7 Ariz. J. Envtl. L. & Pol’y 56

Arizona Journal of Environmental Law & Policy
April 27, 2017

Article
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*56 JUST AND REASONABLE ROOFTOP SOLAR: A PROPOSAL FOR NET METERING REFORM

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*57 I. Introduction

Recent technological, economic, and political developments have turned the electric power sector--traditionally a quiet and stable industry modulated by heavy government regulation--upside-down. Plummeting natural gas prices have enabled natural gas combined cycle plants to challenge coal power plants for baseload generation.[1] Falling capital costs for wind and solar power have underwritten significant growth of renewable capacity on the grid.[2] Smart meters and advanced energy efficiency technology have reconfigured the relationship between the customer and the utility through the potential for conservation.[3] Greenhouse gas emissions from the power sector--30% of total US emissions in 2015[4]--have made the industry a central focus of climate change mitigation efforts.

One of the main developments challenging traditional power sector organization is distributed generation--the presence of small, customer-owned, generating sources connected to distribution grids. The most common distributed generation technology is solar, accounting for over 97% of the installed capacity.[5] Households, businesses, and industrial facilities are installing solar panel arrays on their buildings and land, thereby providing for their own electricity needs.

***58** State and federal policies encourage the development of distributed generation through a variety of incentives, including tax credits, renewable portfolio standards, and rate design.[6] The rate design for distributed generation utilized in most states is known as “net metering.” Under net metering, when distributed generation customers produce more electricity than they consume, they are allowed to run their meters in reverse. At the end of the month or the year, they pay only for the net amount of electricity consumed. Such an arrangement is important as solar power supply imperfectly matches with customer demand. In the middle of the day, solar panels may be generating more electricity than the customer needs. After sundown, the customer draws power from the grid. Net metering allows the customer to receive compensation at retail rates for excess electricity provided to the grid during the day and preserves access to electricity from the grid overnight.

Net metered customers are a small minority, only 0.4% of all utility customers nationwide, but their numbers are growing rapidly.[7] The major electric utilities, seeing the growth of potential competition, have begun to push back against net metering and call for reform.[8] The utilities argue that net metered customers benefit from the grid but pay nothing for its costs, instead shifting these costs onto other customers.[9] Solar power companies and advocates counter that solar power provides extensive benefits to the grid.[10] This debate has ***59** recently played out in administrative proceedings in Nevada, Arizona, and California, and many other states.[11]

Decisions if and when to reform net metering have important ramifications for efforts to mitigate climate change. Solar installations are expected to play a substantial part in reducing greenhouse gas emissions. One widely cited analysis asserts that solar could provide as much as a seventh of the emissions reductions required globally to prevent the worst impacts of climate change.[12] Distributed generation solar (DG solar) accounts for over a third of installed solar capacity (complementing utility-scale solar) and is one of the fastest growing segments.[13] Net metering reform that chokes the growth of DG solar weakens society’s ability to address climate change. Alternatively, the continuation of net metering policies that disproportionally benefit net metered customers may create widespread public backlash and similarly jeopardize important support for solar power. Smart policymaking requires a careful assessment of competing interests to create a fair and sustainable level of support for these technologies.

This article conducts an integrated economic and legal analysis of net metering to investigate the opposing claims made by utilities and solar proponents and to assess the need for reform. Specifically, it examines whether and to what extent net metering causes cost shifting, what costs net metered technologies avoid and what benefits they provide, and how regulators should take these facts into account in setting net metering policy. The economic analysis quantifies every category of avoided costs and provided benefits. The legal analysis determines whether net metered customers should be compensated for the value of the costs and benefits in ***60** each category. This determination hinges on the considerations regulators are permitted to take into account when setting rates. Primary among these considerations are economic efficiency and alignment of rates with cost of service. Secondary considerations for rate setting include environmental protection and distributive equity.

This article concludes that the current extent of cost shifting is negligible. The present ratio of net metered customers to other customers is low enough that any unmet costs through net metering do not amount to a significant burden on other customers. The impacts of net metering on distributive equity and alignment of cost of service are minimal in the short term. By contrast, the environmental benefits from supporting development of solar technologies are significant. Thus, reforming net metering to address cost shifting is not recommended in the near future.

However, as DG solar achieves significant penetration in the long term, the current net metering regime will tax the legal bounds of the public utility regulatory framework. Utility regulators have some latitude to pursue social goals at the margin, but their core mission is to set rates based on cost of service and thereby ensure economically efficient outcomes. Eventually, the amount of DG solar on the grid will lead to a substantial conflict between the use of net metering rates to promote environmental goals and the core regulatory mission of economic efficiency. At that point, net metering will require reform.

Net metering reform based on principles of avoided cost and open access need not and should not choke the growth of DG solar. Regulators should apply those principles, taken from the Public Utility Regulatory Policies Act (PURPA), in conjunction with a modernized conception of electricity supply and use. Namely, electricity today should not be treated as a commodity with a single price, unvarying in time and across space. Rather, a marginal unit of electricity has significantly more value when it is supplied in the peak demand hours of the day, ***61** when the grid is near capacity and the highest cost generators are operating. Similarly, a marginal unit of electricity is much more valuable on a distribution grid proximate to end-users rather than far from demand centers on a transmission line. DG solar has many such valuable attributes, as it is available during the day close to peak demand and on local grids. Reform to net metering should utilize a sophisticated view of avoided cost in order to correctly value and compensate these attributes. Compensating net metered customers at retail rates without any additional charge may fall short of optimal economic efficiency, but compensating such customers at a fixed wholesale rate (as many utilities have suggested) is grossly inefficient. While not legitimate to subsidize the environmental attributes of DG solar through the rate structure, correctly valuing their economic attributes will both increase efficiency and allow for fair and sustainable solar development.

An ideal reformed net metering rate would retain the retail rate structure with a shift to time-based rates, and allow for the addition of a small monthly fixed charge. A retail rate compensates net metered customers for legitimately avoided costs, namely generation costs and variable costs of transmission and distribution. Specifically, compensation for variable transmission and distribution costs recognizes that electricity is more valuable close to the end-user. Similarly, time-based rates compensate net metered customers for their availability close to peak demand. A small fixed charge accounts for the components of the retail rate that net metering does not avoid, namely the fixed costs of transmission and distribution. Additionally, such a charge should incorporate solar integration costs and a discount for avoided future grid upgrades.

Rate reform should occur simultaneously with the removal of caps on the sizes and aggregate capacity of net metered installations, allowing for unconstrained development of the ***62** resource at a fair price. Together, these policy changes would push the amount of net metered capacity on the grid to efficient levels, and continue to provide substantial environmental co-benefits.

Part II of this article offers a technical, legal, administrative, and economic background on net metering and the power sector. Part III proceeds to an economic analysis of net metering, modeling cost shifting at a high-level and conducting an in-depth analysis of avoided costs and added benefits. Part IV overlays a legal analysis on the results of the economic analysis, examining the roles of regulators in ratemaking and how these play out in the net metering context. Part V synthesizes these analyses and makes policy recommendations. Part VI offers concluding remarks.

II. Background

Net metering policies result from the multi-faceted legal and administrative structure regulating the power sector, as adapted to address a generating source operating on a distribution grid. These policies fit within traditional ratemaking for utilities. However, they clash with the standard utility business model, which treats electricity as a commodity with a fixed price, unvarying over time and utility territory. This part offers background on various elements of the policies. The first section presents the technical basis of distributed generation and the need for net metering, followed by background on ratemaking.

These details provide the necessary foundation for subsequent economic analysis of current policies. The second section discusses several important pieces of legislation affecting net metering. In particular, the section introduces the Public Utility Regulatory Policies Act of 1978, which provides a transmission-level analogue for the proposed net metering reforms at the distribution-level. The third section presents the current status of net metering across the states, including recent administrative proceedings in ***63** several states. This section frames the ongoing conflicts between utilities and solar power advocates. The fourth section offers an economic background, based on a series of recent valuations of DG solar. These valuations provide a framework that serves as a starting point for the economic analysis.

A. Technical

Net metering is a policy governing how utility customers are compensated for the electricity they provide to a distribution grid. The hourly variation in rooftop solar generation (also called DG solar) tends not to match the customer's demand for electricity.[14] Net metering regulations allow DG solar customers to buy electricity when needed and sell any excess electricity from their installations into the distribution grid. Customers only pay for the net amount of electricity used--their consumption minus their generation--at the end of the billing period. Effectively, this arrangement means that utilities pay retail rates to net metered customers for any excess electricity they provide to the grid.[15]

Customer Demand and Solar Generation

Generation from solar panels peaks around noon and is nonexistent overnight. In contrast, residential customer demand peaks in the early evening and remains at a low level overnight. Figure 1 shows the interaction of these two effects.

***64 Figure 1: Daily residential customer demand and DG solar supply**

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There are three phases of the relationship between the net metered customer and the grid.[16] The first is conventional demand, in which the customer consumes more than she generates and thus imports electricity from the grid. This occurs overnight, in the early morning, and in the late evening, as pictured by the blue areas in Figure 1. The second phase is energy efficiency, which refers to the portions of the customer's demand that are fully met by her own generation. In this way, the customer's DG solar operates like an efficient appliance that reduces her demand. The dark green area in Figure 1 shows this phase. The final phase is power supply, in which the customer generates more than she consumes, exporting electricity to the grid. This occurs in the middle of the day, as pictured by the light green area in Figure 1.[17] The premise of net metering is that the value of the electricity consumed in the first phase--the blue areas--is ***65** the same as the value of the electricity provided to the grid in the third phase--the light green area.

Trends in Net Metering and DG Solar

The number of net metered customers has expanded rapidly in recent years, though they remain a small minority of all customers. In 2016, there were an estimated 1,340,000 net metered customers nationwide, roughly half of whom were in California.[18] This number is up from 156,000 in 2010 and 7,000 in 2003, an annual growth rate of 50% over thirteen years.[19] (See Figure 2.) Nevertheless, net metered customers are still a small fraction of the total customer base, accounting for only 0.9% of the roughly 151 million utility customers nationwide.[20]

***66 Figure 2: Number of net metered customers in the US, 2003 - 2016**

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The overwhelming majority of net metered customers and capacity are in DG solar systems. In 2016, 99.5% of net metered customers and 96.7% of installed net metered capacity were in DG solar.[21] The bulk of the remaining capacity is in wind installations, though these installations are not growing significantly.[22] Given these statistics, this paper mainly analyzes the challenges for net metering from the perspective of DG solar.

Composition of Regulatory Rates

The electricity rates paid by end-use customers reflect a range of component costs. Designing a fair net metering policy consists of determining what costs net metered customers should pay and what costs they avoid. Broadly speaking, rates are the sum of generation costs, ***67** transmission costs, and distribution costs.[23] Generation costs include fuel costs, operations and maintenance costs, and amortized capital costs necessary to generate the quantity of electricity demanded by end-use customers. This cost fluctuates throughout the year as the quantity demanded, or the load, rises and falls. The average generation cost increases as higher cost generators come online to meet higher loads.

Transmission and distribution (T&D) costs reflect the fixed and variable costs of transporting electricity from power plants to end use customers. Transmission refers to the long-distance movement of electricity on high voltage lines from generating sources to distribution grids. Distribution refers to the lower-voltage movement of electricity around these grids for use by households and businesses.[24] Primarily, the fixed costs of T&D include the amortized capital costs of building transmission lines and distribution wires and the fixed costs of maintaining this infrastructure. Additionally, there are fixed overhead costs in administering and servicing customer accounts and in the depreciation of capital assets. Variable costs include variable operations and maintenance costs in addition to line losses, or the value of electricity lost to heat during transmission and distribution.[25]

***68 Figure 3: Components of electricity rates**

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Types of Rates

The most basic rate structure is a simple cents per kWh rate for all generation within a customer class. Increasingly however, utilities and public utility commissions are adopting time-based rate structures, such as time-of-use or real-time pricing.[26] Under time-of-use pricing, customer rates vary based on the time of day and time of year. For example, a utility may offer a rate structure with different rates from 2 p.m. to 8 p.m. than other times of day and different rates between June and September than other times of year. Rates are generally highest in the summer afternoon windows and lower at other times. This structure more closely aligns the customer ***69** with the actual price of delivering electricity. The price signal leads the customer to reduce demand at high-priced times, resulting in greater grid efficiency overall.[27]

These new rate structures are part of the evolution away from a system that values electricity as an undifferentiated commodity. Instead, these rates recognize that the value of a unit of generation depends on the time of day and time of year it is available as well as its proximity to end-use customers. Reforming rates to reflect these qualities sends a price signal to the market that increases overall efficiency. This principle of differentiated value in electricity across time and space is central to net metering policies and their reform.

B. Legal

Regulation of the power sector is shared between federal and state authorities. The Commerce Clause only grants the federal government power to regulate the interstate transport of electricity and sales at wholesale. Thus, the Federal Energy Regulatory Commission is empowered to regulate transmission grids. Regulation of low-voltage local distribution grids and retail sales falls to the states, where public utility commissions set rates and regulations.[28]

Net metering policies exist within this multi-layered legal framework of federal and state legislation and regulation. As net metering occurs on intrastate distribution grids, states hold the primary authority for its regulation. However, several pieces of federal legislation have shaped the power sector in ways beneficial to net metering, specifically, the Public Utility Regulatory Policies Act of 1978 and the Energy Policy Act of 2005.

These two laws are part of the decades-long effort of power sector restructuring, which was a reaction against the vertically-integrated, regulated monopoly model of the industry's early ***70** history. As the use of electricity spread in the early 1900s, the industry consolidated into a small number of large, private conglomerates called utility holding companies.[29] The holding companies controlled several utility companies, which themselves combined generation, transmission, and distribution into a single company. The Public Utility Holding Company Act of 1935 regulated these companies, most notably by only allowing holding companies to operate within one public utility system.[30] As a result of that law, the business model of vertically-integrated investor-owned utilities operating in only one state was dominant through the 1970s.[31]

In the 1970s and 1980s, a combination of shocks in oil price, a stalling nuclear power industry, and the development of low-cost gas turbines spurred calls for restructuring the power sector. New technologies and updated economics favored a move away from a regulated monopoly structure in generation markets, though it was retained in transmission and distribution markets. Then-prevalent deregulatory ideologies further supported a shift.[32] In response, Congress passed the Public Utility Regulatory Policies Act (PURPA) in 1978.

Public Utility Regulatory Policies Act (1978)

PURPA encouraged the spread of competition across the power grid, setting market and regulatory forces in motion that later allowed the development of net metered technologies. The Act established principles of equal access and compensation on an avoided cost basis, which offer a transmission grid analogue for how reformed net metering might operate on distribution grids.

One of PURPA's main objectives was to diversify the range of energy sources in the power sector. It mandated that utilities grant access to the grid to small power producers and ***71** cogeneration facilities. The utilities had to provide grid interconnection to these facilities and pay the producers a reasonable price for any electricity provided. In relevant part, the Act reads "the Commission shall prescribe ... rules as it determines necessary to encourage cogeneration and small power production, ... which rules require electric utilities to offer to ... purchase electric energy from such facilities."[33] Furthermore, the Act requires that, "No such rule ... shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy."[34] Previously, vertically-integrated utilities primarily transported electricity from their own generation facilities and over their grids to customers in their own territories. PURPA established a principle of equal access to the grid for non-utility generators, forcing the utilities to accept electricity from other parties. At first, equal access applied only to small renewable and cogeneration facilities. However, subsequent legislation and regulation extended these rights to a wide range of non-utility generators.[35]

PURPA also established the principle that non-utility generators would be paid on an avoided cost basis--"incremental cost to the electric utility of alternative electric energy."[36] This principle placed the non-utility generators on equal footing with the utility's proprietary generation sources. Legally, the grid has to be agnostic to the source of the electrons it transports, offering the same price to all generators.

In a separate section, PURPA also established federal standards for electric utility ratemaking. As only the federal power administrations fall under federal jurisdiction for retail rates, this section did not directly affect much generation. However, this section also required state public utility commissions to "consider" these standards and "make a determination" ***72** whether to also adopt such standards.[37] Congress did not have the power to set state standards, but could achieve similar results by requiring consideration of its model standards. The standards in the 1978 Act concerned cost of service, inclining block rates, time-based rates, and load management.[38] Subsequent energy legislation extended this obligation to consider and determine to additional areas.[39]

Energy Policy Act of 2005

The Energy Policy Act of 2005 established a federal ratemaking standard for net metering, amending the "consider and determine" section of PURPA.[40] The standard reads:

> 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.[41]

As a result, all state public utility commissions had to consider a net metering standard and make a decision whether or not to adopt one. This requirement spurred widespread adoption of these policies across the states.[42]

C. Administrative

Policies on net metering that exclusively affect intrastate distribution grids are the responsibility of state legislatures and public utility commissions. As a result, there is no national net metering standard (only the aforementioned federal standard, which binds the federal power ***73** administrations only). Rather, the status of net metering across the country is a function of the independent decisions of the states.

Survey of State Regulations

At a high-level, there is a considerable amount of uniformity on net metering. The details, however, reveal important differences. Limits on individual system sizes and aggregate caps on net metering capacity vary widely across states.

Forty states and the District of Columbia currently have policies mandating that their utilities offer net metering in some form.[43] Two additional states have voluntary policies allowing their utilities to offer net metering. (See Figure 4.)

Figure 4: State with net metering policies, 2016

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Limits on individual system sizes differ between and within states. Many states have different size limits for residential, agricultural, and commercial customers. Limits for residential customers vary from a low of 10 kW (Georgia) to a high of 80,000 kW (New Mexico). Additionally, New Jersey and Ohio have no limits and Arizona limits systems to 125% of a customer's connected load.[44]

Some states also impose a percentage cap on the aggregate amount of net metered capacity allowed. Utilities are not obligated to continue offering net metered rates to new customers once the aggregate capacity of their current net metered customers meets the state cap. Twenty-five of the forty-four net metering states have a cap and an additional three states have a level which triggers a review of their net metering policies. Caps range from 0.2% of total ***74** capacity (Georgia) to 20% of total capacity (Utah). Most caps are between 1% and 5% of total capacity.[45]

Recent Changes and Ongoing Conflicts

The last several years have seen rising discord between utilities and solar power advocates over net metering policies. This discord has played out in administrative proceedings in several states, most notably in Nevada, California, and Arizona. Utilities in these states and allied groups have called for reform to net metering policies.

<u>Utility Position</u>

***75** Generally, the utilities argue that net metering constitutes an unjust and unreasonable cost shift from participating to non-participating customers. They contend that net metered customers with zero annual utility bills benefit from the grid but do not share its costs. Instead, the other traditional customers bear the fixed costs of building and maintaining the grid.[46] The grid provides backup generation to net metered customers for one portion of the time (overnight and when cloudy) and a market for their excess generation another portion of the time (the middle of the day when sunny). However, these customers pay nothing for this valuable service. Often, the utilities propose that net metered customers pay a monthly per-kW fee or per-customer grid connection fee to cover their share of grid usage.[47] Alternatively, they propose that net metered customers be compensated at the lower wholesale rates for their excess generation, but continue to purchase generation from the grid at higher retail rates.[48]

Solar Position

Solar power advocates respond that the benefits DG solar provides to the grid more than compensate for lost revenue from net metered customers. Specifically, they argue that installing DG solar provides peak demand reduction, emissions reduction, and other benefits that reduce the overall grid costs more than the amount of lost rate revenue.[49] For example, DG solar may remove the need for utilities to spend ratepayer money on new distribution lines or new peak generation capacity. As a result, although the utilities may be collecting less revenue, there is no cost shift from net metered to non-net metered customers.[50] A few jurisdictions, namely ***76** Minnesota and the city of Austin, Texas, have adopted value-of-solar tariffs, which explicitly calculate these benefits in addition to avoided costs and arrive at rates for excess solar generation above retail rates.[51]

Recent Proceedings

Since late 2015, Nevada has been one of the main battlegrounds for the net metering conflict. The state previously had a 3% cap on aggregate net metered capacity, amounting to 235 MW.[52] Net metered installations reached this level in August 2015, setting off a wave of regulatory activity.[53] NV Energy, the leading public utility in the state, filed an application with the Nevada Public Utilities Commission proposing an overhaul of net metering rates.[54] The NV Energy proposal would have added a $13.95 per kW monthly demand charge and an $18.15 per customer monthly service charge to net metered customers.[55] The Nevada Public Utilities Commission rejected this proposal, voting instead to keep the current net metering structure in place until the end of 2015.[56] However, in December 2015, the commission reversed course and issued a sweeping order in favor of the utilities, which both increased the fixed service charge for net metered customers and lowered the compensation for excess generation down to wholesale rates. Additionally, the commission applied the order not only to prospective net metered customers, but also retroactively to existing net metered customers.[57] The order was met with loud and widespread opposition, spurring efforts to overturn the action by ballot initiative and ***77** various other legislative and regulatory means.[58] As a direct result, SolarCity, Sunrun, and Vivint (all major solar installers) ceased operations in Nevada, which caused a substantial loss of jobs.[59]

Arizona underwent a similar, though less explosive, conflict in 2013, when Arizona Public Service (APS), the largest public utility in Arizona, filed an application before the Arizona Corporation Commission requesting an immediate change of policy regarding net metering.[60] APS asserted that net metered customers were responsible for a cost-shift on average of $1,000 per system annually, an $18 million shift across all systems.[61] Further, they argued "non-participants are burdened with a disproportionate share of the subsidies required to fund the [net metering] incentives."[62] To remedy this problem, APS recommended either a monthly demand charge of $9.30 to $13.50 per kW or payments to DG solar at wholesale prices.[63] Various solar advocacy groups responded with analyses showing that the benefits of solar in Arizona exceeded its costs. They argued that the utilities should credit DG solar owners with above market rates to reflect this excess value and rejected a demand charge as inappropriate.[64] The Arizona Corporation Commission came to a compromise solution, imposing a $0.70 per kW monthly demand charge on future net metered installations.[65] However, in 2016, APS again filed an application before the commission, proposing to add a demand charge for net metered customers and reduce excess generation payments to wholesale rates.[66] In December 2016, the Arizona Corporation Commission ended net metering for all new DG solar customers. The Commission established instead a process for calculating a specific valuation at which ***78** excess DG solar generation would be compensated. Solar companies reacted negatively, given the uncertainty this order created for potential customers.[67] In March 2017, APS and solar companies jointly proposed a compromise settlement for the solar valuation calculation. Specifically, the settlement's compensation rate for excess DG solar generation is 12.9¢ per kWh, slightly less than the current 13 to 14¢ per kWh, but with a step-down provision over time. The settlement gives DG solar customers a choice between a demand charge and time of use rates with a grid access fee. The settlement requires Commission approval before going into effect.[68]

California has also held extensive proceedings over the future of its net metering program. The state is expected to reach its 5% net metering cap in 2016 or 2017, necessitating an update to the program.[69] Anticipating this, the state's investor-owned utilities requested that the California Public Utilities Commission impose fixed charges on net metered customers, either through demand charges, service charges, or both.[70] In July 2015, as the first part of a regulatory proceeding, the Commission rejected this proposal, but approved a $10 per month minimum bill and left open the possibility of including a fixed charge in future rate cases.[71] A minimum bill would only affect those net metered customers who fully zero out their annual electricity usage. However, the major utilities again requested fixed charges and reduced payments to DG solar in August 2015 filings.[72] In January 2016, the commission completed the regulatory proceeding ***79** with a ruling in favor of solar, preserving net metering rates through 2019 and requiring time-ofuse rates for all new net metered customers.[73]

D. Economic

In connection with these proceedings, utilities, public utility commissions, and solar power advocacy groups have commissioned or conducted studies to calculate the value of DG solar to the grid. Value to the grid considers the costs avoided in generating and transporting a unit of electricity when that unit is generated on-site by a DG solar installation. Differences between studies center around which costs are assumed to be avoided. Each study focuses on a single state, so comparison across studies is imperfect. However, inclusion of retail electricity rates by state allows for rough, general comparisons.

The studies value DG solar in cents per kWh and compare these values to the state retail electricity rate. The studies can also be viewed as quantifying the size and direction of any cost shifting. If the value of DG solar exceeds the retail rate, then net metering undercompensates DG solar customers. If, alternatively, the value of DG solar is less than the retail rate, then net metering overcompensates DG solar customers and thus shifts costs from them to other customers. The results for several of these studies are presented in Figure 5 below.

***80 Figure 5: Economic valua ons of distributed genera on solar**

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The two studies conducted by utilities found that the value of DG solar was less than retail rates.[74] APS found a value of DG solar in Arizona of 3.6¢ per kWh and Xcel found a value in Colorado of 8¢ per kWh, below retail rates of roughly 11¢ per kWh.[75]

The public utility commission (PUC) studies have mixed results. The Maine PUC study found a value for DG solar of 33.7¢ per kWh, significantly higher than retail rates.[76] Hawaii's PUC, in contrast found a value of 29¢ per kWh, 10¢ lower than Hawaii's high retail rates.[77] The ***81** California PUC study also found a value of solar lower than retail rates at 12¢ per kWh.[78] However, the simplification of their inclining block rate structure is expected to reduce the cost shifting extent of California net metering.[79]

The solar power advocacy groups found that the value of DG solar exceeds retail rates in all cases. Utah Clean Energy found a value of 11.6¢ per kWh, slightly higher than Utah retail rates.[80] The Solar Energy Industries Association found a high value of 26.4¢ per kWh in NJ.[81] Finally, Crossborder Energy found a value of DG solar in AZ of 21.6¢ per kWh, significantly more than APS' low estimate.[82]

Differences in values across studies, apart from geographic differences, are largely due to varying assumptions on which costs are actually avoided. Potentially included costs or benefits are avoided energy costs, avoided generation capacity costs, avoided T&D costs, reduced financial volatility, avoided environmental compliance costs, CO_2 emissions benefits, other societal benefits, and the costs of solar integration. The utility studies considered only energy and capacity costs, while the solar advocacy studies tended to include ancillary benefits as well, such as emissions reduction and other societal benefits. The PUC studies split the difference, with some adhering closely to the sparse utility approach and others including additional benefits.[83]

III. Economic Analysis

***82** The previous part has laid out the technical, legal, administrative, and economic bases of net metering. Using that foundation, this part turns to an analysis of the economics of net metering. Two main questions arise in this analysis:

> (1) Do net metering policies shift costs of grid upkeep from participating to non-participating customers and to what extent is this happening or might it happen?

> (2) How should net metered customers be compensated for excess electricity sold onto the grid and should they have to pay anything for connection to the grid?

These may be different versions of the same question. As the background suggested, the answers to these questions are both unclear and highly contentious. In an attempt to answer them, this part begins with a high-level analysis of the extent of cost-shifting. It then proceeds to an in-depth analysis of categories of avoided costs and added benefits and which should be compensated. As such, this economic analysis necessarily integrates legal analysis, as the determination of which categories are compensated is a legal question. Thus, the legal framework governing utility rate setting is introduced here and receives expanded treatment in the subsequent legal analysis.

A. Cost shifting

High-level analysis with conservative assumptions demonstrates that the current level of cost-shifting under net metering has a *de minimis* impact on non-participating customers. For most states, this will remain the case in the near future.

Nationwide, DG solar generation in 2016 amounted to 19,467 GWh. By contrast, utility-scale facilities generated 4,078,670 GWh in 2016.[84] Thus, DG solar installations met 0.48% of ***83** electricity demand in 2016, displacing utility-scale generation. Correspondingly, funds in proportion to this share were displaced from the national revenue requirement.

These displaced funds account for both the fixed and variable costs of electricity. Only fixed costs are shifted onto non-participating customers. The grid responds to the reduced demand from net metered customers by generating less, and thus never incurs the relevant variable costs. For the purposes of this preliminary analysis, it is assumed that all transmission and distribution costs are fixed costs. As the following sections will address, in reality, some of these costs are variable as well. Generation costs are treated as variable since PURPA guarantees the right of solar to displace conventional generation and receive payment tied to avoided costs.[85] This is not controversial as most parties acknowledge that DG solar should at least receive payments at wholesale rates, which are derived from the competitive generation markets.

The Energy Information Administration reports that electricity prices are composed of 65% generation costs, 9% transmission costs, and 26% distribution costs.[86] This analysis assumes that 35% of the electricity price--the non-generation costs--is fixed. Multiplying 35% by 0.48%, the assumed share of net metered generation, gives 0.17% as the upper limit on the portion of the national revenue requirement which are fixed costs not borne by net metered customers. Shifting these costs to non-participating customers results in an average rate increase of 0.17%.[87] For the average residential customer with a $111 monthly electric bill, this amounts to paying an additional 19¢ each month.

Even in states like California with levels of DG solar penetration approaching 5%, the maximum rate increase for non-participating customers through cost-shifting is only 1.8% on ***84** average, or 2 dollars per month.[88] Only once net metered penetration levels reach 10% to 20% does cost-shifting have a significant effect, with rates increasing by 4% to 9%.[89] For most states, this type of penetration is probably about a decade away.

These results are based on conservative assumptions and thus represent a maximum impact of cost shifting. In reality, the shifted fixed costs are likely far lower, as explored in the following sections. Additionally, this analysis holds customers responsible for cost shifting for all their solar generation, rather than just excess electricity sold into the grid. This is akin to holding a customer who installs a more efficient refrigerator responsible for cost shifting. With an adjustment for excess electricity only, cost shifting is even lower than this analysis suggests.

Preventing cost shifting, especially that which disproportionately burdens low-and middle-income customers is a central priority for utility regulators. At this point though, even with assumptions heavily slanted toward finding an effect, cost shifting through net metering is minimal in all states. At current growth trends, states like California and Arizona may have to address cost-shifting concerns within the next five years. For most however, the effect will likely remain insignificant for approximately ten to fifteen years.

B. Compensation Criteria

Nevertheless, it is worth analyzing current net metered rates to determine how a fair and effective rate structure should be designed when penetration levels are higher in the future. The ***85** analysis in the subsequent section examines which cost components of current rates for net metered installations are avoided and which additional benefits are provided. Additionally, the analysis addresses whether utilities should compensate net metered customers for these costs and benefits. The determination of whether a cost is avoided or a benefit provided is a technical question. The determination of whether each avoided cost and provided benefit should be compensated is a legal question.

Specifically, the compensation determination is based on the legal framework for utility rate setting. Under mandates established by state law, public utility commissions set electricity rates for the utilities operating in their states. This function is necessary as electric power grids are natural monopolies. It is inefficient to have more than one grid, so the state grants a monopoly over a given territory to a single utility, but regulates the rates that utility can charge customers. The primary consideration for public utility commissions in the rate setting process is aligning rate payments with cost of service in order to achieve economic efficiency.[90] Some state public utility commissions are also granted flexibility to pursue secondary goals, such as incentivizing positive environmental and other social behaviors.[91]

For the purposes of net metering, it is both economically efficient and a fair alignment of rates to credit net metered customers for grid costs they actually avoid. In doing so, regulated rates mimic free market forces by incentivizing the efficient amount of net metered installations. Compensation above avoided cost leads to an inefficiently high number of installations, where conventional grid components could provide the same amount of electricity at a lower cost. Compensation below avoided cost leads to underinvestment in net metered installations, which would otherwise lower overall grid costs.

***86** Environmental and other societal benefits are also important rate-setting considerations for public utility commissions.[92] DG solar provides many such benefits. While commissions have latitude to pursue these goals on a small-scale or on the margin, it is not clear that the rate structure is the legitimate framework to attempt to influence sector-wide transformations.

The economic analysis in the following section considers each cost and benefit category and applies this legal framework to the compensation determination. The legal analysis in the subsequent part adds greater detail to the competing priorities for public utility commissions and how they affect ratemaking choices.

C. Avoided cost assessment

This section assesses each category of avoided costs and added benefits from net metered installations in an effort to determine whether and how excess electricity from these installations should be compensated. The categories are taken from major studies of the value of DG solar with slight modifications. The assessment analyzes costs and benefits of DG solar, as it is the predominant net metered technology. Actual avoidance and methods of compensation are based on characteristics of net metering given in the technical background. Whether a category should be compensated comes from legal analysis based on the above compensation criteria. The ranges of approximate values for each cost and benefit category derive from several cited valuation surveys.[93] Results are summarized in Table 1 and explained in greater detail below.

The analysis treats cost categories on a nationwide basis and as averages across customer classes. Geographic and customer class differences would introduce significant variability to the ***87** value of some categories and the aggregate value of DG solar. As such, the results here serve as a high-level framework for analyzing net metering compensation. The conclusions hold directionally at the state and customer level, but the precise numbers would vary among particular states or customer classes. The analysis treats the generation side of the power sector as competitive. Even in states without competitive generation markets, PURPA guarantees compensation to non-utility generators at avoided cost levels.[94] This guarantee effects quasi-competition that should result in non-utility generators receiving compensation at levels commensurate with competitive markets.

TABLE 1: COSTS AND BENEFITS FROM NET METERED DG SOLAR INSTALLATIONS				
COST CATEGORY	**AVOIDED / PROVIDED BY DG SOLAR?**	**WORTHY OF COMPENSATION?**	**APPROXIMATE VALUE[95] (¢ / KWH)**	**METHOD OF COMPENSATION**
Energy costs for generation	*Yes*	*Yes*	*3--7 ¢ / kWh*	*Wholesale generation component of retail rates*
Capacity costs for generation	*Yes, partially*	*Yes*	*1--2 ¢ / kWh*	*Time-based rates, wholesale capacity component*
Construction costs for future generating capacity	*Yes*	*No*	*7--8 ¢ / kWh*	*Not additionally compensated, reflected in wholesale prices*
Fixed transmission costs, present	*No*	*Maybe*	*0.5 -- 1 ¢ / kWh*	*Transmission component of retail rates (if compensated), fixed cost charge (if not compensated)*
Fixed distribution costs, present	*No*	*No*	*1--2 ¢ / kWh*	*Not compensated, DG customer pays via fixed cost charge*
Future grid upgrade costs	*Yes, partially*	*Yes*	*0 -- 2.5 ¢ / kWh*	*Discount to fixed cost charge*
Line losses	*Yes*	*Yes*	*0.5--1 ¢ / kWh*	*T&D component of retail rates*
Other variable T&D costs	*Yes*	*Yes*	*0.5--1 ¢ / kWh*	*T&D component of retail rates*
Environmental compliance costs	*Yes*	*No*	*0.5--2 ¢ / kWh*	*Not additionally compensated, reflected in wholesale prices*
CO2 emissions costs	*Yes*	*Likely no*	*1.5--2.5 ¢ / kWh*	*Likely not compensated, can be subsidized separately or included via carbon pricing*
Price volatility	*Yes*	*No*	*0.5--3.5 ¢ / kWh*	*Not additionally compensated, reflected in wholesale prices*
Other societal benefits	*Yes*	*Likely no*	*2.5--20 ¢ / kWh*	*Likely not compensated, can be subsidized separately*
Costs of solar integration	*No*	*No (charged to customer)*	*0--0.5 ¢ / kWh*	*DG customer pays via fixed cost charge*

88** ***Energy Costs for Generation

DG solar offsets the need for electricity from the grid. As a result, central power stations burn less fuel and utilize less labor and equipment. The value of these costs are set by competitive generation markets: generators regularly bid in their production costs, which include fuel costs and O&M costs. Electricity demand determines which generators run, in order of increasing production costs. The marginal generator's costs set the wholesale market clearing price.[96]

DG solar installations are effectively competing in the same wholesale market, but from a downstream position. When a solar installation provides electricity to the grid, the wholesale market clears at a lower demand level and central power stations incur fewer costs. DG solar installations are rightly compensated for these avoided costs, as doing so advances the regulatory goal of economic efficiency. Even in non-competitive generation markets, the legal principle set ***89** by PURPA is that independent power producers are compensated for their generation at avoided costs rates.

It is relatively uncontroversial then, that DG solar installations should receive compensation at wholesale prices for the electricity they provide to the grid. Utilities can provide this compensation via the generation component of retail rates. The value of energy costs is approximately 3¢ to 7¢ per kWh.[97]

Capacity Costs for Generation

Similarly, electricity from DG solar installation partially displaces the need for capacity on the grid at peak demand. Generation markets ensure that the grid meets electricity demand at all times of day. In every time period, the market clears at the price of the marginal generator and all the lower cost generators make a profit. A problem arises, however, in meeting peak demand, the times of the year when demand is highest. The “peaker plants,” which come online to meet this demand, set the market-clearing price with their costs and therefore never make a profit for themselves. Without a chance at profits, these plants would never be built. Many utilities and grid operators remedy this problem through capacity markets, in which peaker plants are paid by kilowatt (rather than kilowatt-hour) to be available at peak demand times.[98]

The peak supply of solar installations overlaps closely, though not perfectly, with peak demand.[99] Power available from DG solar installations during peak demand reduces the need for utilities and grid operators to purchase capacity on capacity markets. Thus, capacity is a valid avoided cost, for which DG solar should receive compensation.

***90** Averaged over the course of the year, avoided capacity costs have an approximate value of 1¢ to 2¢ per kWh.[100] Utilities could offer net metered customers a separate payment for these costs. However, a more natural solution would be to offer net metered customers time-based rates, either time-of-use or real-time pricing. Time-based rates would reflect increases in wholesale prices at high-demand times, internalizing the costs from the capacity markets. Under a time-based rate structure, DG solar installations would receive compensation for providing capacity at high-demand times in proportion to their actual generation at those times. Furthermore, compensating DG solar with time-based rates more accurately reflects the fluctuations in avoided energy costs.

Construction Costs for Future Generating Capacity

In a similar vein, some argue that DG solar should receive compensation for delaying or avoiding the construction of future generating capacity.[101] Indeed, individuals adding capacity to the grid and decreasing their demand reduce the need for utilities and grid operators to arrange for that capacity. Ratepayers thereby avoid bearing this construction cost, which is significant: up to 8¢ per kWh in one study.[102] However, in a competitive market, one producer does not receive excess compensation for meeting demand more cheaply than a future competitor. All producers take the market clearing price. This answer may differ in a regulated T&D market, but it would be undue compensation to pay DG solar for avoided future capacity in the competitive generation market.

Fixed Transmission Costs, Present

***91** Fixed transmission costs include the amortized capital costs of constructing transmission lines and the fixed costs of operating and maintaining them. Electricity from DG solar installations does not avoid these costs. The present transmission grid has already been built and its upkeep is a necessary expense, whether or not electricity from DG solar is sold into distribution grids. There is an argument, however, that DG solar installations should not have to bear that cost even though it is not avoided. Electricity from DG solar installations remains, for all intents and purposes, on local distribution grids. If the owner of the installation does not use all of her generation, the electricity enters the grid and is used by her neighbor or another nearby electricity customer. The relevant electricity never touches a transmission line, so it is not economically sensible to charge the generator of that electricity for the upkeep of those lines.

The counter-argument relies on the regulated-monopoly nature of the grid. All customers within a territory inherently consent to contribute to the construction and upkeep of the grid in proportion to their use. The grid infrastructure comprises both transmission lines and distribution lines. A customer-generator cannot utilize and pay for only one part of this integrated infrastructure.

The value of fixed transmission costs is approximately 0.5¢ to 1¢ per kWh.[103] If compensated, utilities could provide this value via the transmission component of retail rates. If not compensated, net metered customers could continue to receive retail rates and pay a fixed charge of which fixed transmission costs would be one component.

Fixed Distribution Costs, Present

Fixed distribution costs include the amortized capital costs of constructing distribution lines and the fixed costs of operating and maintaining them. As with transmission, electricity from DG solar installations does not avoid these costs, given that they are either already incurred ***92** or necessary. Unlike transmission however, it is clear that customers with DG solar installations use and depend on the distribution grid and can legitimately be required to contribute to its past construction and present upkeep.

The exact value of fixed distribution costs is difficult to determine due to the imprecise divide between fixed and variable costs. Total distribution costs amount to 2.6¢ per kWh on average nationwide, though this includes various variable costs, such as line losses and elements of maintenance.[104] The value of fixed distribution costs alone is likely in the range of 1¢ to 2¢ per kWh. Utilities could include this value together with fixed transmission costs as part of a fixed charge.

Future Grid Upgrade Costs

Future grid upgrade costs are the expected costs of building transmission and distribution infrastructure to meet future demand. Generally, power sector planners size the grid in order to meet peak demand plus an adequate reserve margin. The capacity of the generation facilities, transmission lines, distribution lines, and connecting equipment must be such that this peak-level of electricity can reach customers in each area of a service territory.[105] As explored above, the peak supply of solar installations tends to partially overlap with peak demand on the grid. As a result, adding DG solar capacity reduces the peak demand required of the grid, which in turn reduces the need for both new generation facilities as well as transmission and distribution infrastructure.

It was argued above that DG solar installations should not receive compensation for reducing the need for new generation capacity. In a competitive generation market, the lowest-cost producers sell into the market at the equilibrium price. This provides sufficient incentive to ***93** market players to make investment decisions. In the regulated T&D market, however, the incentive structure is different. When a utility proposes new construction projects, its regulator assesses whether such projects are in the best interests of ratepayers. The regulator allows the utility to build those projects meeting this standard and recover the costs through the rate structure.[106] A market determination of the lowest cost producer of transmission and distribution services does not exist. Thus, it is reasonable for regulators to compensate DG solar installations for the avoided T&D capital investment through their reduction of peak demand.

The value of future grid upgrade costs may vary significantly by location. A specific distribution grid may require costly upgrades to meet demand growth and a few DG solar installations on that grid would be especially beneficial. Similarly, widespread additions of solar installations across an entire region might obviate the need for a higher capacity transmission line to that region. As a result, estimates of the average value of these costs range widely from 0 to 2.5¢ per kWh.[107] Avoided future grid upgrade costs could enter into a fixed charge calculation as a discount.

Line Losses

Line losses occur during the transportation of electricity. Resistance in the transmission and distribution lines causes some of the electrical energy to be lost as heat before it reaches end-use customers. An estimated 5% of electricity generated nationwide is lost this way.[108] Line losses are a variable cost, as the extent of the loss depends on the amount of electricity ***94** transported. DG solar avoids line losses almost completely since the excess electricity generated is consumed nearby. Utilities should therefore compensate DG solar customers for this value.

The value of avoided line losses is approximately 0.5¢ to 1¢ per kWh.[109] Utilities can provide this compensation via the variable T&D component of retail rates.

Other Variable T&D Costs

In addition to line losses, utilities also incur a series of other variable costs in transmission and distribution. Certain maintenance costs and daily grid operations vary with the amount of electricity transported. DG solar avoids these costs and should be compensated for them.

As noted above, it is difficult to precisely separate fixed from variable costs in transmission and distribution. The value of other variable T&D costs is approximately 0.5¢ to 1¢ per kWh.[110] Utilities can provide this compensation via the variable T&D component of retail rates.

Environmental Compliance Costs

Some valuations credit DG solar installations for the avoided costs of environmental compliance at fossil fuel power plants because these power plants have ongoing obligations under the Clean Air Act to reduce their emissions of NO_x, SO_2, and other criteria air pollutants. In many cases, power plants would have to install costly control equipment to meet these obligations. Amortizing investments in the equipment would raise the cost of generation for all ***95** ratepayers. Since DG solar installations displace generation from the fossil fuel power plants, the emissions from these plants decreases and may obviate the need for the control equipment.[111]

This is true--solar panels have much lower associated emissions than fossil fuel power plants. However, this advantage is reflected in the market-clearing price in a competitive generation market. Investments in pollution control equipment raise the wholesale price of electricity, which incentivizes additional DG solar use until the market reaches equilibrium. Paying DG solar an additional amount for avoiding control equipment would be double-counting the advantage and contrary to the regulatory mandate to ensure economic efficiency. The studies that include avoided environmental compliance costs estimate their value (not counting CO_2) at 0.5¢ to 2¢ per kWh.[112]

CO_2 Emissions Costs

Similar to environmental compliance costs, some valuations credit DG solar installations for the avoided costs of CO_2 emissions. DG solar installations cause less fossil fuel combustion at power plants. Less combustion leads to lower CO_2 emissions, which can avoid costs to ratepayers and benefit society.[113] Such crediting takes two forms. In states like California and the Northeastern states where CO_2 emissions are priced, the cost of generation at fossil fuel power plants is higher in proportion to their CO_2 intensity.[114] DG solar avoids this incremental cost. In states where CO_2 emissions are not priced, valuations credit DG solar for CO_2 reductions at the social cost of carbon, which is roughly $40 per ton reduced.[115]

***96** Both of these methodologies are flawed. In the former case, the cost of CO_2 emissions is priced into wholesale generation. As with other environmental compliance costs, DG solar receives credit for its lower CO_2 footprint through its participation in competitive generation markets. Additional compensation is excessive.

In the latter case, crediting DG solar for its environmental benefit to society, which is what the social cost of carbon aims to do, improperly widens the role of a grid regulator. As noted above, the main priorities for public utility commissions are efficiency and alignment of payments with cost of service.[116] Promoting environmentally and socially beneficial ends are only a secondary priority. When DG solar installations are too limited to have a significant impact on economic activity, commissions have the latitude to pursue these secondary priorities. However, when DG solar achieves significant penetration, these secondary priorities will substantially conflict with the priority of economically efficient rates. At this point, DG solar should not receive compensation via the rate structure for a benefit it provides to society outside the grid entirely. Government subsidies or tax credits are a more appropriate means for incentivizing CO_2 reductions. Alternatively, more states may adopt carbon pricing as part of a carbon tax or a cap and trade system. Either way, these incentives come via tax-and-spend legislation or environmental statutes rather than the regulated rate structure. The studies that include avoided CO_2 emissions costs estimate their value at 1.5¢ to 2.5¢ per kWh.[117]

Price Volatility

Fossil fuel power generation depends on the inputs of coal and natural gas, whose prices are volatile. DG solar, by contrast, provides electricity at the same cost over the equipment lifetime-- the amortization of the upfront investment. As such, DG solar avoids the price risk of ***97** fossil fuel generation, which some suggest should be compensated.[118] Indeed, utilities often purchase long-term fuel or electricity contracts at a premium to reduce their price exposure.[119] Arguably, DG solar should receive the value of this premium.

However, as with several cost categories above, price volatility is incorporated into competitive generation markets. The market sets a value for constant prices via contract hedging, and DG solar captures its fair share of that value. Additional compensation would be in excess of its fair share. The studies that include reduction in price volatility estimate its value at 0.5¢ to 3.5¢ per kWh.[120]

Other Societal Benefits

Various studies credit DG solar with a variety of other societal benefits. Among these are job creation, suppression of electricity market prices, and improvements in public health due to decreases in air pollution.[121] The spread of DG solar creates a substantial amount of domestic jobs in installation and maintenance.[122] Lower demand for electricity through distributed generation reduces prices for everyone.[123] Reductions in air pollutants translate into significant health benefits in the communities surrounding power plants.[124]

These benefits, while real and directly tied to DG solar, are tangential to the operation and financing of the grid. For this reason, it is not efficient for grid regulators to incentivize the benefits via the rate structure. As with CO_2 benefits above, state legislatures can subsidize the ***98** creation of these benefits directly via taxation and government spending. The studies that include these other societal benefits estimate their value at 2.5¢ to 20¢ per kWh.[125]

Costs of Solar Integration

The integration of DG solar into the grid presents some specific costs. Utilities have to spend additional amounts on equipment and operations in order to accommodate the intermittent supply of electricity from multiple, decentralized solar panels.[126] At low levels of DG solar penetration, these costs are negligible. As penetration increases toward 30%, integration costs could increase to 5¢ per kWh.[127] For the low levels of DG solar on the grid currently and expected in the near future, this cost is approximately 0 to 0.5¢ per kWh. This is a cost that the DG solar customer should bear, and could come as a component of a fixed charge.

Summary

The above analysis suggests a wide range of cost categories that figure into a determination of how DG solar should be compensated. Furthermore, within many of the categories there is a wide range of values for these costs. This explains much of the variability in valuations of DG solar. Nevertheless, the decomposition into cost categories and analysis of each category’s legitimacy offers a rough sense of the appropriate compensation.

The fair price for DG solar is the sum of the cost categories definitively worthy of compensation, namely energy costs, capacity costs, future grid upgrade costs, line losses, and other variable T&D costs. Counting all these categories, excess generation from DG solar should be compensated at 4.5¢ to 13.5¢ per kWh, or 9¢ per kWh on average. If fixed transmission costs are deemed worthy of compensation (i.e., DG solar should not have to contribute to these costs), this range rises to 5¢ to 14.5¢ per kWh, or 9.75¢ per kWh on average. By comparison, average ***99** retail electricity rates nationwide are 10.1¢ per kWh and range from 8.5¢ to 16.1¢ per kWh across the main regions of the contiguous US.[128] This suggests that the fair compensation for DG solar is on the order of 1¢ to 2¢ less than retail rates. Differences in geography and customer type vary these numbers. These results are presented in Figure 6.

Figure 6: Fair compensa on for DG solar

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There are a number of environmental and societal benefits from DG solar that are probably not worthy of compensation via the rate structure in the long-term, but may call for subsidization from elsewhere. These benefits amount to 4¢ to 22.5¢ per kWh. Generally, it is the inclusion of these benefits that separates the valuations of DG solar conducted by solar power advocacy groups from those conducted by utilities and public utility commissions. Advocacy ***100** groups find a value that is usually higher than retail rates and utilities, while commissions find a value less than retail rates. This analysis accords with the utilities and commissions, though it finds a value for solar that is only slightly less than retail rates.

The most straightforward way for utilities to compensate their net metered customers utilizing DG solar would be to continue to pay retail rates for excess generation, but also to impose a small fixed charge, either per kW or per customer. The components of the fixed charge would be fixed distribution costs, cost of solar integration, a discount for avoided future grid upgrade costs, and maybe fixed transmission costs. Combining these costs suggests a range of - 1¢ to 3.5¢ per kWh for a fixed charge. Given the current levels of excess generation sold into the grid, 50 to 85 kWh per customer per month,[129] the monthly fixed charge should amount to roughly $3 per customer at a maximum.[130]

IV. Legal Analysis

With the foregoing economic analysis in mind, the question becomes if, how, and when net metering should be reformed. The answer depends on the law governing public utilities as interpreted by state public utility commissions. This part carries out the relevant legal analysis in several sections. First, it considers the mission of public utility commissions: what priorities they have, how they balance them, and how this differs between states. Second, it analyzes the legitimacy of pursuing environmental and social goals via the utility rate structure. Third, it examines how PURPA provides guidance for avoided cost rate setting on distribution grids. Finally, it applies the foregoing analyses to net metering in an effort to identify areas for reform.

A. Mission of Public Utility Commissions

***101** State governments are the authorities ultimately responsible for establishing and subsequently amending net metering regulations. State legislatures have generally delegated net metering and utility regulation powers to state public utility commissions. The terms of the delegation differ from state to state. Some public utility commissions abide by narrowly defined missions. These commissions are strict economic regulators, aiming to replicate market forces as closely as possible in their approval of rate cases.[131] Others are activist commissions and, with the blessing of their enabling legislation, pursue a wide range of social projects via the electricity rate structure.[132] The priorities of the public utility commissions and the methods through which these priorities are balanced have key implications for net metering reform.

All public utility commissions primarily consider economic efficiency and alignment of rates with cost of service. The language in enabling statutes often dictates that commissions must set electricity rates that are "just and reasonable." For example, the Texas Utilities Code "establish[es] a comprehensive and adequate regulatory system for electric utilities to assure rates, operations, and services that are *just and reasonable* to the consumers and to the electric utilities."[133] The New York Public Service Law discusses how utilities must provide "service, instrumentalities and facilities" that are "in all respects *just and reasonable"* and that "[a]ll charges ... shall be *just and reasonable*."[134] Similarly, the California Public Utilities Code states, "All charges demanded or received by any public utility ... for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be *just and reasonable*."[135] The Code continues, "The commission shall establish rates using cost allocation ***102** principles that *fairly and reasonably* assign to different customer classes the *costs of providing service to those customer classes* ..."[136] Fairness and justice stand as key priorities for the commissions, upheld by setting rates that reflect what it costs to serve each ratepayer.

The reasonableness referred to in these mission clauses attaches to economic efficiency. The Texas Utilities Code explains further:

> Electric utilities are by definition monopolies in many of the services provided and areas they serve. As a result, the normal forces of competition that regulate prices in a free enterprise society do not always operate. Public agencies regulate electric utility rates, operations, and services, except as otherwise provided by this subtitle.[137]

In other words, the reasonableness criterion replaces market forces in rate setting for public utilities. The monopolistic nature of the industry removes the usual influence of market forces in the direction of efficient outcomes. Instead, the commission must use its expert judgment to replicate those market forces to attain similar outcomes.

Public utility commissions traditionally set rates both for generation and for transmission and distribution. Industry restructuring beginning in the late 1970s added complications. Under the guidance of PURPA and subsequent legislation, the industry transitioned to competitive generation markets. The Texas Utility Code continues:

> The legislature finds that the production and sale of electricity is not a monopoly warranting regulation of rates, operations, and services and that the public interest in competitive electric markets requires that, except for transmission and distribution services and for the recovery of stranded costs, electric services and their prices should be determined by customer choices and the normal forces of competition.[138]

In pursuing economic efficiency, public utility commissions must therefore pursue two different regulatory approaches. With regard to generation, the commissions design regulations to allow ***103** competitive market forces to set prices. With regard to transmission and distribution, the commissions set prices but attempt to do so in a way that replicates market forces. In both cases, the aim is to achieve economically efficient outcomes.

Some public utility commissions adhere closely to these economic goals. Other commissions receive a wider mandate and incorporate a secondary set of considerations into their regulatory agenda. These secondary considerations may include environmental protection, alternative energy development, energy conservation, protection of low-income ratepayers, and other distributive equity concerns.

The California Public Utilities Commission (CPUC) is a prime example of one such activist commission. The California Public Utilities Code states:

> [I]n addition to other ratepayer protection objectives, a principal goal of electric and natural gas utilities' resource planning and investment shall be to minimize the cost to society of the reliable energy services that are provided by natural gas and electricity, and to improve the environment and to encourage the diversity of energy sources through improvements in energy efficiency [and] development of renewable energy resources, such as wind, solar, biomass, and geothermal energy ...[139]

This statutory language allows the CPUC to consider renewables development, energy efficiency, and environmental sustainability alongside the traditional goals of economic efficiency and cost of service alignment.

Additionally, the CPUC requires rate assistance for low-income customers. It states "[t]he commission shall continue a program of assistance to low-income electric and gas customers with annual household incomes that are no greater than 200 percent of the federal poverty guideline levels, the cost of which shall not be borne solely by any single class of ***104** customer."[140] Thus, the CPUC's mandate includes distributive equality through the provision of affordable energy to low-income customers.

Tension can arise between the primary and secondary considerations for public utility commissions. Offering rate assistance for low-income customers represents a deviation from alignment of rates with cost of service. Low-income customers pay below their cost of service and everyone else pays slightly more on average. California employs inclining block rates, such that rates increase with a customer's level of consumption.[141] As a result, high-consumption customers have a greater financial incentive to conserve, but they also pay more than their cost of service. The decisions different public utility commissions make reflect the varying weights each gives to primary and secondary regulatory considerations.

B. Environmental and social goals

For those public utility commissions that pursue a wider set of social goals, the rate structure takes on the qualities of a taxation system. The commissions act like a legislature, setting tax levels via the rates and directing how the collected revenue is used. The utilities are deputized into the role of both tax collector and government agency, collecting funds and spending them on a variety of services. The utilities provide the main service--available and reliable electricity. Activist public utility commissions also sponsor a set of social programs and address issues of environmental protection and distributive equity.

Indeed, the scale of utility finances nationwide is of a similar magnitude to federal and state taxation. Across the total industry, electricity providers collected approximately $364 ***105** billion in revenues from sales to end-use customers in 2012.[142] In comparison, the federal government collected $2.45 trillion in tax revenues[143] and state governments collected $799 billion in tax revenues in 2012.[144] Thus, power sector revenues are almost one-sixth as large as all federal taxation and almost half as large as all state taxation. There is significant potential to utilize this money to pursue social programs.

Quasi-taxation via utility rates has both positive and negative aspects. On the positive side, numerous beneficial programs receive funding through utility regulation. These programs might not otherwise exist. Tight fiscal control, controversy over science, and opposition to redistribution have restricted and prevented funding for various environmental and welfare initiatives from passing Congress and many state legislatures. On the negative side, however, this form of indirect government support means that a series of independent regulatory agencies are manipulating private enterprises to achieve social ends with limited democratic oversight. Furthermore, electricity rates tend to be more regressive than the tax schedule. Even with low-income assistance, costs of energy comprise a larger share of the household budget for low-income earners compared to high-income earners.[145] Funding social programs through the rate structure may impose a greater burden on low-income individuals than if those programs had been funded through tax-and-spend systems.

The controversy over net metering can be viewed, at least in part, as a negative reaction to bureaucrats sidestepping the tax-and-spend legislative process and eschewing the democratic oversight this process entails. Unelected public utility commissioners make administrative ***106** decisions that directly and significantly affect citizens' pocketbooks through the size of their monthly utility bills. Undeniably, some amount of latitude is necessary for these commissioners. The whole administrative state depends on bureaucrats making decisions at their discretion and based on expert input. Some amount of support for environmental and social goals appropriately falls within discretion and expertise. However, when this power extends to the ability to reshape a whole industry and effect wealth transfers between large swathes of citizens, the commissions are operating beyond their delegated authority. Ultimately, as the market penetration of DG solar deepens and cost shifting increases in significance, public utility commissions should retreat to the core principles of economic efficiency and cost of service regulation embedded in their legislative mandate.

C. The PURPA precedent

A return to economic efficiency and cost of service principles, however, does not entail a halt to DG solar development. Rather, applying these principles to net metering rates, coupled with a modern view of electricity supply and use, would allow a robust development trajectory for DG solar that is economically efficient and environmentally beneficial. The precedent set by PURPA in the 1970s and 1980s demonstrates how this reform might take place. PURPA addressed non-utility generating sources selling into the transmission grid at wholesale rates. Effective net metering reform would apply PURPA to customer-owned generating sources selling into local distribution grids at retail rates.

PURPA is based on principles of avoided cost and equal access to the grid. The law mandates that grid owners have to accept electricity from non-utility generators and pay them at a rate that reflects the avoided cost of not buying that electricity elsewhere. PURPA adapts the cost of service regulatory structure of traditional integrated utilities to allow new entrants to ***107** participate. Equal access guarantees new entrants a spot in the market. Compensation at avoided cost puts them on equal footing with traditional utility generators.[146] This legal framework catalyzed the development of significant new generating capacity in the 1980s and 1990s and improved the overall economic efficiency of the electric power industry.[147]

Net metering reform at the state-level should proceed on the same basis, with an important adaptation. Electricity is not truly a commodity, with a single price across space and time. Instead, a marginal unit of electricity is more valuable at certain times of day and when proximate to end-users. Net metering reform should guarantee equal access to DG solar customers and compensate these customers at avoided costs. The avoided cost calculation should reflect not only the wholesale rates guaranteed by PURPA, but also take into account the locational and temporal attributes of DG solar. These attributes translate to additional avoided costs above and beyond wholesale rates. Specifically, DG solar generation avoids costs in variable transmission and distribution and in peak generation. A state-level adaptation of PURPA would correctly value the electricity from DG solar, thereby providing for robust future development, even without compensation for environmental benefits.

D. Areas for net metering reform

This section integrates the foregoing legal analyses with the economic analysis from the previous part to identify specific areas for net metering reform. It addresses each of the considerations for public utility commissions and applies them to net metering rates in light of the preceding commentary on both the appropriateness of social policy in the rate structure and the PURPA precedent.

Economic Efficiency and Cost of Service Alignment

***108** Net metering, as currently practiced, does not perfectly align rates with costs of service. Paying net metered customers retail rates for excess generation is a slight overcompensation, on the order of 1¢ to 2¢ per kWh for DG solar installations, as the above economic analysis demonstrated. At current penetration levels, the cost shifting that would result from this overcompensation is close to negligible.

In the long term, however, a lower rate for excess generation or retail rates coupled with a fixed charge is necessary to align net metering rates with cost of service. Compensating generation from net metering installations at an avoided cost-based rate incentivizes the efficient amount of net metered capacity on the grid. This principle that non-utility generators should be compensated at the "incremental cost to the electric utility of alternative electric energy" comes from PURPA.[148]

Net metering is complicated because it straddles the unregulated and regulated parts of the power sector. Those who install DG solar or other net metered technologies are "customer-generators." They are situated on the distribution grid with other customers but also generate electricity. The compensation for net metered excess generation reflects this divide. Such electricity receives compensation at wholesale prices, which is the avoided cost of generation, just like any other independent power producer under PURPA. But the electricity from net metered installations has additional value. It is available on a distribution grid, proximate to its end-user. As such, it avoids the variable cost of transmission and distribution, including line losses. And in the long term, this electricity also avoids capital costs of grid upgrades. These are "incremental costs to the utility," just as avoided generation costs are. Unlike the competitive generation markets though, transmission and distribution are regulated. No market exists to set ***109** the value for these avoided costs, so the PUCs must fill that role. They calculate the value of the grid costs that a net metering installation avoids and add this value to wholesale prices. This sum gives a net metering rate, which is true to the principle of PURPA and true to the PUC's priority of economic efficiency.

If public utility commissions reform net metering rates in this way, they should couple it with additional changes. For instance, all caps on the amount of net metering should be removed. This removal includes limits on the sizes of individual systems, the inherent compensation cap at annual customer demand, and aggregate caps on net metered capacity across a state or utility territory. A reformed rate would incentivize an efficient level of net metered capacity on a grid at a fair cost of service. Artificial caps constrain the market from reaching that equilibrium. Customers should be able to generate and sell electricity, as long as doing so is economically viable. Constraining them based on their own demand or the amount of capacity on the system is an unnecessary market intervention. The market provides a natural cap because increasing DG solar penetration diminishes the advantage solar has in generating close to peak times.[149] Commissions would augment this effect by increasing fixed charges or decreasing the T&D portion of rates as higher penetration dilutes the avoided cost of grid upgrades.

Environmental Impacts

Net metered installations, which are almost entirely solar and wind power based, have positive environmental impacts. These renewable sources of energy displace electricity from the grid, which, in most states, is primarily generated from fossil fuel combustion. This combustion emits a series of air pollutants, such as particulate matter, SO_2, NO_x, and mercury, which have ***110** severe negative impacts on public health and the environment.[150] Furthermore, fossil fuel combustion emits CO_2, which is the most prolific greenhouse gas and the single greatest contributing factor of global climate change.[151] Displacing this electricity and the associated emissions with DG solar or wind delivers significant benefits to the local, regional, and global environment.

Public utility commissions, especially those with explicit environmental protection mandates, must weigh this benefit when setting net metering rates. They might also consider that the state, national, and global authorities responsible for addressing environmental protection, and especially climate change are only partially upholding this duty. In 2015, the federal government announced regulations for power sector CO_2 emissions. These regulations do not take effect until 2022 and may not survive an ongoing court challenge.[152] A handful of states have begun regulating CO_2, but most continue to allow it to be emitted freely.[153] These realities might counsel public utility commissions to grant extra support to net metered installations in the short-term and on a limited scale. Ultimately, it is the responsibility of legislatures--either Congress or the state legislatures--to use their tax-and-spend powers or environmental protection powers to legislate explicit support for the environmental attributes of DG solar and other net metered technologies. Doing so over time and at scale through the rate structure is distortionary and potentially regressive.

Distributive Equity

***111** The impacts of net metering on distributive equity are not clear-cut. Some analysts have suggested that those who invest in DG solar tend to be high-income individuals.[154] As a result, if there is a significant cost-shifting aspect to net metering, then the policies shift costs from high-income individuals to low-income individuals. However, minority and low-income communities tend to be located closer to fossil-fuel power plants.[155] Net metering's reduction in fossil fuel power generation then disproportionally benefits low-income communities.

Investment in solar need not be restricted to high-income households. New types of net metering arrangements, such as community solar, facilitate utilization of DG solar for renters and residents of multi-family housing. New financing arrangements, such as third-party ownership and loans from green banks, open up DG solar to those with limited capital. These developments expand net metering access and should mute the distributive equity effects of any cost shifting.[156]

Presently, cost shifting is negligible and public utility commissions do not immediately need to address distributive equity in net metering regulations. Conversely, once net metering penetration increases, if it does not spread adequately to low-income households, distributive equity further supports the imposition of fixed charges.

V. Discussion & Policy Recommendations

The foregoing economic and legal analyses suggest several potential net metering reforms, though there is not a pressing need for reform. In the short term, net metering policies should remain largely the same. Cost shifting due to net metering is close to negligible--even with assumptions tilted towards finding an effect, the current level of cost shifting to nonparticipating customers in most states is no more than a 20¢ per month per customer. The actual ***112** effect is likely much smaller than this upper bound. Furthermore, net metered installations, largely DG solar, deliver significant environmental benefits. Utility commissions can promote their environmental priorities without discarding their economic priorities given the negligible cost shifting at low net metering penetrations. Thus, current efforts to reform net metering should be put on hold.

In states like California and Arizona, where penetration is high and growing, this calculus may change in the medium term. A more significant share of generation from net metered installations, on the order of 10% to 20%, may create a significant cost shift, which commissions should address. Nevertheless, most states are unlikely to reach that level for more than a decade.

In the long term, reform to net metering rates will be necessary when these higher penetration levels are reached. Net metered installations should be compensated for excess generation they provide to the grid at a rate that reflects avoided costs. The costs which net metered installations avoid include energy costs, capacity costs, line losses, other variable T&D costs, and future grid upgrade costs. Effectively, the sum of these costs reflects wholesale generation prices plus a spatial component--line losses and other variable T&D costs--and a temporal component--future grid upgrade and capacity costs. Generation from net metered installations should receive credit for the fact that it is proximate to the customer, thereby avoiding line losses and variable T&D. Furthermore, DG solar is available at high-demand times, reducing the need for grid upgrades. Compensating net metered installations for these qualities recognizes the differentiated value of electricity in space and time, resulting in the most efficient generator meeting demand in each hour and location.

However, net metered installations do not avoid the fixed costs of distribution and it is debatable whether they avoid the fixed costs of transmission. There is also a small cost involved ***113** in integrating these installations onto the grid. Not recovering these costs from such installations leads to a misalignment of costs with rates, contrary to a primary regulatory priority. The most straightforward way to reflect this constellation of costs is to compensate excess generation at retail rates, as is done currently, and to add a small monthly fixed charge for net metered customers. The fixed charge would be calculated from the fixed costs of transmission and distribution and the cost of solar integration with a credit for avoided future grid upgrade costs.

A rate structure as outlined above efficiently incentivizes the generation from net metered installations without shifting any fixed costs onto non-net metered customers. Based on the expected small size of the fixed charges and the above-recommended delay, this reform should allow for the development of DG solar and other net metered technologies. Thus, the public utility commissions can achieve their primary priorities of economic efficiency and alignment of rates with cost of service. At the same time, they can also uphold secondary priorities such as environmental protection and promotion of distributive equity.

Along with altering rates, public utility commission should remove all constraints on net metering, both individual limitations and aggregate caps. Many states have caps on individual system sizes or the aggregate capacity that utilities are required to interconnect. The rate reform described above would accurately incentivize the optimal amount of net metered capacity on the grid, which is consistent with the priority of economic efficiency. Artificially constraining this capacity would be contrary to the spirit of the reform and the regulatory priorities.

Through these reforms, net metering would effectively operate as a new version of PURPA, but one based on intrastate distribution grids. PURPA opened access to the grid at interstate transmission lines. Grid access, plus a guarantee of compensation at avoided costs, allowed non-utility generators to start up and expand, diversify power sources, and introduce ***114** competition. The whole power sector became more efficient as a result. Furthermore, many of the non-utility generators that PURPA incentivized were co-generation facilities and small renewable generators. The development of these sources had beneficial environmental and energy security impacts in addition to improving efficiency.

Similarly, net metering reform would fully and fairly guarantee access to the grid at distribution lines. As with PURPA, generators connecting in this way would receive avoided cost compensation for their generation. Correctly calibrated costs and removal of caps would encourage the efficient level of net metered installations on the grid. This would increase competition, strengthen the grid, and provide significant environmental benefits.

Like PURPA, smart net metering reform would usher in a new era for the power sector. Power generation would be both centralized and decentralized. Electricity would not be valued as a simple commodity with one price, but as a complex product with different values depending on the time and place of availability. Customers would straddle the line between consumers and producers, resulting in increased efficiency within the sector. Utilities would receive adequate funding to maintain the optimal level of grid infrastructure and no customers would disproportionately bear the burden of its upkeep. Such a system would enable not only penetration of renewables, but also distributed storage, the integration of electric vehicles onto the grid, and potentially other future technologies. This system is possible, but careful policymaking is necessary to bring it about. Specific policy recommendations in this vein are listed below.

Policy Recommendations

<u>Delay net metering reform</u>: States should delay net metering reform for several years. Cost-shifting is negligible at low penetration levels of DG solar and other net metered technologies. ***115** Distributive equity concerns are real for public utility commissions and should be addressed for net metering once they arise in a significant way. Currently, environmental protection benefits from solar development are significant. Given the minimal threats of distributive inequity or misalignment of cost of service, environmental priorities are better met through maintenance of the current regime. In some cutting-edge states, like California and Arizona, reform to address cost-shifting may be necessary within five years and should proceed according to the below recommendations. Reform is likely unnecessary in most other states for at least a decade, or once net metered capacity reaches 10% to 20% penetration.

Institute time-based rates: Rates for net metered customers (and for all customers) should be on a time-of-use or real-time pricing basis. Such pricing adequately reflects the benefits DG solar offers by making capacity available to the grid during peak demand hours.

When penetration increases, impose small fixed charges: Once DG solar reaches higher levels of penetration, public utility commissions should allow utilities to impose small monthly charges on net metered customers to cover the fixed costs of the grid. These charges should be calculated from fixed transmission and distribution costs and costs of solar integration. These calculations should give credit to net metered customers for avoided future grid upgrade costs. Based on the current level of excess generation sold, these charges should be less than $3 per customer. This upper limit may increase as the level of excess generation per customer increases.

When imposing fixed charges, remove net metering caps: Under a revised rate with a fixed charge, net metered customers should not be limited by the size of their own demand or the net metered capacity already online. Rather, these customers should size their systems based on their own financial and physical constraints. The resulting systems could be larger than their demand ***116** and provide significant generation to the grid. They should receive the efficient level of compensation for all excess generation, not just up to the point of their annual consumption. Such an arrangement incentivizes the efficient level of DG penetration on the grid.

VI. Conclusion

Net metering reform represents a significant opportunity for a power sector in transition. Executed correctly, reform to net metering policies can help forge a dynamic, improved grid with a variety of distributed technologies complementing traditional grid components. Such a grid can deliver economic, environmental, and social benefits to ratepayers and society, while maintaining utility standards of efficiency, fairness, and reliability. The right way to complete this reform requires patience in the present and a thoughtful valuation of costs and benefits in the future. The eventual shift to a time-based net metering rate with fixed charges will underwrite a fair expansion of net metered technologies on the grid and provide significant benefits to all.

Footnotes

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87 The share of the national revenue requirement not paid, 35% of 0.48%, is 0.166%,. Dividing this 0.166% by the share of non-participating capacity, 99.52%, gives 0.167%.

88 This analysis does not take into account inclining block rates, which are used in California. Some analyses have calculated larger cost-shifts in California due to inclining block rates. Net metered customers reduce their most expensive consumption and consequently shift more per kWh than the average retail rate. However, the high-tier inclining block rates already represented a significant shift of costs of service onto high-consuming customers. Blaming these customers for cost-shifting is somewhat hypocritical, when historically they have paid disproportionately high rates whose very purpose was aimed at reducing their demand. Furthermore, the California Public Utilities Commission has announced a simplification of the inclining block rate structure, which largely removes this cost of service disparity. *See* 16 U.S.C. §2621(d)(1)-(6).

89 10% penetration calculations: 10% net metered * 35% maximum fixed share of grid costs / 90% non-net metered = 3.9% increase in rates for non-net metered customers; 20% penetration calculations: 20% net metered * 35% maximum fixed share of grid costs / 80% non-net metered = 8.8% increase in rates for non-net metered customers.

90 *See, e.g.*, Cal. Pub. Util. Code § 739.6.

91 *See, e.g.*, Cal. Pub. Util. Code § 701.1.

92 *Id.*

93 DISTRIBUTED GENERATION FOR ARIZONA, *supra* note 82; METERING IN CALIFORNIA, *supra* note 14, at 2; SHINING REWARDS, *supra* note 10; SOLAR ENERGY INDUS. ASS'N, *supra* note 13, at 4; ROCKY MOUNTAIN INST., A REVIEW OF SOLAR PV BENEFIT & COST STUDIES (2nd ed. 2013); ANNUAL ENERGY OUTLOOK, *supra* note 86; U.S. Energy Info. Admin., *Wholesale Electricity and Natural Gas Market Data*, U.S. DEP'T OF ENERGY, https://www.eia.gov/electricity/wholesale/ (hereinafter *Wholesale Electricity*).

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[116] *See* Cal. Pub. Util. Code § 739.6.

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[120] *Id.* at 20-25; ROCKY MOUNTAIN INST., *supra* note 93, at 35.

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[124] *Id.* at 12-13.

[125] *Id.* at 20-25.

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[132] *See*, *e.g.*, Cal. Pub. Util. Code § 701.1.

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