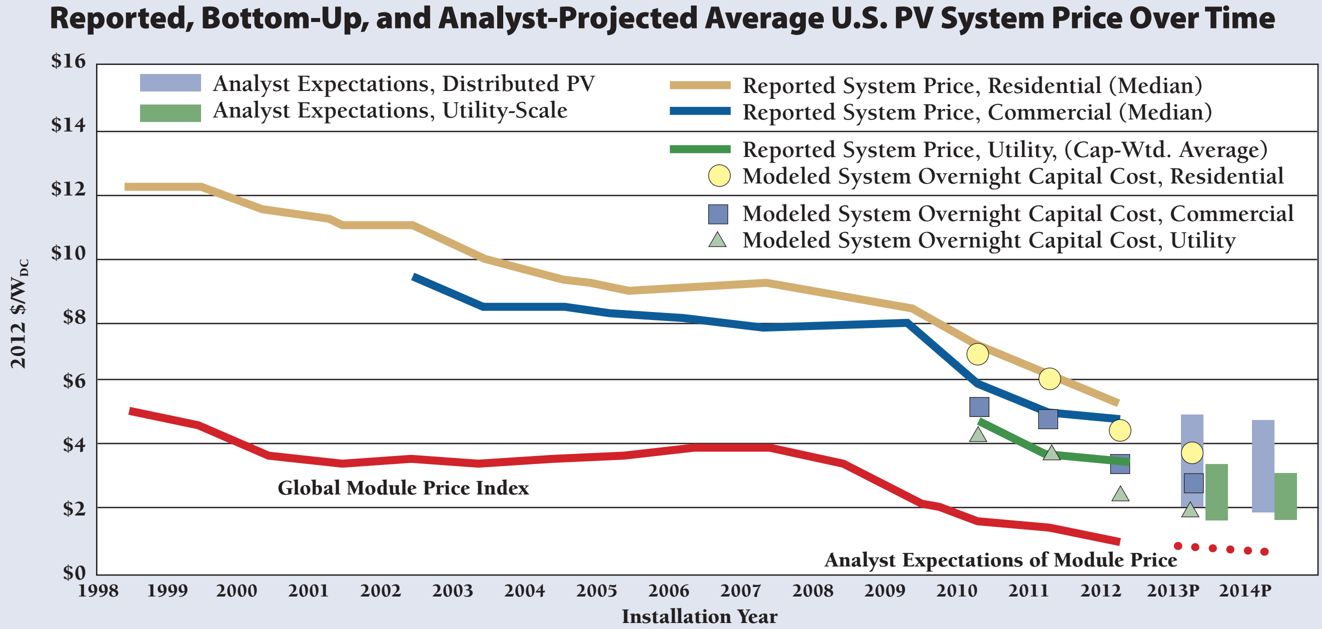
Sources: Based upon data from Bloomberg New Energy Finance (2013) and EIA (2013) [33]

31 LCOE reflects the anticipated average cost per unit of electricity that will be generated over the financial life and duty cycle of a typical generator, including both capital costs and operation and maintenance costs.

32 Balance of system costs refer to all costs of installing a DG system other than the cost of the generation equipment itself. For example, balance of system costs for a PV system includes the cost of an inverter, any incremental metering expense, and the cost of framing and installing the system.

33 LCOE data are based on Bloomberg New Energy Finance, 2013. Retail rates data are from U.S. EIA, 2013.

Figure 5



Source: Feldman et al. (2013).

competition in the electricity sector that did not exist in 1978. Many parts of the country are served by competitive wholesale electricity markets; more than a dozen jurisdictions allow retail competition as well.[34] And new business models are arising that enable third parties to deliver DG options directly to customers in some states, in effect competing with the utility or load-serving entity to sell retail electricity. In particular, third-party ownership of solar PV systems has come to dominate the PV market in states where such arrangements are allowed, as shown in Figure 6. Industry reports indicate, for example, that third parties own more than 60 percent of the residential PV systems installed in California and Massachusetts, and more than 80 percent of the residential PV systems in Arizona and Colorado.[35]

All of these factors in combination are creating a more favorable economic environment for DG and sparking a growing debate over the tariffs that enable it. Customers who see DG investment or leasing as a viable option want tariffs and public policies that are simple and easy to understand, and they want to be fairly compensated for the services and benefits they provide to the utility, other consumers, and society. Utilities are anticipating or experiencing declining kWh sales and the potential for distribution system impacts that could be difficult or expensive to manage. They want tariffs and public policies that protect their ability to collect revenues sufficient to maintain public utility services and to maintain reasonably stable rates. Non-participating consumers want tariffs and public policies that protect them from subsidizing those customers who choose to invest in or lease solar PV. Environmental advocates want to encourage the adoption of clean DG technologies and they support tariffs that recognize both the energy and non-energy benefits (such as cleaner air and improved public health) those technologies such as solar PV and CHP provide.

Across the country, a growing number of state legislatures, PUCs, and individual utilities are beginning to re-examine their DG tariffs. There is a vigorous, sometimes acrimonious debate about the need for policies to promote DG and about whether current policies overcompensate or undercompensate participating customers. At the same time there is the ongoing discussion about whether the utility is over- or undercompensated for the grid services that it provides to DG adopters. As deployment of DG increases, these issues become ever more urgent and the economic impacts of getting compensation wrong (in either direction) become more substantial.

Thus, while improving DG technologies are improving the economic viability of DG, there is a real concern

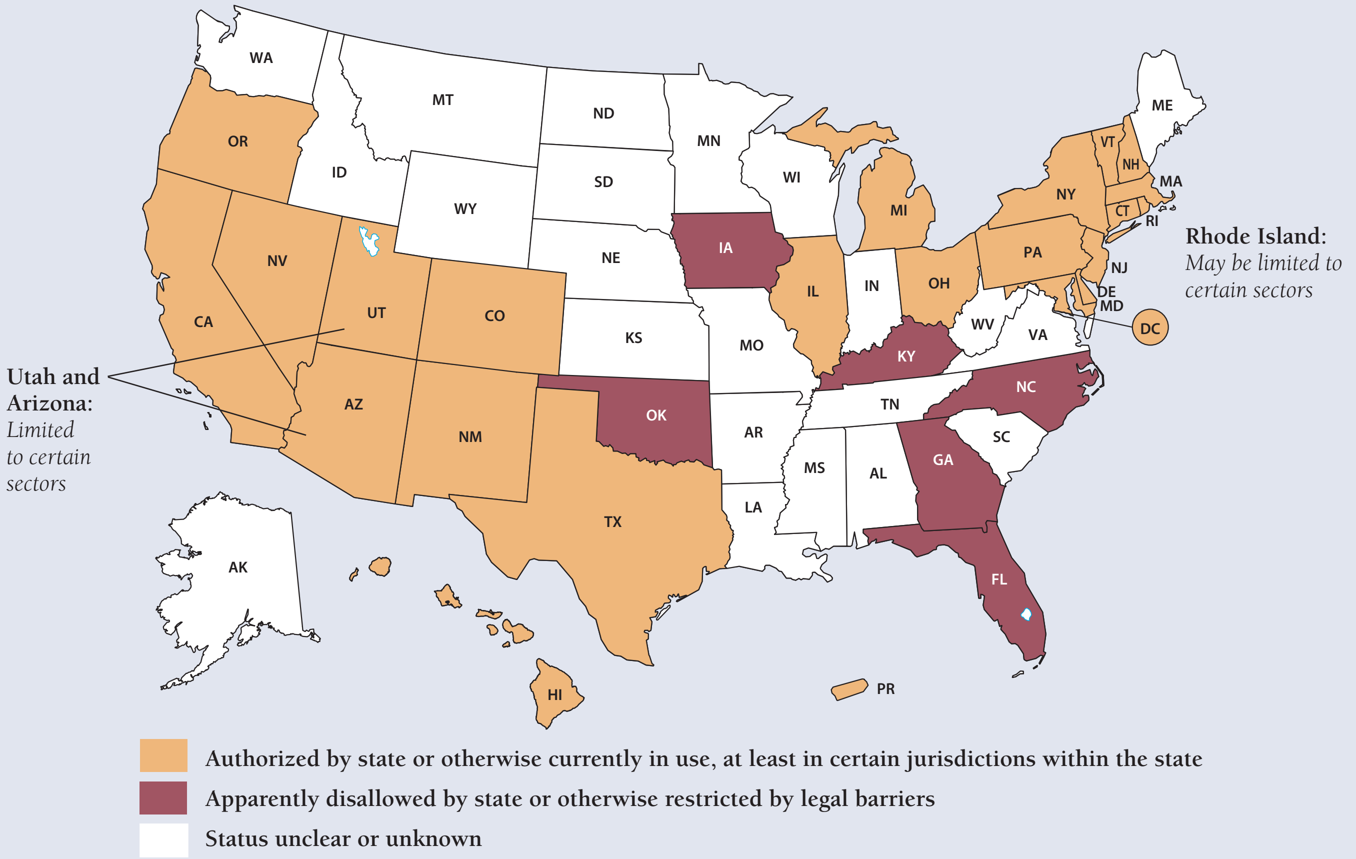
34 For more information on retail competition, refer to http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html.

35 GTM Research and the Solar Energy Industries Association, 2013.

Figure 6

States Allowing Third-Party Ownership of Solar PV Systems [36]

At least 22 states, Washington DC, and Puerto Rico authorize or allow third-party solar PV Purchase Power Agreements (PPA)



among electric utility stakeholders that benefits and costs be accounted for accurately and that the distribution of net benefits or allocation of any net costs be assigned fairly. This section defines the benefits and costs that may be associated with a distributed generation project and characterizes how those benefits and costs affect the value of the project from the perspectives of adopters, non-adopters, the utility and society as a whole. This section will be useful to regulators as they weigh the fairness of tariffs and regulatory treatments.

Specific Sources of Benefits and Costs

The specific sources of benefits and costs associated with DG can be broken down into five categories: DG program cost, utility system benefits, benefits to participants, non-energy benefits to participants, and societal non-energy benefits. DG program cost includes costs borne by utilities, participants, and non-participants. Many of these costs and benefits are similar to those provided by energy efficiency programs. We recommend regulators consult RAP's recent comprehensive study of energy efficiency costs and benefits, "Recognizing the Full Value of Energy Efficiency," for more detailed explanations of those sources of benefit or cost that are common to DG and energy efficiency.[37] Those sources of benefit and cost associated with DG that are not associated with energy efficiency will be separately summarized below.

Examples of program cost include the cost of administering a DG program, the installed cost of the DG system, and the costs associated with metering, interconnection, and system integration. The utility system benefits are the largest category of benefits. The long run marginal cost is the appropriate metric to use to represent the utility system avoided cost, because a DG investment by consumers should be considered to be a resource rather than merely a device to achieve short-term load reduction. As such, the utility system benefit

36 Map available at http://www.dsireusa.org/documents/summarymaps/3rd_Party_PPA_map.pptx.

37 Lazar and Colburn, 2013.

should include all avoided marginal costs, including avoided transmission, net avoided distribution and avoided generation cost, avoided line losses, avoided reserve requirements, and avoided renewable portfolio standard compliance costs.

Benefits to participants may include items like reduced fuel consumption or reduced future energy payments. Non-energy benefits to participants may include items like increased property value, comfort, enhanced energy reliability, and improved productivity. Societal non-energy benefits may include items like air quality impacts, water quantity and quality impacts, enhanced energy system resiliency, and economic impacts.

Distributed Generation Program Costs

DG installed costs include both the cost of the DG equipment as well as the cost of all labor and other equipment that are required to enable a fully functioning DG system. The installed cost is paid for primarily by the participant, but state and federal tax benefits and utility incentive payments may offset part of the installed cost. While Lazar and Colburn[38] note that energy efficiency programs include "measure costs," which analogously are partially paid by the participant, DG also includes metering, interconnection, and system integration costs, which may be paid for partially or entirely by the participant. Metering costs are sometimes paid for exclusively by the participant, but in other cases they may be shared by the utility or third parties. Interconnection and system integration costs are very low for low penetrations of DG and for smaller DG systems, but higher penetrations of DG and larger DG systems may include additional costs to interconnect incremental facilities or to accommodate facility operation with system resources. The larger the DG project, the more likely the project is to include a specific interconnection system impact study, additional interconnection hardware, and thus additional cost.[39]

Utility System Costs and Benefits

DG is likely to obviate the need for some energy, capacity, and ancillary services, because DG reduces system demand and thus affects the quantity of resources that the utility must procure.[40] In addition, DG may provide incremental energy, capacity, and ancillary services to the system during those hours when the customer is a net generator of electricity. The incremental net generation further obviates the need for system resources and thus avoids additional costs. Different types of DG have different operational capabilities and thus the value of capacity and ancillary services from an installation varies by technology type. Services that can be provided by some technologies include regulation service, reactive power service, load following service, and ramping service. The value of capacity and some ancillary services varies by location and time on the utility's system, with DG in some locations having high value and DG in other locations having low value.

Although energy efficiency can have avoided distribution cost benefits, DG is different in that it can either avoid utility distribution system expense or cause the utility to incur some incremental distribution expense. High penetrations of DG or large DG installations may cause distribution expense, whereas smaller and appropriately located DG facilities are likely to avoid incremental DG expenses and thus produce a net savings in distribution outlay.[41]

For an excellent survey of how many of these benefits and costs have been applied in recent studies, we recommend Rocky Mountain Institute's, "A Review of Solar PV Benefit and Cost Studies," which describes the assumptions, data sources, and findings of approximately 15 recent DG studies.[42]

Stakeholder Perspectives

Energy-producing consumers, non–energy-producing consumers, the utility, and society as a whole have different perspectives on translating the sources of benefit and cost into a net value assessment. Starting with California's Standard Practice Manual more than 30 years ago, energy efficiency programs have been evaluated from a number of perspectives. The Participant Cost Test (PCT) represents a benefit/cost ratio representing the value of participating in an energy efficiency program.

38 Lazar and Colburn, 2013.

39 For more information on the magnitude of the direct, metering, interconnection, and system integration costs in the case of high penetration solar DG, see Bird et al., 2013.

40 Rooftop distributed PV also provides a shading benefit that can reduce temperature gain in structures, thus further reducing the demand for electricity beyond the demand displaced by PV production.

41 See Bird et al., 2013 for a more detailed discussion of the potential for increased distribution system costs in situations where solar PV penetration is high and concentrated in specific locations on the grid.

42 Hansen et al, 2013.

The Ratepayer Impact Measure (RIM) test represents a benefit/cost ratio representing the impact of an energy efficiency program on electricity rates when the sources of benefits and costs are narrowly defined. Some argue that the RIM test by itself is not representative of the non-participant perspective because it does not include the non-energy benefits that accrue to non-participants as citizens, such as public health benefits, environmental benefits, and economic development benefits.[43] The Program Administrator Cost (PAC) test (also referred to as the Utility Cost Test [UCT]) represents a benefit/cost ratio from the utility perspective, where the utility or a third-party entity is a passive administrator of an energy efficiency program. The Total Resource Cost (TRC) test and the Societal Cost Test (SCT) represent a benefit/cost ratio for society as a whole, wherein the TRC typically excludes non-energy benefits, and the SCT typically includes non-energy benefits.[44] Table 2 summarizes the purpose of these five tests when they are adapted to the context of DG evaluation.[45]

Table 2

The Purpose of Stakeholder Perspective Tests

Perspective	What Constitutes "Value"
DG Customer (PCT)	Will the DG customer's costs decrease?
Other Customers (RIM)	Will utility *rates* decrease?
Utility (UCT or PACT)	Will the utility's *costs* (revenue requirement) decrease?
Total Resources (TRC)	Will the sum of utility costs and DG customer costs decrease?
Society (SCT)	Will total costs to society decrease?

States have used the PCT, RIM, PAC (or UCT), and TRC (or SCT) to evaluate energy efficiency programs in a way that is consistent with the public policy purpose for implementing energy efficiency programs in that state. For example, states that are seeking to meet a technology penetration target want to assure that the incentive value proposition offered to program adopters is adequate to ensure sufficient participation. For these states, consideration of the PCT results in light of the incentives being offered is necessary to ensure public policy penetration targets will be met. For states where the public policy driver is a clean energy policy aimed at supporting a wide range of non-energy benefits like

43 Keyes and Rabago, 2013.

44 Each of the tests described here can also be represented as a net benefit value rather than a benefit/cost ratio. Similar tests have been developed to gauge the cost-effectiveness of demand response programs, as noted Woolf et al., 2013.

45 While time honored benefit and cost testing has served us well, efforts to improve upon established methods and definitions are underway. The Energy Efficiency Screening Coalition just produced, "Recommendations for Reforming Energy Efficiency Cost-Effectiveness Screening in the United States" in November 2013 and it represents some valuable current thinking on cost effectiveness reform. See Energy Efficiency Screening Coalition, 2013.

Table 3

Net Value From the Energy-Producing Customer Perspective

Cost or Benefit Category	Treatment in the Participant Cost Test
DG program costs	Installed DG system costs, balance of system costs, and any NEM and interconnection costs assigned to the customer. All costs are calculated net of any tax savings and incentive payments.
Energy and resource benefits to participants	Fuel, water, and energy bill savings
Non-energy benefits to participants	Property value and "walk the talk" benefits
Net value	The net bill savings depend on the quantifiable factors above and are affected by tariff terms and rate design, and the net value is the combined effect of energy and non-energy costs and benefits.

promoting public health, protecting the environment, or promoting energy security by reducing dependence on imported energy, an SCT that includes some valuation of these non-energy benefits is important to assessing the net value created by adding that program.[46]

The Net Value Proposition from the Energy Producing Customer Perspective

Energy producing customers experience costs and benefits as indicated in Table 3. These customers incur DG costs and enjoy energy cost savings, and some non-energy benefits.[47]

The net bill savings to the participant depend on the rate design and tariff applicable for the host utility, and the applicable rate design and tariff can be different for different generation technologies. The net value to the energy-producing consumer includes the net energy and resource savings as well as any non-energy benefits. The effect of different rate designs and tariffs on the net value enjoyed by energy producing consumers will be discussed in detail in Section 3.

The Utility Net Value Proposition from the Program Administrator Perspective

DG that serves retail load directly, under any form of NEM or FIT, is a concern to utilities for a number of reasons, but two reasons are most commonly cited. First, in many states the utility is providing an incentive to the customer, in the form of credit at the retail rate for power received by the utility, whereas the utility arguably is avoiding only the power supply component of that rate. Second, the utility is losing revenue from the amount of power previously purchased by the consumer that is displaced by onsite generation. These two effects, plus a number of others indicated in Table 4[48], add up to a net value proposition for utilities associated with DG. It is important to note in reviewing the sources of benefit identified that the value of DG to the electric system varies by technology, location, and time. In particular, several of the utility system benefit attributes depend on the technology, location, and time of energy production, and thus the net value of a given DG project will vary based on these factors.

Program Costs

Utilities incur administrative costs to enter into contracts with NEM and FIT generators. The level of cost depends on whether customers require meters of a type different from the type normally required, and utilities may incur incremental operations and maintenance (O&M) expenses to provide for the metering, invoicing, and payment processing. Finally, some states provide for shareholder incentives for utilities that enter into contracts for renewable energy resources, including those

46 See Keyes and Rabago, 2013 for further discussion of this perspective.

47 A more detailed breakdown of these sources of costs and benefits based on Colburn and Lazar (2013) is shown in the an online appendix available at: http://www.raponline.org/document/download/id/6897

48 For more detail see the online appendix available at: http://www.raponline.org/document/download/id/6897

Table 4

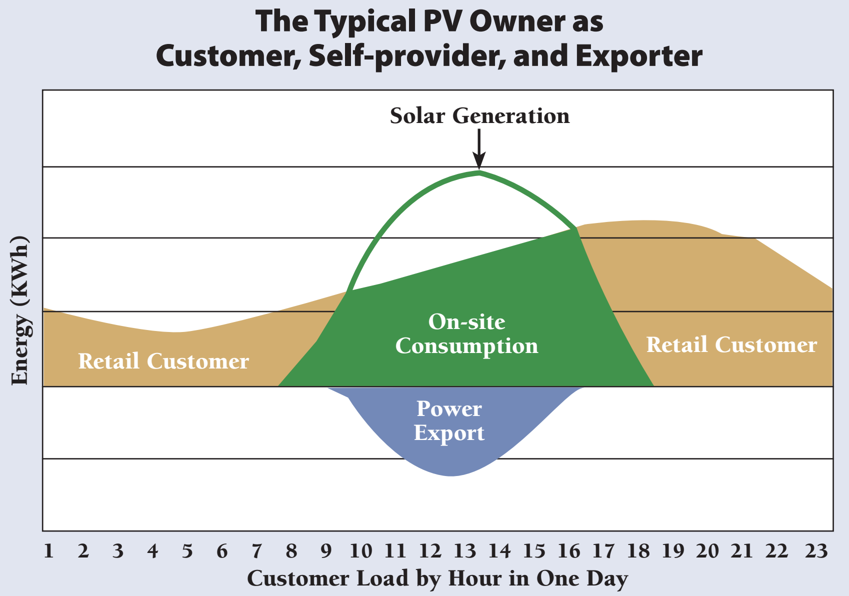
Benefits and Costs in the Utility Cost Test

Cost or Benefit Category	Treatment in the Utility Cost Test
DG program costs	Program administration costs, any incentive costs paid to DG adopters financed by utility rates and other DG costs assigned to the utility, as well as any lost revenues to the utility
Utility system benefits	Avoided energy, capacity, and ancillary service costs, avoided transmission, net avoided distribution, and avoided costs associated with reduced line losses, reduced reserves, reduced uncollected bills, and reduced service terminations and other factors
Non-energy benefits	Avoided unrecovered termination costs, and avoided unpaid bills
Net revenue impact	Net revenue impact depends on the quantifiable factors above and is affected by tariff terms, rate design, and the presence or absence of decoupling

procured through NEM or FIT.

Even in cases in which some investment is required on the part of the utility, the administrative and O&M expenses are very minor, and cost recovery is left to general rate proceedings. But incentives are different, and most states where incentives are paid to DG adopters provide for timely recovery of these incentives through a tariff surcharge in which utilities are allowed to separately recover the incentive expenses. A public benefits charge is an example of such a tariff surcharge. It can be separately stated (rare), incorporated into a more general fuel and purchased power recovery mechanism (more common), or deferred for subsequent recovery, with accrual of interest during the deferral period.

Figure 7



Adapted from Beach et al., 2013.

Lost Revenues in the Context of the UCT

From the perspective of a program administrator, the lost revenues to the utility include the revenue lost from all kWh of energy not sold because of DG. Decoupling is the tool designed to offset this quantity of lost revenues.[49]

Utility System Benefits

Utility system benefits include all energy, capacity, ancillary services, transmission, and distribution costs that are avoided by the installation of the incremental DG facility. At high levels of penetration or for large DG facilities, there may be a net transmission, distribution, or ancillary service/integration service cost that counts against the avoided cost and thus reduces the avoided cost value of the DG facility to the utility. As discussed earlier, the value of DG is technology- and location-specific, so the avoided cost value to the utility will likewise be technology- and location-specific.

The Utility Net Value Proposition from the Shareholder Perspective

The consideration of net revenue impact on utility shareholders is different from the impact on the utility as a program administrator, and requires some background discussion. When considering the impact of DG on utility resources, the owner of DG may appear to have three different relationships with his or her utility. First, during times when the distributed system is not generating electricity, the customer's load will look just like that of any other customer. Second, when the system is generating electricity equal to or less than the customer's onsite consumption, the customers will have reduced load, similar to what might happen if he or she had deployed energy efficiency measures. Third, when the customer generates more power than he or she consumes, the customer becomes an exporter of electricity to the system. Different technologies are using and exporting to the grid to varying degrees based on their consumption and production profiles. These changes have measurable impacts on electric utilities, and on the non-participating customers. All three relationships are illustrated in Figure 7 as they might happen for a typical customer with a PV system.

Typical electric utility rates recover most of the cost of electric service through the per-kWh energy rate. Sales to larger commercial and industrial customers typically include a demand charge, based on the customers' highest hourly usage, so the revenue decline from these customer classes will usually be small. On the other hand, small commercial and residential customers who may install NEM systems seldom pay a demand charge. The revenues a utility recovers from customers who choose to install PV may include payment for net energy purchases by customers, revenues from standby or fixed charges,

49 For more on decoupling, see Revenue Stabalization Mechanisms in Section 3, and Lazar, Weston and Shirley, 2011.

and any revenues associated with special equipment (such as the customer's portion of smart meter costs, if any) purchased from the utility by customers.

The Net Value Proposition from a Non-Participant Perspective

There is more than one way to capture the non-participant value proposition. For each of the three alternatives we discuss, it is important to recognize that many customers cannot afford to incur the capital cost of participating in DG programs and may not qualify for financing programs. These "have not" customers require separate consideration as a matter of public policy, and some states have chosen to implement single-family and multifamily subsidy programs for lower income customers. As we discuss the three different views on non-participant valuation, parallel consideration of the situation of these customers should be kept in mind.

First, one may consider the interests of non-participating customers narrowly, based on how the reduction in sales to adopting customers affects the rates that all customers pay. The RIM test attempts to capture this perspective. When retail customers conserve energy, invest in energy efficiency, or install self-generation of any type, customer contributions to fixed costs can decline. The installation of DG that serves retail load directly, under any form of NEM, will be a concern to non-participants if they are not convinced that the system economic benefits offset the reduction in revenues available to cover fixed costs. Table 5 reflects the factors relevant to the RIM test.

Some applications of the RIM test fail to capture the full long-run marginal cost avoided by the installation of customer-sited DG, so it is important to note that the definition of RIM that we cite above includes all of the utility system benefits arising from avoiding transmission, distribution, and generation investment as well as avoided portfolio standard compliance costs, reduced line losses, and all of the other factors cited. Including all of these factors and going beyond simply accounting for short-run avoided variable cost is important to assessing any non-participant impact. Including all of these benefits is an important first step for accurately addressing whether there is in fact a cross-subsidy of participants by non-participants.

A second way of capturing the net value proposition from the non-participant perspective is to consider that participating customers and non-participating customers together constitute the citizenry of our society, and the proportion of society choosing to participate in DG programs is only a fraction of those citizens who support clean energy goals. Polling consistently puts support for clean energy well above 50 percent nationally and the adoption rates for solar PV are less than one percent.[50] This second perspective from which non-participants view the value of DG may be more accurately represented by a TRC or SCT perspective. Citizens who support clean energy and environmental public policy goals are likely to incorporate non-energy benefits in their valuation, and thus an SCT score is a reasonable proxy for these non-participants. We will discuss the TRC and SCT tests below, but generally these tests add to the RIM test the

50 Refer, for example, to March 2013 Gallup poll results at http://www.gallup.com/poll/2167/energy.aspx and April 2013 Yale/George Mason University poll results at http://environment.yale.edu/climate-communication/files/Climate-Policy-Support-April-2013.pdf

Table 5

Benefits and Costs in the Ratepayer Impact Measure Test

Cost or Benefit Category	Treatment in the Ratepayer Impact Measure Test
DG program costs	Program administration costs, incentive costs, and other DG costs assigned to the utility and flowed through to ratepayers at large
Utility system benefits	Avoided energy, capacity, and ancillary service costs, avoided transmission, net avoided distribution, and avoided costs associated with reduced line losses, reduced reserves, reduced uncollected bills, and reduced service terminations; and other factors
Net non-participant bill impact	The net non-participant bill impact depends on the quantifiable factors above and is affected by tariff terms and rate design

consideration of a wider range of non-energy benefits.

A third interpretation of the non-participant perspective was recently posited, which argues that non-participant benefits should include the portion of non-energy benefits that accrue to the local population residing within the service territory of the utility.[51] The authors argue that economic development benefits, environmental benefits, and health benefits are enjoyed by non-participants and participants alike, and so they should be included along with the traditional RIM components in assessing the non-participant's net value proposition.

The Net Value Proposition from a Societal Perspective

Higher penetration of DG resources produces benefits and costs for society as a whole. The TRC test evaluates those energy-related benefits and costs that are more readily quantified with expressed economic values. The SCT includes all of the quantified benefits and costs from the TRC but adds consideration of some non-energy externalities that are benefits or costs from a societal perspective but are not readily expressed in economic values at the present time. Citizens who value all of the resource benefits as well as the non-energy benefits of DG programs are likely to value the programs from a TRC or SCT perspective, regardless of whether they are participants or non-participants. A summary of the two tests and the factors that play into the computation of the test results is shown in Table 6. It is worth emphasizing that non-energy benefits are not just environmental externality and environmental resource benefits. Increased energy security is a significant category of non-energy benefits for many citizens. Increasing energy security through improved grid resiliency and grid security is highly relevant to current public policy concerns spurred by significant climate events, national security, and cyber-security concerns. Interest in grid resiliency and security has spurred investment in a range of renewable and CHP DG technologies.

The results from the TRC and SCT tests are useful in guiding the level of DG penetration that will be consistent with the public interest. The choice of a tariff option and tariff attribute values selected (e.g., the level of any fixed or variable charge, the periodicity of netting if the tariff is a NEM tariff) are relevant to the TRC or SCT in so far as those choices should be chosen to support the attainment of a socially beneficial level of DG penetration.

51 Keyes and Rabago, 2013.

Table 6

Benefits and Costs in the Total Resource Cost and Societal Cost Tests

Cost or Benefit Category	Treatment in the Total Resource Cost Test	Additional Factors Included in the Societal Cost Test
DG program costs	All costs incurred by the participant and the utility are included	No additional factors
Utility system benefits	All utility system benefits identified in Table 4 are included	No additional factors
Benefits to participants	Participant resource and fuel savings	No additional factors
Non-energy benefits to participants	Participant O&M savings or costs	Participant health
Non-energy benefits to society	Water quantity and quality benefits	Air quality and energy security benefits
Net social impact	The TRC represents all energy-related costs and benefits as well as non-energy benefits that are quantifiable, and it is not affected by the rate design or tariff design.	The SCT represents the TRC costs and benefits plus certain additional non-energy benefits, primarily environmental.

Sources of Mutual Benefit and Sources of Conflict Among Stakeholder Value Propositions

Although there is much discussion of conflicts among the perspectives of different stakeholders, it is worth reflecting on the mutual benefits of procuring cost-effective generation resources. The utility system benefits are enjoyed by all: participants, non-participants, utilities, and society as a whole. If the long-run marginal avoided cost associated with DG installations is greater than the cost imposed on non-participating customers, then the discussion of non-participating customer harm should be a short one. The first step in assessing the extent to which conflict among customers exists and in assessing which customers are being subsidized should therefore be an accurate and complete accounting of long-run marginal avoided costs. If the net benefits are positive, then it is worth assessing whether distributed generating customers are being paid enough.

The Possibility of Non-Participants Cross-Subsidizing DG Adopters

If the utility system benefits created by DG do not exceed the cost to non-participating ratepayers, then a Commission will need to consider and adopt a full definition of non-participant benefits to define the metric to assess the presence or absence of cross-subsidization. Having adopted the metric and having assessed the net value proposition for non-participants, a Commission may then be in the position of having to mitigate any cross-subsidization from non-participants to participants or to reward any cross-subsidization from participants to non-participants. Fairness demands that the test of whether cross-subsidization exists should contemplate the possibility that participants are actually undercompensated for their resource.

To the extent a cross-subsidy exists, the cross-subsidy should be rectified by adjusting the terms of the tariff and the rate design applied in the tariff. The next section will take up the issue of how to equitably set the tariff terms and rate design.

The Possibility that Too Little DG is Being Added

Another potential source of conflict among stakeholders might be in the determination of the economic potential of DG. That is, how many MW of DG are merited based on the net value proposition from a social perspective. Answering this question starts with a Commission determination of what benefits and costs should be included in the SCT or TRC test. Regulators might consider an interpretation of the public interest in light of any legislation, policy, or regulation that has been adopted to implement DG as a guiding principle in this discussion. To the extent the enabling language encompasses a broad range of non-energy benefits, that broad range should be considered and reflected in the adopted valuation specification. This question is separate from the consideration of tariff and rate design.

The Possibility that Utility Financial Health and Reliability of Service Will Be Compromised

Another source of potential conflict is the possibility that revenue under-collection will affect utility financial health, which may in turn compromise reliable service. As DG becomes more economical and common, there may be a significant decline in revenue collection. In order to ensure that the utility is not biased against cost-effective DG, decoupling may be considered.[52] The decoupling consideration is separate from the rate design and tariff consideration. However, over the longer term, the prospect of reduced revenue may require a tariff adjustment to ensure that required grid services are adequately financed.

The Possibility that the Utility Will Become an Impediment to DG Adoption

There are three forces determining the negative earnings impact on utility shareholders, and if the net impact is negative then one can expect utility reluctance to accommodate all cost-effective DG. First, the utility loses revenues as a result of the onsite consumption element of NEM output. To the extent that the displaced retail revenue otherwise exceeds short-term costs during the time and location of DG, there will be a resulting adverse impact on earnings. Second, for FITs and some NEM tariffs, the utility incurs a cost in purchasing the power exported to the grid that may exceed the cost of conventional power. Both of these can have an impact on utility shareholders (until rates are adjusted to reflect changes in sales) and on non-participating customers (in the long run). Finally, the utility can experience a

52 For more information on decoupling, see Revenue Stabilization Mechanisms in Section 3. For a complete discussion of decoupling, see Lazar, Shirley, and Weston, 2011.

net decrease in investment opportunity if the loss of investment in distribution and generating resources exceeds any incremental investment opportunity created by increasing DG.[53] Examples that may act to increase investment opportunity include incremental investment on the distribution system to enable net backflow of electricity to the grid, and shared investment opportunities in which the utility participates in leasing DG equipment or invests in a portion of the control equipment (such as smart inverters, solid state transformers, or enhanced two-way metering equipment). The potential that higher levels of solar PV penetration may cause additional utility investment to maintain system reliability is beyond the scope of this paper but is discussed elsewhere.[54]

Toward Fair Compensation

The next section will address these potential sources of conflict and recommend regulatory approaches for fairly reconciling them. The first step toward addressing each of these is to consider a set of fundamental regulatory principles that have been familiar first articulated Bonbright's "Principles of Public Utility Rates" and continue to be relevant today.[55] Bonbright's principles can be summarized as follows:

- Tariffs should be practical: simple, understandable, acceptable to the public, feasible to apply, and free from controversy as to their interpretation.
- Tariffs should keep the utility viable, effectively yielding the total revenue requirement and resulting in relatively stable cash flow and revenues from year to year.
- Rates should be relatively stable such that customers experience only minimal unexpected changes that are seriously adverse.
- Tariffs should fairly apportion the utility's cost of service among consumers and should not unduly discriminate against any customer or group of customers.
- Tariffs should promote economic efficiency in the use of energy as well as competing products and services while ensuring the level of reliability desired by customers.

The first Bonbright principle, to keep things simple and practical, is especially important to keep in mind as we consider alternatives to relatively well-understood tools like NEM.

The second step toward fairly reconciling these sources of conflict is to determine whether a serious cross-subsidy problem even exists by carefully aligning the valuation criteria used by the commission with an interpretation of the public interest for the state and utility in question. The third step is to establish tariff and rate design approaches that address the current conflicts and resolve cross-subsidy issues, if a cross-subsidy has been determined to exist. The fourth step is to resolve the remaining sources of conflicts with appropriate regulatory treatment. For example if the value proposition is deemed so favorable for DG that revenue erosion occurs and affects reliable grid service, a regulatory treatment such as decoupling can be offered as a complement to any proposed tariff to address this revenue deficiency.

53 Of course, this latter category of impact can also be viewed neutrally or even positively if there is regulatory lag (in rate recovery) and/or the utility's marginal return is at or below a normal return.

54 See Bird, et al. (2013) for a discussion of costs that may be added with higher solar PV penetration.

55 Bonbright, 1961.

Section 3. Distributed Generation 2.0

Distributed Generation 1.0 in all states has included some combination of PURPA, NEM and FIT tariffs. Use of these tariffs has increased in most states over the last five years as generation technologies have improved, generation costs have declined, customer preferences for clean energy have increased and public policy toward clean, distributed energy has turned more favorable. The first goal in establishing Distributed Generation 2.0 is therefore to evolve these tariffs and perhaps introduce some new tariff mechanisms that can take advantage of the capabilities that the power sector has today. A second and equally important goal ought to recognize the reality that Distributed Generation 2.0 tariffs are occurring during a time of transition. Recognizing this transition period, we recommend that regulators consider Distributed Generation 2.0 tariffs that set the stage for further evolution of the tariffs as the companies, consumers, markets and institutions that make up the power sector learn to use the capabilities that advanced information, communications and control systems offer. The second goal of Distributed Generation 2.0 is therefore to implement tariffs that will facilitate the further transition toward Distributed Generation 3.0 as the power sector matures.

Meeting both goals requires that regulators recognize the difference between the value of services provided from a utility to all of its customers and the value of service provided by the producing customer to the utility and its customers. The difference between the value of these respective services has a long history and it is founded in the principle of establishing a fair rate. Historically regulators have interpreted a fair rate as one that reflects the cost of service and applies to all customers. Some regulators have chosen to base cost of service on embedded costs (i.e., all costs incurred to date to provide current service), whereas others have chosen to base cost of service on marginal costs (i.e., the incremental costs incurred to serve incremental needs). In contrast, the fair compensation paid by a utility to a firm operating in a competitive market environment is based on its marginal cost of service.

This is a critical concept for DG tariffs such as NEM and FIT, because every utility customer (DG owner or not) is entitled to receive service on the same terms, and these terms are based on an administered cost of service calculation. However, those DG customers who produce power are offering a long term product with a service life of 20 years or more to the utility and as such are helping the utility and its customers to avoid the long run marginal cost of new resources. Thus it should not be surprising that the basis for the value of services offered by the utility to DG customers differs from the value of services offered by the DG customer to the utility.

Distributed Generation 2.0 needs to establish fair value in each direction. Determining a fair value for the services offered by the utility to the DG producing consumer will be based on these historic principles based on treating all of its customers fairly. Determining a fair value for the services offered by the DG producing consumer will depend on the valuation methodology the regulator establishes as discussed in Section 2, and the regulator will need to base that value on the benefits and costs included in the chosen methodology.

At the same time, Distributed Generation 2.0 needs to establish tariffs that set the stage for the further evolution of the power sector. Improving information, communications and electric system control technologies will prod evolution of electricity markets and institutions and concomitantly evolve the nature of the services offered from demand side resources to the electric system operator. Thus if we are successful in formulating a value of service that is fair today, we still must remain cognizant that the value is likely to evolve tomorrow.

The Bottom Line: Toward a Two-Way Distribution Tariff

The bottom line is that a two-way fair exchange of respective services seems to indicate the need for tariffs that explicitly acknowledge those respective values that each party offers to the other, and it needs to be flexible enough to accommodate the value of new services provided as they evolve. Thus Distributed Generation 3.0 seems to be evolution toward something like a two way distribution tariff where each party is explicitly compensated for the services it offers to the other.

We do offer a two way distribution tariff alternative in this section, but the problem with implementing such a tariff at this time is that electricity markets and institutions are still learning how to effectively use information, communication and control systems technology and thus the value of services provided is not yet transparent. Analysts have begun to talk about a transactive energy economy where all parties providing services are compensated for those services, but the information and institutional infrastructure we have today is simply not yet up to that task. So, while a two way distribution tariff scores highly on achieving the goal of pointing us in the right direction toward Distributed Generation 3.0, it appears the NEM and FIT tariff constructs are likely to be with us for a while longer.

Pointing NEM and FIT Tariffs in the Right Direction

NEM and FIT tariffs can be adapted to achieve our two goals of addressing the conflicts that we see today and pointing us toward Distributed Generation 3.0. The key to achieving both of these goals starts with the regulator making a conscious decision of a valuation methodology and of the costs and benefits to include in their valuation of DG. The implementation of DG tariffs that point in the right direction should apply the valuation methodology chosen and build off of the two way fair value principle enunciated above: the prices charged to DG customers for grid services should normally be based on the same principles as retail rates for other consumers, while the prices paid to those customers for their power production should normally be based on the same principles as wholesale power rates paid to other producers for long term resources taking into account all relevant resource attributes. Relevant resource attributes include things like the location on the grid where power is delivered, the time at which it is delivered, the duration over which it is offered, whether it is a renewable resource and whether it has other non-energy attributes that the regulator has deemed applicable.

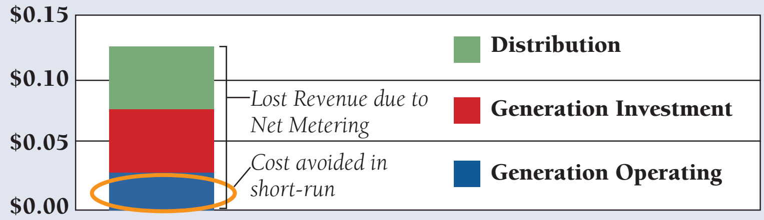
Utility Concerns

As alluded to in Section 2, utilities are increasingly concerned that onsite generation is compromising their revenues, net income, and indeed, their entire business model.[56] In response to this concern, many utilities are seeking revisions to their tariff design to increase the fixed charges paid by distributed resource owners to be connected to the grid. These utilities argue that an increase in the fixed charge is necessary to offset revenue attrition associated with the decreased load.

Figure 8

One Utility View

Avoided Cost Due to Net Metered Generation Is Less than Retail Rate



J. Lazar, 2013

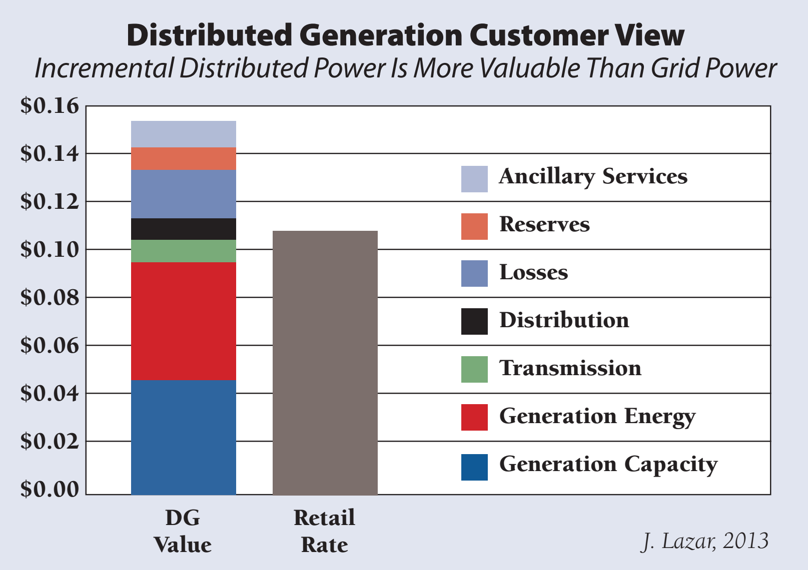
This position is based on the assumption that all customers have an equal (or similar) responsibility for financially supporting the infrastructure that provides service. The utility may argue that the presence of NEM and FIT generation does not displace underlying grid costs or administrative costs, and only assists the utility in avoiding power costs, measured by either fuel costs alone or by total investment and operating costs for power production. This is typically much less than the retail rate.

Distributed Generation Customer Concerns

NEM customers may see things very differently. They may see that the value of incremental renewable energy added to the grid at the distribution level is much *more* valuable than the average price of grid-supplied power. First, it is new and should be compared to other new resources, not to older coal, hydro, or nuclear generation

56 See, e.g., Kind, 2013.

Figure 9



and for recovering distribution costs incurred by the grid operator where the current "end-block" retail rate exceeds long-run marginal cost.[57] The specific examples discussed below focus more on the design of residential rates than commercial and industrial rates, but the principles applied in composing these solutions are generally applicable. Options are presented and evaluated from the four net value perspectives introduced in Section 2.

that forms the foundation of existing rates. Second, it is delivered at the distribution voltage level, avoiding distribution, transmission, and generation capacity costs. Third, it is cleaner and should be appropriately valued.

Under these circumstances, the net-metered customer may take the position that they are subsidizing the grid (bringing more value than they receive in compensation), even though there is no question that the customer is using some grid services for which he or she does not make an explicit payment.

Comparing Concerns

Both of these views may have legitimacy. At a minimum, on very high-cost utilities (i.e., Hawaii, California, New England), retail rates may already be higher than long-run marginal costs. Conversely, on low-cost utilities (i.e., Pacific Northwest, Mid-continent), retail prices are likely well below the long-run marginal cost needed to add new generation resources plus distribution capacity to the system. Regardless of a utility's rates, however, a DG customer deserves to be fairly compensated for the full value of the resource provided, just as the grid service provider deserves to be fairly compensated for the full value of the services it provides. In fairly compensating each, all customers, including non-participants, will be fairly treated by ensuring their costs do not exceed the value of all services they receive.

This section focuses the fair compensation discussion on a question of specific interest in a number of places in the United States today: what options are available for structuring compensation for NEM and FIT generators

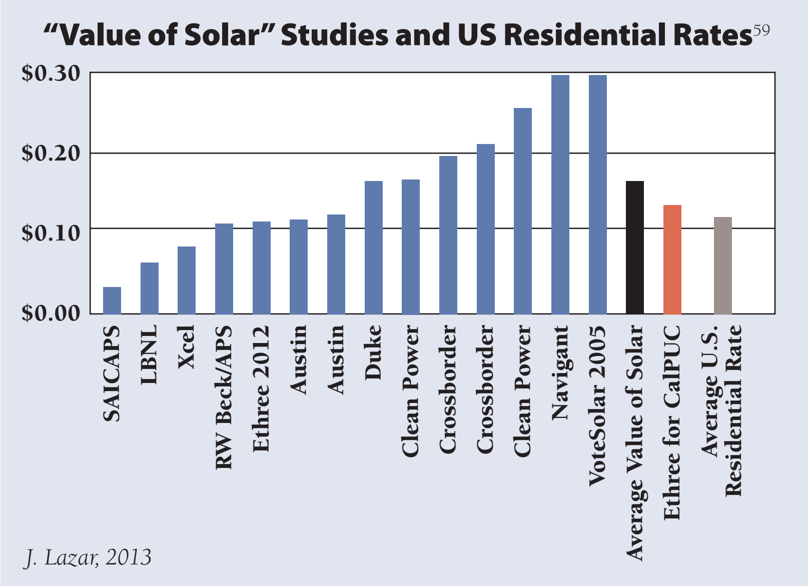
Historically, large power generators have been connected to the utility grid at the transmission level and paid a wholesale price for power. Customers of the utility pay for both the wholesale cost of power and the cost incurred by the utility or a load-serving entity to ensure reliable delivery of that power. These latter costs include transmission, distribution, ancillary services, and other costs borne by the utility or load-serving entity. The price paid to the large power generators is typically based on a computed "avoided cost" where the avoided cost is the cost of obtaining the power from other available resources connected to the transmission system. In competitive supply regions, the decision to contract for supply is theoretically made by consumers, not necessarily by utilities, but because most consumers choose to purchase through a marketer, aggregator, or utility rather than to self-generate, the price they pay for power is still based on the competitive wholesale price. It is not uncommon on low-cost systems for some purchased power contracts to be at prices above the utility's retail rates.

The current cost/benefit debate related to distributed generation has spawned a number of valuation studies that seek to quantify the costs and benefits of solar PV NEM programs. The Rocky Mountain Institute (RMI) recently compiled a comprehensive survey of these studies.[58] The studies reviewed by RMI have reached widely varying conclusions about the "value of solar," in part because they have studied different utility systems from different stakeholder perspectives, and in part because of methodological differences. The average "value

57 The end-block retail rate is the highest cost rate in an inclining rate block structure, and it is the rate applied for all incremental consumption over a threshold level of energy consumption in the given billing month.

58 Hansen et al., 2013.

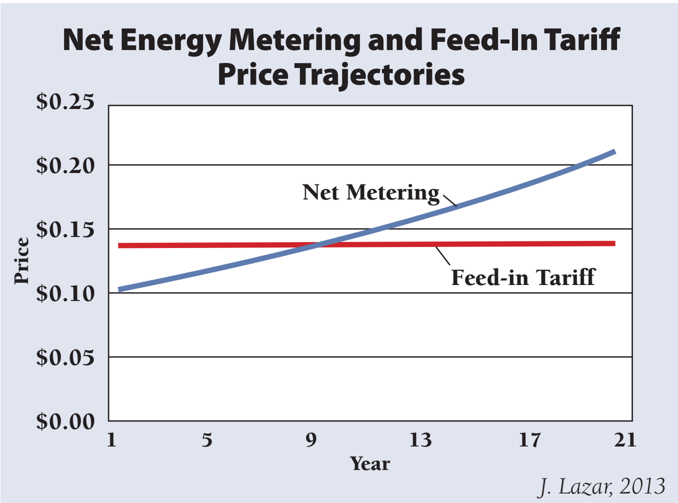
Figure 10



of solar" in these studies was just under $0.17/kWh, compared with an average U.S. residential retail rate of $0.125/kWh. This suggests that NEM may represent a net benefit to the utility system and non-participating customers, i.e., it is producing value in excess of the price (avoided retail rate) paid to the PV customer. Most recently, the California PUC commissioned a "value of solar" study, which found a lower value of $0.115/kWh, and suggests that average residential rates are very close to the value of solar.[60]

The range of values offered in this debate is wide indeed, depending on geographic factors, the avoided costs considered, and the point in time when the study is prepared. Utilities are becoming fairly assertive that NEM is an "infant industry subsidy," should be phased out as the solar industry grows out of infancy, and that these customers should pay substantial fees for grid access and interconnection. Similarly, in places where FIT compensation was set at a premium above wholesale generation market values, utilities argue that this creates a condition of unfair competition where FIT-eligible resources do not have to compete against non–FIT-qualifying resources, whereas utility-scale resources must compete with conventional resources.

Figure 11



The issues are somewhat different for NEM and FIT resources. With NEM, the customer is being compensated effectively at or close to the retail price, where retail price includes generation, transmission, distribution, and ancillary services costs as well as utility management costs, taxes, and overhead costs. Because it is tied to a retail price, NEM compensation also changes over time as retail prices change. For FIT generators, there is a direct cash compensation per kWh, which can be tailored to the precise nature of the product received, and defined in advance by contract. In general, the compensation to NEM customers will increase over time with retail rates, whereas that to FIT generators may stay more stable. If the "value" is the same and the compensation is the same, these compensation trajectories will cross near the mid-point of the expected system lifetimes.

For this reason, we treat NEM and FIT separately below.

Net Energy Metering

What follows is a discussion of three possible approaches designed to provide reasonable compensation to the NEM resource owner, reasonable compensation to the utility, and reasonable costs borne by non-participant and "have-not" utility consumers who remain dependent on the mix of resources available to the utility. Each of these is a distinct position that should be contemplated and addressed by utility regulators.

First if existing retail rates are not designed to reflect long-run marginal costs, then those rates are measuring "cost" differently from the way in which any potential buyer would look at acquiring power from a new

59 Energy + Environmental Economics, 2013; Hansen, 2013; Average retail rate from U.S. EIA, available at: USEIA, http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_3. Accessed November 16, 2013.

60 Energy + Environmental Economics, 2013

resource. As explained below, this discriminates against the net-metered supplier.

If retail prices are lower than long-run marginal costs, NEM will give the seller less compensation than the value of his or her product. In this situation, simply avoiding a (low) retail rate provides the NEM customer with less compensation than the NEM resource brings to the grid, and will lead to less than the optimal amount of NEM resources being developed. If the NEM supplier is providing power to the grid at less than long-run marginal cost, then the "have-not" customers are receiving the benefit of that power at a price lower than the utility would otherwise incur to acquire that power. One solution to this is for the utility regulator to raise end-block energy rates, and to reduce grid access fixed charges and initial block rates, in order to align tailblock rates with long-run marginal costs. If this is done, the NEM customer will receive fair compensation through avoidance of the tailblock retail rate.

In parts of the country with high utility rates, retail rates may be above long-run marginal cost. Where retail tailblock energy rates are equal to or greater than long-run marginal costs, the NEM customer is receiving full value (or more) for the power he or she delivers, and the regulator may need to set grid access charges to recover the cost of providing grid services to the NEM customer to avoid cost shifts to non-participants. We discuss several approaches that would achieve this goal that are designed to identify options that provide fairness to large and small non–NEM customers, plus fairness to NEM customers in rate design. One approach that may be viable that we do not discuss in our examples below is a minimum bill approach. The approach is simple. To the extent that a regulator determines that an applicable distributed generation tariff under-collects revenue in support of the utility infrastructure, a small minimum bill payment may be associated with DG tariffs so that all DG customers are contributing a minimum amount toward maintenance of that infrastructure. The minimum bill payment should be as small as possible so that it does not weaken the consumers incentive to economize on energy and peak demand consumption. This approach will be mentioned again as an alternative to straight fixed variable rates below.

Typical Residential Rate Design and Three Alternative Rate Design Approaches

This section describes typical current residential tariffs and then offers different ways that have been proposed to address the situation in which tailblock rates equal or exceed long-run marginal costs, with illustrative rates including a typical current residential rate for reference.

Table 7

Typical Rate Design and Three Alternative Approaches (1)

Type of Charge	Unit/ Usage	Typical Current Residential Tariff	Option 1: Fixed Monthly Charge	Option 2: Demand Charge	Option 3: Bidirectional Distribution Charge
Monthly fixed charge	$/Month	$5.00	$35.00	$5.00	$5.00
Demand charge	$/kW/Month		$ –	$3.00	$ –
Distribution Charge	$/kWh		$ –	$ –	$0.03
Off-Peak Energy	$/kWh	$0.145	$0.08	$0.08	$0.08
On-Peak Energy	$/kWh	$0.145	$0.15	$0.15	$0.15
Average Customer Bill					
Fixed Charge	Per Customer	$5.00	$35.00	$5.00	$5.00
Demand Charge	10 kW Demand	$ –	$ –	$30.00	$ –
Distribution Charge	1,000 kWh total energy	$ –	$ –	$ –	$30.00
Off-Peak Energy	500 kWh off-peak	$72.50	$40.00	$40.00	$40.00
On-Peak Energy	500 kWh on-peak	$72.50	$75.00	$75.00	$75.00
Total Monthly Bill		**$150.00**	**$150.00**	**$150.00**	**$150.00**

The four options include a traditional current rate design and three alternative approaches to address the concerns about NEM pricing. We will refer to the DG technology in effect in this section as a PV technology in order to make the context of the examples easier to understand, but it is intended that these approaches can be applied to other residential DG technologies. Each approach produces $150 per month in revenue from the average grid customer using 1,000 kWh per month.

Although the *average* customer may be indifferent to the rate design, specific customers will be very sensitive to the rate design. Apartment dwellers use much less energy than average, and will be adversely affected by an increased fixed charge. PV customers also use much less energy than average, but may have high demand on the utility after sunset, and will be adversely affected by anything but the current rate design. The challenge for the utility regulator is to be "fair, just, and reasonable."

Typical Current Residential Tariff

Most tariffs for large utilities in the United States include a fixed monthly fee of $0 to $10/month, plus one or more blocks of energy consumption. For simplicity, Table 7 shows a $5/month monthly fixed charge, plus a flat per-kWh price of $0.145/kWh, a value selected to be arguably above the long-run marginal cost of supply, at least according to the study prepared for the California Public Utility Commission (CPUC) by EThree.[61] A NEM tariff would credit this customer $0.145/kWh for all power fed to the grid, a price that includes all utility costs except for the metering and billing costs covered by the $5 monthly fixed charge.

If combined with a revenue stabilization mechanism such as decoupling, this rate design can provide substantial compensation to a NEM customer, without adversely affecting the utility's net income stability. In the absence of decoupling, the utility will see its earnings eroded as this rate design would likely cause rate attrition.

The decoupling mechanism would introduce periodic rate adjustments when sales are displaced by on-site generation that would impact non-participants and participants alike. Some advocates for consumers have expressed concern that NEM would impose rate impacts such as this one without producing off-setting benefits to non-participants.

If the tariff design includes seasonal, time-of-use, or inclining block rate elements (all of which are generally considered beneficial for achieving goals of economic efficiency), the net income impacts on the utility and the rate impacts on non-participants associated with lost revenue adjustments would be increased. The extent to which this amounts to a net cost imposed on non-participants depends on one's view on the value of the benefits shared by non-participants. See Section 2 for more discussion of this issue.

Option 1: A Fixed Charge for Distribution Costs

Utilities often advocate mitigating this revenue attrition by adopting a fixed charge for distribution service, generally equal for all customers. The Pedernales Electric Cooperative, with a $22.50/month fixed charge, is one example of this, and other utilities are seeking even larger fixed fees.[62]

This is generally known as "straight fixed/variable" rate design, with all fixed costs recovered through a fixed charge, and only variable costs included in the per-kWh charge. From an energy efficiency, renewable energy, and economic efficiency perspective, this is probably the worst solution to the revenue attrition challenge.

This type of rate design creates particularly severe impacts for small-use residential customers, including apartment dwellers for whom utility distribution costs are typically much lower (because of their geographic concentration). The effect of straight fixed/variable ratemaking has been studied extensively, and the adverse impacts well documented.[63]

In our example, we converted the flat rate to a time-of-use (TOU) rate, in order to recognize that power is more valuable at certain hours, and in order to more fairly value the output of the onsite generating facilities, which (at least in the case of PV systems) typically produce during the day when power is (currently) most valuable.

A straight fixed/variable" rate design promotes: :

- Significant bill increases for small-use customers;
- Cost shifts from suburban/rural (high-use, high distribution cost) customers to urban (low-use, low distribution cost) customers;

61 Energy + Environmental Economics, 2013.

62 San Diego Gas and Electric Company proposed a fixed fee that would reach $38/month in a docket on residential rate design before the California PUC, but the California legislature took action to limit fixed charges to no more than $10 per month.

63 For a detailed explanation of how this type of rate design results in significant changes in usage and adverse impacts on small users, see: Lazar, 2013, Appendix A.

- Significant increases in overall usage, as customers respond to a lower price per kWh for incremental electricity consumption; and
- Significantly less financial incentive for customers to install energy efficiency or onsite generation resources.

Option 2: A Demand Charge-Based Distribution Charge and TOU Rate

A second approach would be to charge residential customers a monthly fee based on their maximum level of usage at any hour during the month. This could be done through a rate element called a "demand charge" that is applied to the highest kW usage. This is commonly seen in tariffs for commercial and industrial customers, but is very uncommon in the United States for residential consumers. Our example also includes a TOU rate design, with higher energy prices during on-peak than during off-peak hours.

This approach is often considered "fair" by distribution engineers, because each component of the distribution grid is sized to a particular level of demand, and the costs are somewhat linear with increased demand. It is still a volumetric form of rate design, but based on the maximum volume during a period of the month, rather than the total volume for the month. Because apartment dwellers typically have lower kWh consumption and lower kW usage, they will, appropriately, typically experience lower bills relative to a tariff change that increases the fixed monthly charge equally for all customers.

It is critical, however, that if a demand charge is implemented at the residential level, that certain precautions be taken:

- The demand charge should be applied to the highest hour (or multiple hours) of demand, not to a shorter period of usage. Although there are instances of commercial rates being based on the highest 15 minutes of demand, regulators should avoid shorter periods because they increase the risk of certain random or inadvertent behavior driving charges beyond their ability to effectively manage. Large commercial customers typically subject to demand charges have diversity of multiple uses on the customer's side of the meter, so that intermittent uses tend to average out at the meter. Individual residential consumers do not have this diversity, but as a group residential customers do have significant diversity. Using a short period to measure demand could impose an incremental cost on smaller, especially, residential consumers who happened to have the coffee pot, microwave, and hair dryer going for a few minutes at the same time.
- The level of the demand charge must be carefully calculated to take into account the diversity of customer demands in order to produce the correct level of revenue.

Peak demand for residential customers is typically varied, with many different peak hours among the members of that class. The sum of residential customers' individual hourly demand is likely to be much higher than the maximum class demand imposed at the time of the system peak. The residential demand charge can be expected to be therefore significantly lower than it would be for the class of commercial customers. However, when applied to the higher sum of individual demands, should produce a similar level of revenue based on the system peak demand contribution of each class.

A residential demand charge for PV customers is an option that can be easily implemented on systems that do not have advanced metering infrastructure (AMI) installed, because it requires only that a demand meter be installed in place of a kWh meter. Nearly all utilities have these for their commercial customers, and their meter readers and billing systems are set up to handle these data. The next option, the bidirectional energy-based distribution rate, is a preferable approach where AMI is available.

The Arizona Corporation Commission has adopted a variation on demand-charge-based distribution charge and time of use rate for the utility Arizona Public Service in a decision issued in November, 2013. Beginning in 2014, the utility's NEM tariff for new photo-voltaic (PV) installations will include a monthly demand charge of $0.70/kW/month, applied based on the kilowatt capacity of the PV system (about $4.90 per month for a typical 7 kW residential rooftop PV system). This compensates the grid for the customer-specific distribution costs associated with providing service, but is far less than the full local loop costs that the utility sought.[64]

Net metered PV customers will generally prefer a conventional residential rate design over a demand charge. As shown in Figure 7, the PV customer's peak demand on the utility system likely occurs at a time of the day after the PV system is no longer producing power, whereas their net energy use may be very small, zero or even negative. Thus while this customer will

64 APS, 2013.

benefit from the TOU rate design, they will also likely experience a cost increase associated with the demand charge. Whether the customer prefers this tariff over a conventional NEM tariff will depend on the net impact of these two effects.

Option 3: A Bidirectional Distribution Rate

A bidirectional distribution rate is a fundamentally different approach, but would produce similar results to a demand charge for typical customers without imposing a complex rate design on the small customers who do not own DG systems.

Under this approach, when a NEM customer is taking power from the grid, he or she would pay the full grid cost, including production, transmission, and distribution system expenses. When reverse-metering to the grid, he or she would also pay for grid access, but pay only the distribution rate of a few cents per kWh. The concept is that the NEM customer taking power from the grid needs the grid in order to have reliable service, and should pay the same rate as other customers. This same customer, however, also "needs" the grid when he or she is in an exporting condition, and pays the same distribution charge when feeding power to the grid.

This approach requires metering that is able to measure power flows in either direction. Most smart meter systems can do this, but the meter data management systems must be programmed to collect the data. With these data, at the end of the billing period, the NEM customer would receive a multipart bill with a:

- Fixed charge (for metering and billing, in our example);
- Charge for power received, on a TOU basis;
- Charge for grid service for power received;
- Charge for grid service for power provided; and
- Credit for power provided, on a TOU basis.

What is most different about this approach is that the customer is paying for grid service whether he or she is receiving power or supplying it to the grid. The theory is that the customer has built a system that requires a grid in order for all of the power to be used, and should contribute to the cost of the grid for both uses. This is a significant change from traditional rate making, in which "loads" not power suppliers pay for all grid services, but perhaps consistent with other well-known regulatory principles like "cost causers pay."

The strength of this proposal is that it collects revenues to cover some grid costs from NEM customers, whether they are receiving or exporting power, but allows these costs to remain 100-percent volumetric in proportion to actual energy flows. It also provides for all customers, not just those NEM customers, to pay for their electricity service on a volumetric basis, preserving the incentive to both conserve electricity (for all customers) and to size their DG systems to their onsite needs (for customers who have DG). It should also be noted that smart meters would need to be installed for customers with DG, but not for other customers.

Comparing the Options

It is useful to develop hypothetical rates for each rate option, and then to compare these options for some illustrative customers. The hypothetical rates begin with an assumed flat rate, and then develop three different options, each with a TOU rate design.

With hypothetical rate designs, one can then measure customer bills for typical customers. For this purpose, we have identified four hypothetical customers:

- ***Apartment Dweller:*** 5 kW maximum demand; 500 kWh consumption, 50 percent on-peak
- ***Typical Residence:*** 10 kW maximum demand; 1,000 kWh consumption, 50 percent on-peak

Table 8

Typical Rate Design and Three Alternative Approaches (2)

Type of Charge	Unit/ Usage	Typical Current Residential Tariff	*Option 1:* Fixed Monthly Charge	*Option 2:* Demand Charge	*Option 3:* Bidirectional Distribution Charge
Monthly Fixed Charge	$/Month	$5.00	$35.00	$5.00	$5.00
Demand Charge	$/kW/Month		$ –	$3.00	$ –
Distribution Charge	$/kWh		$ –	$ –	$0.03
Off-Peak Energy	$/kWh	$0.145	$0.08	$0.08	$0.08
On-Peak Energy	$/kWh	$0.145	$0.15	$0.15	$0.15

- ***Large Residence:*** 20 kW maximum demand; 2,000 kWh consumption, 50 percent on-peak
- ***PV Customer***[65]**:**10 kW maximum demand; 1,000 kWh total consumption, 50 percent on-peak; 1,000 kWh total onsite production; 500 kWh imported from grid off-peak; 500 kWh exported to grid on-peak

Using the illustrative rate design, and the illustrative customers, we can compare customer bills. In each of the three cases, the PV customer winds up with a zero bill, a happenstance that occurs because of the sharp TOU rate differential, and the assumed on-peak export, on-peak consumption built into the illustrative customer characteristics. The actual bill for each customer would, of course, depend on their actual load shape. (Table 9)

This alone, however, does not convey how much each customer would pay for distribution service. For the NEM PV customer, we show the breakdown of his or her bill under each rate design in Table 10.

With this breakdown, we can see that in each of the three rate options, the illustrative PV customer is paying $35 for distribution service – about the same as a a customer would pay under the fixed charge approach. The PV customer, under the bidirectional rate, is paying $0.03/kWh for 500 kWh received from the grid, and $0.03/kWh for 500 kWh delivered to the grid, plus the

65 For simplicity, we use a limited set of hypothetical residential customers, including a customer with a PV system, to compare rate options and illustrate the concepts presented in this paper. This does not imply that the concepts are solely applicable to residential customers or solely to distributed PV systems.

Table 9

Hypothetical Customer Bill Comparison

Type of Charge	Unit/ Usage	Typical Current Residential Tariff	*Option 1:* Fixed Monthly Charge	*Option 2:* Demand Charge	*Option 3:* Bidirectional Distribution Charge
Apartment Dweller	5 kW Demand, 500 kWh	$77.50	$92.50	$77.50	$77.50
Average Customer	10 kW Demand, 1,000 kWh	$150.00	$150.00	$150.00	$150.00
Large User	20 kW Demand, 2,000 kWh	$295.00	$265.00	$295.00	$295.00
PV Customer	10 kW Demand, 1,000 kWh Total Usage, 500 Exported On-Peak, 500 Imported Off-Peak	$5.00	$ –	$ –	$ –

Table 10

PV Customer Bill Breakdown Under Each Rate Design

Rate Element	Typical Current Residential Tariff	*Option 1:* Fixed Monthly Charge	*Option 2:* Demand Charge	*Option 3:* Bidirectional Distribution Charge
Fixed Charge	$5.00	$35.00	$5.00	$5.00
Demand Charge	$ –	$ –	$30.00	$ –
Distribution Charge	$	$	$	$30.00
Off-Peak Energy	$72.50	$40.00	$40.00	$40.00
On-Peak Energy	$(72.50)	$(75.00)	$(75.00)	$(75.00)
Total Bill	$5.00	$0.00	$0.00	$0.00
Total Distribution Service	$5.00	$35.00	$35.00	$35.00

billing and collection fee of $5/month. But because a NEM customer buys power from the grid during off-peak hours (when power is cheap), and sells it to the grid during on-peak hours (when power is more dear), that customer's "net bill" comes to zero under the illustrative assumptions.

The point of this is that a properly designed TOU rate can provide benefits to the PV customer that may offset the distribution costs, under any approach for recovery of distribution system costs.

Advantages and Disadvantages of a Bi-directional Rate

The bidirectional rate has a number of advantages and disadvantages compared with conventional NEM pricing schemes.

The biggest advantage is explicit recognition of the fair compensation to the utility for services provided to the customer, and likewise explicit recognition of fair compensation to the PV customer for services provided to the utility. As technology and the electricity system continue to evolve, explicitly accounting for the value of services flowing in each direction will become increasingly important. Improvements in information, communications, and electric system control technologies will increasingly blur the distinction between production and services provided from the customer side of the meter and those services provided from the utilities side of the meter. As third-party providers such as independent power generators and aggregators play an increasing role and as the utility role changes over time, being explicit about the value of services provided will become more complicated, more important to keep straight, and compensate properly. Without explicit recognition of the value of some of these services, there is a danger that some important reliability services will continue to be undercompensated, an outcome that could lead to their scarcity and related electric system reliability risks.

Another advantage is that the time-varying structure provides the PV customer a strong incentive to maximize system output and minimize onsite consumption during higher-value hours. Finally, because NEM customers would pay for distribution in a way that reflects their actual use of the grid, this approach provides an incentive to size the system to the load, thereby ultimately diminishing the load that the local distribution grid must carry.

The principal disadvantage of a bidirectional rate is that it is relatively complex, and simplicity is generally considered a virtue in rate design. Some analysts will argue that the network distribution costs should be charged to all distribution customers on a subscription basis, because when the PV systems are displacing the network capacity, it is unlikely to be redeployed to serve other loads. Others may argue that tariff design should price all distribution service on a capacity basis, because that is the engineering criterion by which they are designed. It is worth noting that most prices to residential consumers are volumetric, and that the bidirectional rate would retain this approach.

The most common rate design advocated by electric utilities is a flat charge for distribution service, an approach that is beneficial to utilities for revenue stability, beneficial to large users in the form of lower bills, and harmful to small users, including apartment dwellers who have the lowest cost of distribution service because of their geographic concentration and low per-customer capacity requirements.

Distribution services should be priced according to a volumetric measurement of usage. This can be done on a demand basis or an energy basis. If NEM customers are able to take advantage of a TOU rate design, they should be able to offset much or all of the distribution service costs they incur by providing valuable power to the grid during high-usage periods of the day.

Dynamic Pricing

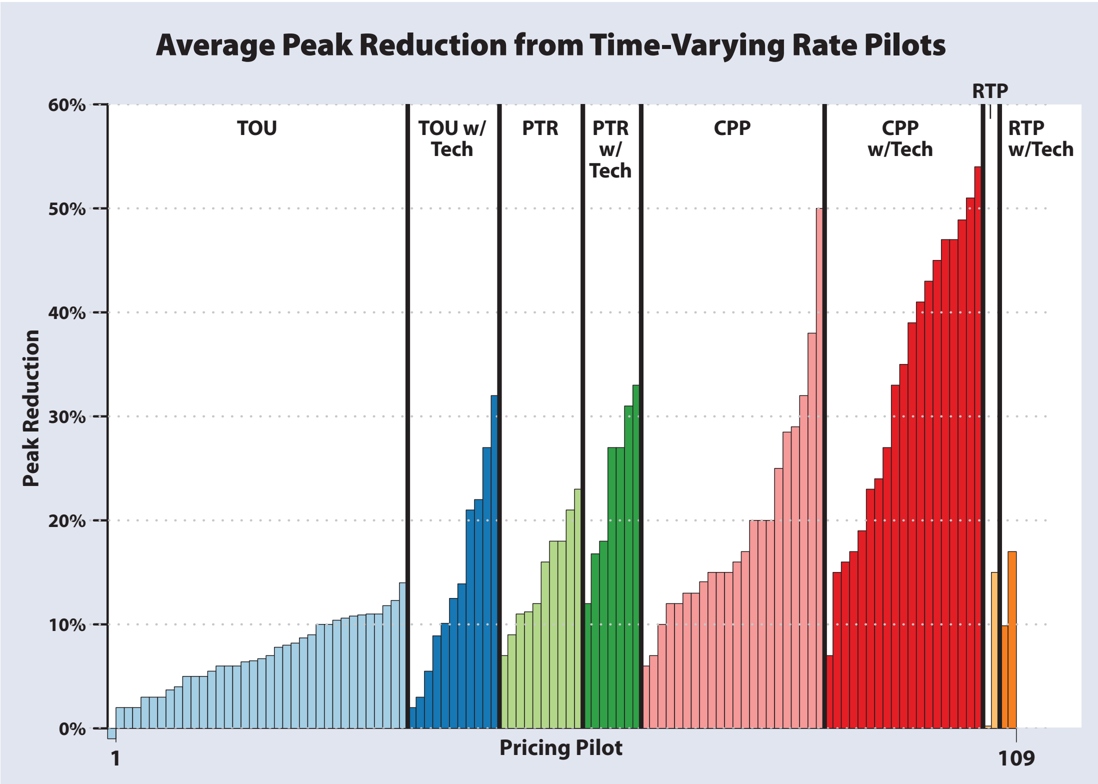
Many analysts recommend going beyond simple TOU pricing that we included in all three options earlier, to what is known as "dynamic pricing," an approach in which the price charged (or paid) varies with market supply conditions. On a hot summer day, prices might rise to $1.00/kWh or more, and during night-time hours or slack periods when nuclear, wind, or solar power gluts the market, prices would drop significantly. As markets and institutions evolve to the point that information technology is used well, and information systems effectively communicate system needs and prices to consumers and third party service providers, these variations in prices will be effectively managed by end users or by a new class of service providers and aggregators that offer new service options that leave consumers better off. At present, markets and institutions have not effectively harnessed information technology and so the potential of dynamic pricing is hobbled and thus we devote relatively little time to it here. Perhaps it will have a larger presence in Distributed Generation Tariffs 3.0.

At the present time dynamic pricing is too complex to show a simple numeric example because the price structure of a dynamic pricing tariff is not well-established. Furthermore, dynamic pricing may be viewed as a mechanism that could be equally applicable to Options 1, 2, and 3 , as an alternative to TOU pricing. The promise for dynamic pricing is significant as evidence suggests that customers will sharply curtail their peak demand in response to dynamic prices. Most of the dynamic pricing experiments performed to date have been with what is known as "critical peak pricing" (or CPP) in which customers have a predictable TOU rate, like those included in the options above, except that for a limited number of hours per year, the utility can raise the price sharply. A typical critical peak price allows the utility to call 15 "events" per year of no more than 4 hours per event. A true "real-time price" (or RTP) allows the utility to change the price every hour without limitation.

Figure 12 shows how peak demand can be affected by different types of advanced pricing.[66]

What this shows is that using CPP or RTP is likely to produce a higher peak load reduction than a simple time of use price would do, because the price signal is concentrated in a short period, and customers can make adjustments to their consumption patterns for that short period.

Figure 12



Feed-In Tariff (FIT) Pricing

As contrasted with a NEM rate, which allows customers to shave their bill by feeding excess usage to the grid at the retail price, a FIT pays the customer a different rate for selling energy than the retail rate for consuming energy. And, as we noted in our definition, a FIT rate is typically higher than the otherwise applicable value of nonrenewable power.

The principal purpose of a FIT is to provide a simplified and defined price that a small power producer can secure with a minimum of negotiation or other transaction costs. A secondary purpose is to establish, typically, a premium price for a premium (i.e., renewable) resource. Although a FIT could be restricted to premium products where a premium payment is applied, or applied to all qualifying distributed generation without an assumed premium payment, the term "Feed-In Tariff" is used in this paper to include both.

For the purposes of this paper, we have defined a FIT as a standard price offer to a small distributed generator, with a premium above the utility's avoided cost to reflect (at least) locational and environmental benefits of eligible resources. This distinguishes a FIT from simple avoided cost pricing, or what we have called a "PURPA tariff." The magnitude of the premium is generally determined by the regulator. In some cases the premiums are purely political in nature, designed to achieve explicit policy goals such as renewable energy encouragement and local economic development.

The earliest experiences in the United States with FITs were the Standard Offer prices developed in California in the early 1980s. These were primarily directed at industrial cogeneration at oil refineries, forest

66 From Faruqui et al., 2012.

products facilities, and other industries. In these, a premium price was incorporated, in part to recognize the risk reduction to utilities associated with having other investors accept the risk of project non-performance.[67] More recently, FITs have been implemented in many states and localities. These range from a traditional European-style FIT as offered by Gainesville Regional Utilities to the "value of solar" pricing methodology adopted by Austin Energy. Nearly all of these tariffs contain some premium over the otherwise applicable avoided costs that a nonrenewable generator would receive for equivalent energy delivered to the grid.[68] In some cases, the premium is related to explicit benefits, such as line loss reduction, avoided reserves, delivery to the utility in the service territory avoiding transmission costs and risks, avoidance of fuel cost risk, and compliance with renewable energy mandates.

In Germany and Spain, FITs carrying a high premium for solar and wind projects were very successful at attracting developers, but ultimately were found to impose too severe a cost on nonparticipants, and were greatly constrained after the economic crisis of 2008. The characteristics of the European FITs included differentiation between energy sources, and between size of generating units. This was done to make smaller units profitable without providing windfall profits to larger units. As illustrated below, the Gainesville Regional Utilities FIT follows the European model:

A FIT is distinguished from NEM in several ways. First, it typically provides for a fixed price (or price formula) for the length of the commitment, as opposed to a rate that automatically adjusts whenever retail prices change. Second, it is normally designed based on the voltage level at which power is delivered to the buyer, with a higher price paid for power delivered at the distribution voltage level. Third, it is often subject to a higher maximum size (up to 80 MW, under the PURPA definition of "small power producer"), whereas most NEM tariffs limit system size to the estimated onsite energy requirements.

A FIT is also different from a utility perspective in several ways. First, the customer is normally required to deliver all output of his or her facility to the utility; diversion for onsite usage is normally not allowed. This means that the utility is assured of receiving the full load shape of the resource; for solar, this is particularly important, because solar output tends to peak during the business day. At least under current penetration levels, this coincides with the time of day during which power is generally more valuable. Probably more important, from the utility's perspective, the customer purchases from the utility all of the energy it consumes onsite, so is therefore paying its "share" of the fixed costs recovered in rates.

The customer may be required to meet interconnection standards that are more restrictive than those for smaller NEM resources. Finally, the purchaser may have the authority to "dispatch" the FIT resource which gives the purchaser, subject to tariff conditions, the flexibility to ramp up or curtail the generator depending on its highest value use to the purchaser. For CHP, the ability to dispatch may actually involve ramping the unit up and down as utility load changes; for solar or wind resources, it may involve curtailment of deliveries when other resources must run for economic or operational reasons.

67 Lazar, 1982.

68 For discussion of the tariff innovations in California for DG less than 20 MW with the passage of AB 1613 see DOE's SEE Action CHP Guide (2013).

Table 11

Gainesville Regional Utilities FIT for Systems Energized in 2013	
Amount:	Rooftop- or pavement-mounted systems <10 kW: $0.21/kWh
	Ground-mounted systems <10 kW: $0.21/kWh
	Rooftop- or pavement-mounted systems >10 kW to 300 kW: $0.18/kWh
	Ground-mounted systems >10 kW to 25 kW: $0.18/kWh
	Ground-mounted systems >25 kW to 1,000 kW: $0.15/kWh
Terms:	20-year contract
Eligible system size:	Ground-mounted systems maximum: 1,000 kW
	Building- or pavement-mounted systems: 300 kW

Elements That Utilities Seek in a FIT

Utilities typically seek elements that protect the utility shareholders and non-participating bill payers from significant adverse impacts of a FIT. These elements often include:

- A price that is related to the utility's short- and long-run avoided costs; the ideal price would start low and grow over time to reflect rising values over time and achieve intergenerational equity;[69]
- Prices that are not higher for smaller systems, unless the value of the output can be shown to be greater;
- A contract term long enough to allow deferral of other generating capacity;
- Ability to control the output of the generator within reasonable limits; and
- Contractual terms that tie compensation to customer generator performance.

Elements That Investors Seek in a FIT[70]

In considering various aspects of a FIT, investors seek the following attributes:

- A price that is related to the system cost, including a return on investment: this typically means prices that are higher for smaller systems;
- A flat price over the project lifetime, or a front-loaded price, to help make the project economics feasible and reduce investment risk;[71]
- Recognition that the power is usually coming to the utility at a favorable point of interconnection;
- A contract term long enough to recover the capital investment; and,
- Assurance that all of the output of the system that is made available to the utility will be paid for.

Third-party PV leasing companies seek an additional element that is frequently lacking in FIT policies, namely that the FIT be enduring and stable. These companies do not raise capital one PV system at a time; rather, they raise enough capital to allow the installation of large numbers of PV systems over a period of time. To do this, investors need to know with relative certainty that a favorable tariff will be available at a later date when the leasing companies deploy this capital and install PV systems. There is a sense among these companies that NEM policies, which tend to have a longer history and larger program caps than FIT policies, are more enduring and stable. As previously noted, the U.S. experience with FITs includes several examples of small program caps that were achieved (fully subscribed) relatively rapidly.

A Value of Solar tariff can be viewed as a variant of a FIT. The key difference, to date, is that FIT arrangements set the price to be paid for the life of the agreement or resource (10 – 20 years) while the Value of Solar tariff (at least in Austin[72]) has been subject to periodic unilateral amendment by the utility regulator, a practice that would give financiers of solar systems considerable discomfort.

Common Ground

Both utilities and investors have a common interest in longer-term contracts. For the utility, this provides the ability to defer construction or contracting for new generating capacity. For the investor, it provides assurance of recovery of the investment over time.

The interest of utilities in rates based on incremental utility system costs will generally be consistent with the interest of larger DG systems, those measured in 1 to 20 MW, because evidence shows that systems of that size are more economic than smaller systems. Although the installed cost per kW may be higher for small systems than for larger ones, the interconnection and transmission costs are typically lower. Smaller DG systems, i.e., those that can connect to distribution systems also provide significant value due to their ability to avoid line losses. FIT prices based on incremental utility system costs, however, will generally be inconsistent with the interests of residential and small commercial systems, where

69 In contrast, utility-owned resources cost the most in early years and decline over time. Utility-owned resources are most expensive in the early years, because the rate-making formula initially provides a return on the entire investment plus depreciation expense, whereas in later years the capital recovery reflected in rates declines as the investment is depreciated and the rate base goes down. Thus FIT resources do a better job of matching value to cost recovery, and do a better job of assigning costs to the consumers who benefit, thus improving intergenerational equity.

70 We use the term "investors" here to refer to the parties providing the capital and taking the financial risk in an energy facility. This may be the owner of the facility, it may be a financier, or there may be shared risk between them.

71 Sometimes investors are able to accept a lower return in the early years if there are accelerated depreciation or other tax benefits available.

72 Austin Energy, 2013.

Value of Solar Tariffs

FIT or Value of Solar rates are sometimes called Buy-All/Sell-All rates. Many utilities prefer to enter into agreements whereby they take 100 percent of the output of a DG system, and the consumer purchases 100 percent of their needs at the applicable utility tariff. The benefits for utilities include:

a) All of the purchased power cost can be flowed through the purchased power and fuel adjustment clause, avoiding any risk for net revenue loss (which can otherwise be addressed with a revenue stabilization mechanism like decoupling).

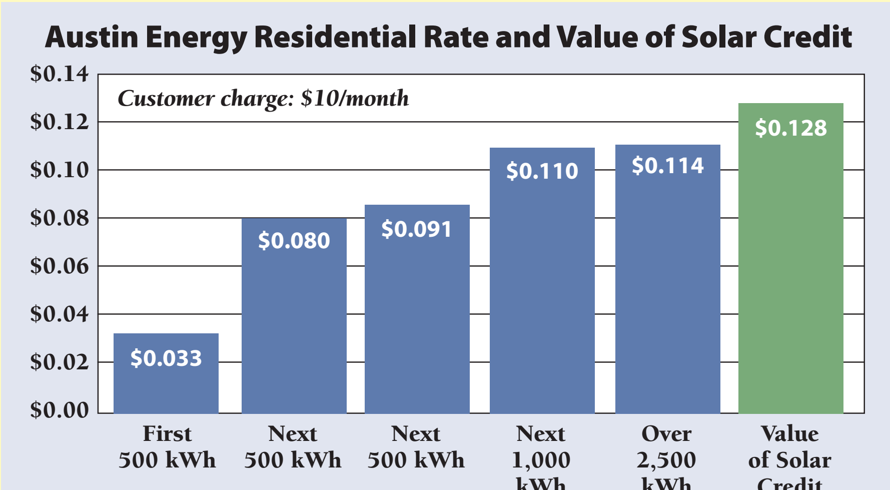
b) All of the power from a renewable DG system can then be claimed as "utility system power" to help the utility meet a state-imposed RPS.

c) The customer is not being "subsidized" because he or she is paying the same retail tariff as other customers for power consumed (even though it may be lower than the price he or she receives for their renewable production).

One consideration for consumers is that power purchased at a retail rate may contain up to 15 percent in local and state taxes, whereas consuming onsite power avoids these utility revenue taxes. A buy-all/sell-all arrangement removes this potential cost advantage to the consumer.

Austin Energy has been a leader in this area, with a premium "Value of Solar" formula for setting a purchased power price that generally exceeds the retail distribution tariff. Austin Energy has structured its inclining block rate design so that the customer generally saves money under this arrangement, compared with NEM.

Figure 13



J. Lazar, 2013 based upon Austin Energy website data

the diseconomies of scale generally are greater than the benefits of distribution-level connection.

Finally, the interest of utilities in cost-based rates will generally be consistent with the interests of PV generators, because the output of PV systems is concentrated during the daytime, when electricity loads are higher and power costs greater. A TOU-based rate will recognize this value. At some level of solar saturation, however, this may create a need to redefine on-peak versus off-peak hours.

Some Fundamental Conflicts

There are some basic conflicts between the interest of utilities and those of DG system investors with respect to FIT. The most elementary of these is that small systems are more expensive per unit of output, and utilities do not perceive the value of the power to be measurably different for systems that connect to the grid at the distribution level. The framework of the European (and certain states and municipalities) FIT, therefore, is generally not something utilities consider appropriate.

The ability to control output is another area of conflict in power system management. Utilities have some resources that cannot be shut down without advance notice, such as nuclear units, and others with limited ability to quickly increase or decrease output, such as coal and combined-cycle generators. This can create a situation in which the utility has more generation than load. Large renewable energy additions exacerbate this challenge due to their inability to be dispatched. San Diego Gas and Electric has predicted that by 2020 they will be facing an extremely challenging situation in the late afternoon, as the need for system generation to ramp up to meet demand will be faster than their resource mix is capable of providing. In a three-hour period, they will need to increase system generation from resources other than wind and solar from approximately 1,500 MW to approximately 3,500 MW. The ability to curtail output from distributed generators, even for short periods, may be important to system reliability.

Figure 14 illustrates the expected load situation in Southern California by the year 2020, with significant additions of wind power, distributed solar generation, and central station solar generation. The grid operator will see a rapid decline in the net load to be served from traditional grid resources in the morning, and a very fast ramp rate required in the afternoon as solar generation declines just at the time system loads are peaking. The dotted line is the total electricity demand; the solid line is the net grid requirements, excluding generation from wind and solar sources, that need to be served with other (controllable) grid resources.

Obviously nonutility generators have the opposite interest: ensuring that they get the maximum utilization from their resources, and the maximum revenue from the utility.

This is a very real conundrum. Maui Electric (MECO) now has approximately as much wind generation installed as it has night-time load. If all the wind turbines are operating at night, the utility would need to have its thermal plants operating at zero. But if they are completely shut down, they may not be able to start up and come up to full output fast enough to meet daytime loads, so they normally run the thermal plants at a reduced output at night, to be prepared for daytime loads. For a limited number of hours in 2012, MECO forced some of the wind turbines offline, reducing their revenue. The Hawaii PUC severely penalized MECO for this action in their 2013 rate decision.[74] The experience in Maui is unlikely to be replicated by a mainland system any time soon, simply because of the availability of transmission interconnections, but it provides an indication of the type of challenge that may be ahead for the industry.

Most utility regulators are unlikely to approve a FIT regime that could threaten the reliability of electric service. One likely result of this conflict is that future FIT agreements will need to contain very specific language allowing, but limiting, the authority of electric utilities to reject output for a limited number of hours per year. The nature of these limits will depend on the flexibility of the grid to which the generator is connected; large grids with extensive transmission interconnections will have greater flexibility than small isolated systems like those in Alaska, the Hawaiian Islands, Guam, American Samoa, and the U.S. Virgin Islands.

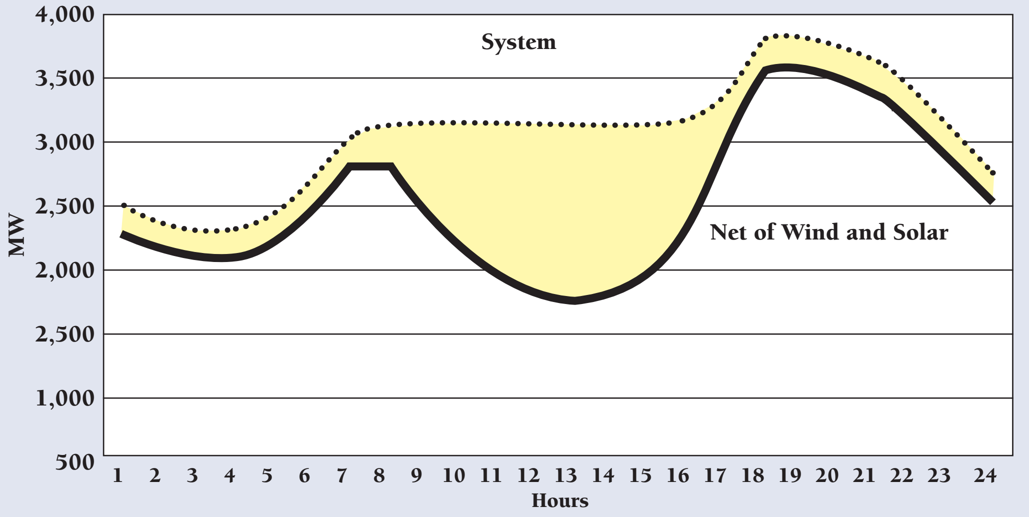
Reconciling the Conflicts

The European practice of providing higher payments per kWh for smaller-scale systems based on the higher cost of these systems has already found its way into some state and municipal FIT determinations. However, it is unlikely to receive more widespread adoption by state regulators, given the determination by FERC that these are wholesale transactions subject to PURPA avoided cost

Figure 14

"Duck Curve" Showing Net System Demand on System with High Levels of Solar and Wind Generation [73]

December Peak Day 2020



73 San Diego Gas and Electric submittal to California PUC in Docket #12-06-013

74 Hawaii PUC Decision No. 31288, May 31, 2013.

standards and FERC regulation . Unless regulators find that the smaller systems provide greater system benefits, such a rate would likely be found to be discriminatory.

Second, there are many categories of benefits that can be better reflected in the prices that are offered through a FIT arrangement. The full value of DG should be recognized, barriers removed, and prices adjusted to reflect this differential value from other resources.

Third, regulators would do well to strengthen linkages between DG and system benefits by encouraging stronger linkages between the timing and location of generation through rate design and interconnection policies. The ability to curtail output for short periods of time will likely become increasingly essential. Regulators will need to address this as intermittent generation becomes a significant share of the utility resource base, but that treatment should be equitable. Utilities will need to maximize the flexibility of existing resources, acquire storage capacity, and improve interconnections in order to minimize the frequency and length of curtailment of FIT output. FIT investors may need to accept that a limited amount of curtailment is essential to assure reliable electric service.

A Hybrid Approach

A state PUC may be torn about which option to choose, especially as DG customers vary in size and complexity, and a single approach might not adequately meet a utilities varied needs. On the one hand, it may not want to complicate matters for customers comfortable with the simplicity of NEM, especially smaller residential customers with on-site PV systems less than 5 kW. On the other hand, PUC members may feel that some more value based and accurate way of valuing customer PV sales to the grid is appropriate as the scale gets large enough, especially due to larger customers with larger PV systems entering the system.

A PUC could decide on a hybrid approach using two systems that are differentiated by the size of the PV system. For smaller customers, NEM could continue. Meanwhile, a different system of the sort discussed herein could be introduced for larger customers.

The result would be that a significant share of kWhs bought from customers would be more accurately priced, while for many thousands or even millions of smaller customers, the simplicity of net metering can be maintained.

Revenue Stabilization Mechanisms[76]

Lost retail revenues related to NEM are a significant concern for electric utilities in the same way that energy efficiency investments by utilities have been in the past because they have exactly the same impact on earnings. However, even the highest saturation of onsite generation in the United States – Hawaii – is amounting to no more than approximately 1 percent of customer revenue per year, comparable to the level of impact many states are achieving with energy efficiency. Although these lost revenues create a problem that should be considered and addressed, it is not an unmanageable challenge.

Figure 15 shows an illustrative calculation for one electric utility in the southwest United States, showing how a one-percent reduction (or gain) in sales would affect net income for shareholders. A one-percent loss of sales results in a 12-percent loss in net income.

Energy efficiency expenditures in the United States exceed $10 billion per year, and utilities would not engage in uncompensated activity without a contest. For this reason, regulators have addressed lost revenue for energy efficiency with two different mitigation mechanisms: revenue regulation (decoupling) and lost revenue adjustment mechanisms (LRAM). Both of these mechanisms can be applied to reduced sales due to NEM system installations.

Revenue decoupling consists of small periodic rate adjustments to align actual revenue with allowed revenue as determined by the regulator. Although California, Maine, and Washington were pioneers of decoupling, it is now in place in more than a dozen states to ensure that reduced sales resulting from energy efficiency do not adversely impact utility net income. The process for decoupling is very simple:

- The regulator determines an allowed (typically non-power) revenue for a defined period;
- At the end of the defined period, actual revenue is compared to allowed revenue; and
- A small credit or surcharge is implemented, normally on a per-kWh basis, to refund the surplus or recover the deficiency.

A revenue decoupling mechanism would operate no differently for lost margins owing to NEM than it

76 This section on revenue stabilization is based on a more thorough treatment of the subject in Lazar, Shirley, and Weston, 2011.

Table 12

An Example of the Impact of Sales Decline on Earnings					
	Revenue Change		*Impact on Earnings*		
% Change in Sales	Pre-tax	After-tax	Net Earnings	% Change	Actual ROE
5.00%	$9,047,538	$5,880,900	$15,780,900	59.40%	17.53%
4.00%	$7,238,031	$4,704,720	$17,604,720	47.52%	16.23%
3.00%	$5,428,523	$3,528,540	$13,428,540	35.64%	14.92%
2.00%	$3,619,015	$2,352,360	$12,252,360	23.76%	13.61%
1.00%	$1,809,508	$1,176,180	$11,076,180	11.88%	12.31%
0.00%	$0	$0	$9,900,000	0.00%	11.00%
-1.00%	-$1,809,508	-$1,176,180	$8,723,820	-11.88%	9.69%
-2.00%	-$3,619,015	-$2,353,360	$7,547,640	-23.76%	8.39%
-3.00%	-$5,428,523	-$3,528,540	$6,371,460	-35.64%	7.08%
-4.00%	-$7,238,031	-$4,704,720	$5,195,280	-47.52%	5.77%
-5.00%	-$9,047,538	-$5,880,900	$4,019,100	-59.40%	4.47%

does for energy efficiency. In fact, a revenue decoupling mechanism established with energy efficiency as the primary focus would address the lost revenue aspect of the utility's concern with NEM without any special design changes whatsoever.

LRAMs have also been established for energy efficiency programs in more than a dozen states. These generally have the following framework:

- A utility margin per kWh is computed in a general rate case; this may be a "gross margin," meaning the difference between the retail rate and avoided variable power supply costs in the short run, or it may be a "distribution" margin that excludes any power supply-related costs.
- For each kWh of conservation program savings (or DG-driven sales reduction), the utility is allowed subsequent recovery of the lost margin, until the next rate case, through a tariff rider.
- In the next rate case, the adjusted sales volume is taken into account in setting future rates, and the tariff rider for previous conservation savings is ended (but it continues for new conservation savings after the test year).

The principal difference between decoupling and LRAM is that decoupling takes into account all changes in sales volumes (up and down), whereas LRAM addresses only margin recovery for decreased sales from specified programs. A decoupling mechanism, therefore, by its very design, accounts for the lost sales attributable to NEM, whereas an LRAM would need to be specifically designed to include not only energy efficiency program-related sales reductions, but also sales reductions owing to the onsite consumption of power from NEM systems.

Lost Investment Opportunity Impacts and Regulatory Mitigation Measures

When utilities meet electricity demand in part through NEM or FIT customer generation, the utility does not typically own any portion of the DG resources that provide the electricity. Because utilities earn their profit as a percentage of their investment in utility plant (i.e. generation, transmission, and distribution facilities), increasing amounts of load met through DG resources means a smaller utility with smaller profits – unless compensating investment opportunities that come with expanded DG completely match or exceed the investment lost. Although some increase in distribution system investment is likely with higher DG investment, and some jurisdictions are considering utility business models in which the utility would take on a portion of the customer side of the meter investment (e.g., investing in two-way metering or smart inverters, or leasing generation equipment to the customer), the net investment required by the utility will likely become smaller as DG expands. Thus the utility rate base will likely erode somewhat over time. The utility rate base, on which it earns a return, is the sum of investment in utility assets, less the accumulated provision for depreciation that has been paid.[77]

However, slower growth in rate base investment opportunity does not necessarily harm existing shareholders. In theory, the allowed rate of return is only equal to the actual cost of debt, plus the market-determined cost of equity capital. If the regulator has set the rate of return correctly, existing shareholders do not benefit from a growth in rate base. In order to finance the additional utility plant, the utility would need to issue additional debt and additional shares of stock, and the owners of these bonds and shares would get the return that accrued from ownership of the additional rate base. Existing shareholders would be unaffected.

Sometimes, however, the utility rate of return is set higher than the actual incremental cost of capital, and shareholders in this situation would lose earning opportunity from the reduced investment opportunity that comes with increased DG adoption. As of 2013, the allowed return on common equity for most U.S. electric utilities is at or above 10 percent, while independent (i.e., non-utility) analysts testifying in rate proceedings have calculated the market-determined cost of equity to be in the 8-percent to 9-percent range.[78] Electric utility shares for utilities in this favorable situation sell at a premium above their book value, because the allowed return exceeds the market-required return, and the market bids up the share prices. Under these circumstances, in which the utility can invest in a new plant, earn a 10-percent return, pay out only 85 percent to 90 percent to new shareholders, and can sell incremental shares at a premium above their book value, existing shareholders do experience reduced earnings with reduced investment opportunity.

Thus reduced investment opportunity does not harm existing shareholders unless the regulator allows the allowed rate of return to drift above the market required incremental rate of return. So one solution to this perceived harm is for regulators to update the allowed rate of return periodically, and keep it close to the market-required return. While this would remove the dis-incentive for utilities to support increasing levels of DG penetration, it does not provide a positive incentive for utilities to encourage cost-effective DG. Mechanisms that could provide this positive incentive might include allowing utilities to earn a profit on power derived from non-utility generators (such as NEM or FIT customers), by providing utilities with the opportunity to share in the capital investment required for high penetration DG, or by providing utilities with an incentive return on equity (ROE) opportunity if they implement best practices for open access DG and achieve high levels of DG adoption. If regulators see a need to incentivize utilities to be more receptive to NEM and FIT resources, this option is available. This approach has been used for energy efficiency investments by a few regulators.[79]

77 For a detailed explanation of the regulated utility rate setting process, see Lazar, 2011.

78 See, e.g., CPUC Dockets 2013.

79 The Washington and Nevada Commissions tried (and then rescinded) mechanisms to allow an equity return bonus on energy efficiency investments; the Washington Commission is currently allowing an equity return on a hypothetical investment in a power plant, and Duke Energy has proposed being allowed to charge for energy efficiency at the level of cost that would have been incurred had a power plant been built. All of these have been very controversial among consumer advocates, although the Nevada program succeeded in restarting and growing demand-side management programs in Nevada, making demand-side management programs a preferred investment over generation in the eyes of shareholders.

Section 4: Conclusion

Resources on the customer side of the meter are playing an increasingly larger role in meeting the needs of customers themselves as well as the needs of the electric system. The cost and performance of distributed generation technologies have improved significantly and are expected to continue to improve. As these improvements in generation technologies are joined with improvements in information, communications, and electric system control technologies, electricity markets and system operations will evolve so that the capabilities of distributed resources will increase and the scope and value of services provided will increase as well. Additionally, as the role of customer energy efficiency and generation resources increases in scope and value, regulators will have to be vigilant to ensure that customers are being fairly compensated for the services that they provide to the utility and the electric system.

At the same time, regulators need to ensure that the utility is being fairly compensated for the services that it provides to all customers, including those customers who operate customer-sited DG. The electricity grid is providing valuable and essential services today that ensure reliable service for its customers and it is in the public interest to ensure that utilities are fairly compensated for these services. While the grid will likely become far more distributed in the future than it is today, and the introduction of microgrids will make parts of the electric system far more self-sufficient, electric utilities will continue to play a role for the foreseeable future and ensuring fair compensation for utility services will continue to be an important regulatory task.

While striking this balance of fair compensation, regulators will also want a system that is administratively manageable and understandable to customers, solar equipment providers and utilities.

Against this backdrop of technological and institutional change on both the customer and utility sides of the meter, most of the current PURPA, NEM and FIT tariffs are relatively crude mechanisms for ensuring that customers are fairly compensated for the value of their generation resources. This paper concludes that these mechanisms can be adapted to meet current and emerging challenges. As electric system institutions evolve to take full advantage of information, communications and control technologies, it is likely to be possible to more explicitly value all of the services provided to the electric system by customers while continuing to recognize the value of those services provided by utilities, and a whole new set of markets and exchange mechanisms are likely to develop over time to ensure that prices paid match values provided for a wide range of services.

However, the more immediate task faced by regulators today is to adapt the NEM and FIT mechanisms to ensure fair compensation on all sides. The first lesson regulators should take away from this paper is that context matters. We have seen strains appear in the application of the tariffs as very rapid distributed generation penetration has begun in some specific locations. The more significant sources of strain appear to be exacerbated by rate designs, particularly among investor-owned utilities in California, where the tail block of inclining block retail rates is well in excess of the long run marginal cost of service. These more extreme anomalies have made it clear that regulators need to pay attention to the respective roles and relationship among rate design, regulatory treatments to address lost revenues, and distributed generation tariff mechanisms such as the NEM and FIT tariff mechanisms. At the same time, we also recognize that in most of the US tail block rates are far below the value of adding additional renewable resources, and subsidies may run in the other direction (DG customers may be subsidizing other customers). Regulators need not look to faraway jurisdictions for the answers to these difficult questions. Regulators can take stock of the unique circumstances in their own states and within each respective utility service territory, and make decisions based on those specific circumstances.

Recommendations for Regulators

We recommend regulators follow several principles as they consider designing DG tariffs that represent fair compensation.

1. **Recognize that value is a two way street.** Customer side of the meter resources like distributed generation, energy efficiency, demand response and storage are resources that produce value for the electric system. The electricity grid offers valuable services to DG customers and it will continue to do so for the foreseeable future. Customers, the utility and third party participants in exchanges should all be fairly compensated for the services they provide each other with due consideration of the full range of benefits and costs associated with each service delivered..
2. **Distributed generation should be compensated at levels that reflect all components of relevant value over the long term.** The distributed generation resource provides a broad range of services and values and should be fully compensated for those values. This means including avoided energy and capacity cost, as well as the avoided generation, distribution, and transmission, avoided line losses, avoided price and supply risks associated with renewable, non-fossil resources and all other utility system benefits identified in Section 2. It should also be recognized that the avoided cost is location specific as putting DG specific places on the network may avoid more future costs, other locations may avoid less future cost.
3. **Select and implement a valuation methodology.** Distributed generation resources provide utility system benefits and non-energy benefits. There are many sources of benefits and costs that should be accounted for to fully value a distributed generation resource. The regulator should decide on a methodology and implement the methodology consistently so that distributed generation resources are fairly valued and the presence of any potential inequities can be judged objectively.
4. **Remember that cross-subsidies may flow to or from distributed generation owners.** Regulators should remain objective and allow for the possibility that the value provided to all customers by DG may be greater than the costs incurred to support the presence of distributed generation tariffs. Conversely, regulators should be open to the possibility that non-participating customers may be getting less value from distributed generation than they are paying to support those tariffs.
5. **Don't extrapolate from anomalous situations.** Some places, like southern California, have very high tail block electricity rates which are far in excess of long run marginal costs of service. Problems that have arisen in that situation, or any other relatively anomalous situation, should not be used to drive policy or tariff solutions in states with completely different situations. Regulators should build policies, regulations and tariffs that recognize the characteristics of their state and the utility in question. See Bird, et al. (2013) for a list of questions that regulators can ask stakeholders to diagnose the characteristics of their specific context.
6. **Infant-industry subsidies are a long tradition.** Land grants to railroads were used to encourage construction of infrastructure in the 1800's. Air mail contracts helped launch commercial air service. Military contracts helped subsidize the development of semiconductors. At some point an industry becomes mature, and should compete without subsidies, but regulators should be mindful that financial assistance to prove up promising new industries is a long-established practice.
7. **Remember that interconnection rules and other terms of service matter.** The focus of this paper has been on tariffs but that does not mean that interconnection rules and other terms of service, like standby charges are not important. To the contrary, distributed generation should have fair and open access to the grid at non-discriminatory terms and rates and regulators should ensure such access through administered rules and incentive programs. Incentive programs for utilities to move their open access beyond established rules to "best in class" open access innovation should be considered by regulators.
8. **Tariffs should be no more complicated than necessary.** Remembering Bonbright (1961): Tariffs should be practical. Tariffs should be simple, understandable, acceptable to the public, feasible to apply, and free from controversy as to their interpretation. Established tariffs like the NEM tariff have the virtue of being simple and relatively well-understood. At the same time, NEM tariffs are a blunt instrument and their inherent imprecision should be acknowledged. The alternatives, however, may be too complex for consumers to fully understand. . In weighing the policy, regulation and tariff options possible for distributed generation one should keep in mind both the virtue of simplicity and the virtue of adequate precision as one deliberates on fair compensation.

9. **Support innovative business models and delivery mechanisms for DG.** Leasing and aggregation of loads for NEM have been game changing approaches that have significantly supported solar PV uptake in Colorado, California and elsewhere. These approaches support cost-effective deployment of distributed generation policy and should be encouraged. They make it possible for lower-income consumers and even renters to participate in DG development. For a more complete discussion of business model approaches for solar PV see Bird, et al. (2013).
10. **Keep the discussion of incentives separate from rate design.** In seeking to identify a rate design that provides fair compensation across the board, regulators should keep separate any discussion of specific incentives to support a specific technology. Rate design should be about fair compensation for value of services provided and fair allocation of the costs to reliably operate the system. If policy makers feel for any reason that additional incentives are warranted, those incentives should be added in a transparent manner that does not distort or obscure the assessment of fair compensation.
11. **Keep any discussion of addressing the throughput incentive separate.** Accounting for utility lost revenues associated with declining utility load may be an issue that regulators want to address. There are regulatory treatments like decoupling that can effectively address that concern. But the discussion of addressing the throughput incentive and rate design for DG tariffs should be considered separately.
12. **Consider mechanisms for benefitting "have not" consumers.** With current financing mechanisms, low-income consumers will not be likely investors, owners, or even hosts to renewable energy resources. Ensuring fair compensation for the value of electric services provided will protect low income customers from being over-charged, but any incentives implemented with ratepayer funds to support any DG technology will end up primarily in the pockets of relatively wealthy customers who can afford to invest capital in DG or who have a high enough credit rating to qualify for leasing contracts. Since low income customers contribute to the revenue pool that supports incentive payments, it is fair for them to benefit from at least a pro-rata portion of their contribution toward these payments. Regulators can support programs such as group NEM that make use of these funds to offer benefits directly to lower income consumers, and they should choose programs that demonstrated the greatest benefit per dollar invested. These will often be energy efficiency programs and perhaps demand response programs and hot water storage programs, but less often renewable energy programs.

Getting NEM and FIT Right

Both NEM and FIT arrangements should reflect the unique characteristics of distributed resources. These unique characteristics will be discussed by regulators as they define a valuation methodology and they will likely include discussion of the clean, distributed generation benefits such as: delivery inside the service territory (which means lower line losses, lower transmission and distribution capacity requirements), improved reliability compared with equivalent resources located outside the service territory, and lower fuel cost, lower fuel supply cost, and less environmental risk compared with fossil-fueled resources. NEM and FIT are each legitimate approaches if done well. They are not necessarily mutually exclusive alternatives and may be used in a complementary fashion as suggested in the Hybrid Approach on page 46.

Specific Recommendations regarding NEM implementation

1) NEM tariffs should recognize that the renewable resource is a premium product that offers different benefits than the average of resources that make up the retail rate. In some cases this may justify full NEM treatment, as these other benefits may roughly equal the perceived subsidy in granting a rate credit that includes a distribution cost component that may not be avoided in the short run.
2) Modifying retail rate designs to collect distribution costs in a fixed monthly customer charge is not a preferred path. Rate design of this type tends to penalize apartment dwellers and other urban residents, who typically impose lower distribution costs on the utility than the average customer. Setting the tail block of an inclining block rate structure at the long run marginal cost is more equitable than increasing the fixed monthly charge because it does not discriminate against low income and low volume electricity consumers, it does not discriminate against urban and apartment dwelling consumers and it is consistent with valuing the avoided cost component of DG at the long run marginal cost.
3) Time-varying arrangements for general application should be considered, either on a default or optional basis. If available to consumption customers, these

TOU tariffs should over time be made mandatory for DG customers so that their prices – in both directions – are more closely related to the value of the power they consume and provide.

Specific Recommendations for FIT Implementation

1) FITs should provide customers with stable tariff terms for a long duration, at least ten years, in order to provide up-front certainty about project economics.
2) Utilities and regulators should design different FITs for different types of resources that reflect the specific attributes and values provided by those resources.
3) Policy makers and regulators should consider auctions or other market mechanisms in order to set FIT prices that are no higher than they need be to encourage cost-effective deployment of DG.
4) Policy makers should commit to a stable, long-term FIT policy, allowing for the possibility that prices and other tariff terms may change over time but not unpredictably or radically.
5) After regulators ensure that FIT prices reflect value and are no higher than necessary, they should make sure that program caps are not unreasonably restrictive so as not to interfere with the goal of policy stability.

While the urgency to address compensation of distributed solar PV is highest in those states where its penetration is highest, trends of declining PV installed cost and increased customer choices suggest that these matters will come to most if not all regulatory commissions sooner or later. The principles we enunciate here are intended to guide regulators as they evolve their distributed generation tariffs to address the concerns being heard from different corners today as well as to position the power sector to take advantage of the best new technologies as they become available. The over-riding principle we suggest is one of fair compensation: fair compensation for all who provide power sector services, fair compensation for the value delivered for services provided, fair compensation so that customers are not over-charged for the services they receive, and fair compensation so that valuable services will be compensated and grow as customer preferences and technological capabilities evolve.

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