2016

The Price is Right: Investigating Net Metering Policies for Rooftop Solar in California

Jesse Honig
Pitzer College

The Price is Right:
Investigating Net Metering Policies for Rooftop Solar in California

Jesse Honig

A Thesis Submitted in Partial Fulfillment of a Bachelor of Arts Degree in Economics
and
Environmental Analysis

Pitzer College, Claremont, California
April 26, 2016

Professor Maya Federman
&
Professor Brinda Sarathy

Abstract

As an increasing number of homeowners decide to take advantage of distributed renewable resources such as rooftop solar, we may need to rethink the current regulatory paradigm and governance structure of the electric market. This thesis examines the shortcomings of current net metering programs in California. While the current Net Metering 2.0 proceeding highlights a clash of solar advocates and electric utilities, it is in fact revealing an underlying structural flaw that has been present all along. In order to send the appropriate price signals to solar customers, both the structure by which utilities recover costs and the rate at which solar customers are compensated must be reconceived. I show how the current debates over the appropriate price to compensate solar customer are built on a flawed rate structure. Without addressing the underlying inefficiencies of current rate structures, it is unlikely that we will maintain utilities' financial ability to operate and maintain grid infrastructure and provide solar customers with the proper incentives to reach the ideal transition to solar energy.

Acknowledgements

To my mom, without whom none of this would be possible.

A special thank you to my readers, Maya Federman, Brinda Sarathy, and Melinda Harrold-Menzies. Thank you for the countless comments and invaluable guidance that you provided throughout this process. But more importantly, you all shaped my experience during my time at Pitzer, and for that I am incredibly grateful. And to Bowman Cutter—your Intro to EA class exposed me to the field of environmental economics, while the rest of your classes nurtured my interests and led me to this point.

Of course, to all my friends who supported me throughout this process. I swear you will never hear me say the word “thesis” ever again.

List of Acronyms

CAISO: California Independent System Operator Corporation
DG: Distributed Generation
RPS: Renewable Portfolio Standard
NEM: Net Energy Metering
IOU: Investor Owned Utility
PUC: Public Utility Commission
COSS: Cost of Service Study
GHG: Greenhouse Gas
MW: Megawatt
kW: Kilowatt
REC: Renewable Energy Credit
CSI: California Solar Initiative
CAPUC: California Public Utilities Commission
PG&E: Pacific Gas & Electric
SCE: Southern California Edison
SDG&E: San Diego Gas & Electric
MASH: Multi-family Affordable Solar Housing
SASH: Single-family Affordable Solar Homes
NSHP: New Solar Homes Partnership
ERP: Emerging Renewables Program
CARE: California Alternative Rates for Energy

Introduction

In January 2016, solar advocates achieved a substantial victory for the future of rooftop solar in California. The Public Utilities Commission released a decision on California's net energy metering program, "sid[ing] mainly with the solar industry and its proponents" (Cardwell, 2016, p. 2). This kept current policies largely intact, and was also considered to be a loss for electric utilities, who have already filed to overturn it. As net metering programs are coming into question in many states, it is important to examine the long-term viability of such programs, particularly as the volume of rooftop solar continues to grow.

Debates about renewable energy programs such as net metering are situated within a much broader discussion of methods to effectively address climate change and other environmental concerns. In order to avoid the most severe damages of a changing climate, it is widely believed that the United States must decrease its greenhouse gas (GHG) emissions 80% by 2050. In fact, many suggest that this represents only the most conservative scientific findings and that much more dramatic cuts will be necessary to avoid catastrophic changes. For the U.S. power sector, this means changing the means of generation on a scale that has never been seen before—with the exception of the rise of fossil fuels. In many spheres, the problem is discussed as simply developing the capacity to provide enough new renewable generation to meet our energy needs. However, to see this as merely a challenge of scale is profoundly misguided. Many new technologies present not only economic feasibility challenges, but also pose technical and regulatory ones. For many renewable technologies, especially wind and solar, increasing capacity requires finding a way to match generation with demand. In the absence of viable and scalable storage technologies, the intermittence and variability of renewable resources is often the biggest challenge.

This, however, is not the most pressing issue to confront in our attempts to make the necessary emission reductions that are necessary. As an increasing number of people decide to take advantage of distributed renewable resources such as rooftop solar, we need to rethink the current regulatory paradigm and governance structure of the electric market. The challenge therefore is not only finding a way to install enough new generation capacity, but additionally to devise a regulatory and transmission system that is capable of coordinating massive energy efficiency and distributed renewable efforts.

Many countries have recognized the need to radically transform their power sectors to significantly decrease greenhouse gas (GHG) emissions associated with the production and provision of electricity. California, although not a country, remains one of the largest economies in the world, and has long been on the forefront of climate policy and legislation. This commitment has been substantiated by AB32—the state's climate policy—along with net zero energy goals, and renewable portfolio standards. California is currently in the process of radically restructuring the way that it provides power to its residents and end users. This has resulted in an unprecedented attempt to change both the supply and transmission systems. Under current policies, older, dirtier, fossil fuel power plants are being phased out and replaced by either natural gas plants or renewable power generation. The state is attempting to utilize renewable resources at utility, community, and individual levels. The ambitious goals that have been established by California require that every aspect of the current electricity system be re-examined. The growing network of renewable energy technologies is encouraging new schools of thought regarding utility ownership models, customer engagement, and ownership of electric generation (Jeremy Carl, Dian Grueneich, David Fedor, n.d.).

One aspect of the state's renewable energy plan is the widespread distribution of rooftop solar. Unlike large, utility-scale solar plants, rooftop solar is considered a form of "distributed generation," usually small-scale, customer-sited generation systems. State political leaders continually affirm the potential importance of rooftop solar energy. In 2006, then-Governor Arnold Schwarzenegger introduced the Million Solar Roofs initiative. More recently, Governor Jerry Brown has also set a goal for California to generate 12,000 MW of distributed generation[1] (DG) by the year 2020, further signaling the central role of DG technologies in California's path forward (Jeremy Carl, Dian Grueneich, David Fedor, n.d.). Since then, California has led the nation in solar installations, ranking #1 in annual solar installations since 2013 (Association, 2015). While there has been significant discussion regarding the technological difficulties associated with the state's ambitious goals, there has been far less discussion of whether the current regulatory framework and utility models will be able to facilitate the massive transformation that is required to reach the socially efficient level of distributed solar.

The challenge of finding a regulatory structure for increasing amounts of distributed generation is especially pronounced in California, where utilities represent a variety of business models. While California is host to both public and investor owned utilities, it is for the most part serviced by a central grid, "characterized" as Peskoe (2016) states, " by large power plants interconnected by high-voltage transmission lines"

[1] Distributed generation, also called customer-cited generation, refers to small-scale generation that is primarily targeted at providing generation for on-site consumption. Most systems range from 1kW-10kW in size, and the most popular type of residential DG is rooftop solar (Costello, 2015).

(p. 16). Currently, the spread of DG solar is seen by utilities as a disruption that is being introduced to a system that relies on regulated, central monopolies. In California, the most relevant debate is over the future of net metering, a program that began in 1995, and allows solar customers to sell excess energy back to the grid. Recently, a number of cases have been brought before Public Utilities Commissions in a number of states, including California, Arizona, and Nevada, questioning the structure of net metering. In California, the most significant proceeding is one known as *Net Metering 2.0*. It is the program that has largely allowed the solar industry to boom in California to the extent that it has. The premise of the claims brought forward by many Investor Owned Utilities (IOUs)—privately held companies, such as PG&E, that are regulated by the CPUC—is that solar customers are being compensated more than they should be for the energy that they generate, and that the net energy metering (NEM) program should be re-evaluated.

The underlying concern of electric utilities facing increasing DG generation is derived from the misalignment of how utilities incur costs and how these same costs are recovered. While there are numerous debates about the details, the underlying structure of utility cost recovery is largely responsible for the opposition to DG technologies that many utilities now express. In order to better understand the current conflict, I first present a brief history of the development of electric utilities, the central grid paradigm, and the current regulatory structure. After looking at this history in Chapter 1, Chapter 2 examines the repercussions of an increasing development of solar generation. In this chapter, I also look more closely at current policies designed to promote renewable energy in California, situating the current net metering debate within the context of broader policy discussion. Chapter 3 looks more specifically at the recent rise in rooftop solar and some of the policies that have allowed for this growth. Finally, Chapter 4 provides a theoretical framework for understanding the proposed modifications to net metering policy, using economic models to analyze arguments made by both electric utilities and solar advocates. Ultimately, this thesis reveals the shortcomings of the net metering paradigm. I show how the current debates over the appropriate price to compensate solar customer are built on a flawed rate structure. Without addressing the underlying inefficiencies of current rate structures, it is unlikely that we will provide solar customers with the proper incentives to reach the ideal transition to solar energy.

I. Electricity in California

The California Electric System

Before attempting to examine the regulatory and governance structure of the electricity market, it is important to consider how this market first came to be, as well as the functions that it was originally designed to serve. It might seem that the electric grid simply provides energy to all those who are connected, but it actually reflects a complex balancing act of regulators, generators, and operators. While many people focus on issues of pricing electricity, the physical complexity of the electric system is often overlooked. The California electric grid provides over 30 million consumers with their daily energy needs. The California Independent System Operator Corporation (CAISO) is the institution that is responsible for coordinating California's wholesale electricity markets. This entails matching the production of over 670 power plants with the millions of residential, commercial, and industrial customers in the state (Trabish, 2012). The primary purpose of the electric market in California is to perfectly match the supply of energy produced with the demand for energy. In the absence of any significant storage technology, this constraint must be met on a second to second basis. This aspect of the electric system, along with the high fixed costs associated with constructing and operating the grid, require it to be carefully regulated. Unlike other goods, periods of "surplus" or "shortage" in the electricity market can result in significant service interruptions and are considered unacceptable.

In order to understand the basic physical transformations that the grid must accomplish, Peter Fox-Penner proposes an analogy to a series of ponds connected by small channels. Each pond represents a generator, with a waterfall feeding into it. The rate at which the water is flowing into the pond from the waterfall is the rate of electricity generation for that generator. The channels linking ponds represent the transmission system, allowing water to flow freely between all ponds.

In this system, the ponds are all at identical elevations. The result is that if water is added to any particular pond, it is naturally diverted to all other ponds through every channel until the levels of all ponds in the system has equalized. This is the way that electricity is distributed throughout the transmission network, without the ability to direct specific flow through a particular channel. Connected to various ponds are the energy consumers, who are able to take water through a small straw. The challenge for the entire power system is to maintain a stable level of water in all the ponds. A shortage or surplus will result in service interruptions and possibly blackouts. This means ensuring that the amount of water flowing into the ponds exactly equals the amount being withdrawn on a second to second basis. It is the responsibility of the CAISO to ensure that all electricity demand is met by utilizing the most socially efficient generation resources. However, in the presence of a negative externality associated with some forms of generation, it is unlikely that the CAISO will be able to achieve this goal.

The CAISO is responsible for managing the flow of electricity for approximately 80% of California along with a small number of areas in Nevada (Trabish, 2012). The CAISO is considered the largest of the 38 balancing agencies in the western interconnection. A balancing agency is responsible for ensuring that supply and demand of electricity are matched for a given service area. While the CAISO is responsible for managing the flow over most of California's service areas, there are a number of areas that are overseen by local public power companies, such as the Los Angeles Department of Water and Power. The primary purpose of any electric system is to provide the most reliable electricity to all of its end users at a reasonable price. California's grid is the result of decades of experimentation and transformation. Within the United States, there are a number of states in which electric markets are still vertically integrated. However, California is not the only market in which the generation and distribution of electricity are separated. States including Nevada, Arizona, and New York also use wholesale markets to facilitate the sale of energy. Furthermore, the majority of service areas are serviced by large, central grids, leaving only rural areas to be served by microgrids. Understanding the basic technological complexities allow us to better grasp the implications of current policy changes. Specifically, by looking at how the physical grid and its regulation developed over time, we can better understand the debates over current net metering policies.

The Central Grid Paradigm[2]

While electric utilities have existed for over a century, they have taken many forms and advocated for a number of different (and sometimes contradictory) industry policies. The current manifestation of electric utilities and the electric grid is often described as the Central Grid Paradigm. This is characterized by a central grid—massive power generation plants that are connected by a high-voltage transmission system. This stands in stark contrast with proposals to decentralize the electricity system through the development of microgrids (Walton, 2015). In order to fully understand the role of the

[2] This overview of electric utilities has been largely adapted from (Peskoe, 2016). Ari Peskoe is a Senior Fellow in Electricity Law at Harvard Law School, focusing primarily on electricity regulatory issues.

electric utility in the current debate over DG solar resources, it is important to have a sense of the history of electric utilities in the United States.

The defining characteristic of electric utilities to policy makers and economists alike is the monopolistic structure that most utilities are granted. Utilities are considered natural monopolies, due to the high fixed costs of providing service. While this has certainly been true for the past many decades and is characteristic of almost all utilities currently operating in the United States, this was not the case for their entire history. When the first electric utilities began to operate, they did so in an intensively competitive environment. At the end of the 19th century and beginning of the 20th century, the electric industry was flooded with new investors. During this period, it was relatively common for electric companies to engage in the production and sale of other electric components in addition to pure energy. Some companies were even known for providing their customers with light bulbs.

At this early stage of the industry, there were effectively no regulatory restraints placed in regard to where utilities could operate or what type of customers they could serve. The result was that multiple utilities often attempted to operate within the same area, and would compete for the same customers. This form of competition drew many utilities into densely populated, wealthy downtown areas, which contained the most valuable customers. This over-investment of highly urban districts resulted in duplicate capital investments from multiple companies. This was not only an extremely expensive way to do business, but also immensely inefficient from a resource allocation perspective. Over time, many utility companies could not continue to compete in this environment and either dropped out of the market or began to consolidate with other firms.

While competition is normally considered a necessary precondition for an efficient market, in the early 1920s, the resulting duplicative grid infrastructure was ultimately deemed to be “futile, chaotic, and destructive” (Peskoe, 2016, p. 11). This was true to the extent that there were calls from the industry for the state to intervene and place some limits on competition. Many utilities advocated for the establishment of state sanctioned monopolies that would be regulated by a commission of highly competent and educated officials. While giving up the freedom of a perfectly competitive market might have required some sacrifices, the utilities had much to gain from this maneuver. Granting monopoly status would greatly reduce the risk of investment and would minimize concerns that potential investors had regarding the volatility of the industry. This effective decrease in the cost of expansion would allow utilities to grow and invest at an unprecedented rate.

Throughout the early 20th century, this form of governance and institution regulation of utilities gained popularity across the country. Almost every state passed legislation that provided some degree of protection for electric utilities. While in some cases the designated service areas were technically non-exclusive, it mattered very little and competition between utilities for the same customers was rare. So, even for utilities that were not granted explicitly monopoly status, this period was marked by the increasing tendency to grant electric utilities “de-facto monopolies” even in the absence of exclusive service areas.

According to historian Richard Hirsh, this period of increased regulatory oversight was indicative of a consensus that had been reached between the electric industry, politicians, economists, and financiers of the electric industry. Each constituency stood to gain from the increasing oversight of the industry. For the utilities that remained, the legitimization of their monopoly rights created a sense of stability, predictability, and permanence. This solidification as the primary power provider allowed them to raise more capital for their investment, as the risks to potential investors were significantly decreased. However, it also was a means of decreasing the corruption that was occurring on the municipal level and also granted regulators the ability to place some limits on increasingly powerful companies. Finally, for many economists of the time, this represented a shift towards increased efficiency. Many agreed that in the case of electric utilities, a properly regulated monopoly would be more efficient than allowing perfect competition. The high fixed costs and decreasing average costs associated with the electric utility industry makes it incompatible with a competitive structure. The shift towards a regulated monopoly structure prevented the splitting of the market, which would have not only resulted in duplicate investments in transmission and distribution infrastructure, but also would have acted as a barrier to firms in reaching economies of scale.

This transition to regulated monopolies in the electric industry, largely completed by the end of the first half of the 20^{th} century, gave rise to the manifestation of utilities with which we are now familiar. Not only did this movement represent a significant increase in efficiency—decreasing the amount of energy needed to provide the same service—but also radically changed the way that utilities approached their own operation. While the increased efficiency provided some benefits to environmentalists, increased pollution associated with higher levels of electricity consumption as well as a poorly designed pricing structure resulted in continuing environmental damages. In this new form of regulation, many monopolies held either perfect or close to perfect monopolies over the production and distribution of electricity. Hirsh also proposes that once exposed to this, IOUs worked tirelessly to maintain their newfound control by encouraging development of technologies that would preserve this system. Working closely with allies in the manufacturing industry, IOUs "sought to stifle radical inventions that could upset the central station paradigm and threaten established financial interests." (Peskoe, 2016, p. 16) While the pursuit of the central grid model proved to be wildly successful for utilities, it also required capital on an unprecedented scale. This new sense of predictability attracted large quantities of financial capital, and utilities were unsurprisingly fixated on maintaining the conditions that would allow for their continued growth. Another important characteristic of this period was an ever-increasing demand for electricity. Resulting from both intentional programs developed by utilities as well as the external trend towards increased electricity consumption, this resulted in steadily increasing sales for electric utilities for a number of decades. This, along with steadily decreasing electricity rates led regulators to not be overly concerned with the details of the ratemaking process so long as customers continued to pay less and utilities were able to capitalize on continuing investment opportunities. At the time, the structure of recovering large fixed costs through volumetric rates posed little to no threat, however, it set the stage for the challenges that we currently face regarding DG resources.

Principles of Ratemaking

In granting electric utilities de-facto monopolies over service areas, it was critical that there was adequate regulatory oversight to ensure that customers were not taken advantage of. The Public Utilities Commission (PUC) is the primary regulatory body that is responsible for the oversight of the ratemaking process, but is often given little guidance on how to determine if rates are acceptable. For over a century, strong regulation has acted as a mechanism for setting prices in the absence of competition. As Peskoe (2016) notes:

> The foundational legal premise for this arrangement is that the IOU "was created for public purposes [and] performs a function of the state." As an instrument of the state, it has unique authorities, such as the power to exercise eminent domain. In turn, the government has a responsibility to 'protect the people against unreasonable charges for services rendered by [the IOU].'" (p. 10)

The purpose of this arrangement was to establish a rate of return for utilities that they would have theoretically earned in the presence of competition. Rates therefore, are set to allow the utility to cover the costs of providing electricity to the public while still earning a reasonable return on their capital investments: generation, transmission, and distribution capital. Under this paradigm, however, negative externalities in the generation of electricirty are still largely ignored, preventing utilities and regulators from reaching the most socially efficient outcome. By tying rates to utility costs, it was theorized that utilizes would not be able to charge customers an unreasonable rate and earn excessive profits. Additionally, under this structure, utilities were able to set different rates for the different classes of customers—industrial, residential, and commercial—to recover the costs that each class incurred. However, according to Peskoe (2016), this newfound process created a sense of "false precision." He claims that the processes allowed for IUOs, along with other interested parties, to present their own cost allocation studies. Consequently, each study either implicitly or explicitly promoted the financial interests of its author, allowing regulators to choose between competing studies. As a result, "regulators, courts, and economists have long-understood that allocating utility costs rests on 'judgment,' not science" (Peskoe, 2016, p. 10). In many cases, the guidance to PUCs is simply that rates must be "just and reasonable" and not "unduly discriminatory." Over time, provisions for PUCs increased, and their role in regulating utility rate setting became more pronounced.

This granted the PUCs the responsibility of making two key determinations. First, they now had to be able to estimate the costs that a utility faced over a given year. This would be used to project expected costs over the next period and would therefore inform the revenue requirement that the utility was entitled to. Second, PUCs were now responsible for overseeing the allocation of this revenue requirement between the different classes of customers. Initially, utilities conducted Cost of Service Studies (COSS) to advise the revenue requirement. However, by the 1960s, a consensus had developed among economists that utilities should use marginal cost of service studies to determine how the revenue requirement will be distributed among customer classes. That is, instead of looking at the entire set of costs, one should look at the costs of providing the *next* unit of electricity. This was a significant shift in ratemaking processes, as it emphasized analyzing costs at the margin. It should be noted that while both COSS and marginal COSS can be useful in advising rate design, they are both considered relatively "subjective," "imprecise," and not accurate enough to calculate the precise cost of providing service to a particular class. In an attempt to prevent discrimination, utilities were forced to average costs across all residential customers and could not charge individual residential customers different rates for providing the same service. Consequently, some customers paid more than the costs associated with providing their service while others were able to underpay. Many of the challenges are present in both

COSS and marginal COSS methodology, as many costs to utilities cannot be accurately attributed to a particular customer class. As James Bonbright—a foremost public utility economist at the time—wrote: "the choice of formula depends, not on principles of cost imputation but rather on types of apportionment which tend to justify whatever rate structure is advocated for non-cost reasons" (Peskoe, 2016, p. 23).

More recently, there has been an increased desire among utility and PUC regulators to attempt to align customer rates more closely with the costs that they incur on the utility. Up until this point, most residential customers paid the same rates, and time varying rates were not widely available. Analysts have a difficult time reaching agreement on what type of COSS study to use (marginal or embedded) or on a standardized methodology for allocating costs between customer classes. As a result, analysts and regulators make judgment decisions that often stand to benefit their clients. Peskoe (2016) argues that even if a consensus on methodology could be reached, the use of time-invariant prices inherently means that customers are not paying the precise amount that they are costing the utility. He concludes that "cross-subsidization between ratepayers in the same class is thus a feature of electric utility rates" (p. 26). An additional concern is the impact of negative environmental externalities on the ratemaking process. Without an effective price on pollution, it will be excluded from cost of service studies, and rates will be set below the socially efficient level.

Competitive Forces in a Monopolist's World

At first glance, the arguments presented by utilities in the current Net Metering 2.0 case may seem to resemble those that were made in the middle of the 20th century. The most direct connection is the argument that NEM creates cross subsidies between customer classes. In the 1950s and 1960s, it was the oil and gas companies that argued against the programs of electric utilities, claiming that they were able to socialize the costs across their entire customer base. In the current proceedings, it is now the electric utilities invoking the same argument against NEM programs that support solar installations. Nonetheless, there are major differences between the current and earlier examples. The electric heating programs, for example, were able to recover some of their costs through increased electricity sales. Of course, it is difficult to determine if this was actually the case or simply an argument put forth by the electric utilities. The current debate, however, cannot make this claim. In the 1960s, utilities claimed that the increased electricity sales resulting from customers switching from gas to electric heating offset the costs of their incentive programs. Now, however, instead of increasing electricity sales, the installation of solar decreases them, making it impossible for fixed costs to be recovered in the same way. Utilities claim that these cross subsidies are unacceptable and should be entirely avoided. However, Peskoe (2016) would argue that these types of cross subsidies are inherent to the ratemaking process. Additionally, utilities are now required by law to provide service to their customers, which was not true during the middle of the 20th century. The few similarities between the current net metering case and the programs provided by electric utilities in the middle of the 20th century provide some insight into current policy discussions.

The electric utility industry described above has existed primarily in an environment of government-sanctioned monopoly model. Most recently, as many consumer and environmental advocates have placed increasing pressure on the need for a cleaner energy supply, this deeply rooted power structure is being challenged. In many places across the United States, utilities are finding that their customers are increasingly seeking to generate their own energy. The most animated debate in this regard concerns the rapid expansion of DG solar technologies. In California, this phenomenon is particularly salient, as the state has the largest growth of rooftop solar in the country (Association, 2015). For many within the utility industry, this is simply an issue that must be addressed as they continue to operate under the central grid paradigm. However, there are discussions among many constituencies as to what degree the expansion of DG solar, along with other renewable technologies, will impact the ability of utilities to continue to operate under the central grid paradigm. Not only are these technologies allowing customers to purchase energy from other sources, but it is also disrupting the way that utilities are used to recovering costs of transmission.

Many recognize the increasing presence of distributed solar as a form of competition. Understanding the implications of this transition can be informed by examining moments in history when there were similar introductions of competitive forces. Throughout the past century, there were three periods during which competition was introduced into the utility industry, both from within and from external sources. These examples are not exactly analogous to the current situation, as utilities are now legally required to provide service to all their customers, and are subject to heavy regulation. Previous instances of competition, nonetheless, provide a useful perspective on current policies, demonstrating some of the regulatory challenged that exist in an industry characterized by high fixed costs.

In the late 1940s and through the 1960s, in the aftermath of World War II, electric utilities saw massive increases in electricity sales and consumption, growing at an average rate of 9% annually between 1949 and 1969 (Peskoe, 2016). This was partially due to the deliberate effort of utilities to persuade customers to use electricity not just for lighting, but also for heating and hot water. They did so by providing customers with electric appliances as well as by offering rebates to customers who switched to electric heating. This horizontal expansion brought electric utilities into services that had previously been provided by local oil and gas distributors. This newfound competition was hardly welcomed by the oil and gas companies, who claimed that the utilities' efforts to expand into their service markets constituted an unfair overreach.

This conflict was made worse as utilities intensified their efforts to increase the role of electric power in the American home. To start, utilities began to leverage their connections with the manufacturing industry to promote the concept of the "total electric home." These efforts did not stop at simply promoting products. In many cases, utilities would offer homebuilders rebates or free services in exchange for constructing homes with electric heat and hot water installed. A more popular approach was to offer rebates to customers who would make those types of improvements on their own homes. The utilities were able to capitalize on the fact that electric homes used 2.5-3 times as much energy as their nonelectric counterparts, which would increase their sales for decades to come. These changes resulted in significantly higher demand for electricity. In doing this, electric utilities were not only able to promote the transition to electric homes, but were also able to spread the costs of these programs across all of their customers.

Oil and gas distributors saw this as a form of unfair competition on the part of electric utilities. Throughout the late 1960s, they often took their complaints to Public Utilities Commissions across the countries, hoping to gain protection through regulation.

Their claim was that the use of promotional subsidies to electric heating constituted unfair competitive strategies. Unfortunately for them, their complaints were met with little to no response on the part of regulatory bodies. In fact, many commissions found their complaints to be distasteful. As Commissioner Arthur L. Padrutt responded:

> We see a growing number of cases where unregulated industries invoke the regulatory process against their utility competition. They would use regulation to inhibit competition against themselves while remaining free to compete as they please. As a regulator, I find this a distasteful trend. It amounts to a perversion of the regulatory process and should be sharply resisted (Moore, 1967, p. 16).

Despite these complaints, the golden age of electric utilities continued through the 1960s. A combination of the achievement of economies of scale, along with a number of legal and regulatory victories allowed electric utilities to greatly increase their customer base and sales volumes. Electric utilities, which were used to experiencing peak demand during the winter months, now found that in many parts of the country the peak demand was shifting to the summer months. The prevalence of air conditioning technologies along with a population that increasingly demanded temperature controlled environments vastly increased electricity use during the summer months across the country.

At the time, many electric utilities were responsible for both the generation and transmission of electricity. The shift of peak loads from the winter to summer months meant that a large portion of their infrastructure sat idle for many months of the year. Supposedly, they set their research and sales teams to work to find innovative methods for increasing the utilization of their facilities and subsequently increase sales. In an attempt to increase winter electricity sales, many electricity companies turned to electric heating as the obvious first choice (Moore, 1967).

Oil distributors took issue with the practice of subsidized electric heaters and filed numerous complaints claiming that utilities had an unfair advantage because electric utilities could recover the costs of these programs through the ratemaking process. These complaints often failed in state legislatures, as IOUs were able to argue that these subsidies were good for the customer base as a whole, allowing them to lower costs further by achieving further economies of scale.

After being turned away from the vast majority of state legislatures, the oil and gas companies began to file complaints under the guise of disenfranchised customers. They claimed that they were facing unfair discrimination by these programs and that they were being forced to recoup the costs associated with providing subsidies. This, they argued, amounted to a cross subsidy that they did not feel they should pay (Moore, 1967). They further claimed that “forcing existing customers to subsidize new customers amounted to unjust or undue discrimination, which is generally prohibited by state law” (Peskoe, 2016, p. 37).

As discussed above, the majority of state legislatures sided with the electric utilities, and refused to act on the complaints of the gas companies. Most regulatory bodies denied that the promotions offered by electric utilities were unlawfully discriminatory, and also upheld the programs on different grounds. In the most striking case, coming out of Delaware, the commission upheld the utility’s programs—a decision that was widely influential in subsequent cases across the country (Moore, 1967). The logic of the commissioner was that the programs were justified because of the disparity between summer and winter peak loads (P.S.S., 1964):

> The primary motive for a promotional campaign for electric heating was claimed to arise from a disproportionate demand for electrical current during

> summer months. This demand, generally resulting from increased use of air conditioning, has been met by electric utilities through the expansion of generating and transmission facilities. These same facilities, however, are not utilized to their fullest during winter months. […] In an effort to utilize this idle generating capacity, electric utilities have commenced a program of aggressive promotion of electric usage. Since the expansion of most home appliances is limited by market forces, it was determined that recent advances in the technology of home heating provided a basis for new sales of electric current. **It was felt that a successful entrance upon the heating scene of a new fuel required the use of certain inducements to entice customers away from traditional fuels, such as oil and gas**....
>
> The amounts of the promotional allowance was based upon a balancing of various factors. The amount must be sufficiently large to be attractive as well as compensatory for additional cost on the one hand, and still bear a reasonable economic relationship to the increase in revenue to be expected from the additional current expended. (

Another common target of oil and gas companies' complaints was the practice of installing underground electric wires to provide service to customers. Many electric utilities developed programs incentivizing the transition from overhead to underground wiring to accommodate increased electric demand from new electric appliances. At the time, customers preferred to have underground wiring, but the costs associated with this technology were often prohibitive. The programs that utilities established provided financial incentives for customers to decide to receive service via these underground cables (Moore, 1967). Through these programs, electric utilities were able to remove another barrier to converting more customers to electric heat and water heaters. This further angered oil and gas companies that viewed this as an unfair subsidy to convince customers to convert from gas to electricity.

In both cases, the utilities claimed that these programs were justifiable for a number of reasons. First, they argued that they were in the general interest of the public—a view that was largely supported by utility commissions across the country. The main premise of regulators was that by increasing the load factor of their facilities, the electric utilities could decrease the unit costs associated with providing service to their customers. So, the electric utilities were supported so long as they could argue that their programs would decrease the costs of providing service to customers in the long run.

Additionally, some commissioners claimed that it would be an abuse of their power to intervene and prevent the utilities from implementing their programs. They were often satisfied so long as utilities demonstrated that the increase in electricity sales would offset the costs of the programs. One court concluded that utilities are “engaged in vigorous competition with suppliers of other forms of fuel or energy [and] that a business either grows or decays and when it is allowed to disintegrate, there is damage to customers as well as to stockholders” (*Gifford v. Central Maine Power Company*, 1966, para. 8).

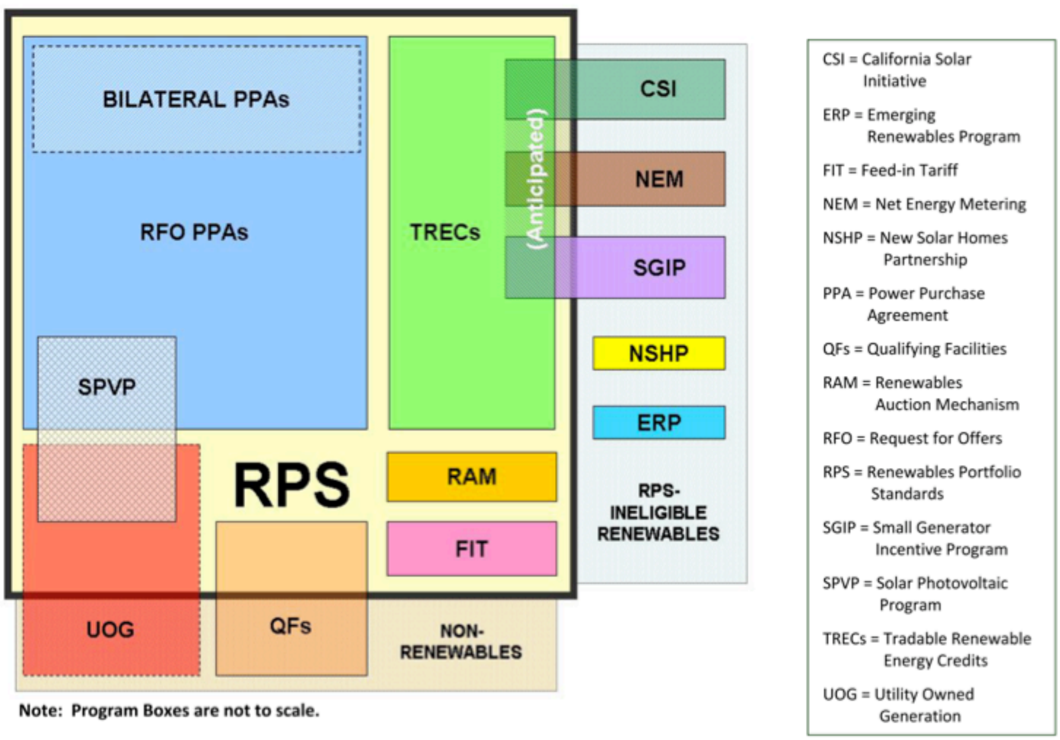
While Public Utilities Commissions are responsible for preventing utility companies from charging unreasonable rates, it appears that in many instances, they have intervened to ensure the success of the central grid. Although this is not included in the PUC’s objective function, their decisions to intervene (or not) were instrumental in the success of electric utilities converting customers to electric heating. The tendency of PUCs to protect the central grid paradigm might suggest that they would side with the interests of electric utilities claiming that rooftop solar would disrupt their ability to provide reliable service. However, net metering is not the only incentive available to those who wish to install rooftop solar in California. This debate is situated within California’s web of renewable energy policies, as it has developed as a leader in climate and energy policy.

II. Renewable Energy Policy in California

For many years, California has been on the cutting edge of climate and environmental policy. As the world's 8th largest economy California has earned its place amongst world economies and is now looked to as a source of inspiration and guidance for many countries seeking to implement effective climate policies. California has long been recognized as a subnational actor tackling a global challenge, providing valuable policy insights to groups throughout the United States and across the globe (Mazmanian, Jurewitz, & Nelson, 2008). The most overarching intervention was the passing of Assembly Bill 32, the Global Warming Solutions Act of 2006, the primary goals of which include: 1) reducing greenhouse gas (GHG) emissions to 1990 levels by 2020, 2) developing a scoping plan to meet new targets, and 3) regulating a number of GHGs, including, CO2 (Adams, Nichols, & Goldstene, 2008).

While this policy does not explicitly create mandates for the electricity sector, it set the stage for a slough of policies that would target specific aspects of the generation, transmission, and end-use consumption of electricity. The California Public Utilities Commission, the California Energy Commission, and a number of other state agencies are responsible for establishing programs that create incentives for the installation, development, and purchase of renewable energy. This has largely been an attempt to correct for the un-priced positive externality of avoided pollution that is associated with renewable generation. However, in the absence of a singular agency or institution responsible for guiding renewable energy programs, California has developed an extremely complex system of over 13 programs targeting different renewable technologies (Rogers & Stueve, 2012). This has resulted in a system that is inefficient, difficult for the public to understand, and one with overlapping jurisdictions. With no single agency responsible for overseeing the direction of renewable energy policies or identifying regulatory gaps, this patchwork of programs will continue to provide less than ideal results (Jeremy Carl, Dian Grueneich, David Fedor, n.d.). Figure 1 illustrates the scope and complexity of renewable energy programs within California.

Figure 1: Renewable Energy Programs in California (Rogers & Stueve, 2012)



While AB32 set long-term goals for emissions reductions, the specific targets for individual sectors (industrial, residential, commercial, etc.) were not included. For the electric sector, this gap was filled by the Renewables Portfolio Standard (RPS). This legislation sets requirements for regulated retail sellers of electricity to purchase a certain percentage of their energy from eligible sources of renewable energy. The first RPS was set in 2002, prior to the passage of AB32, and required CPUC regulated retail sellers of electricity—primarily Investor Owned Utilities (IOUs)—to purchase an additional 1% per year from renewable sources until 20% of sales were reached in 2017. For environmentalists and those interested in energy conservation, this represented a significant step in the right direction, as IOUs provided approximately 68% of retail electric sales (Rogers & Stueve, 2012).

The next modification to the RPS came with the passage of Senate Bill 107 in 2006. SB 107, implemented during the same year as AB32, demonstrated an increasing commitment to meeting climate goals, demanding a 20% RPS goal by 2010. The most recent modification to the RPS program took place in 2011, when the standard was increased from 20% to a 33% goal by 2020 for regulated retail sellers and publicly owned utilities (Rogers & Stueve, 2012). In meeting the goals set out by the RPS standards, all investor owned utilities are required to submit annual plans on how they plan to make progress on reaching the standards.

To keep track of how much renewable energy is generated and purchased by individual entities, the California Energy Commission uses Renewable Energy Credits (RECs). One REC is a certificate of proof of generation of one MWh from an eligible renewable source. In the simplest cases, the REC is bundled with the energy that it is associated with. Alternatively, RECs can be sold as unbundled commodities, where the energy itself is not purchased. This degree of flexibility allows sellers of retail electricity to meet their targets under the RPS at a lower cost. These unbundled RECs, also referred to as Tradable RECs (TRECs), can be traded amongst firms in a secondary market, providing a further degree of flexibility. Tradable RECs ensure that the renewable generation exists, but does not necessarily have to be delivered by the same utility. This however, does not account for reduced sales resulting from energy efficiency improvements. Investments in energy efficiency are managed under different programs, largely targeting end users of electricity.

However, there are some limits placed on the freedom of retail electricity sellers to source RECs to meet RPS goals. SB X1 2 (which established the 2011 RPS standard) also lays out requirements for the types of RECs that entities in the electricity market can utilize. Minimum requirements are set for the proportion of bundled RECs that must be purchased, while a cap (as a percentage) is placed on how many unbundled RECs can be used to meet RPS goals (Rogers & Stueve, 2012). This prevents utilities from simply purchasing their entire requirement through unbundled RECs, but not actually having to deliver renewable energy to end-use customers.

While California currently has 13 programs designated to increase the role of renewables in our energy mix, there are four policies that specifically target small scale distributed solar resources (i.e., energy produced by individual home owners who install solar panels): the California Solar Initiative, the New Solar Homes Partnership, the Emerging Renewables Program, and Net Energy Metering. These programs were instituted to encourage solar systems that provide energy "behind the meter"—that is, the electricity is produced and consumed on the customer side of the meter. Because the energy is largely consumed directly by the customer's home, utilities are unable to measure how much was produced. Energy that is generated by rooftop solar that directly serves a customer's on-site consumption may not be counted towards the utility's RPS requirement. However, when generation surpasses consumption and energy is sold back to the grid, the utility may count this excess generation towards their RPS requirement. Additionally, the installation of a residential solar system will decrease the amount of electricity that the customer requires from the grid. Since the RPS obligation is expressed as a percentage of retail sales, this decrease in sales reduces the total amount of renewable energy that is required for the utility to meet the RPS target. This is a relatively small effect, and is much less significant than if the utility could simply count DG generation towards their RPS requirements.

The California Solar Initiative (CSI), one of the most significant policies, was originally developed in 2005 by an executive order of Governor Schwarzenegger. After passing over a number of regulatory hurdles, the program was adopted by the CPUC in December, 2006, and was launched at the beginning of 2007 (Rogers & Stueve, 2012). The goal of the program was to increase the generation from solar resources as well as assist solar installations in achieving economies of scale so that they could continue to develop independently. The original target was to reach 1940 MW of installed solar capacity by 2016. This program specifically targeted customers served by Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric, representing approximately 70% of electric customers in the state (*California Solar Initiative Program Handbook*, 2014).

The program was designed to target residential systems as small as 1 kW capacity up through systems of 1000 kW (1MW)—which could fit on the roof of a large store. The CSI built on nearly a decade of previous solar policies, including the Emerging Renewables Program and the Million Solar Roofs Program (*California Solar Initiative Program Handbook*, 2014; Rogers & Stueve, 2012). The CSI also included a number of separate initiatives, each administered independently. These included a research, development, and deployment (RD&D) program which targeted solar technologies that furthered the goals laid out by the CSI and dedicated $50 million to such technologies. Additionally, programs targeting low-income customers were administered separately, and were allocated budgets of $108 million to encourage solar growth in single and multifamily low-income housing units (Rogers & Stueve, 2012). The lack of coordination among programs has been consistently cited as one of the main weaknesses in California's efforts to expand renewable energy (Jeremy Carl, Dian Grueneich, David Fedor, n.d.)

The CSI ended almost two years ahead of schedule, with the final funds being spent in 2014. However, the early termination and decline in available rebates is not an indication that this program was a failure. To the contrary, the CSI exceeded its initial target by hundreds of megawatts. Additionally, the fact that the program terminated with little windfall or media noise demonstrates that it achieved its goal of helping solar installations reach the necessary scale needed to operate more or less on their own. Unlike other states and countries that have rolled back solar subsidies and witnessed a decline in installations, the decline of CSI actually coincided with increasing solar installations throughout the state. This was made possible by other state and federal tax credits and incentives. The percentage of residential installations receiving state incentives through the CSI declined steadily between 2012 and 2014, allowing the program to be slowly phased out (Lacey, 2014). While the CSI was instrumental in the initial rise in rooftop solar, now that it has concluded, other programs will have to be used to provide incentives for rooftop solar. Net metering is the policy that has primarily filled this gap, and continues to provide the greatest incentives for those who install rooftop solar.

The New Solar Homes Partnership (NSHP), a program established in the context of the CSI, was designed to target solar installations on new housing units. (Arriaga, Nasim, & Nguyen, 2015). This program provides incentives for new residential buildings that purchase energy from the state's IOUs, with different incentive structures for market-rate housing projects and qualified affordable housing projects (Rogers & Stueve, 2012). Most of the incentives come in the form of rebates, and are determined by the size of the solar installation. They range from $0.75/watt to $1.50/watt, depending on the type of housing unit and other energy efficiency certifications of the unit. Currently, the NSHP has helped finance almost 150 MW of solar capacity on new housing units ("New Solar Homes Partnership," 2016). The CSI and NSHP provided direct incentives for the installation of solar, but did not provide compensation for the actual generation. While this was effective in promoting the initial expansion of solar, we now must look to policies that encourage the generation of solar energy, not just installation. Net metering is the policy that provides such an incentive and will also likely be the longest lasting.

Net Energy Metering (NEM) has been one of the most popular programs for encouraging the growth of DG solar in most states, particularly in California. While many of the other programs in California have either begun to be phased out or have ended completely, NEM is still considered necessary to make solar a financially viable option for residential customers (Lacey, 2014). NEM is one of the oldest standing policies targeting renewable energy in California. It was originally established in 1995 under California Public Utilities Code 2827 to provide net metering for wind and solar systems with capacities less than 10 kW. In 2001, net metering was expanded to include projects up to 1 MW in size, and again expanded in 2003 to develop a program targeting biogas digesters and fuel cell technologies.

NEM is designed to provide customers with an incentive to install onsite renewable power systems. The vast majority of customers that utilize net energy metering are those with rooftop solar systems. NEM allows customers use the grid when their solar systems do not generate enough to meet their demand, but also requires utilities to buy excess generation from solar customers when their production is greater than consumption. Most of the time, the energy generated from rooftop solar is used to directly service the needs of the household. However, when the generation exceeds the customer's demand, the utility must buy this energy, and the customer receives a credit on their bill. Customers usually do not receive actual cash payments, but rather receive credits for their energy bills for a given billing period. At the end of the 12-month billing period, customers are billed for their total energy use minus the credits from excess generation.

While many of these policies were targeted to increase the deployment of rooftop solar, utility scale solar facilities also offer similar benefits. Utility scale solar is normally bought and sold in the wholesale market, and is usually a much less expensive investment. In some cases, utility scale plants can be 50% less expensive per kWh than an equivalent capacity in rooftop generation (Tsuchida et al., 2015). While it is still important to incentivize the installation of rooftop solar, we should also be mindful of deploying solar resources in the most cost effective way possible.

While NEM has been considered an extremely successful program, imposing it on the pre-existing rate structure effectively punished utilities, which relied on volumetric sales to recover their costs. For this reason, IOUs such as PG&E have not only been hesitant to embrace net metering, but have aggressively fought to end it. Part of this problem is due to the lack of time-of-use metering, which would more accurately compensate rooftop solar generators for their energy. However, even with time varying prices, utilities would still be reliant on using volumetric rates to recover fixed costs.

III. Creating a Sustainable Path for Solar

Concerns over Rooftop Solar

While policies such as the ones described in Chapter 2 have succeeded in increasing distributed solar capacity, this expansion has still occurred within a system that was not intended to facilitate bidirectional energy sales. As distributed solar resources (primarily rooftop solar) become increasingly prevalent in California, utilities have begun to cite them as a potential threat to business and regulatory models that must be dealt with immediately (Kind, 2013; Owens, 2012). At current levels, rooftop solar may not pose an imminent threat to the viability utilities operating and maintaining the grid, but with predictions of sharp declines in the price of solar technology and rapid increases in installations, the influence of DG solar will definitely increase in years to come. For decades, utilities have built the grid largely to deliver electricity to end customers—it was never designed to have electricity flow in the other direction. At low levels of penetration, customers selling energy back to the grid—creating a system in which electricity flows both directions—does not pose extreme problems, but as the volumes of electricity flowing back into the grid increase, many utilities are concerned about both technological and cost recovery issues that may arise. Addressing the issues associated with the recovery of grid and transmission costs now will allow solar to continue to grow without these concerns as it reaches higher levels of penetration.

In the case of electricity *generation*, a large number of companies are able to compete to sell their energy in the same market (CAISO). However, the business of electricity *distribution* has a dramatically different set of characteristics. As outlined in Chapter 1, the period of competition in the distribution market proved to be a dramatic failure, and has since been converted largely to monopolies. Because the transmission system requires such massive capital investments in the grid infrastructure, it would not make sense to have multiple transmission networks providing service to the same set of customers. Instead, the regulatory body grants a utility monopoly rights to a service area. The regulatory body is then responsible for ensuring that electricity prices are kept relatively close to the cost of service. The transmission system is responsible for providing a way to transport electricity from the generating source to the end use customer. Thus, electric utilities must provide service to the customers in their area as well as recover the costs of constructing and maintaining the grid along with the cost of purchasing generated electricity.

In order to ensure reliable and high quality service, the transmission system must be sized correctly to be able to handle the maximum load that will be demanded of it. Each part of the system is generally designed so that its minimum capacity is determined by the highest load that it must be able to accommodate (also including a margin of error). In this way, the costs of the transmission system increase as the amount of capacity it requires increases. Because the transmission system is largely influenced by its maximum load, the impact that a single customer has on the necessary size (and consequently the cost) of the system is determined largely by the customer's portion of the substation peaks. The majority of the costs that are incurred to the distribution system are derived from infrastructure and are largely fixed in the short run (Cicchetti, Dubin, & Long, 2004).

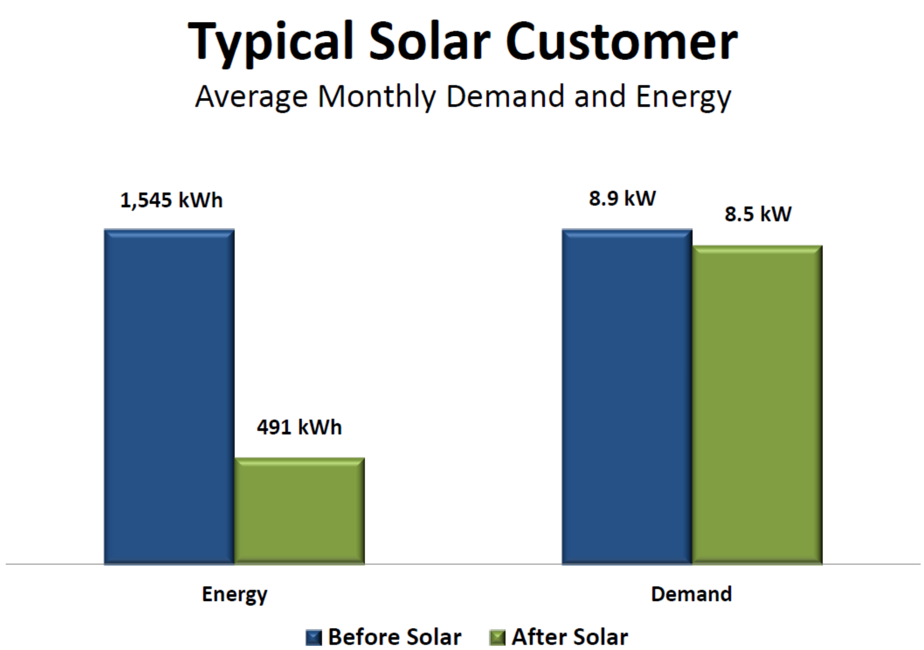
These types of costs can be characterized by whether or not they vary with customer size or load. First, there are some fixed costs that do not change with the customer size or load. It is important to note that the concept of fixed costs is often interpreted differently in the utility setting. Some will refer to fixed costs as those that truly do not vary with the customer size. This definition would mainly include billing, metering, customer service, and administrative costs. In this sense, the behavior of individual customers has no effect on these costs, although the utility may attempt to lower them by increasing their efficiency in the long run (Cicchetti et al., 2004).

Alternatively, there are also a few types of costs that do vary with customer characteristics. The first type varies with the total amount of energy used by the customer. That is to say that the potential load of the customer requires certain infrastructure investments. For example, a customer that uses all her electric appliances simultaneously will require a larger connection than one who spreads that same use out over the course of a day. These differences in customer size are reflected by the difference in cost of connecting a large mansion versus a small residence. In fact, some utilities (e.g. Salt River Project in Arizona) have attempted to isolate these costs by charging customers a fee that is determined by their amp service. In addition to costs that vary with customer size, there are also those that are largely determined by the peak load of the customer. In order to provide reliable service, a utility must make infrastructure investments sufficient to cover the maximum load that they anticipate experiencing. Depending on regional characteristics, the peak electrical demand is influenced not only by the time of day, but also the time of year. As this peak demand changes, utilities can expand or contract the size of the distribution system. However, costs associated with accommodating changes in system demand are considered fixed in the short run, but may be adjusted in the long run. In the short run, utilities cannot change the size of the distribution system, but they are able to accommodate changes in peak demand by modifying the size of the grid over longer time horizons. These distinctions may seem trivial, but are central to many discussions of cost recovery. Many scholars who study electric utilities cite a need to recover costs by charging customers for the costs that they incur. In order to do so, one must first have a basic understanding of the different types of costs.

Historically, utilities have recovered the majority of their costs through volumetric ($/kWh) charges. Customers are simply billed for the total amount of energy used, with little to no regard for how or when it is consumed. In a growing system, this straightforward method of pricing was beneficial for both the customer and electric utility: it accounted for an increasing revenue stream as sales continued to grow, while simultaneously simplifying the bill that the customer received. It also gave customers a very clear signal of "use less, pay less/use more, pay more." More recently, utilities have begun to experiment with different rate structures, but still primarily rely on some form of volumetric rates to recover their costs.

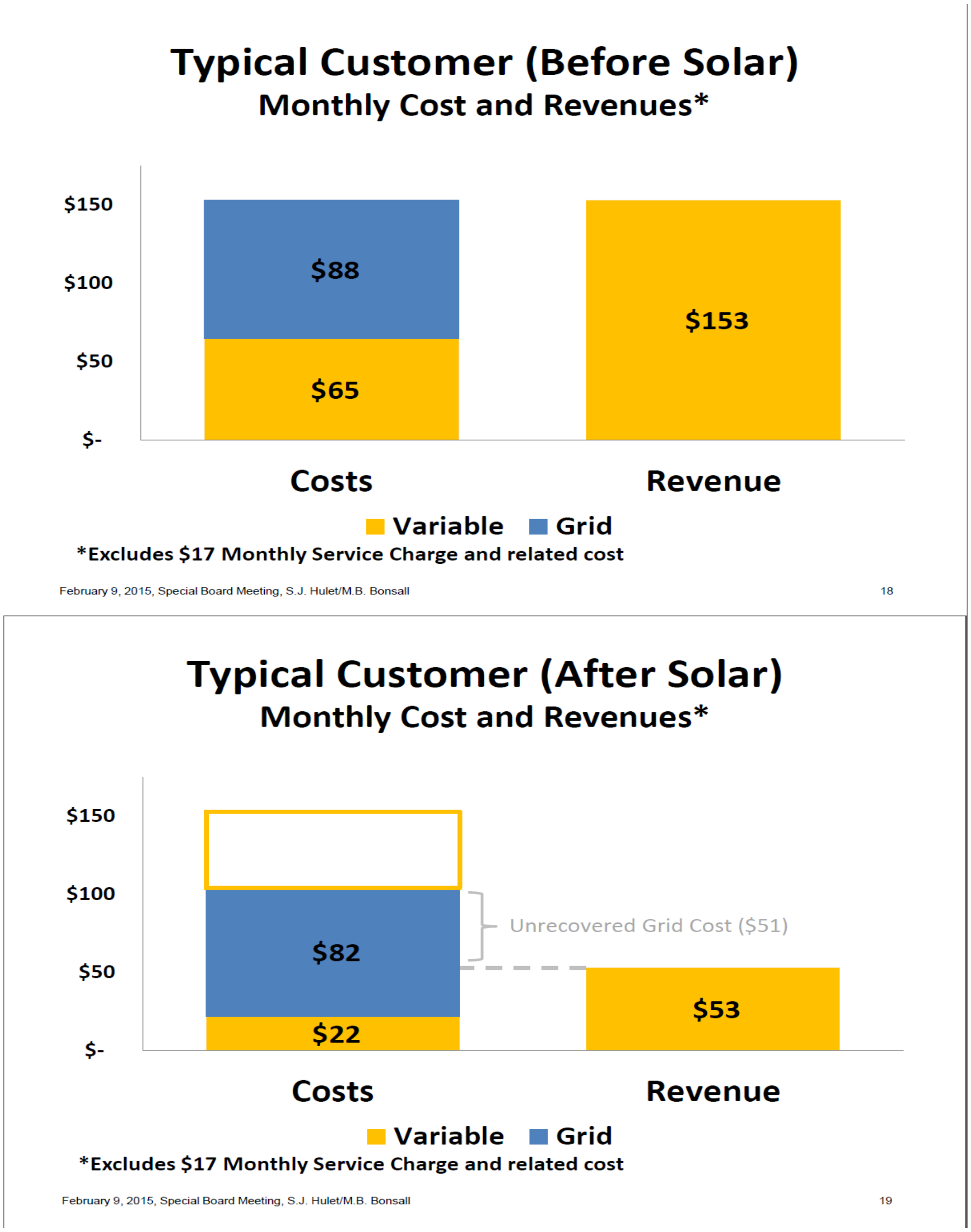
With the expansion of DG resources and storage technologies, many within the industry have become increasingly concerned with the implications for cost recovery. Originally, this simple form of billing may have been adequate, but as distributed generation continues to expand, recovering fixed costs through volumetric rates will result in an inefficient outcome. Customers utilizing DG resources pay significantly less in volumetric rates due to decreased consumption. However, as described above, utilities size the transmission system based on instantaneous demand (kW), not volumetric demand (kWh). Additionally, as we shall see in Chapter 4, the absence of un-priced environmental externalities further decreases the efficiency of this rate structure. Figure 2 illustrates how adopting solar technologies impacts the characteristics of a customer, with their maximum demand remaining the same while volumetric usage falls sharply. Figure 3 depicts the implications of these changes for the recovery of fixed costs through volumetric rates for electric utilities.

Figure 2: Average Monthly Demand and Energy Use (Arizona Public Service)



Source: Arizona Public Service

Figure 3: Effects of Solar on Costs and Revenues (Feb. 9, 2015, Special Board Meeting, S.J. Hulet & M.B. Bonsall)



This demonstrates how a customer who switches to solar dramatically decreases their volumetric energy usage, while their maximum demand remains relatively unchanged. Because utilities rely on volumetric rates to recover the fixed costs of grid investments, the drop in energy use associated with solar installations results in unrecovered grid costs. Under net metering programs, the reduction in energy use translates directly to a reduction of revenue for the electric utility.

Current Regulatory Proceedings

AB 327

One of the most prominent manifestations of the economic conflicts between solar advocacy groups and utility advocates is the discussion of net metering practices. This is exemplified in a case that has recently come before the California Public Utilities Commission, and emerged from the passage of AB 327 in 2013. Net metering was originally intended to encourage the installation and utilization of DG renewable resources. Under current[3] (Net Metering 1.0) net metering policies, customers who are eligible for the program are able to receive full retail credit for the energy that they produce. However, there was no accompanying rate structure change that occurred with the implementation of this program. In order to qualify for the program, a customer is limited to operating a "small" renewable facility, which has been capped at 1MW of generating capacity. Customers are able to receive the retail rates for the energy produced by being charged for their net energy use—hence *net* energy metering. By only charging customers for the energy use in excess of their generation, they are effectively compensated at the rate at which they would have purchased electricity from the grid. In

[3] Throughout this piece, I will refer to policies in place before the NEM 2.0 case as "current." Because this is being written while the proceedings are still underway, it is important to make this clarification. Any policy or legislation that has been the result of NEM 2.0 shall be identified as such.

California, the vast majority of customers that participate in NEM are those who have installed small solar arrays on their homes or businesses (CAPUC, 2014b).

For nearly two decades now, modifications to the NEM program in California have usually focused on the types of energy that can qualify and limits that are placed on the number of participants in the program. The current limits on net metering were established by Pub. Util. Code 2827(c)(4)(B), which set the limit for net metering under IOUs at 5% of the aggregate customer peak demand. This cap was established to prevent unknown consequences of high levels of bidirectional electricity flow between the grid and DG systems. As of 2013, the cap for net metering (measured by the peak demand of customers) was 5258MW, but only 1882MW were enrolled in the net metering program (36% of the cap) (Heeter, Gelman, & Bird, 2014). This program was originally intended to only allow a relatively small number of households to participate, but the PUC is currently attempting to craft a policy that would have no cap on participation.

The most recent legislation regarding NEM in California is Assembly Bill 327 (AB 327), passed by Governor Brown in October 2013. AB 327 gives the Public Utilities Commission the authority to "address current electricity rate inequities, protect low income energy users and maintain robust incentives for renewable energy investments."[4] AB 327 has a number of directives that specifically address the pricing of electricity in the context of solar production: 1) ensure that renewable energy generation on customer sites continues to grow sustainably, 2) new tariffs are established on the basis of actual costs and benefits of renewable energy generation, and 3) "ensure that the total benefits

[4] In a letter to State Assembly Members regarding AB 327, from Governor Edmund G. Brown Jr., October 7, 2013.

of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs" (E. Brown, 2013, p. 91).

In addition to these primary directives, SB 327 states that the commission pay special attention to low-income customers who are participating in the California Alternative Rates for Energy (CARE) program. The bill mandates that in assessing new rates, these customers not be unduly burdened. Most of the installed capacity is on homes that are owner occupied. Not only do these customers tend to be higher income, but people who rent their homes may not have the authority to install solar at all. While SB 327 opens the door for utilities to propose fixed charges to recover some of the costs, it also states that in doing so, along with any rate changes, the changes "do not unreasonably impair incentives for conservation and energy efficiency, and do not overburden low-income and moderate-income customers" (E. Brown, 2013). Low-income customers a especially effected by rate changes, so it is important to take care to not adversely impact them.

The most pertinent part of this legislation is the language regarding the development of a successor to the current NEM program. The legislation aims to enable a net metering tariff that would expand on the current program and would be a long-term policy for residential customers wishing to install DG resources. This reflects the rapidly increasing rate at which renewable technologies are being installed in California—the conditions of the DG landscape have changed radically since the first manifestation of the NEM program. AB 327 mandates that the PUC establish a successor to the current NEM program by December 31, 2015 (released February 5, 2016). The new contract or tariff must be made available to customers of large electrical corporations starting July 1, 2017, or if ordered to begin by the PUC because the utility has reached the NEM program limit (E. Brown, 2013). The bill also specifies that the contract or tariff approved by the commission shall be available to all eligible. In this way, one of the primary purposes of this legislation is to provide a form of NEM that will be more viable in the long run, one that will not limit the number of customer-generators.

Net Metering 2.0

Leading up to this proceeding, which began in July 2014, decisions made in other commission cases have been reached that have implications for Net Metering 2.0 moving forward. Specifically, D.15-07-001 (July 2015) resulted in a number of changes to both residential rate design and the process that the PUC must follow in the Net Metering 2.0 case. The most relevant changes include: 1) A modification of the current four-tiered residential rate structure that will narrow it to two-tiers by 2019, 2) the implementation of minimum bills for customers instead of fixed charges, 3) a ruling that fixed charges (including demand charges) will not be imposed until the process of streamlining the tiered rates has completed and time of use rates have been implemented, 4) establishing that the consideration of fixed charges must be initiated in an IOUs rate case, and 5) the development of time of use rates for residential customers that will launch pilot programs in summer 2016 (CAPUC, 2014a). The tiered pricing structure allows utilities to charge different prices for energy depending on how much a customer uses. The higher tiers are usually much more expensive, incentivizing customers to reduce the amount of energy that they use. The changes represent a significant shift towards a more efficient rate structure. In the current proceedings developing a successor to the NEM tariff, the commission is mindful of the dramatic changes that will be taking place over the next few years and has expressed concern for instituting dramatic changes to the NEM program without fully understanding the impacts on customer bills or utilities (CAPUC, 2014a).

The current proceeding is the result of AB 327. While there have been a number of other proceedings that address specific aspects of NEM, many of them were consolidated under this case to make it easier to coordinate the decisions. At its commencement, it was anticipated that through this case, the PUC would identify a number of key elements necessary to move forward with a new NEM program, as well as propose a NEM tariff that would succeed the current policies. The commission is anticipated to: 1) identify guiding principles that would assist in developing and evaluating options for NEM successors, 2) identify “program elements” and features that could be included in a proposed program, 3) develop a method for estimating the costs and benefits of various policy options (the “Public Tool”), and 4) develop a number of options for a NEM successor program (CAPUC, 2014b).

In the past year, other states have had similar proceedings in their respective Public Utilities Commissions. In Nevada, the Public Utility Commission released a decision that dramatically cut the state’s net metering program. Prior to the decision, Nevada had experienced a “solar gold rush,” and was one of the largest installers of rooftop solar in the country (Brady, 2016). The recent decision, however, dealt a devastating blow to the solar industry, which “pretty much killed off residential solar in Nevada” (Brady, 2016, p. 2).

The proposed changes include increasing fixed charges for solar customers from \$12.75/month to \$38.51/month by 2020, and reducing the rate at which customers can sell energy to the grid from $0.11/kWh to $0.026/kWh over the same period (Pyper, 2016). For many customers who see average bill savings of $11 to $15 per month from installing solar, the increase in fixed charges alone would offset any savings (Pyper, 2015). As a result, many solar companies have been forced to reduce or eliminate their business operations in Nevada.

In its decision, the PUC argued that these reduced rates more accurately reflect the costs and benefits associated with serving solar customers. Additionally, the changes to the Nevada rate structure apply to a large number of existing solar customers, who had made the decision based on much higher levels of compensation. Whether on not this change in rate structure increases the efficiency of rooftop solar, it is clear that it has dramatically reduced the viability of solar in the state.

Fortunately, California legislators have been able to use the Nevada experience as a tool for understanding the implications of making significant changes to existing policies. This further demonstrates the importance of net metering as an incentive for customers to install rooftop solar, but also the impacts of introducing a high degree of uncertainty for customers who sell their energy back to the grid.

IV. Proposed Changes

In the California proceeding of Net Metering 2.0 various parties have been asked to submit proposals for a successor tariff to the current net metering program. These proposals can be grouped into four main categories: 1) those that keep the current form of NEM, providing full retail rate credits to customers with onsite generation, 2) those that maintain full retail compensation for NEM, but add a demand charge or installed capacity charge (a type of fixed charge), 3) those that allow customers to use onsite generation for direct usage, but receive compensation for exported electricity at less than the retail rates[5], and 4) those that establish a "value of renewables" tariff, under which customers are credited for the "avoided cost" to the utilities resulting from their onsite generation (CAPUC, 2014a). Within these categories, the majority of solar advocacy groups proposed rates similar to (1) in which customers would continue to receive full retail rate net metering for their generated energy.

Pacific Gas & Electric submitted a proposal similar to (3), allowing customers to receive compensation for generated power at rates less than retail prices, while also being subject to demand or capacity charges (CAPUC, 2016). PG&E suggests that customers under their NEM program be compensated for the generation rate that they pay on their bills, approximately $0.097/kWh, significantly less than the current retail rate that customers receive.[6] Under their proposed tariff, customers would also be charged a demand charge, calculated using a customer's period of maximum demand. California utilizes a competitive bidding process to allow utilities to acquire generation from different energy sources. While each generator may offer a different price, the market-

[5] Some proposals also include demand charges or installed capacity charges.
[6] Customer bills consist of generation, transmission, and distribution components.

clearing price is ultimately the price that is paid for every unit of electricity at that time, regardless of the generation type. Thus, even though the marginal cost of operating a solar facility is almost zero, the energy sold (if not already contracted) is sold at the market clearing price.

This approach would reduce the current problem of recovering fixed costs through volumetric rates. One of the reasons that customers currently receive such high rates for generated electricity is the high share of fixed costs that are included in the volumetric rates that they pay. Splitting a customer's bill into a demand charge and volumetric rates would attempt to minimize this. Demand charges are not new. They have commonly been implemented with commercial and industrial customers, although some utilities have begun to roll out demand charges for their residential customers. The proposed demand charge would be used to recover the distribution costs that a customer incurs to the grid. Since utilities are forced to size distribution to meet customer peak demand, this charge would represent these costs and not the cost of purchasing energy (T. Brown & Faruqui, 2014). Utilities size their distribution system to meet maximum instantaneous demand (i.e., kW) rather than to meet volumetric demand. Demand charges are a step in moving distribution tariffs towards cost causation: charging customers based on their maximum kW demanded sends a more targeted signal of "demand less, pay less/demand more, pay more", thus helping utilities to recover their costs of distribution more efficiently. While this type of rate design more accurately aligns costs with prices, it requires metering technologies that many customers do not have installed.

When oil and gas distributors were challenged by competition from electric utilities attempting to gain market share in the heating of American homes, the issue was less about utilities offering to heat people's homes, but rather that they were providing financial incentives and subsidies for the one-time costs of customers switching to electric heating. Furthermore, the electric utilities were allowed to write these costs off in their cost of service studies, and recoup them through electric rates. Oil and gas distributors were upset by these programs and fought them fiercely.

However, the tides have changed. Utilities are now faced with the threat of distributed solar resources. While there are some similarities between these two cases, the current expansion of solar is substantially different than the events of the 1960s. Across the country, rooftop solar is gaining popularity and installed capacity is growing at unprecedented rates (Association, 2015). As distributed solar continues to boom, utilities are becoming increasingly concerned with the impacts that it has on their financial sustainability. Specifically, utilities are concerned that they are being forced to transmit customer generated solar for free and that they will have to make up lost revenue through non-solar customers. In California, utilities such as PG&E are focused specifically on Net Metering 2.0 and how increasing installed solar capacity along with the emergence of storage technologies could disrupt the electricity market. With DG solar installations nearing the 5% cap and projections of increasing rates of installations, it seems probably that DG solar will play an increasing role in California's generation mix in the years to come ("Devolving power," 2014). It is clear that rooftop solar is seen as a threat by utilities, and at first glance it may seem reminiscent of the 1960s, when electric companies attempted to transition customers away from gas heating. However, in this case, utilities may very well be justified in their opposition. It is also possibly due to a concern with becoming obsolete.

Most of the opposition to NEM programs in California comes from IOUs and their respective advocacy groups. The proceedings of Net Metering 2.0 have drawn extensive comments and pressure from the utility interest groups. The most prevalent arguments that these groups cite (the ones that seem to have the most traction) are that current net metering rates shift costs between customer classes, and that customers with DG solar are not being held responsible for paying their fair share to the grid (Trabish, 2016), which may in fact be true. Furthermore, utilities have now turned to minority and low-income areas for support—claiming that the rise of solar will drive up their rates in the absence of a government subsidy. In the recent hearings, the primary opposition from electric utilities has come in the form of arguments against cross subsidies that are occurring and the need for rates that more accurately charge customers for the costs they incur, calling this "cost causation" (Warrick, 2015).

As outlined in the previous section, utilities continue to make claims that solar customers—who dramatically reduce their bills through NEM programs—should still be responsible for a substantial amount of costs that are associated with providing them service. Because the utility is still required to meet its revenue requirement, the sales losses to solar customers must be made up through increasing rates to all customers, which disproportionally affects non-solar customers. The lost revenue from solar customers that must be made up by the remainder of the customer base is considered cost shifting from one group to another. In this way, customers who decide not to install solar must pay for the fixed costs of the grid while solar customers will contribute much less, even though they continue to use it. PG&E has claimed that the successor tariff to the current NEM program would result in $2.5-$5 billion in cost shifting by 2020 (Electric, 2015). The premise of this argument is relatively simple and has been documented in countless publications (see, for example: Lee, 2016; The Electricity Journal, 2013; Trabish, 2015b). Despite these arguments, utilities continue to promote their support for customers who wish to adopt rooftop solar (Electric, 2015).

PG&E's proposal reflects its interest in reducing the amount of cost shifting between classes and increasing the alignment of costs with residential rates. First, their proposal recommends changing the compensation rate for energy sold to the grid from the retail rate to the generation rate, estimated at approximately $0.097/kWh (CAPUC, 2016). The proposed demand charges in association with PG&Es rate structure would be designed to recover the costs that vary with the customer's load. As we will see below, the underlying issues involve more than simply an analysis of utility costs and customer rates.

Theoretical Framework

As solar technologies become increasingly less expensive, it is ever more clear that we must utilize these resources in the most efficient way possible. Solar—both central and rooftop systems—present certain technical challenges of intermittency and reliability, so we cannot simply assume that all of our energy can come from these sources without first ensuring that we have a system in place that is capable of storing, transmitting, and distributing this type of generation. While pricing and providing incentives for central, utility scale solar plants will be a critical policy issue in the foreseeable future, it is beyond the scope of this paper. Instead, I focus on the rapidly increasing demand for rooftop solar systems.

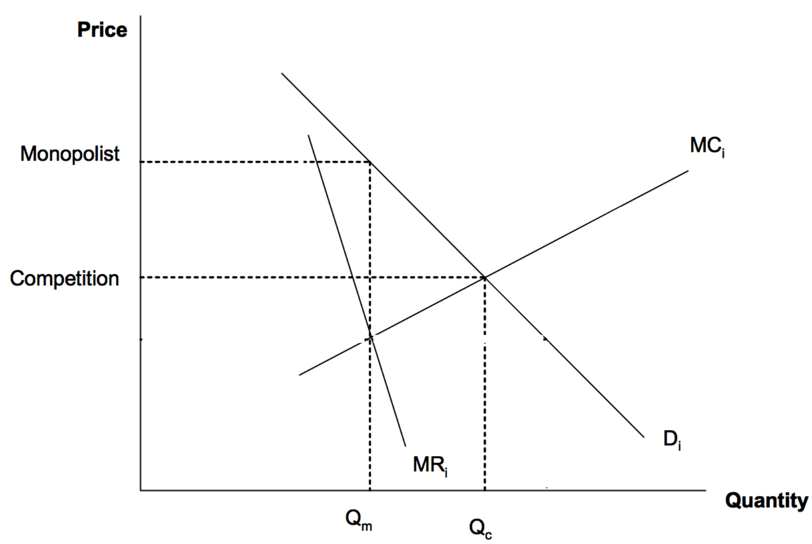
The policy that is currently being examined in California—Net Metering—plays a central role in determining how solar expands in the coming years. This policy credits solar customers for the excess energy that they produce with on-site solar systems. The rate at which customers are currently credited is the retail electricity rate. IOUs, however, argue that this rate is too high. At first glance, it may seem like this is simply a discussion about a reasonable price for solar energy. A closer examination reveals that it actually results from an attempt to expand the net metering program within a system that was not designed to effectively handle this type of policy.

In implementing a transition to renewable energy, the incentives that are provided to renewable energy production directly affect the amount of generation capacity that is installed. If the price at which solar generators are able to sell their energy is set too high, we will see an overinvestment (above the socially efficient level) in distributed renewables. Alternatively, if the price that generators are offered is too low, we will see investment that is below what would be optimal. Many economists and policy makers agree that the use of accurate price signals is the most efficient way to allocate resources, including with distributed solar generation (Lazar, 2011). This, in essence, is what the current debate over Net Metering is about—sending appropriate price signals to customers who wish to install rooftop solar.

Electric utilities are unique in that they are considered to be natural monopolies. That is, the firms are characterized by decreasing average total costs, and engaging in competition would increase the cost to provide their service. As a monopoly, electric utilities warrant some form of regulation (Nicholson & Snyder, 2010). Without regulation, monopolistic firms have the ability to influence the market price by determining the quantity that they produce. In the case of electric utilities, however, their monopoly power is heavily regulated by the PUC. The need for price regulation comes from the fear that, if left unattended, a monopoly power would charge its customers prohibitively high rates.

It is generally understood among economists and politicians that a reasonable goal is to attempt to maximize social welfare. This has been a strong rationale for increasing competition in many markets, but is also at the center of utility regulation. The general illustration of a monopolistic firm is presented in Figure 4. In this case, the firm experiences increasing marginal costs (MC) and also influences the market price, and therefor faces a downward sloping demand curve. Without the presence of externalities, the socially efficient outcome is where a perfectly competitive market would settle—at Q_c. This outcome is efficient because all customers who are willing to buy at this price are able to, and all firms willing to sell have been included. The price associated with this point is $P_{competition}$ and is considered the market-clearing price. Any deviation away from this quantity will result in some deadweight loss (DWL), as

Figure 4: Supply and Demand of a Monopolistic Firm (Cicchetti et al., 2004)

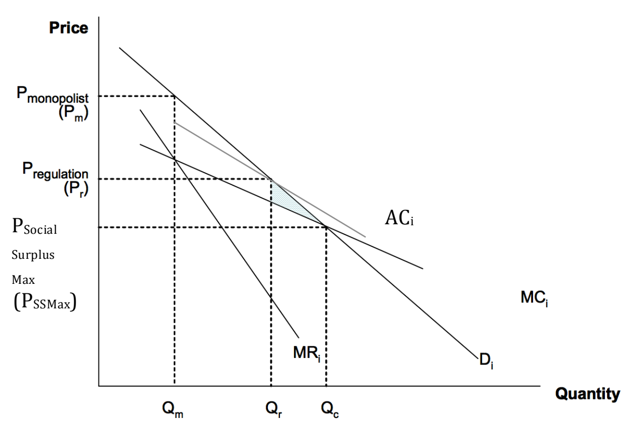


transactions have either been restricted, or too many have occurred such that the MC was greater than the marginal benefit.

If left unregulated, the firm will chose a quantity Q_m such that their marginal revenue from providing the last unit of output (MR_i) is equal to the marginal cost associated with providing that same unit of output (MC_i). By doing so, the firm is able to maximize its profits, and will charge its customers a price of $P_{monopoly}$, which is equivalent to the price that customers are willing to pay for that quantity of service (Nicholson & Snyder, 2010). Because one of the original goals of electricity price regulation was to ensure that no customer was charged more than the marginal cost of providing them service, the price with regulation ($P_{regulation}$) would be set at P_{SSMax} and the quantity produced would be Q_{SSMax}. At both $P_{monopoly}$ and $P_{regulation}$ there is a net welfare loss associated with too little or too much (respectively) electricity provided.

Figure 5 illustrates a similar monopoly situation, but with some differences that make it more characteristic of electric utilities. In this case, instead of facing an upward sloping marginal cost curve, the firm experiences decreasing marginal costs. This is generally considered more characteristic of natural monopolies. Because the natural monopoly is characterized by large fixed costs and decreasing marginal and average costs, marginal cost pricing will often result in losses to the electric utility. The same principles can be used to

Figure 5: Decreasing Cost Monopolistic Firm (Cicchetti et al., 2004)



determine $P_{monopoly}$ and P_{SSMax} and are shown on the graph. However, because marginal costs are decreasing, setting the price equal to the marginal cost will result in inadequate revenue for the firm to recover its costs. In attempting to price electric service so that it represents the marginal costs associated with providing service, the regulator must accept that this will result in the utility operating at a loss. The regulator must either accept this, or adjust the price to a point above the marginal cost so that the firm can break even. If the regulatory body does not wish to subsidize the utility indefinitely, it must raise the price so that it is equal to the average costs of the utility. In this way, the regulator can ensure that utilities are not taking advantage of their market power, while simultaneously allowing them to meet their breakeven level of profits.

Before examining the current debate over Net Metering, it is helpful to illustrate how energy might be sold back to the grid under a more efficient system. In this model, we would have energy generated by rooftop solar sold back to the grid at a price that is exactly equal to its societal value at the time it is sold back. This would result in an efficient investment in distributed generation, so long as the costs of other sources of energy also reflected their full costs and benefits to society. And therein lies the problem: there are a number of un-priced externalities that exist in the production of electricity that are not accurately reflected in the prices that power consumers pay.

Understanding the benefits and value of energy generated from rooftop solar systems is critical to determining the efficient price at which households should be compensated. For many years, one of the main rationales for promoting solar generation has been the slough of environmental and public health benefits associated with producing green energy. These systems are much larger, and sell energy in the wholesale market. Thus, it is unclear the level at which we should invest in rooftop solar versus utility scale solar or other clean energy systems. One argument is that rooftop solar generation will displace some quantity of grid generation, reducing GHG emissions as well as local pollutants. Not only are the environmental and public health benefits of distributed solar the most popular reason for providing additional incentives, but they are also the easiest to estimate. Advocates of rooftop solar also argue that investing in rooftop solar creates jobs, provides energy security, and stabilizes energy prices. The range and magnitude of these benefits is still widely debated and they are therefore excluded from most analyses (Borenstein, 2011).

The most common method used to determine the cost of a particular energy source is called the levelized cost of energy (LCOE). In theory, the LCOE represents the constant price for generated power that would ensure that the net present value of energy generated is equal to the net present value of the cost of producing that energy. There are many factors that contribute to these estimates, many of which (costs of current technologies, efficiency of technologies, etc.) are fairly easy to determine. However, there are often wide discrepancies in the estimates due to assumptions about macroeconomic trends as well as future technology costs and capacity factors. LCOE estimates can be helpful in drawing comparisons between generators, and they are often central to policy discussions. However, there are differences even within generators of the same fuel source that make such comparisons problematic. Borenstein (2011) explains that because different technologies are designed for different types of energy production, they are not feasibly substitutable. For example, combined-cycle gas turbine plants are extremely efficient to operate, but are generally very expensive to build.

Alternatively, single-cycle combustion gas turbines are significantly less efficient, but are also much cheaper to build. Consequently, combined-cycle plants run most of the time and provide the "base" power load, while single-cycle plants are only fired up during periods of peak demand, and are only operated a few hours every year.

Additionally, these estimates do not reflect the time variation in energy prices. In the California wholesale market, energy prices can fluctuate a factor of 10 throughout a day. Without the use of time varying rates and meters that can measure time-of-use, it is not possible to reflect this fluctuating value of energy to the end-use customer. The size of the deadweight loss associated with this is directly determined by which price is chosen and how volatile the price is over the course of a day.

The Scoping Plan following AB32 outlined numerous tactics for reaching California's climate goals, the most far-reaching being the California cap and trade (CAT) program. Unlike many emission policies, often criticized for being inflexible and inefficient, CAT programs increase flexibility by allowing emission reduction goals to be met in a cost-efficient manner. In the California program, emission permits are both distributed to firms as well as sold through state auctions. During the original allocation, the State sets a cap on the total emissions by only allowing a certain number of permits, which firms may then trade in secondary markets. At the end of the year, every firm covered by the program must turn in the number of permits that covers their emissions for that period. Firms with an inadequate number of permits face severe fines.

As I previously suggested, the presence of environmental externalities associated with certain types of production of electricity is often the main rationale for many efforts to provide subsidies to renewable generation. In California, the CAT program will cover

85% of all emissions by 2015—when distributors of transportation fuels and natural gas are set to fall under the cap (Hsia-Kiung, Reyna, & O'Connor, 2013). Following this expansion, the total cap is set to be cut 12 MMTCO2 (Million Metric Tons CO2) each subsequent year, which, according to Adams et al. (2008), will provide approximately 22.5% of reductions needed to meet the 2020 goal. Although currently many utilities receive most of their permits for free, many firms have to purchase permits through state auctions. This process allows the government to collect revenue and invest in further emission reductions, which, according to Hsia-Kiung et al. (2013), is crucial in meeting reduction goals.

While the cap and trade program has priced some negative effects of emissions, the price for permits has remained near $12/ton for the past few years. The EPA estimates of the social cost of carbon (SCC) range from $11 to $56, depending on the discount rate used. These estimates include damages associated with climate change, as well as health impacts associated with a changing climate. However, this does not include acute health impacts, and excludes many impacts of climate change, due to a lack of precise data (EPA, 2015). These estimates for the price of carbon in terms of damages associated with climate change (excluding acute health impacts associated with the combustion of fossil fuels) represent the conservative end of the literature. Estimates of the SCC depend heavily on a number of assumptions used in climate models, including the uncertainty of temperature change associated with GHG levels as well as estimated costs of climate damage. The literature on SCC estimates include estimates ranging from $12/ton CO2 (Nordhaus, 2011) to $85/ton CO2 (Stern & Taylor, 2007). It has also been noted that the literature on estimating the SCC is still somewhat optimistic, and that the true cost of carbon may be much greater (Tol, 2008; Weitzman, 2007). Furthermore, these estimates do not include acute health impacts of particulate mater or other local pollutants, which may cause damages up to approximately $0.03/kWh, depending on the type of fuel used to generate electricity (Soderholm & Sundqvist, 2003). The price of permits traded in the California carbon market is significantly below most estimates for the social price of carbon, and would suggest that the entire externality has not been internalized.

In a perfectly efficient market, electric generators would be required to pay for the pollution that they produce, and these costs would simply be another input into their business model. While there are some mechanisms currently in place to price such externalities, they do not cover a wide enough range of pollutants or sources to effectively internalize pollution externalities. The most direct solution is to simply price the external costs of pollution through a tax or permit program. Following one of these approaches would create appropriate price signals for renewable generation. Or, at least, it would correct for the negative pollution externalities—not accounting for non-pollution benefits of solar generation.

In its simplest form, a price on pollution would increase the cost of producing dirty energy, and make alternative sources of energy more appealing. The implementation of a tax can be visualized in both the wholesale and retail markets. In the wholesale market, the price that generators are willing to accept bids would simply increase, raising the market clearing price and reducing the market quantity. In the retail market, the implementation of this tax would shift the marginal cost curve up, also resulting in higher prices and lower market quantities. The higher prices of dirtier energy would provide price signals for customers wishing to sell self-generated energy back to the grid.

However, there are a number of complexities in the energy markets that would prevent this type of simple tax from working. In addition to numerous political constraints that have made such a policy unlikely, the current structure of the electricity market would prevent it from being fully effective. In order for it to be successful, customers wishing to sell energy back to the grid would have to be compensated exactly the value of the power that they displaced, ideally at the exact time they displaced it. This would require a billing mechanism that charges and credits customers for the wholesale prices of electricity.

A price on pollution would increase the private costs that utilities face so that they would match the social costs of these forms of pollution. If electricity generators had to pay a tax on input fuels that reflected the costs to society of burning that particular fuel, they would treat this as just another cost of doing business. This would result in a higher wholesale price of electricity, depending on the carbon intensity of the generated electricity. This price signal would be passed on to end-use customers in some form. This would provide them varying degrees of incentive to generate solar energy, depending on the type of energy that they would be displacing. If these conditions were met, a direct price on pollution would produce much greater efficiency.

Conclusion

Many utilities, including PG&E claim that they "[support] our customers who want to 'go solar'" (Electric, 2015, p. 2). At the same time, however, many solar advocates claim that the rates proposed by utilities would stifle, if not destroy the attempts to expand rooftop solar, and that "the utilities are fighting tooth and nail" (Warrick, 2015) to get commissions to side with them. It is unclear through the proceedings to what extent electric utilities are in support of the expansion of rooftop solar and net energy metering. As some analysts have suggested the question may ultimately be about the structure of utility rates as a whole, and not just net metering. As one phrased it, "If my neighbor invests- or leases – solar panels and ends up using less, my rates go up to make up the difference. Should I get angry at my neighbor for installing solar PVs […] or should I conclude that the tariffs charged by my local utility need a fundamental overhaul?" (The Electricity Journal, 2013, p. 2).

Electric utilities have cited the duties of the commission in their opposition to NEM throughout this case. One of the main requirements for the PUC in this case is that it develop a successor tariff that "ensures that customer-sited renewable distributed generation continues to grow sustainably" (CAPUC, 2014b). Not surprisingly, this has become a contentious issue within the proceedings. Solar advocates, including CALSEIA and TASC have suggested that sustainable growth be defined as "growth [that is] robust enough to overcome actions that can reduce or inhibit growth, such as the looming end of the ITC for residential customers […] and continue on a constantly growing course" (CAPUC, 2016). This definition should come as no surprise from the solar advocates, as it would prevent the establishment of barriers to expanding DG solar. Electric utilities, including PG&E however, put forth a definition of sustainably as “without subsidy from other ratepayers” (CAPUC, 2016). This should also not be surprising.

It is clear that there is no objective definition of what was meant by “sustainable” growth of the solar industry. Both sides have put forth rationales that would support their vested interests. If followed, the utility’s definition would promote an end or curtailment of NEM policies, while the solar advocates’ would result in more robust market conditions for distributed solar. In the proceeding, the commission developed a definition that it deemed to be a reasonable compromise. It defined sustainably as “preserving and fostering sufficient market conditions to facilitate robust adoption of customer-sited renewable generation while minimizing potential cost impacts to non-participants over time” (CAPUC, 2016). While this was interpreted by the commission as being in the middle of the two proposed definitions, it was still widely contentious among solar advocates. Analysis of proposed rates using the Public Tool relies heavily on a number of assumptions. Solar advocates claim that the projections of the costs to install residential solar are much lower than in reality. This would overestimate the ability of solar to overcome market barriers, skewing the results against DG solar (CAPUC, 2016).

Furthermore, another widely debated aspect of this proceeding has been in the interpretation of prior legislation requiring the commission to ensure that “the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs” (CAPUC, 2014a). There has been much debate on how to calculate these costs and benefits, and how to interpret the results. The commission does acknowledge that at this time, it is simply easier and more straightforward to calculate the costs associated with DG solar than it is to attempt to calculate the benefits.

While many solar advocates proposed the addition of a number of benefits associated with DG solar, the commission decided that their recommendations were premature and that it was not possible at this time to include these benefits. Among the suggested benefits were the "Societal Cost of Carbon, Reliability and Land Use Benefits, Local Economic Benefits, Societal Cost of PM 10, Societal Cost of NOx, and Water Use" (CAPUC, 2016). The estimated costs and benefits range widely from benefits of $2.1 million per year to costs of $5 billion per year (Beach & McGuire, 2013; Litteneker & Walter, 2014).

What has been made clear by the arguments presented in this proceeding is that developing a successor to the current NEM program will involve a number of decisions that involve high degrees of uncertainty. The difficulty is that each side has presented a different set of goals that should be targeted. Solar advocates clearly favor proposals that would encourage the growth of rooftop solar (as demonstrated by their definition of "sustainable growth" and objection to solar cost estimates), while electric utilities—continuing to claim they support DG solar—advocate for policies that would diminish the benefits to customers adopting solar generation technologies. As Peskoe (2016) commented on the development of utility regulation, the outcome is largely determined by subjective decision-making, as many ratemaking proposals often rely on "imprecise" measures. It is unclear to what extent each constituency is attempting to reach an efficient outcome, or if they are simply trying to achieve their own goals. Without examining the entire electricity market, attempting to make small changes to the ways we buy and sell energy will be largely unsuccessful.

Over the past two decades under net metering policies, we have seen tremendous growth of rooftop solar installations. While this can be partially attributed to rapidly decreasing costs of solar PV technologies, it is also largely due to the financial incentives that have been put in place by local, state, and national agencies. While net metering has been touted as one of the most influential of these policies, we are now finding that it may not be as sustainable as previously thought. While originally intended to promote the growth of distributed solar, imposing net metering onto a rate structure that relies on volumetric rates to recover fixed costs has put electric utilities at a disadvantage. Continuing to provide solar customers retail rate compensation for their generated energy—in the absence of government subsidization—will put increasing financial stress on electric utilities.

In order to develop a net metering program that is acceptable to both electric utilities and solar advocates, and to achieve the socially efficient outcome, the underlying rate structure and un-priced environmental externalities must be addressed. In most states, rate structures for residential customers are only beginning to be re-examined. Additionally, California has one of the most comprehensive carbon trading programs in the country. While many states are attempting to create more efficient electric markets, there are none that have solved both problems of externalities and underlying rate structures. As outlined above, consumer bills must be changed so that fixed and variable costs are recovered through separate mechanisms. This structure was developed in a time when increasing electricity sales and steadily decreasing electricity prices (as they achieved economies of scale) allowed utilities to be less concerned by the exact ways that they recovered their costs. This model was viable when the relationship between buyers and sellers of electricity was unidirectional. Net metering policies developed in recent decades, and the subsequent growth in rooftop solar have shown that this pricing model is not compatible with an electric system in which customers are both consumers and producers, buyers and sellers, of energy.

In addition to changing the underlying rate structure, solar customers must also receive the correct price for the energy that they generate. Specifically, they should be compensated at the exact value of the energy that they have offset. Because the most commonly cited benefits (at least in the scope of this thesis) of rooftop solar is offsetting pollution from dirtier sources of energy, the price for solar customers should be equal to the societal cost of this pollution (i.e. the benefit of avoiding it). This requires that the price of energy be allowed to fluctuate throughout the day, reflecting the different sources that are being utilized. Finally, the pollution associated with the production of non-solar energy must be priced correctly and internalized by electricity generators.

While the current Net Metering 2.0 proceeding highlights a clash of solar advocates and electric utilities, it is in fact revealing an underlying structural flaw that has been present all along. In order to send the appropriate price signals to solar customers, both the structure by which utilities recover costs and the rate at which solar customers are compensated must be reconceived. Unless and until the price is right, net metering will likely continue to provoke aggressive opposition from electric utilities. Promoting endless rooftop solar expansion will not sufficiently reduce our greenhouse gas emissions to avoid the most severe impacts of climate change. Continuing to subsidize rooftop solar will help reach these goals, but we should simultaneously address underlying structural issues if we hope to have rooftop solar provide a significant share of our energy in the future.

Bibliography

Adams, L., Nichols, M., & Goldstene, J. (2008). *Climate Change Proposed Scoping Plan. California Air Resources Board for the State of California.*

Arriaga, B., Nasim, F., & Nguyen, L.-Q. (2015). *New Solar Homes Partnership Guidebook. California Energy Commission*. Retrieved from http://www.energy.ca.gov/renewables/06-NSHP-1/notices/2015-07-24_NOA_nshp_guidebook_9th_Edition.pdf

Association, S. E. I. (2015). *Solar Market Insight 2015 Q4. SEIA*. Retrieved from http://www.seia.org/research-resources/solar-market-insight-2013-q3

Beach, R. T., & McGuire, P. G. (2013). *Evaluating the Benefits and Costs of Net Energy Metering in California*. Retrieved from http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf

Borenstein, S. (2011). The Private and Public Economics of Renewable Electricity Generation. *NBER Working Paper Series*, 28. http://doi.org/10.1257/jep.26.1.67

Brady, J. (2016). Nevada Solar Power Business Struggles to Keep the Lights On. Retrieved from http://www.npr.org/2016/03/11/470097580/nevada-solar-power-business-struggles-to-keep-the-lights-on

Brown, E. Assembly Bill No. 327 (2013). Retrieved from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327

Brown, T., & Faruqui, A. (2014). *Structure of electricity distribution network tariffs: recovery of residual costs. Prepared for the Australian Energy Market Commission*. Retrieved from http://www.ksg.harvard.edu/hepg/Papers/2014/Brattle report on structure of DNSP tariffs and residual cost.pdf

California Solar Initiative Program Handbook. (2014). Retrieved from http://www.gosolarcalifornia.ca.gov/documents/CSI_HANDBOOK.PDF

CAPUC. (2014a, July). *Proposed Decision. California Public Utilities Commission.*

CAPUC. (2014b, July). *Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs. Docket 14-07-002.* http://doi.org/10.1017/CBO9781107415324.004

CAPUC. (2016, February). *Decision Adopting Successor to Net Energy Metering Tariff.*

Cardwell, D. (2016). California Votes to Retain System That Pays Solar Users Retail

Rate for Excess Power. *New York Times*. Retrieved from http://nyti.ms/1KdY2GC

Cicchetti, C. J., Dubin, J. A., & Long, C. M. (2004). *The California Electricity Crisis: What, Why, and What's Next*. Norwell, Massachusetts: Kluwer Academic Publishers.

Costello, K. (2015). Utility Involvement in Distributed Generation : Regulatory Considerations White Paper. *National Regulatory Research Institute*, (February). Retrieved from http://nrri-web.github.io/reports/electricity/Distributed-Generation/

Devolving power. (2014). *The Economist*. Retrieved from http://www.economist.com/node/21598668/print

Electric, P. G. and. (2015). *Pacific Gas and Electric Company Notice of Ex Parte Communication. California Public Utilities Commission.*

EPA. (2015). Fact Sheet Social Cost of Carbon, (224459), 1–4.

Gifford v. Central Maine Power Company (1966).

Heeter, J., Gelman, R., & Bird, L. (2014). Status of Net Metering : Assessing the Potential to Reach Program Caps. *NREL Technical Reports*, (September). Retrieved from http://www.nrel.gov/docs/fy14osti/61858.pdf

Hsia-Kiung, K., Reyna, E., & O'Connor, T. (2013). Carbon Market California. Retrieved from http://www.edf.org/sites/default/files/content/ca-cap-and-trade_1yr_22_web.pdf

Jeremy Carl, Dian Grueneich, David Fedor, C. G. (n.d.). *Renewable and Distributed Power in California: Simplifying the Regulatory Maze. Hoover Institution.* Retrieved from http://www.hoover.org/research/renewable-and-distributed-power-california-simplifying-regulatory-maze-making-path-future

Kind, P. (2013). *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business. Edison Electric Institute*. Retrieved from http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf

Lacey, S. (2014, November 4). The End of a Solar Era : The Legacy of the California Solar Initiative. *Greentech Media*, 1–7. Retrieved from http://www.greentechmedia.com/articles/read/the-legacy-of-the-california-solar-initiative

Lazar, J. (2011). *Electricity Regulation in the US: A Guide. Regulatory Assistance Project*. Retrieved from http://books.google.co.uk/books/about/Electricity_Regulation_in_the_US.html?id=pAEkygAACAAJ&pgis=1

Lee, M. (2016, August 3). Opening salvos in California's rooftop solar struggle. *San Diego Tribune*. Retrieved from http://www.sandiegouniontribune.com/news/2015/aug/03/how-much-for-rooftop-solar/

Litteneker, R., & Walter, S. (2014). *Pacific Gas and Electric Company's Application for Rehearing of Decision 16-01-044. California Public Utilities Commission.* http://doi.org/10.1017/CBO9781107415324.004

Mazmanian, D., Jurewitz, J., & Nelson, H. (2008). California's Climate Change Policy: The Case of a Subnational State Actor Tackling a Global Challenge. *The Journal of Environment & Development*, *17*(4), 401–423. http://doi.org/10.1177/1070496508325438

Moore, J. T. (1967). Competitive Activities of Regulated Utilities. *1967 Ann. Rep. Sec. Pub. Util. L. 15*. http://doi.org/10.1525/sp.2007.54.1.23.

New Solar Homes Partnership. (2016). Retrieved from http://www.gosolarcalifornia.org/about/nshp.php

Nicholson, W., & Snyder, C. (2010). *Intermediate Microeconomics and Its Application* (11th ed.). Mason, Ohio: Cengage Learning.

Nordhaus, W. (2011). *Estimates of the Social Cost of Carbon: Background and Results from the RICE-2011 Model. National Bureau of Economic Research Working Paper Series*.

Owens, D. (2012). Facing The Challenges of A Distribution System In Transition. Retrieved from https://www.documentcloud.org/documents/1374670-2012-eei-board-and-chief-executives-meeting.html#document/p48/a191712

P.S.S., D. Delaware Power & Light Co., 56 P.U.R.3d I (1964).

Peskoe, A. (2016). Unjust, Unreasonable, and Unduly Discriminatory: Electric Utility Rates and the Campaign against Rooftop Solar. *The Texas Journal of Oil, Gas, and Energy Law*, *Forthcomin*, 1–81. Retrieved from http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2735789

Pyper, J. (2015). Nevada Regulators Eliminate Retail Rate Net Metering for New and Existing Solar Customers. *Greentech Media*. Retrieved from http://www.greentechmedia.com/articles/read/Nevada-Regulators-Eliminate-Retail-Rate-Net-Metering-for-New-and-Existing-S

Pyper, J. (2016). Does Nevada ' s Controversial Net Metering Decision Set a Precedent for the Nation? *Greentech Media*. Retrieved from http://www.greentechmedia.com/articles/read/nevada-net-metering-decision

Rogers, N., & Stueve, M. J. (2012). *The Renewable Jungle: A Guide to California's Renewable Policies and Programs. Division of Ratepayer Advocates*. Retrieved from http://www.dra.ca.gov/uploadedFiles/Content/Energy/Renewable_JungleRevisedJan31FINAL.pdf

Soderholm, T., & Sundqvist, T. (2003). Pricing environmental externalities in the power sector: Ethical limits and implications for social choice. *Ecological Economics*, *46*, 333–350. http://doi.org/10.1016/S0921-8009(03)00185-X

Stern, N., & Taylor, C. (2007). Climate Change: Risk, Ethics, and the Stern Review. *Science*, *317*(July), 203–204.

The Electricity Journal. (2013). Net Metering: Guilty as Charged. *The Electricity Journal*, *26*(September), 2–4. http://doi.org/10.1016/j.tej.2013.11.011

Tol, R. S. J. (2008). The Social Cost of Carbon: Trends, Outliers and Catastrophes. *Economics*, *2*(25), 0–23. http://doi.org/10.5018/economics-ejournal.ja.2008-25

Trabish, H. (2012, March 29). How Electricity Gets Bought and Sold in California. *Greentech Media*. Retrieved from http://www.greentechmedia.com/articles/read/How-Electricity-Gets-Bought-and-Sold-in-California

Trabish, H. (2015). Inside California's rate restructuring plan and the battle for fixed charges looming over it. *Utility Dive*. Retrieved from http://www.utilitydive.com/news/inside-californias-rate-restructuring-plan-and-the-battle-for-fixed-charge/402117/

Trabish, H. (2016, February 1). Inside the decision: California regulators preserve retail rate net metering until 2019. *Utility Dive*. Retrieved from http://www.utilitydive.com/news/inside-the-decision-california-regulators-preserve-retail-rate-net-meterin/413019/

Tsuchida, B., Sergici, S., Mudge, B., Gorman, W., Fox-Penner, P., & Schoene, J. (2015). *Comparative Generations Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area*. Retrieved from http://brattle.com/system/publications/pdfs/000/005/188/original/Comparative_Generation_Costs_of_Utility-Scale_and_Residential-Scale_PV_in_Xcel_Energy_Colorado%27s_Service_Area.pdf?1436797265

Walton, R. (2015). With state funding, 83 New York communities planning microgrids. *Utility Dive*. Retrieved from http://www.utilitydive.com/news/with-state-funding-83-new-york-communities-planning-microgrids/402691/

Warrick, J. (2015, March 7). Utilities wage campaign against rooftop solar. *The Washington Post*. Retrieved from http://www.washingtonpost.com/news/energy-environment/wp/2015/02/20/solar-energys-new-best-friend-is-the-christian-coalition/

Weitzman, M. L. (2007). *The Role of Uncertainty in the Economics of Catastrophic Climate Change*. *AEI-Brookings Joint Center for Regulatory Studies* (Vol. 07).