Pricing Policies for the Integration of Distributed Energy Resources in Utility Systems

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Disclaimer

Opinions expressed in this report represent a consensus of the authors and do not represent the positions or policies of DTE Energy or the University of Michigan.

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Executive Summary

Traditionally, electricity has been transferred from large generating stations to distant demand centers. Due to the decreasing cost of solar photovoltaic (PV) systems and renewable energy policies, decentralized distributed generation (DG) has been increasing across the US.

Our team of five graduate students completed a project with DTE Energy's Corporate Strategy Group as part of the requirement for the Master of Science degree in the School of Natural Resources and Environment at the University of Michigan. The project was undertaken to assess pricing policies for compensating DG owners and the effects of those policies on DG and non-DG customers for the state of Michigan.

Although solar insolation is less available in Michigan than in some markets such as California, Hawaii, or Arizona, the growth in solar installations is expected to continue to rise, making such a study prudent for Michigan decision makers. The financial impacts of growth in the solar DG market will need to be considered by Michigan utilities to ensure they can continue to meet the shifting needs of consumers, while also adapting their business model to meet the expectations of investors.

Historically, utilities have been natural monopolies and therefore are guaranteed by a regulatory body to recover the cost needed to operate and maintain the grid. This 'cost recovery' is traditionally accomplished by having customers pay a fixed amount for each unit of electricity they consume. This amount includes fixed charges and variable charges and is referred to as a 'bundled retail rate'.

Under current federal law, utilities are required to compensate solar DG owners for the electricity they produce. The amount that DG owners are compensated at varies by utility and state. DTE currently uses a policy called net metering, which compensates DG customers for the energy they produce at the retail rate. In other words, DTE pays customers for energy produced through solar panels at the same rate that customers buy energy from DTE. While the impact of net metering policies has historically been small, growth in DG adoption could lead to significant losses in revenue for utilities as DG customers avoid paying their share of fixed costs. These losses are made up for by increasing retail rates for all customers. This increase in retail rates affects non-DG customers as their electricity bill increases every year to account for the 'cost-shift'. This cost-shift is also called a 'cross-subsidy' because non-DG owners are subsidizing DG owners financially.

The three main objectives of this project were to:

1. Review distributed generation pricing policies throughout the United States
2. Develop a model to compare relevant pricing policies to DTE customers to understand the impacts on DG and non-DG customers, especially the 'cost-shift'
3. Recommend pricing policies for DTE's customer base based on the analysis

Our methods included literature reviews and quantitative analysis. The literature analysis focused on synthesizing passed or proposed distributed energy policy trends across the United States as of 2016. We developed a model to understand the effects of compensation policies and retail rate structures on net present value and payback period for DG customers and average retail rate and ‘cost-shift’ for non-DG customers. We analyzed the effects of compensation policies such as net metering, value-of-solar, and net billing and also analyzed retail rate structures including block volumetric rate structure and time-of-use rate structure. We then performed a sensitivity analysis over wholesale electricity prices and retail rate escalation to understand the impact on results. We also discuss stakeholder perspectives, energy justice for low-income customers, as well as the environmental and health benefits for all customers.

The findings of this research suggest that given the historic low adoption growth rate, DTE could maintain the current policy of net metering for the duration of the modeled period through 2031, unless the DG adoption drastically increases. It is our opinion that bill increases for non-DG customers are minimal ($2.67/month increase on monthly bill in 2031 compared to no cross-subsidy scenario) and the health and environmental benefits of solar DG generation exceed the cost-shift to non-DG customers under the business-as-usual scenario. Current net metering programs therefore help support the residential solar industry and create a net benefit for all customers when environmental and health costs are considered.

Furthermore, alternative policies, such as net billing or a low value-of-solar policy could severely limit DG adoption in the near future. Additionally, the impact to low-income customers can be mitigated by the introduction of a small monthly fixed charge to DG customers that increases annually to cover the cost-shift for low-income customers. As solar adoption nears 1% of DTE’s total generation, alternative policies should be considered to prevent significant cross-subsidization. At that time in the future, solar costs should be low enough to help sustain positive economics for DG customers under a new policy that minimizes cross-subsidization such as a fixed charge, net billing, or a low value-of-solar.

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Introduction

Distributed generation (DG) from residential solar rooftop photovoltaics (PV) is expanding across the United States, growing from 1.4 GW of new installed capacity in 2014 to 2.58 GW in 2016 **[1]**. This trend has been driven by government incentives (e.g. tax credits) and decreasing prices of rooftop solar systems. The deployment of solar DG is expected to continue to rise, even in states with poor solar resource, like Michigan. This paper will examine the impacts of this trend on customers of DTE Energy, an investor-owned gas and electric utility serving southeast Michigan and the Michigan 'Thumb' region, including greater Detroit.

Specifically, this paper will focus on net energy metering (NEM or 'net metering'), a policy that permits customers with rooftop PV systems (or other qualifying DG systems) to offset the energy they purchase from utility companies by selling the excess solar electricity they produce back to the utility at the retail rate of electricity. Since the early 2010's, NEM policies have come under fire from utilities and some observers for overvaluing distributed solar energy. These complaints typically center around two grievances: that utilities lose revenue needed to recoup fixed costs and provide shareholders with reasonable returns on equity, and that this lost revenue requires rate increases which disproportionately affects non-DG owning customers (in particular, low-to-middle income customers). The latter of these is typically referred to as a 'cost-shift' to non-DG owning customers, or as a 'cross-subsidy' from non-DG owning customers to DG owning customers. On the other hand, the existence of a subsidy to DG-owning customers often makes residential solar PV projects financially solvent, helping encourage investments in them. This, in turn, helps address climate change and air pollution by displacing coal and gas-fired electricity.

In this paper, we reviewed DG compensation policies across the United States to understand trends in how states are managing this cost-shift resulting from increasing distributed solar generation. Once we identified popular policies, we created a spreadsheet-based model to estimate the impacts of such policies in the DTE footprint. The measured impacts are the value of residential solar projects (NPV and payback periods of distributed solar projects) and impact on non-DG customers (increase in electricity bills). The results of this model help quantify the magnitude of financial impacts on the primary stakeholders impacted by distributed generation compensation policies. The model was created with input from the School of Natural Resources and the Environment (SNRE) at the University of Michigan and DTE, and was designed to flexibly allow a greater range of compensation policies than are presented below. While such a model cannot accurately model the nature of the utility business model or account for the full costs and benefits of distributed solar, it can help inform decision makers of certain large-scale impacts of policy changes.

The first section provides background and context for the project. It begins with a bird's-eye view of the electric power industry structure and electricity regulation. It then moves on to describe distributed generation, and net energy metering, and the issues arising from it. It then discusses popular policy instruments aimed at correcting these issues. The following section describes the specific structure of our model, the basic assumptions of our analysis, and the outputs we seek to examine. Section three shows the modeled results for all policy scenarios considered. The next two sections raise five key discussion points stemming from the results and use them to inform our recommendations and conclusions. Finally, the appendix includes policy briefs on the status of recent net metering reforms in each state in which they occurred as of July 2016.

Background

Electric Power Industry Primer

Electric Power Systems

An electric power system (or 'power system') is a network of electrical machines which supply, transport, and use electricity. The interconnected network of transmission lines, power plants, and end-users of electricity in the United States, often referred to as the electric grid (or 'the grid'), is a large-scale example of a power system **[2]**.

Power systems are often divided into three components: generation, transmission, and distribution (see Figure 1). Generation refers to power plants, or facilities that produce electricity from fuels such as coal, gas, petroleum, wind, etc. Once electricity is produced, it is sent through high voltage transmission lines across long distances (typically between cities or states). Transmission lines terminate at substations in areas where electricity is consumed. Once the transmission line ends, a network of smaller, low-voltage lines, known as a distribution system, delivers power from the substation to individual households, commercial enterprises, and industrial facilities **[3]**.

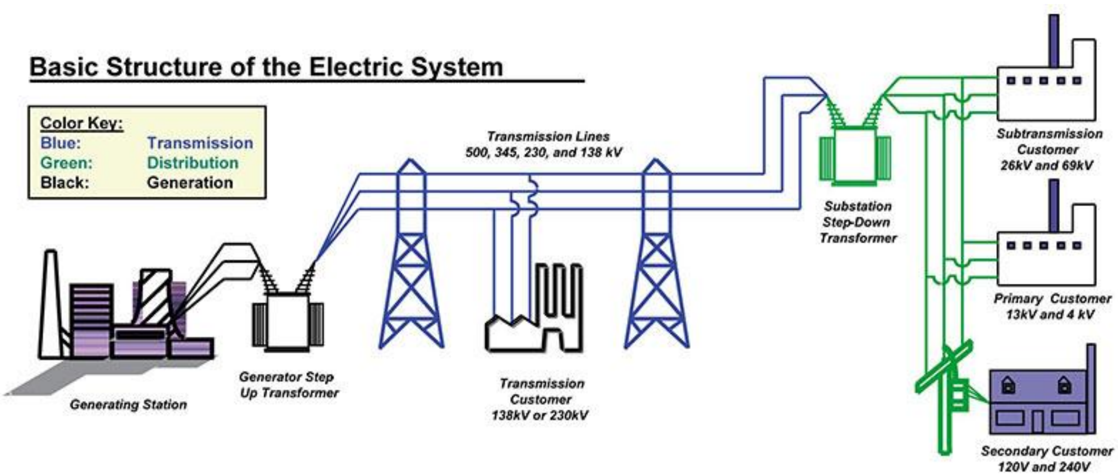

Figure 1 Structure of the electric grid ***[4]***

A key defining characteristic of the electric grid is the lack of storage. Electric supply and demand must be matched in real time, requiring responsive and controllable generators, good knowledge of customer usage patterns, instantaneous communication between different levels of the supply chain, and reliable fuel sources and consumption.

Traditional Structure of the Electric Power Industry

Electric power systems in the U.S. have been traditionally operated as vertically-integrated monopolies, in which one company owns generation, transmission, and distribution assets and is the sole provider of electricity in a geographical area. This company has traditionally been an investor-owned utility (IOU) or a municipality **[5]**. Customers typically have no choice of their electric provider; therefore, state public utility commissions (PUCs) set the retail price of electricity such that prices are not too high and the utility can collect a reasonable return on its investments. In exchange for this guarantee of returns, the utility ensures it has the resources to reliably meet demand in its footprint. This tacit arrangement between state governments and vertically-integrated utilities is known as 'the regulatory compact' **[6]**.

Industry Deregulation and Restructuring

Beginning with the passage of the Public Utility Regulatory Policy Act (PURPA) in 1978, the utility industry saw waves of deregulatory action aimed at introducing competition. PURPA, among other things, required utilities to purchase power from qualifying facilities (QFs) at an avoided cost rate. Qualifying facilities refers to small renewable power production facilities (less than 80 MW) and certain cogeneration facilities (those producing electricity and another form of useful energy) **[7]**. This allowed new companies that only owned generation assets to participate in the wholesale production of electricity. It also opened the door for end-use customers to own and operate small generators in their homes or at commercial locations to not only offset their consumption, but act as small-scale electricity merchants. Though the passage of PURPA was not intended to call into question the designation of the utility as a natural monopoly, the incentives it provided combined with innovations in small-scale power production technology demonstrated that competition in power markets could be economically efficient **[8]**.

Deregulation continued throughout the 1990s, with the Energy Policy Act of 1992 (EPACT 1992) and FERC orders 888 and 889. Among other things, EPACT required the Federal Energy Regulatory Commission (FERC), the federal agency regulating wholesale power transactions, to open up the transmission grid (still typically owned by the vertically-integrated utility) to non-utility wholesale generators **[9]**. To comply, FERC issued orders 888 and 889 in 1996, requiring public utilities to separate the parts of their businesses that own transmission and the parts that own generation, and allow fair access to the transmission system by all parties interested in selling wholesale power **[10]**. In response, some utilities opted to sell their transmission assets entirely, while others simply functionally separated their transmission business from their generation and distribution functions. Entities known as Regional Transmission Organizations (RTOs) began to emerge in the late 1990s to manage open-access to the transmission system and operate wholesale electricity markets. Deregulated retail electricity markets have also appeared in several states, allowing end-use customers to choose from whom they purchase their power **[11]**.

Structure of the Electric Power Industry in Michigan

The state of Michigan is primarily served by two investor-owned utilities: DTE Energy, operating in Detroit and much of southwest Michigan, and Consumers Energy, operating in most of the rest of the lower peninsula. In the early 2000s, both IOUs opted to sell their transmission assets to comply with Michigan Public Act 141, which required either the divestiture of transmission assets or the joining of an interstate RTO **[12].** Both newly independent transmission companies would go on to join the nascent Midwestern Independent System Operator (MISO), the RTO for the region. These transmission companies, ITC and METC, are now collectively owned by ITC Holdings. DTE and Consumers both retain functionally separate generation and distribution assets, and participate in MISO's wholesale energy markets.

Public Act 141 also opened up the Michigan market to retail choice. This allowed end-use customers to purchase electricity from a licensed Alternative Energy Supplier (AES) instead of their local utility. Several power marketers now exist in Michigan to cater to this market **[13]**. Act 141 was amended in 2008 to cap the total amount of retail electricity that could be sold under choice programs at 10% **[14]**. Michigan legislators perennially introduce legislation to alter the cap, remove it, or eliminate retail choice entirely. Most recently, a significant omnibus energy bill became contentious when proponents of retail choice felt the bill threatened the retail choice program **[15]**.

Retail Electricity Rates

Both of Michigan's IOU's retail electricity rates are regulated by the Michigan Public Service Commission (MPSC). In exchange for serving anyone in their footprint, the MPSC sets the utilities' rates such that they are able to recover all fixed and variable costs incurred in meeting demand and provide a reasonable return for investors. Any time a utility wishes to change its rates, it must initiate a legal proceeding through the MPSC known as a rate case **[16]**. Rate cases can take up to a year to be adjudicated **[17]**.

A typical electricity bill is split up into fixed and variable costs. The fixed fees are often referred to as transmission or distribution fees, but can include any number of fixed costs. Variable (or 'volumetric') fees are charged per kilowatt-hour (or 'kWh', the standard unit measure of electrical energy), and typically make-up most of a customer's bill. Though bills are split into variable and fixed fees, it is not necessarily the case that all fixed costs are recovered through fixed fees. Utilities will often bundle a portion of their fixed costs with their variable costs in a single variable fee to encourage end-users to practice energy efficiency. Figure 2 shows the cost breakdown of a typical American residential customer's monthly bill.

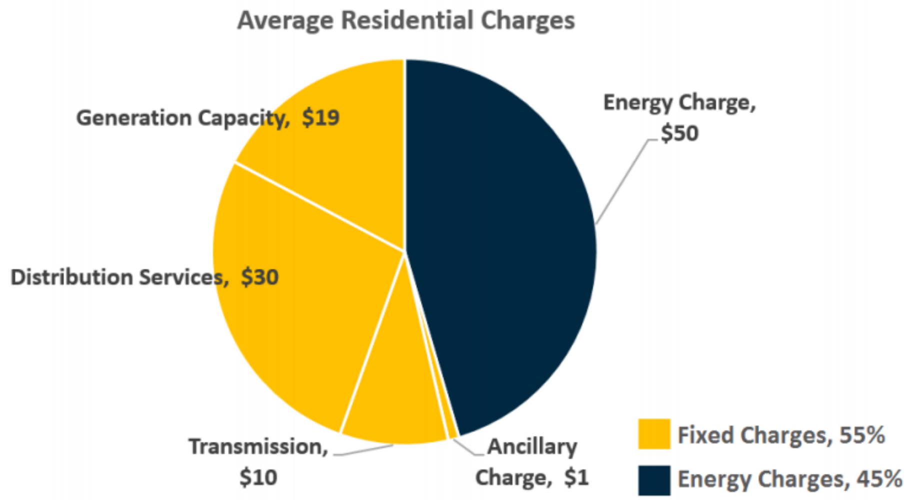

Figure 2 Average residential charges including fixed and variable charges [18] [19]

Distributed Solar Photovoltaics

Distributed Generation

Distributed generation (DG) typically refers to either generation located at or near the load it serves or generation which feeds directly into the distribution network (as opposed to the transmission network) **[20] [21]**. These definitions are often functionally equivalent. Distributed generators can include microturbines, small hydro, wind, and solar photovoltaic systems **[22]**. Distributed generators are installed by commercial, industrial, and residential facilities to offset electricity costs, ensure reliability through backup generators, or for environmental reasons. Distributed generators often serve as components of microgrids, small, localized electric grids that can detach from the larger grid and operate autonomously **[23]**.

Solar Photovoltaic Systems

Solar photovoltaic (PV) systems are among the most common distributed generation options for household use, with over 2000 MW installed domestically in 2016 **[24]**. PV power generation specifically refers to the process of converting sunlight into energy through semiconductors which exhibit a physical process known as the photovoltaic effect **[25]**. These semiconducting materials often come in the form of cells arranged on panels and mounted on rooftops or on the ground.

A typical solar PV system consists of the panels themselves, mounting systems that can range from fixed-mounts to smart tilting-mounts, an inverter that converts the DC-power the panel produces to AC-power that can feed into the larger electric grid, cables to connect the system to ones building, and optionally, an extra electrical meter, and battery to store excess energy **[26]**.

The solar PV industry consists of researchers, manufacturers, distributors, installers, project developers, lessors, and financiers, and employed over 260,000 people domestically in 2016, with almost 3,000 of those located in Michigan (4000 by other estimates) **[27] [28]**.

Residential Solar Photovoltaics Ownership

The PV market is typically divided into two classes: the utility-scale market PV market and the behind-the-meter (or distributed PV) market. Utility scale projects are large scale projects, typically over 1 MW in size, which aim to supply wholesale electricity and feed directly into the transmission network. Behind-the-meter projects are small distributed projects which are installed on homes or commercial entities. In 2015, the residential solar market accounted for over 2 GW of the almost 8 GW domestic solar market **[29]**.

Residential utility customers have several financing options when it comes to installing PV systems on their houses. In general, customers either lease or own solar panels. When a solar system is leased, a third party owns the system infrastructure and associated tax credits, while the customer receives a lower electricity bill. The lessor has the option of sharing tax credits and payments for excess generation with the lessee. This system allows an environmentally-conscious customer to offset their carbon emissions without having to worry about system details, component failure, or long-term system ownership **[30]**.

Solar ownership gives the customer full control of all the financial incentives of a PV system, such as bill and tax credits and increased property values. While ownership can be the most economical option, it exposes a customer to the risk of expensive equipment failure and long-term system degradation. Solar loans are available from numerous banks at a range of rates, down payments, and loan terms.

Benefits of Distributed Photovoltaics

Distributed PV systems can provide financial, environmental, and system maintenance benefits to a variety of stakeholders. The following list of benefits is not exhaustive **[31][32][33]**:

Fuel prices: PV systems draw energy from the sun, so the fuel cost is zero. Because PV will typically displace the highest costing power plants to operate, this can save the utility money they would have needed to use on the open market.

Generation Capacity: Utilities are required to maintain enough generation capacity to meet demand needs plus extra reserve capacity for extra high peaks. Because the sun shines the brightest when loads tend to be highest, PV can help decrease those peak loads, allowing utilities to defer investing in expensive reserve generators.

T&D Losses and Capacity: When electricity is delivered through transmission and distribution lines, energy is lost due to heat dissipation. Distributed generators located on site can minimize those losses by reducing the cable distance between the generator and the load. Likewise, local generators decrease the need for new interstate transmission lines to move energy over long distances.

Emissions: Solar energy produces no direct emissions and often displaces coal or natural gas generation, which emit SOx, NOx, and CO_2. These substances have significant direct and indirect effects on human health and climate.

Ancillary Services: Ancillary services refer to anything that is required to ensure the reliable operation of the electric grid. The power electronic inverters associated with individual solar systems could have the capacity to provide voltage regulation, reactive power injections, and other services **[34]**.

Other Financial Benefits: Distributed PV can provide a fuel price hedge, lower wholesale prices by decreasing demand, decrease the need for gas-electric coordination including pipeline reservation, and more.

Costs of Distributed Photovoltaics

Total Cost of System: Despite falling prices, distributed PV systems are still quite expensive and out of reach for most households. In areas with low solar resource, it remains an open question as to how profitable PV ownership can be.

Emissions from Manufacturing: The production of solar panels can lead to emissions of SO_2 and CO_2, while transportation costs can significantly increase emissions levels. Additionally, roughly half of all solar panels are produced in China, whose power system is primarily coal-based **[35]**. Despite this, lifecycle CO_2 emissions per kWh are still around 10 times lower than natural gas and around 20 times lower than coal **[36]**.

Ancillary Services: In many cases, distributed PV can increase the need for ancillary services. One commonly-cited issue is related to ramping, or the ability of a power system to quickly increase generation to meet demand. High penetrations of PV can increase situations where fast ramping is needed if the sun goes down before peak demand periods end (see Figure 3) **[37]**. PV can also cause over-voltages and other service issues.

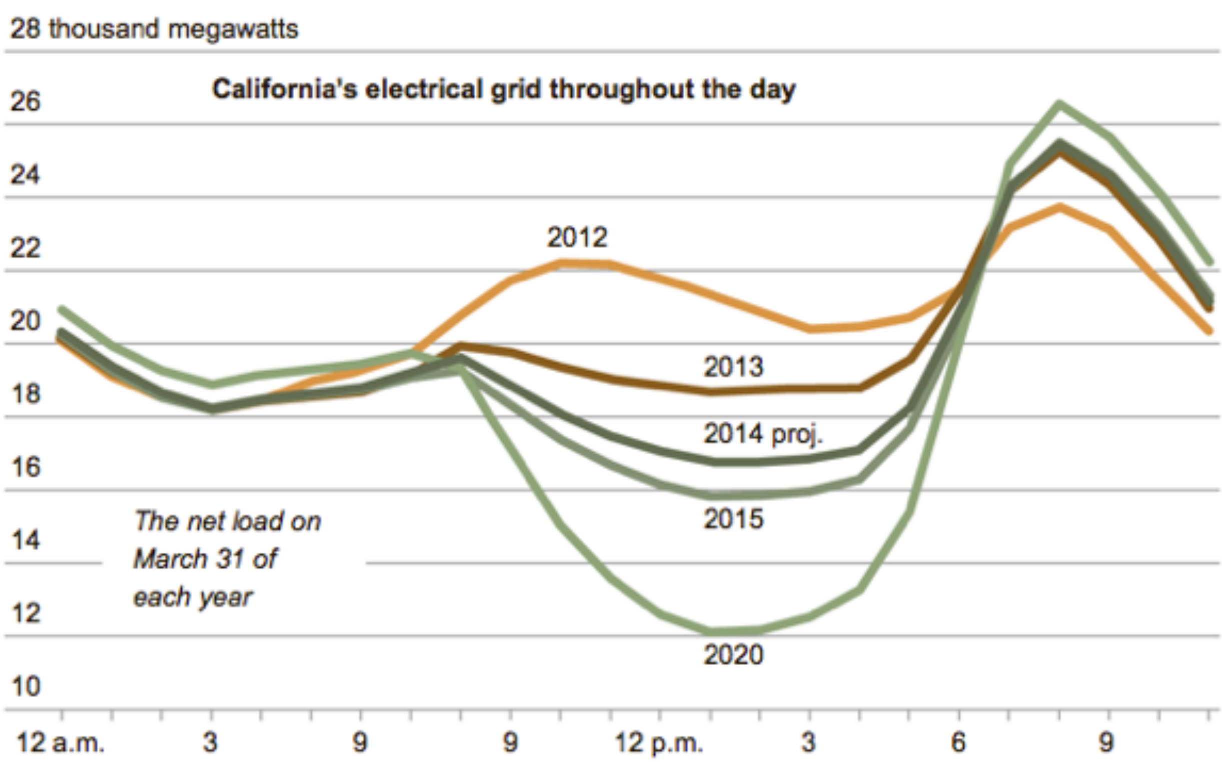

Figure 3 The 'Duck Curve' shows the net load after solar and wind serve some of the load. Overgeneration in the afternoon and quick ramping up in the evening are some concerns expressed by the utility [38]

Deferred Capacity and Fuel Prices: The deferred capacity and energy value of distributed PV depends on the energy sources it is displacing. It is possible that there are situations in which distributed PV could cause increased capacity needs (if more flexible generation is needed, for example) or wholesale market inefficiency (if solar forecasting is poor).

Trends in Distributed Solar

The domestic solar industry has experienced significant growth over the past decade, with yearly installed capacity increasing from 0.5 GW in 2009 to over 7 GW in 2015, 2 GW of which came from distributed solar on residential properties **[39]**. By the third quarter of 2016, solar accounted for 39% of all new electric capacity. This trend has largely been driven by falling costs of solar. The two trends can be seen together in Figure 4 **[40]**.

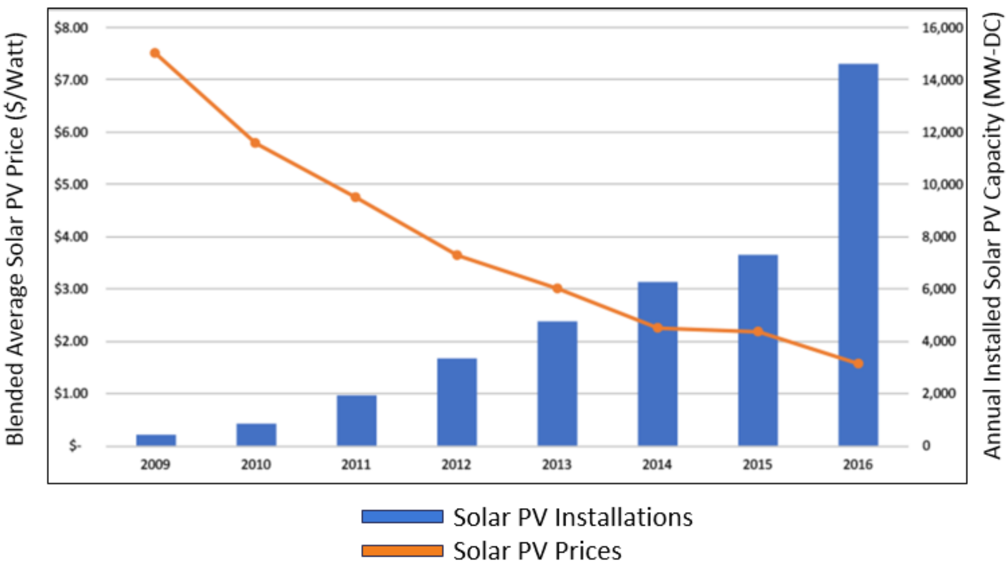

Figure 4 Solar prices are declining and installed solar photovoltaic capacity is increasing from 2009 to 2016 [41]

As of September 2016, the installed solar capacity in Michigan is 25 MW (52% residential, 44% commercial, 4% utility-scale), ranking it 34th nationally. Michigan is expected to install 387 MW of solar electric capacity, leveling up to 28th in the country over the next 5 years. This amount is more than 24 times the amount of solar installed over the last 5 years. There is currently 35.4 MW of solar capacity installed in Michigan, 15.9 MW of which was installed in 2016. Five thousand Michigan homes are powered by solar power in some form and solar accounts for 0.04% of the state's annual generation. SEIA has forecasted 537 MW of solar will be added over the next five years **[42]**.

The cost of solar has declined precipitously over the last few decades, with the rate of decline leveling off in the past few years. According to the Lawrence Berkeley National Lab's 'Tracking the Sun IX' report, price decreases since 2009 have been primarily driven by falling 'soft costs', i.e. marketing and sales, system design costs, permitting, installer fees, etc **[43]**.

Federal Solar Policies

While most solar policy is set at the state level, at least two major federal programs have played significant roles in solar pricing and adoption: the Investment Tax Credit (ITC), and the Department of Energy's SunShot Initiative.

The residential ITC is a financial incentive offered by the federal government for residential solar customers, providing a tax credit system and installation costs. The incentive amount is 30%. As of late 2016, the ITC has been extended until the end of 2019. In 2020, the rate will drop to 26%, and in 2021 to 22%. After 2021, the ITC will be obsolete for residential customers and 10% for commercial customers. Since its initial passage in 2006, the ITC has been a critical driver of lowering the cost of solar, which has dropped more than 60% over the last 10 years, and lead to large deployments of solar energy nationwide. The planned gradual phase-out of the ITC is expected to impact solar customers and players in the industry significantly.

Since its launch in 2011, the goal of the SunShot Initiative has been to drive down the cost of solar electricity to the point at which it is cost-competitive with traditional sources of electricity by 2020 without subsidies. In November 2016, the SunShot Initiative announced further cost targets to be achieved by 2030: \$0.05 per kilowatt hour for residential PV, \$0.04 per kilowatt hour for commercial PV, and \$0.03 per kilowatt hour for utility-scale PV. The SunShot Initiative primarily funds cooperative research, development, demonstration, and deployment projects by private companies, universities, state and local governments, nonprofit organizations, and national laboratories to achieve the goals. Since the cost of solar electricity is one of the major factors to affect the adoption rate, the SunShot Initiative's success is expected to have a major impact on solar market in the U.S (Figure 5) **[44]**.

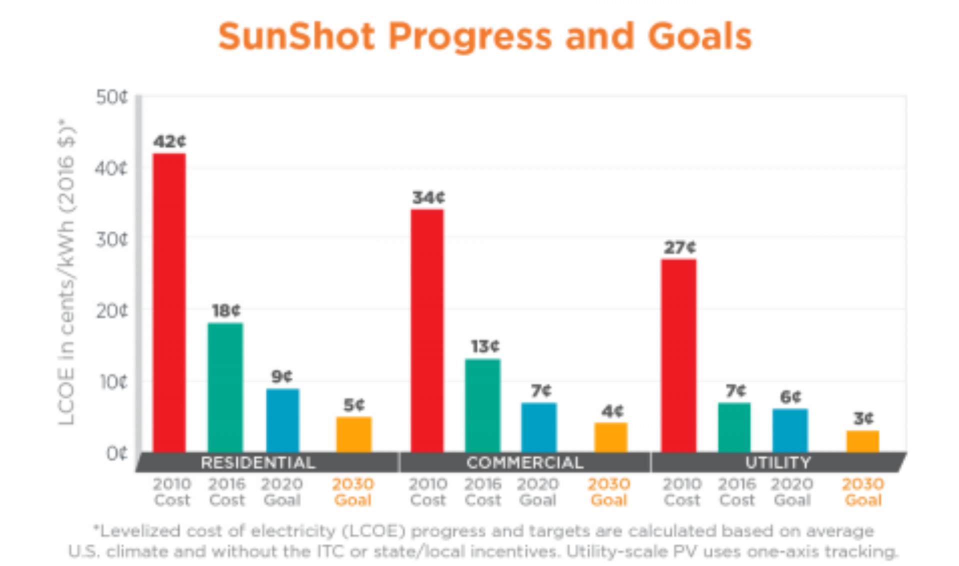

Figure 5 SunShot's progress towards decreasing the cost of solar by 2030 [44]

Net Energy Metering

Net Energy Metering Overview

As most residential PV installations count as QFs under PURPA, owners of such systems are entitled to compensation at an avoided-cost rate for the energy they produce. The most popular policy for compensating these customers has historically been net energy metering (NEM or 'net metering').

Under NEM, a QF simply connects to the meter that reads electricity usage at the household level. When a customer consumes electricity from the grid (when solar power is not enough to meet the household's energy needs), the meter rolls forward, counting the amount of energy consumed from the utility. When the customer is producing excess energy (more solar than they can use), the meter rolls backwards, essentially counting the amount of energy provided to the utility. The utility then charges the customer based on the meter reading at the end of the month multiplied by the retail rate of electricity. If the meter reads negative, the utility actually compensates the customer for the net energy they have provided back to them at the retail rate. As of 2017, mandatory NEM policies exist in 41 states and the District of Columbia **[45]**.

Some details of NEM policies can vary from state to state, though at their core they remain the same. For example, many states have caps on the total number of solar customers eligible for net metering. Some states allow customers to amass credits for the energy they produce and roll them over into the next month. Some require customers installing solar to pay for interconnection labor and studies associated with hooking up to the grid **[46]**.

An Argument Against Net Metering: Overvaluation and Cross-Subsidies

In the late seventies and eighties, deployments of QFs were small, and net-metering remained an uncontroversial and functionally simple policy. As the residential solar market expanded, allowing utility customers to install greater capacities of generation at lower costs, utilities began to show hostility to the policy **[47]**.

The common argument against NEM goes like this: a typical utility bill includes some amount of fixed service charges related to transmission and distribution costs, followed by a volumetric (per kWh) rate that depends on the monthly meter readings at the customer site. As described above, this volumetric rate does not only include variable costs, but also a certain amount of fixed costs and profit margins. The benefit of the 'bundled' volumetric rate precedent is that it encourages energy efficiency through behavioral changes. The drawback is that it obscures the sources of the charges on a utility bill **[48]**.

Because the bill is structured this way, when a utility pays a solar PV owner for a kWh of electricity at the retail rate, they are paying them the cost of the energy and a portion of their infrastructure costs. Those infrastructure costs have to be paid back no matter how much electricity they sell directly. Severin Borenstein of the Energy Institute at Berkeley compared NEM to a customer bringing a home-grown zucchini to a grocery store and asking to be paid the grocery store's zucchini rate or in new zucchini next month **[49]**. Surely, the grocery store would tell you that they do not purchase small amounts of wholesale goods at retail prices, and that they must factor in their building, employee, lighting, and heating costs into their prices **[50]**. The same concepts apply to electricity, except the scale of fixed costs can be much larger.

Many utilities and like-minded observers argue that net-metering over values energy produced by distributed PV systems in the way described above, and that in implementing such a policy, states are requiring the utility to provide a subsidy to PV owners. The argument is often extended to include a ‘cross-subsidy’ of funds that flow from customers that do not own DG to customers that do. That argument claims that utilities must raise their rates for everyone to make-up for lost revenue that went to solar subsidies, and that those rate increases primarily burden customers who do not own DG systems. Some of those customers tend to be the more economically disadvantaged, making the cross-subsidy regressive **[51]**.

It should be noted that some cross-subsidies are already baked into ordinary retail rates. Many retail rates are ‘block volumetric’, meaning there are different retail rates for different levels of electricity usage. For example, in the DTE footprint, customers pay one rate for electricity used up to 17 kWh in one day, after which they pay a higher rate. Such a rate scheme punishes those who consume more, and rewards those who consume less. Because electricity usage is roughly correlated with income level, this can amount to a subsidy from higher income households to lower income ones **[52][53]**.

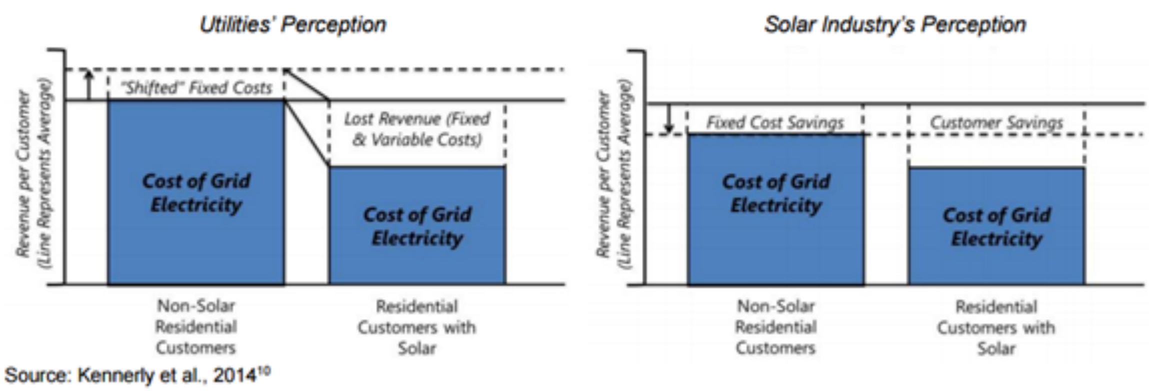

Figure 6 Differences in perceptions of net energy metering policies by utilities and solar industry [54]

California is an example of a state with both high levels of distributed PV and a large utility (PG&E) with a multi-tier block volumetric retail rate **[55]**. A study conducted by E3, an energy consultancy based in San Francisco, to evaluate ratepayer impacts of California’s NEM program, found that with NEM, DG-owning customers paid 81% of their full cost of service, compared to 154% without NEM and DG **[56]**. This study could be taken to illustrate both types of cross-subsidy mentioned above.

Additionally, a CPUC study conducted in 2013 projected a $1.1 billion annual cost shift due to NEM programs by 2020. Although this study was used by several free market groups to argue against NEM policies, it also found that NEM customers paid 103% of their full of cost of service **[57]**.

Both of the above studies illustrate the difficulty of distinguishing the fixed-cost cross-subsidy associated with NEM policies and fair-share pricing policies. As former FERC chairman Jon Wellinghoff and James Tong note, “there is a difference between cost shifting and not-paying one’s fair share” **[58]**.

Arguments for Net Energy Metering

An implication of the studies above provides one argument for NEM. That is, even if this particular cross-subsidy exists in practice, NEM is just one of many cross-subsidies that determine whether a particular customer pays the full share of their cost-of-service. Therefore, policies should not be developed to correct the NEM cross-subsidy specifically, but rather to ensure that a less arbitrary goal is met. For example, 'to ensure every customer pays for their full cost-of-service when all is said and done', or 'to ensure that low-income customers have an energy burden below a certain threshold while paying at least a particular percent of their cost-of-service'. In other words, the attacks on NEM based on cross-subsidization are disingenuous because they ignore true 'costs of service'.

A more common argument is that typical 'solar valuations' and 'cost of service' calculations ignore environmental and health benefits of solar power. By this argument, one could acknowledge that NEM subsidizes solar by shifting costs, but argue that these subsidies are warranted, not only because they help account for displaced CO_2 emissions, but because they will further incentivize customers to adopt solar. If a state or utility acknowledges climate change and other adverse health effects of fossil generation, they will surely want to encourage adoption of PV.

Finally, NEM proponents can argue that it is the most administratively simple policy to enact. It does not require extra metering infrastructure and is already well-understood by customers. While simplicity might not be the most compelling argument on its own, it becomes more persuasive the smaller the cross-subsidy is. Replacing a long-standing policy with a more complex one to fix a cross-subsidy that only affects non-DG customers by (say) less than a few dollars over ten years could be seen as excessive.

Pro-Net Metering

Home solar companies such as SolarCity, Vivint, and SunRun, as well as solar advocacy groups such as Solar Energy Industries Association (SEIA) and the Alliance for Solar Choice have been actively lobbying states to avoid changes to traditional retail rate net metering.

In California, supporters of solar lobbied the Public Utilities Commission (PUC) to preserve retail rate net metering for months in late 2015, delivering 130,000 petitions from state solar customers. Clean energy companies spent $1.5 million on lobbying efforts to raise Massachusetts' aggregate net metering cap in 2015 alone - up significantly from previous year.

Other states to preserve retail rate net metering include Colorado and South Carolina.

A Shift Away from Net Metering

Some entities are proposing to leave net metering behind entirely.

In Hawaii, a temporary net metering successor tariff allows customers to forfeit the ownership of their net-excess generation in exchange for expedited permitting and installation.

The Maine legislature proposed a market-based scheme in which customers sell their excess generation to utilities through long-term contracts, who in turn sold that electricity into the ISO-New England market. The bill passed both houses but was vetoed by the Governor.

Louisiana has proposed ending net metering for new solar customers.

New Hampshire may develop a net metering successor tariff within the next year.

Alternatives to Net Energy Metering

If it is decided that a Net Energy Metering policy is no longer suitable or sustainable for their state of company, an alternate policy to comply with PURPA must be designed. Because the technical details of net metering programs can vary greatly from state to state, utilities, state, and local policy makers have wide latitude in designing alternate policies. The following sections catalogue the suite of policy instruments open to decision makers tasked with designing a solar PV compensation policy.

Compensation Structure

Compensation structure refers to the different ways utilities can treat generation that is produced under different conditions. The following compensation structures are the most common.

Buy-All-Sell-All: Under a buy-all-sell-all program, the customer pays a set rate for all electricity consumed, whatever the source of the electricity. The utility pays the customer another rate for all electricity produced by the PV installation, whether that energy was consumed on site or exported to the grid. These two rates can be different or the same. This typically requires a two-meter set-up, one of which measures gross electricity produced by the solar panels while the other measures gross household consumption **[59]**.

Net-Excess Generation vs. Real-Time Consumed Generation: Alternatively, utilities can choose to only purchase electricity that is produced in excess of a customer's real-time consumption. In other words, any electricity that the customer sends back to the grid because they do not need it to power their home (net-excess generation) is given one price, while electricity that is produced and immediately consumed on site (‘real-time consumed generation’) is not purchased by the utility in any way, or can be priced separately. This structure is sometimes referred to as ‘net billing’ **[60]**.

Compensation Rate

Compensation rate refers to the designated dollar value of distributed solar PV. Any compensation rate may be paired with a particular compensation structure to form a solar policy.

Retail: In most states, the default compensation rate is the retail rate of electricity. This is the volumetric rate that is charged to end-use utility customers and which appears on utility bills. It typically contains all variable costs and some portion of fixed costs, as well as a separate volumetric distribution charge.

Wholesale: The wholesale rate of electricity is the going price of marginal generation on a wholesale market. This rate can reflect the value of an organized market such as those administered by PJM Interconnection or MISO Energy. As most organized markets clear each hour for the day-ahead price or every five minutes for the real-time price, compensation can be trued-up at any one of these intervals.

Value-of-Solar Tariffs: Value-of-solar tariffs (VOST) seek to more accurately price the value of distributed PV resources by meticulously identifying the costs and benefits of distributed generation, valuing them, and including them in a single volumetric rate. This can include factors such as avoided fuel cost, environmental impacts, deferred infrastructure investments, etc. VOSTs currently exist in Minnesota and Austin, Texas, and several other states are performing VOST studies **[61] [62] [63]**.

Avoided Cost: Avoided cost rates are the cost marginal cost of purchasing electricity from the next cheapest source, and can include the value of the energy and the capacity. The term is ambiguous, but is sometimes used due to its appearance in the text of PURPA (PURPA does lay out some minimum requirements for avoided-cost calculations). One example of an avoided cost rate could be the power supply cost recovery (PSCR) factor that many utilities use to compute the average cost of each kWh produced **[64]**.

Retail Rate Structures

While the ordinary retail rate structure may seem disconnected from solar policies, it can have significant effects on the economics of solar panel ownership. The most common utility rate structures are listed below.

Flat: In a flat rate structure, consumers are charged one price for each kWh of electricity purchased from the utility.

Block Volumetric: In a block volumetric structure, the consumer is charged at one rate for each kWh purchased until usage exceeds a set threshold, at which point the rate changes. DTE Energy currently uses a form of this rate structure in which customers are charged a higher rate for electricity consumed beyond 17 kWh within a single day.

Time-of-Use (TOU): TOU rates change depending on the time of day at which electricity is consumed. Portions of the day are typically separated into 'off-peak' and 'on-peak' hours, during which electricity is cheaper and more expensive, respectively. This rate structure encourages consumers to use less electricity during 'on-peak' hours, when wholesale electricity costs are higher due to increased demand.

Rate-Unbundling: Unbundled rates are rates which transparently separate all fixed and variable costs on a customer's bill. This would lead to drastically lower volumetric rates and higher fixed fees.

Dynamic Retail Rates: Dynamic retail rates are those which change over time with changing market conditions. Like wholesale markets, a dynamic retail market would reflect the changing marginal cost of producing electricity, as well as the relationship between supply and demand.

Other Policy Options

Fixed Charges: Fixed charges refer to fixed monthly fees attached to the utility bills of solar or non-solar customers for any reason.

Demand Charges: Demand charges are fees which are computed by multiplying the demand charge fee by the peak electric consumption in a customer's monthly bill. They have been proposed as ways to encourage efficiency and peak-shaving. They have occasionally been proposed as fees for solar customers only **[65]**.

Minimum Bills: A minimum bill is a way for utilities to guarantee that a solar customer is paying some share of fixed costs. A minimum bill policy has been implemented in Massachusetts **[66]**.

Caps: Two different cap policies can be implemented when it comes to distributed PV. The first is a statewide cap, which limits the amount of solar capacity that can participate in pure NEM programs and is typically expressed as a percentage of the previous year's peak demand. The other is an individual system cap which limits the size (in kW) of a PV installation that is eligible for participation in the NEM program. The latter policy is typically used to prevent merchant generation **[67]**.

Recent Policy Highlights

Fixed Charge Increases More than 25 utilities have proposed fixed charges for all or some customers with a median proposed charge of $13.44 per month. States include Utah, Arizona, Arkansas, and Colorado.

Time-of-Use Some states require Time-of-Use tariffs to be implemented in conjunction with net metering where rates are adjusted based on the time of day and prices are known by consumers in advance. States include: California, Nevada, and Hawaii.

Limits on System Capacity Some utilities are cracking down on individual system capacity limits to disincentivize 'merchant generators' from over-sizing their systems. States include: Kansas, Montana, Arizona, Arkansas, and Rhode Island. Additionally, as states reach their aggregate net metering caps, solar advocates and utilities have debated if and how to raise them. States include: California, Massachusetts, Hawaii, New Hampshire, Idaho, Louisiana, New York, Vermont, and Virginia

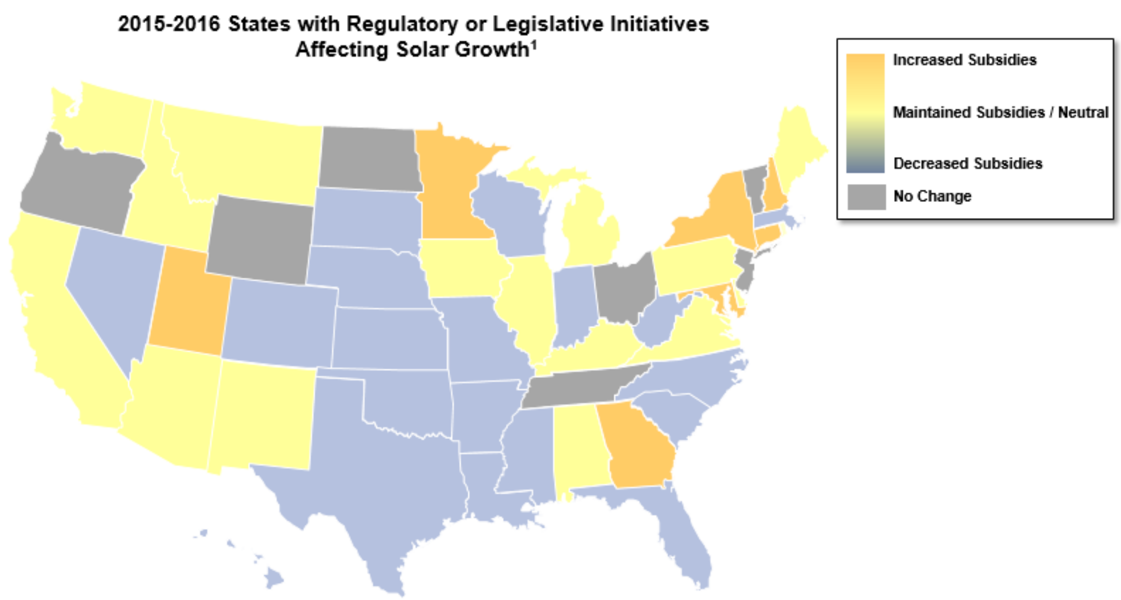

Figure 7 Recent state policy actions proposed that affect solar DG subsidies [68]

Modeling and Methodology

Core Economic Model

Our goal was to model the effects of distributed PV adoption on utility systems under a variety of compensation policies. To do so, we created a spreadsheet-based model to forecast key indicators related to retail rates, PV ownership economics, and non-DG customer utility bills. The basic underlying assumption of this model is that any revenue lost to the utility from compensating DG customers is recovered by raising the retail cost of electricity for all residential customers the following year. The model also computes environmental and health benefits from coal and natural gas generation displaced by DG.

The model is split into three major modules:

1. *Hourly Household Model (or the 'Hourly Model')*: This module accounts for the consumption, generation, and billing of a single 'typical' Michigan household at the hourly level from 2017-2031.

2. *Retail Rate Model (or the 'Rate Model')*: This module takes in the initial retail rate and rate structure that DTE charges residential customers, and inflates each year based on the fixed charge cost-shift principle described in the 'Background' section.

3. *Customer Economics Model*: This module computes the net present values (NPVs) and payback periods for a typical residential solar project that installed in each modelled year (2017-2031).

The modules' functional relationship can be seen in Figure 8. The user defined inputs such as rate structure, compensation structure, discount rate, etc., feed into the three modules. The following sections will describe each of the modules, as well as the key inputs and outputs, in detail.

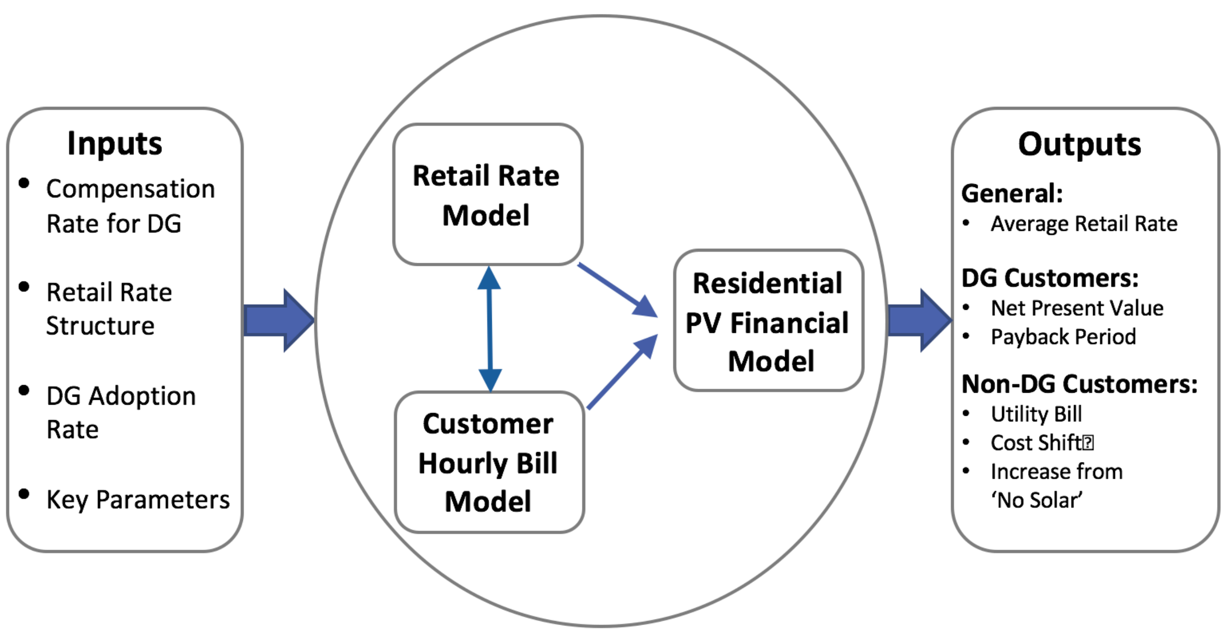

Figure 8 Core Economic Model Framework

Key Controllable Inputs

We model three retail rate structures: (i) DTE Standard, which is the block volumetric pricing structure currently in effect in Michigan, and (ii) time-of-use (TOU), a pricing model which has different rates for on-peak and off-peak hours, and (iii) a simple, flat rate. We chose the three retail rate structures in order to demonstrate the differences in impacts on DG customers and non-DG customers between them. For these retail rate structures, we consider three types of compensation rates for electricity production by DG customers: (i) retail rate, (ii) wholesale rate, which compensates DG customers at the MISO hourly market rate, and (iii) value-of-solar, which compensates the DG customer at a fixed rate based on VOS studies. The compensation can either be for all electricity produced by DG customers or only for the excess electricity (above consumption) produced by a DG customer. The model also allows users to include interconnection fees, demand charges, and other arbitrary fixed fees. Figure 9 shows a snapshot of the model's input page.

1 **Inputs to the Main Model**

	Selection	Value	Unit
Compensation Rate	1		
Compensated For	2		
Retail Rate Structure	1		
Interconnection Fees	1	100	$
Discount Rate		8%	

Selection Options					
1	Retail	2	Wholesale	3	VOS/custom
1	Excess	2	All		
1	DTE Standard	2	TOU	3	Flat

VOS Rate		VOS Escalation
0.20	$/kWh	2.5%

2 **Parameters for Sub-models**

	Selection	Value	Unit
Adoption Rate		20%	
MISO escalation rate		0.00%	
Utility escalation rate		2.50%	
Demand Charge		0	$/kW
Fixed Charge		0	$/month
Initial Solar Cost		3.5	$/Wdc
Annual Solar Cost Decrease		5%	

Figure 9 Core Economic Model Input Framework

Some notes should be made about the parameters that are not directly related to the retail rate. The *discount rate* is used to compute the NPV and IRR of projects in the customer economics model. The *adoption rate* controls how many new customers install solar panels year to year. We keep this at either 20%, based on recent historical trends, or 36.5%, the rate that would be required if 5% of the total residential load was to be met by DTE DG customers' generation. by the end of the 15-year period. The *MISO* and *utility escalation rates* control how fast the wholesale and retail price of electricity grows (excluding the modeled cost-shift). The *demand charge* and *fixed charge* work as described above and on a monthly basis. The *initial solar cost* and *annual solar cost decrease* feed into the customer economics model and control the rate at which capital costs of solar project decline. There is a firm floor of $1/Wdc-installed cost built into the model.

Key Parameters

The key parameters represent major assumptions of our analysis. They are held constant in the results section, while a sensitivity analysis is conducted on some of them in the discussion section. The default utility rate escalation is assumed to be 2.5% per year from 2017-2031 without any DG-related cost-shift **[69]**. This is driven by the utility's revenue requirement. The MISO price escalation rate is assumed to be 2.81% per year based on EIA natural gas price forecasts for 2017-2031 **[70]**.

The median price of solar installations has been falling by 6%-12% per year and for the purposes of the model, we have assumed that it will fall by 5% each year for the model duration with a floor at $1/Watt and a starting price at $3.5/Watt **[71]**. This assumption significantly affects the NPV and payback periods of DG customers. Though our model can take any discount rate as the input, we have shown the results for 8% discount rate to keep the results consistent **[69]**.

The average size of the solar DG system installed is assumed to be 6.5 kW as this system would be sufficient to meet the yearly load of an average consumer and is equal to the total residential installed DG capacity per DG customer in 2015. The average electricity consumption is 8,043 kWh and it is assumed that no individual customer load growth takes place due to energy efficiency improvements **[72]**.

Hourly Model

The Hourly Model models the electricity consumption, generation, and utility bill of an average DTE customer for each hour of the day over the course of 15 years (from 2017 to 2031). The hourly load shape comes from NREL's System Advisory Model (SAM) and is scaled up to Michigan's average residential electricity usage **[73] [74]**. The hourly output for a PV panel was obtained from NREL's PVWatts using an average 6.5 kW DC system **[75] [76]**. We chose to keep the average system size and yearly load shape constant, as we assume advances in energy efficiency offset load growth. The hourly load and solar production data are used to calculate the cost of electricity each year for both a DG and non-DG owning customer, using the retail rate structure and compensation rate as inputs. Once a customer's total electricity bill is computed (with and without solar), the model uses hourly MISO day-ahead electricity prices and subtracts it from DTE's hourly payments to find DTE's total revenue lost to DG customers. This lost revenue is sent to the Rate Model, which uses it to compute the next year's retail rate, which is sent back to the Hourly Model. The Hourly Model also finds the difference in utility bills between the solar-owning and non-solar-owning customer to compute the financial benefit of solar ownership, which is sent to the Customer Economics Model. Figure 10 shows a snapshot of a portion of the Hourly Model.

Year	2017		For 6.5 kW	C
Month	*Day*	*Hour*	*AC System Output (W)*	*Hourly Gross Load*
1	1	0	0	0.545981822
1	1	1	0	0.47756575
1	1	2	0	0.457127906
1	1	3	0	0.450313955
1	1	4	0	0.437483687
1	1	5	0	0.480510445
1	1	6	0	0.593118328
1	1	7	0	0.733957343
1	1	8	130.578	0.645122132
1	1	9	408.438	0.516128702
1	1	10	964.549	0.505412095
1	1	11	1046.594	0.504332551
1	1	12	1415.69	0.500150656
1	1	13	1273.913	0.509461719
1	1	14	1346.054	0.528729166
1	1	15	515.389	0.569526026
1	1	16	394.481	0.71151406

Figure 10 Hourly Model tracks electricity generation and consumption for a typical residential customer for each hour of the day over 15 years

It should be noted that the Hourly Model does not accurately capture the utility's lost revenue, as it makes the assumption that the only cost of PV is that of remuneration for energy, and the only avoided cost is wholesale energy. In reality, there are many more factors that would need to be taken into account to accurately determine the utility's lost revenue, though the two included are significant factors.

Rate Model

The purpose of the Rate Model is to compute the new retail rate of electricity each year after shifting avoided fixed costs from PV-owners to non-PV owners. The model does this by first computing the revenue the utility loses in a particular year due to payments made to all DG customers. It receives this information for one customer from the Hourly Model and multiplies it by the total number of DG customers that year. Once it has computed that amount, it divides it by the total number of kWh they expect to sell next year to determine the per kWh amount that needs to be added to the retail rate. It should be noted that this per kWh adder is added onto the previous year's retail rate only after the rate has been escalated at the user-specified rate (2.5% is our pre-set value). For TOU and block volumetric rate structures, the same average rate adder is added to each pricing tier. Once the new retail rate is computed, is sent to the next year's Hourly Model.

Once the new retail rates are found, we compute the amount of additional money a non-DG customer has to pay because of these increased retail rates. To do this, we simply find the average rate increase for a non-DG customer and multiply it by the number of kWh they consume. Figure 11 shows a small snapshot of the Rate Model.

		2017	2018	2019	
	Units	1	2	3	
Residential customers served by DTE		1,968,528	1,977,386	1,986,285	1
Growth Rate for Residential customers served by DTE		0.45%	0.45%	0.45%	
Number of Solar Residential Customers		1,332	1,598	1,918	
Average Size of Solar System	**kW**	6.50	6.50	6.50	
Total electricity produced by solar customers	**kWh/year**	10,767,530.26	12,921,036.31	15,505,243.57	18,60
Total revenue lost to Net Metering	**$**	$953,864.18	$1,131,571.76	$1,374,814.93	$1,67
Average Electricity Consumption by Customers	**kWh/year**	8,043	8,043	8,043	
Customer Electricity Consumption Growth Rate	**per year**	0.00%	0.00%	0.00%	
Total Electricity Consumption	**kWh**	15,832,870,704.00	15,904,118,622.17	15,975,687,155.97	16,047,57
Growth Rate Solar Residential Customers	**per year**	20.00%	20.00%	20.00%	
Distribution Cost	**$/kWh**	0.05666	0.0580765	0.059528413	0.06
Utility Rate Escalation		2.50%	2.50%	2.50%	
Utility Distribution Cost Escalation		2.50%	2.50%	2.50%	
Increase in Average Rate due to cost shift by DG	**$/kWh**	$0.00006	$0.00007	$0.00009	$
Amount Non DG Customers have to pay more	**$/year**	$0.48	$0.57	$0.69	
Weighted Average Rate ($/kWh)	**Old Rate**				
Flat Rate	0.1594	0.1594	0.1634	0.1676	
High (Above 17kWh)	0.0942	0.0942	0.0966	0.0991	
Low	0.0789	0.0789	0.0809	0.0830	
High (Nov to May)	0.1092	0.1092	0.1119	0.1148	
Low (Nov to May)	0.0418	0.0418	0.0429	0.0440	
High (June to Oct)	0.12922	0.12922	0.1325	0.1359	
Low (June to Oct)	0.0435	0.0435	0.0446	0.0458	
Amount non DG customers pay	**$**	2209104465	2252669892	2297540675	234

Figure 11 A snapshot the Rate Model

Customer Economics Model

The purpose of the Customer Economics Model is to quantify the impacts of policy choices on the economics of residential solar PV projects. The two primary indices we use to measure the financial viability of such projects are the net present value (NPV) and payback period. NPV is a common metric of profitability that can be used to value projects. Specifically, it refers to the difference between the present value of cash inflows and present value of cash outflows **[77]**. Payback period refers to the number of years it takes for a customer to recoup their initial investment (in computing payback period, we assume a customer pays for the project up front).

To compute these metrics, we model the yearly finances of a typical solar owner who is installing a project in the year in question. Figure 12 shows an example image from the customer model. In this snapshot, a customer has purchased and installed residential solar panels in 2016 and paid the full cost up front. The size of the system, loan terms (if applicable), tax credits, discount rate, and customer tax bracket can all be manipulated by the user if they choose. The revenue to the customer is determined by the Hourly Model and the Rate Model. For the example shown, the project NPV is negative 5.5 thousand dollars, indicating a highly unattractive project. Though it is not picture, the project payback period is 18 years.

	Rated DC power	kWdc	6.5				
	First year Production	kWh/yr	8083.73				
	System Degredation affecting Revenue	%/yr	0.00%				
	System Costs						
	System Costs	$	22750	3.5	$/Wdc Cost of Solar		
	ITC	30%	6825				
	Final Cost	$	15925				
		$/Wp	2.45				
	Down payment	$	15925				
	Loan principal	$	0				
	Financing						
	Loan interest	%/yr	4.50%				
	Loan term	yr	25				
	CRF	(i, n)/yr	0.067439028				
	Annual payments	$/yr	0				
	Other Assumptions						
	Marginal tax bracket	%	25%				
	Nominal discount rate	%	8%				
2016							
			2016	2017	2018	2019	2020
	Year		0	1	2	3	4
	Payment	$/yr	15,925.00	0.00	0.00	0.00	0.00
	Interest	$/yr		0.00	0.00	0.00	0.00
	Delta balance	$		0.00	0.00	0.00	0.00
	Loan balance	$	0.00	0.00	0.00	0.00	0.00
	Fixed Charge	$/yr	-100.00	0.00	0.00	0.00	0.00
	Net cost of PV	$		0.00	0.00	0.00	0.00
	PV kWh generated	kWh/yr		8,083.73	8,083.73	8,083.73	8,083.73
	Utility price	$/kWh		0.00	0.00	0.00	0.00
	Revenue to Customer w/o Degredation	$/yr		707.78	721.76	737.73	755.33
	Revenue to Customer with Degredation & Demand Charge	$/yr		707.78	721.76	737.73	755.33
	Net cash flow	$/yr	-16,025.00	707.78	721.76	737.73	755.33
	Internal rate of return (IRR)		4.25%				
	Net present value (NPV)		($5,572.07)				

Figure 12 A snapshot of the Customer Economics Model

When presenting results related to NPV, we will always assume a certain set of parameters. First, the loan term is always 25 years with 0 down at an interest rate of 4.5%. Second, each customer installs a 6.5 kW system, which we determined to be the average size in the DTE footprint based data from EIA form 826 **[78]**. Third, due to implementation challenges, we did not include system degradation or inverter repair. To make up for this we raised our nominal discount rate from 5% to 8%. We include the option for interest payments to be tax deductible in the case of a secured loan.

The federal investment tax credit (ITC) is present until 2021. We assume it begins at 30% and gradually ratchets down to 0% by 2022, which is the current state of the credit for residential customers **[79]**. We do not assume any ITC extensions. We assume our customer has enough taxable income to claim the entirety of the tax credit in the first modeled year.

Environmental and Health Benefits Module

This additional model attempts to quantify certain environmental and health benefits of increased solar penetration in economic terms. The module assumes that all distributed solar generation will displace marginal resource in particular natural gas and coal. The amount of natural gas and coal generation that is displaced for each kWh of solar energy produced is based on forecast on generation mix data provided by DTE **[80]**. While the core model attempts to compute some of the costs that are borne as a result of these compensation policies coupled with increasing solar adoption, this module attempts to compute some of the benefits as a point of comparison.

Environmental and Health Benefits of Avoided Carbon Dioxide Emissions

To compute the environmental and health benefits of avoided carbon dioxide emissions, we used the formula:

*Value of Avoided CO2 Emissions ($) = E*H*C*P* ,

Where:

E = Energy produced by distributed solar (kWh)

H = Heat Rate of Offset Generation (Btu/kWh)

C = CO2 Emissions from the Offset Generation (lbs CO2/MMBtu)

P = Social Cost of Carbon ($/lb CO2)

To calculate the kWh of coal and gas-fired electricity offset by the solar electricity produced in the 2017-2031 time-frame under the scenarios of 20% and 37.5% solar adoption rates per annum, we used forecast of future Michigan generation mixes (only considering gas and coal) only to get the rate of change over time.

To obtain a more accurate picture of forecast between coal and gas, we used data of fuel on the margin from MISO both in summer and winter seasons. Then, using the rate of change over time from the generation mix forecast, we calculated the expected offset share of coal and natural gas from 2017 to 2031.

Year	Coal	Natural Gas
2017	53%	47%
2020	56%	44%
2025	48%	51%
2031	47%	53%

Table 1 Offset Share of Coal and Natural Gas from 2017 to 2031

We assumed a heat rates of 11,166 Btu/kWh for coal and 7,050 Btu, kWh for gas, and an emissions rate of 117 lb CO2/MMBtu for natural gas and 214.3 lb CO2.MMBtu for coal **[81] [82]**.

The social cost of carbon is an estimate of the value of climate change-related damages and includes factors such as changes in net agricultural productivity, human health, property damage from flood risk, changes in energy system costs, etc. We used an estimate from an EPA study which forecasted future social costs of carbon. While the study was most recently updated in 2016, it should be noted that there is significant uncertainty in this metric, and the original report should be referred to for further details **[83]**. We inflated those values from 2007 to 2014 dollars (see table 2).

Year	2017	2020	2025	2031
Social Cost of Carbon	$45.85	$50.55	$55.26	$61.34

Table 2 Adjusted social costs of carbon in 2017 dollars

Health Benefits of Avoided NO_X, SO_2, and Particulate Matter Emissions

In addition to CO_2, we consider several other emission types associated with fossil fuel-powered electric generation, in particular NO_X, SO_2, and particulate matter (PM). Health effects associated with the emissions of these substances include illnesses, premature mortality, workdays lost, and direct costs to the healthcare system. In a 2015 study, the national average economic value of health impacts of fossil fuel used for in-state electricity generation was valued at $0.19-$0.45 per kWh for coal and $0.01-$0.02 per kWh for natural gas **[84]**. Specifically, the economic health impact value within Michigan for fossil fuels combusted in-state for electricity is $0.19 per kWh. In order to demonstrate the magnitude of the externality, the health value of distributed solar generation is larger than the retail rate of electricity (which is less than $0.10/kWh). Another study priced the "true monetizable costs" of coal on health impacts at close to $0.17/kWh in Michigan **[85]**. For this reason we chose the upper bound of the first study for natural gas ($0.02/kWh) and the economic value of coal is $0.17/kWh.

The health value of offset emissions was then calculated in the same way as the avoided CO_2 benefits, only with the substances mentioned above and the health values associated with coal and natural gas mentioned immediately above instead of a social cost of carbon. To compute the total amount of avoided SO_2 and NO_x emissions, we used emissions rates from EPA **[86]**. The average emission rates for coal are 0.408 lb/mmbtu for SO2 and 0.156 lb/mmbtu for NOx. The average emission rates of natural gas are 0.0016 lb/mmbtu for SO2 and 0.03 lb/mmbtu for NOx.

Model Results

Here we present the model results from five policy scenarios. In the first three scenarios, we analyze net metering (business-as-usual), net metering with two fixed charges ($10 and $25), a low and high value-of-solar tariff, and net billing for the block volumetric rate structure that DTE currently uses. The fourth and fifth scenarios use an alternate rate structure, namely, time-of-use rate structure. We have analyzed business-as-usual net metering and value-of-solar under time-of-use rate structure.

As the DG adoption rate is an input rather than a dependent variable, the health and environmental benefits are independent of the policy. Based on our reference and high growth rates, the health and environmental benefits have been quantified.

In the final section, we compare all the policy scenarios on NPV for DG customers, change in utility bill for non-DG customers, and net benefits when health and environmental benefits are accounted for.

Core Model Results

Scenario 1: Business-as-Usual Case

The business-as-usual case assumes that DTE continues with their current rate structure and compensation policy i.e. retail rate net metering. DTE currently uses a two-level block pricing structure where the daily consumption of electricity is charged at a lower rate up to a fixed number of units and then increased to a higher rate for each additional unit consumed. As of February 7th, 2017, DTE charges residential customers 13.611 cents/kWh for the first 17 kWh consumed in a day and 15.175 cents/kWh for every kWh consumed beyond 17 kWh. These number reflect both energy and variable distribution charges **[87]**.

Business-as-Usual Effects on Non-DG Customers

Figure 13 shows the effect on the average retail rate paid by non-DG customers through 2031, assuming all revenue lost to distributed generation is compensated for by raising retail rates for all residential customers. The average rate paid is computed by dividing the average annual bill by the total number of kWh consumed by a non-DG customer.

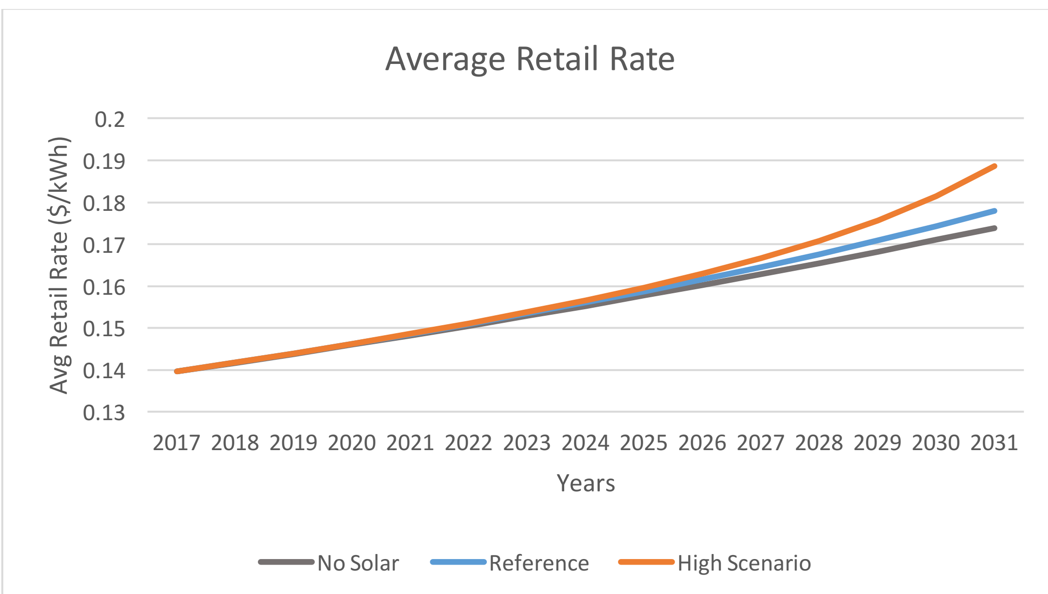

Figure 13 Average retail rate for DTE customers under business-as-usual

The three lines represent the different adoption trends discussed above. In the ‘No Solar’ scenario, there is no further residential solar adoption in the period between 2017-2031. In this case, rates rise from an average of 14 cents/kWh to just shy of 17.5 cents/kWh. The rise in rates in this scenario is due to increases in the utility’s revenue requirement that are not explicitly modeled here. The reference scenario, which assumes an annual solar adoption increase of 20%, causes the average rate paid to increase to roughly 17.8 cents/kWh by 2031, a 2.3% increase over the ‘No Solar’ scenario. The high growth scenario, which represents an annual adoption rate of 36.5%, represents an 8% increase over the ‘No Solar’ scenario by 2031. The final rate for this scenario is almost 19 cents/kWh.

To gauge the effect these rate-increases have on non-DG customers, we can look at the total cost shifted onto the typical non-DG customer each year. Table 3 summarizes the amount a typical non-DG customer would have to pay each year in the reference and high growth scenarios. The second two rows display the same information as the first two, but discounted at an 8% rate. By the year 2031, the extra cost per year would rise to between $31.86 and $117.76, numbers which represent the individual subsidy each non-DG customer would end up providing to DG customers.

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ref	$ -	$ -	$ 0.57	$ 1.27	$ 2.13	$ 3.18	$ 4.47	$ 6.03	$ 7.93	$ 10.25	$ 13.06	$ 16.49	$ 20.65	$ 25.70	$ 31.86
High Scenario	$ -	$ -	$ 0.64	$ 1.53	$ 2.77	$ 4.50	$ 6.88	$ 10.18	$ 14.75	$ 21.07	$ 29.85	$ 42.09	$ 59.22	$ 83.37	$117.76
Ref (PV)	$ -	$ -	$ 0.49	$ 1.01	$ 1.57	$ 2.17	$ 2.81	$ 3.52	$ 4.29	$ 5.13	$ 6.05	$ 7.07	$ 8.20	$ 9.45	$ 10.85
High Scenario	$ -	$ -	$ 0.55	$ 1.22	$ 2.04	$ 3.06	$ 4.34	$ 5.94	$ 7.97	$ 10.54	$ 13.83	$ 18.05	$ 23.52	$ 30.66	$ 40.09

Table 3 Increase in non-DG customer bill each year with business-as-usual

Business-as-Usual Effects on Customer Economics

Figures 13 And 14 show the NPV and payback periods, respectively, for typical solar projects in the DTE footprint at the time of installation over the fifteen-year period considered. Project NPVs are strongly driven by the magnitude of the retail rate. In 2017, the only thing that makes projects profitable is the presence of the 30% investment tax credit (ITC). The gradual decrease of value from 2020 to 2023 coincides with the ITC ratcheting down to 0%. In both the reference and high growth scenarios, PV installations become highly profitable by 2031, reaching between 10 and 15 thousand dollars after discounting. Likewise, payback periods continue to decline reliably after the expiration of the ITC, from between 13 and 14 years in 2023 to a low of 7 to 8 years in 2031.

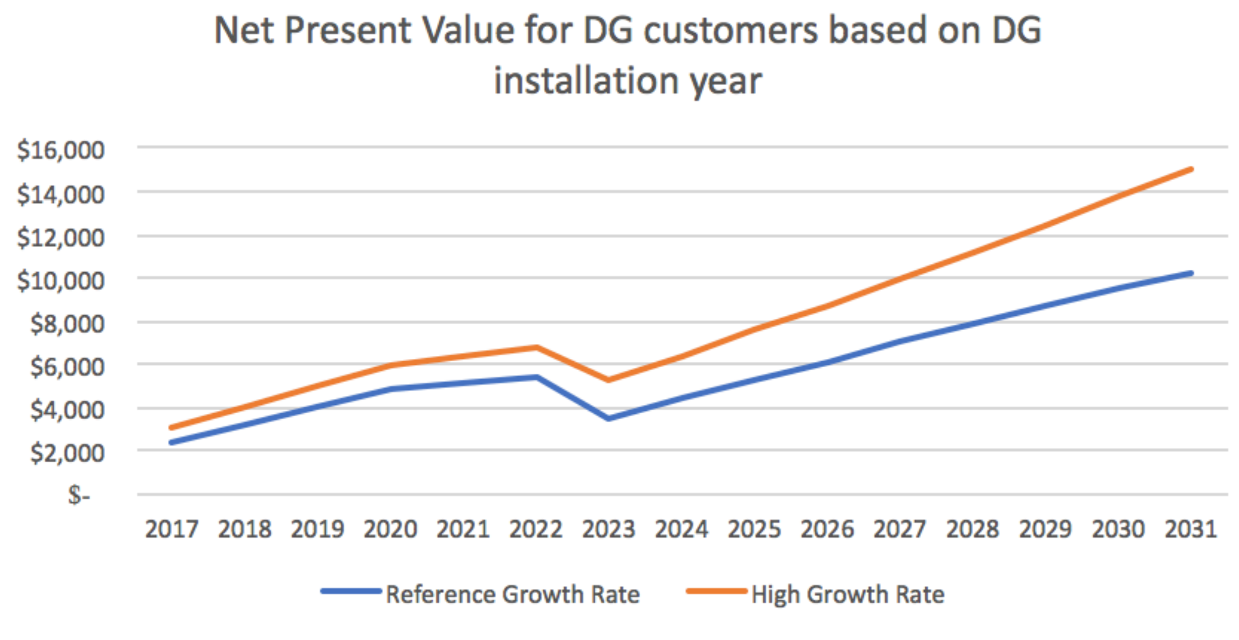

Figure 14 Net present value for DG customers under business-as-usual

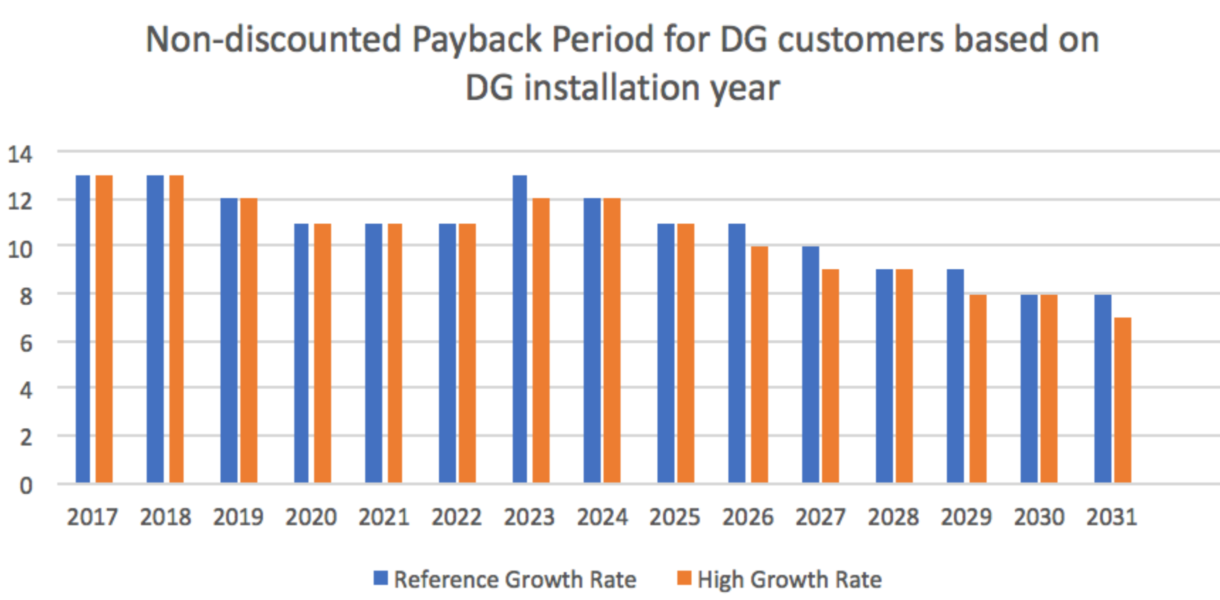

Figure 15 Payback periods for DG customers under business-as-usual

Business-as-Usual plus Fixed Charges Effects on Solar Customers

Many states have proposed fixed charges for solar customers to reduce the subsidy that retail rate net metering necessitates. The following section explores the impacts of both a $10 and $25 monthly fixed charge for solar customers.

Figure 16 shows the effect that retail rate net metering would have on retail rates. As expected, both the $10 and $25 fixed charges bring rates down by 2031, but only marginally so. Table 2 shows the total amount of subsidy the average non-DG customer would pay each year compared to the 'No Solar' case. Compared to the reference case, a $10 fixed charge would lower the cross-subsidy by 32%, while the $25 fixed charge lowers the subsidy by 40%. A 40% savings on solar cross-subsidies for a non-DG customer amounts to roughly $13/year.

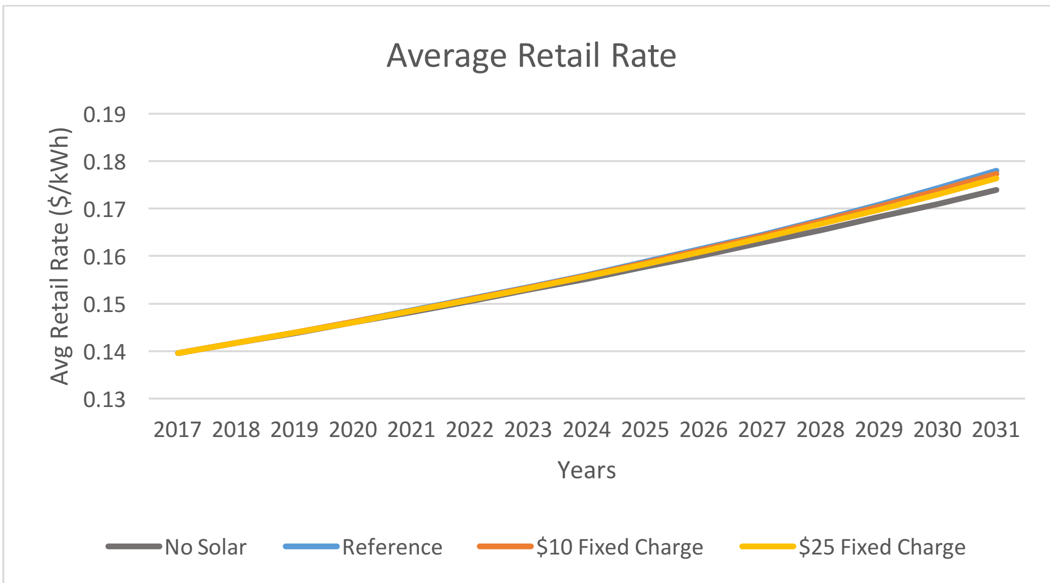

Figure 16 Average retail rate for DTE customers under business-as-usual with fixed charges

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ref	$ -	$ 0.48	$ 1.07	$ 1.78	$ 2.65	$ 3.72	$ 5.02	$ 6.60	$ 8.52	$ 10.85	$ 13.68	$ 17.12	$ 21.30	$ 26.38	$ 32.55
$10 Fixed Charge	$ -	$ 0.40	$ 0.89	$ 1.48	$ 2.21	$ 3.09	$ 4.18	$ 5.50	$ 7.10	$ 9.06	$ 11.44	$ 14.33	$ 17.85	$ 22.13	$ 27.34
$25 Fixed Charge	$ -	$ 0.28	$ 0.62	$ 1.03	$ 1.54	$ 2.16	$ 2.92	$ 3.85	$ 4.99	$ 6.38	$ 8.07	$ 10.14	$ 12.67	$ 15.76	$ 19.53
Ref (PV)	$ -	$ 0.45	$ 0.92	$ 1.41	$ 1.95	$ 2.53	$ 3.16	$ 3.85	$ 4.60	$ 5.43	$ 6.34	$ 7.34	$ 8.46	$ 9.70	$ 11.08
$10 Fixed Charge (PV)	$ -	$ 0.37	$ 0.76	$ 1.18	$ 1.62	$ 2.11	$ 2.63	$ 3.21	$ 3.84	$ 4.53	$ 5.30	$ 6.15	$ 7.09	$ 8.14	$ 9.31
$25 Fixed Charge (PV)	$ -	$ 0.26	$ 0.53	$ 0.82	$ 1.13	$ 1.47	$ 1.84	$ 2.25	$ 2.69	$ 3.19	$ 3.74	$ 4.35	$ 5.03	$ 5.79	$ 6.65

Table 4 Shows the increase in non-DG customer bill each year with business-as-usual plus fixed charges

The effect of fixed charges on NPVs is starker, as can be seen in Figure 17. Figure 17 shows project NPVs going negative in 2017 and 2018, and dropping to zero in 2023 after the ITC phases out. While the NPV does climb back up to over $6000 dollars by 2031, it should be noted that this still assumes a constant annual DG adoption growth rate of 20%. It is possible that this rate would drop significantly after the implementation of any fixed charges. If adoption rates drop, rates do not inflate as quickly, causing NPVs to drop.

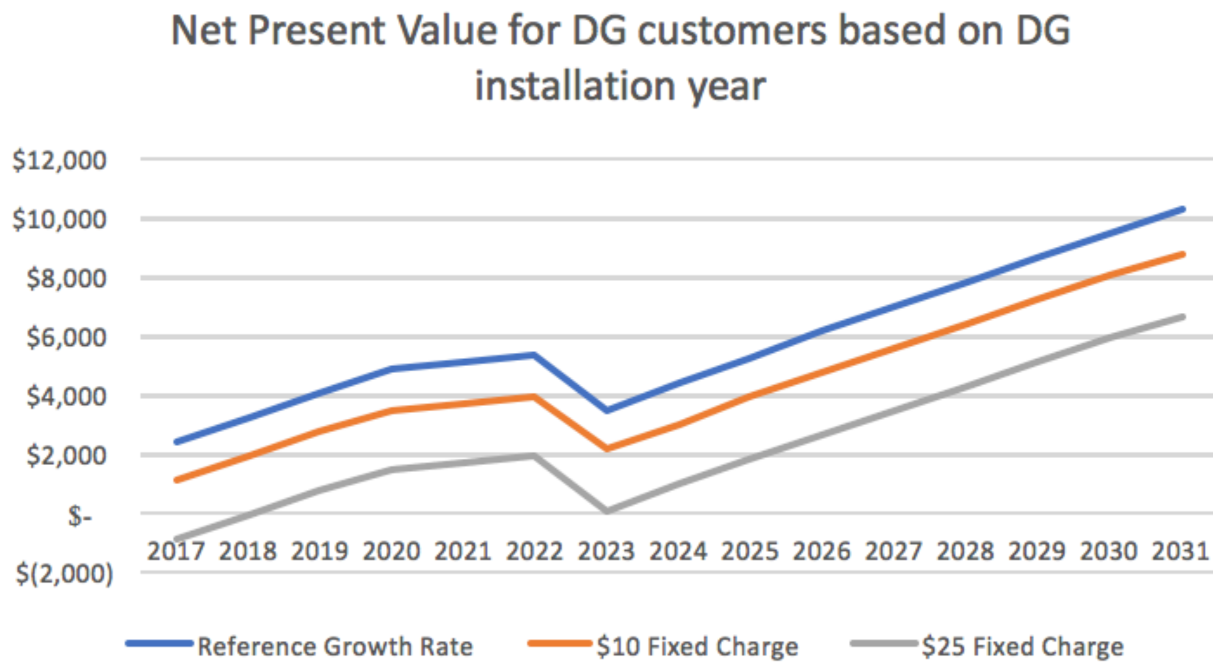

Figure 17 Net present value comparing business-as-usual with fixed charges

Scenario 2: Value-of-Solar Tariffs

Value-of-solar tariffs are designed to account for all of the benefits and costs of distributed solar PV. They can be designed for either buy-all-sell-all models or just for excess generation. To come up with a VOS rate, a study must be conducted. As one might expect, studies conducted by different entities can have wildly different results depending on what they consider to be valid costs and benefits. Here we consider two significantly different VOSTs, one proposed by NREL in 2012, and one proposed by DTE in *2013* as a way to reflect the wholesale cost of generation in Michigan **[88] [89]**. The NREL valuation includes energy and generation, capacity, transmission and distribution, avoided line losses, reactive power support, environmental benefits, and other miscellaneous benefits. They found that solar was valued higher than the retail rate of electricity, at an average of 13.8 cents/kWh. On the other hand, DTE's internal 2013 study valued solar in their footprint at a mere 3.9 cents/kWh, only accounting for energy and capacity costs. For more information on these estimates, one can read the MPSC's solar working group report **[90]**. We use these two values as high and low estimates of the value-of-solar. We use buy-all-sell-all compensation structures and escalate the VOST at the same rate as the retail rate (2.5%).

Low Value-of-Solar Rate

Figure 17 shows the effect of the low VOST on retail rates. The most immediately noticeable aspect of this graph is that in both the reference and high scenarios, retail rates actually get lower. This is because DG customers are actually compensated at less than even the wholesale rate of electricity, resulting in a subsidy from DG owners to non-DG owners. The magnitude of this cross-subsidy can be seen in Table 5, in which the average non-DG owner saves $20.42 by 2031 on their electric bill in the high growth scenario and $5.16 in the reference scenario.

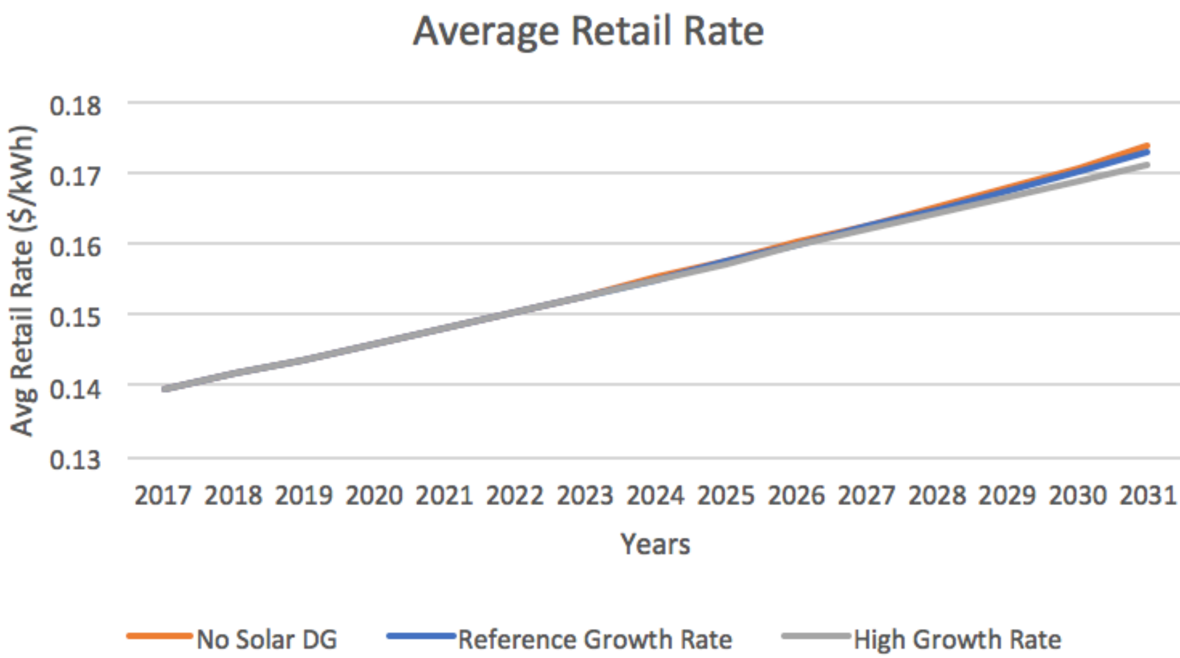

Figure 18 Average retail rate for DTE customers under low value-of-solar rate

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ref	$ -	$ (0.05)	$ (0.13)	$ (0.22)	$ (0.34)	$ (0.49)	$ (0.68)	$ (0.91)	$ (1.20)	$ (1.56)	$ (2.01)	$ (2.56)	$ (3.25)	$ (4.10)	$ (5.16)
High Scenario	$ -	$ (0.05)	$ (0.15)	$ (0.28)	$ (0.47)	$ (0.75)	$ (1.13)	$ (1.67)	$ (2.44)	$ (3.51)	$ (5.02)	$ (7.15)	$ (10.16)	$ (14.40)	$ (20.42)
Ref (PV)	$ -	$ (0.05)	$ (0.11)	$ (0.18)	$ (0.25)	$ (0.33)	$ (0.43)	$ (0.53)	$ (0.65)	$ (0.78)	$ (0.93)	$ (1.10)	$ (1.29)	$ (1.51)	$ (1.76)
High Scenario (PV)	$ -	$ (0.05)	$ (0.12)	$ (0.22)	$ (0.35)	$ (0.51)	$ (0.71)	$ (0.98)	$ (1.32)	$ (1.76)	$ (2.33)	$ (3.07)	$ (4.03)	$ (5.30)	$ (6.95)

Table 5 Shows the increase in non-DG customer bill each year under low value-of-solar rate

Customer economics are hit hard, however. Figure 18 shows a consistently negative NPV (even with an 8% discount rate), while Figure 19 shows that there is no payback for any customer installing before 2027, with extremely high payback periods for those who install after that (between 20 and 25 years). Note that both the reference and high growth scenarios have the same effect on customer economics because of the buy-all-sell-model.

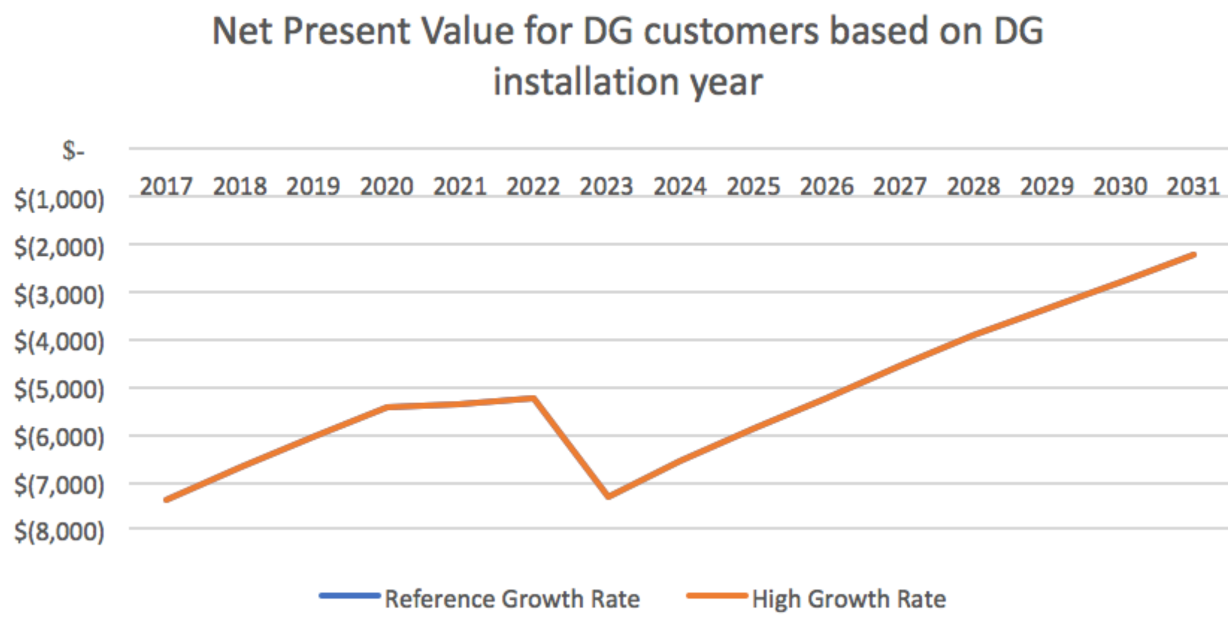

Figure 19 NPV for DG customers under low value-of-solar rate

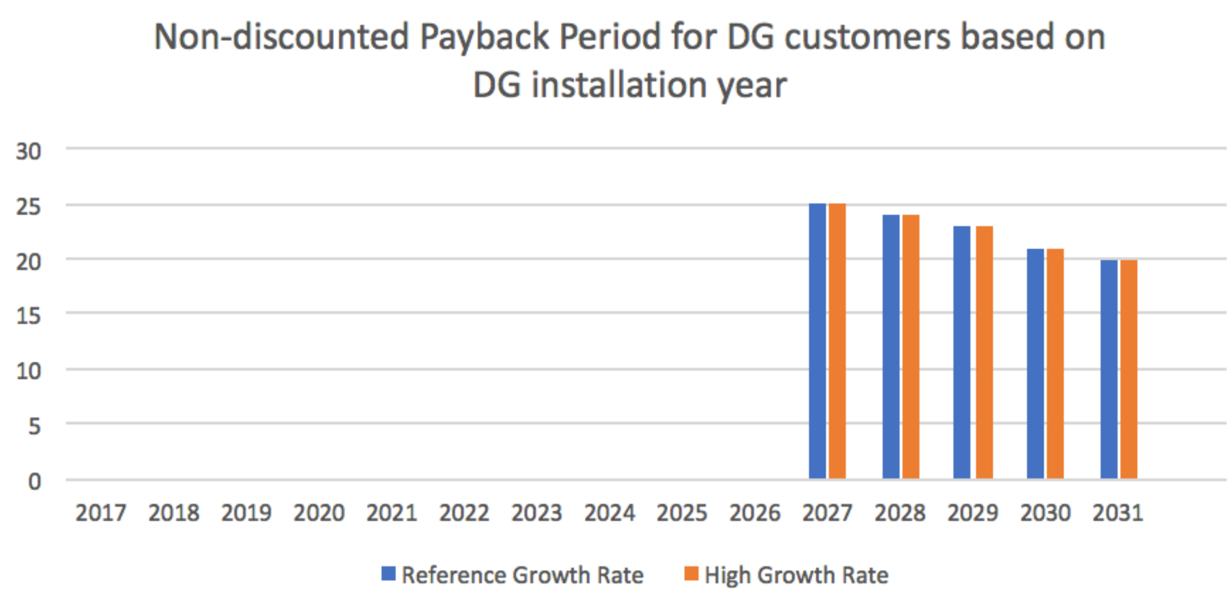

Figure 20 Payback period for DG customers under low value-of-solar rate

NREL-Recommended Value-of-Solar Rate

The NREL-recommended rate of 13.8 cents/kWh results in the typical cross-subsidy from non-DG customers to DG-customers. The retail rate rises to between 17.9 cents/kWh and 19.1 cents/kWh (from 17.4 cents/kWh), while the annual cross-subsidy in 2031 comes out to between

$37.4 and $133.7. Figure 21 shows project NPVs growing to over $12,000 by 2031 compared to -$2000 under the DTE rate, while Figure 22 shows payback periods dropping to 7 years.

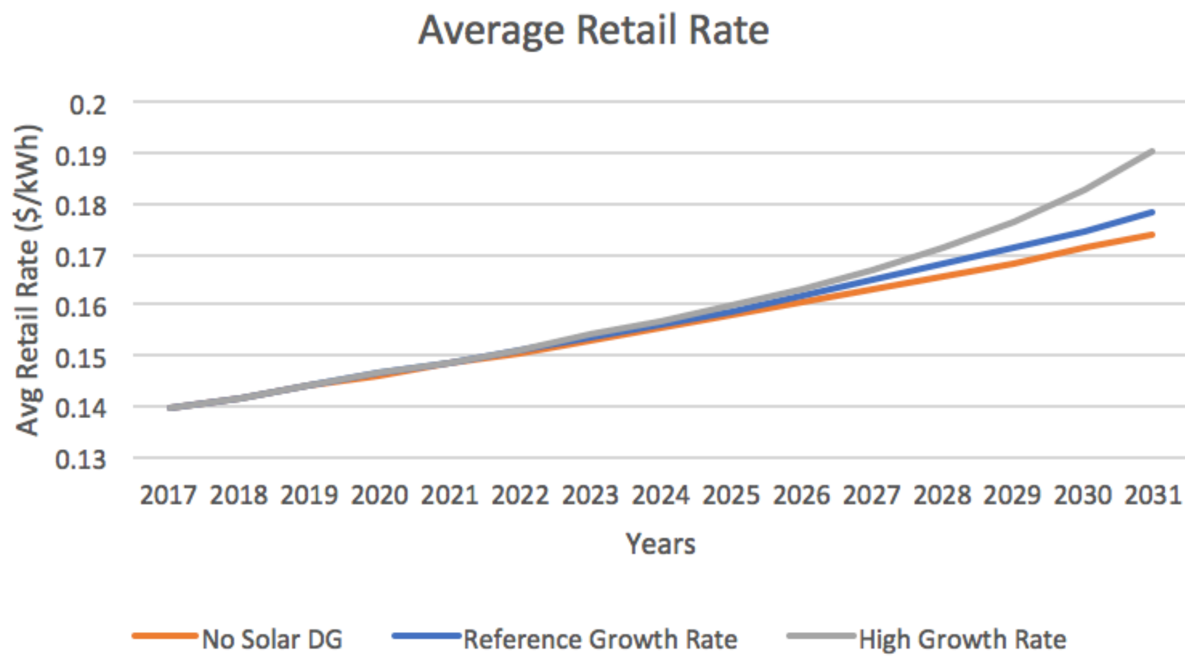

Figure 21 Average retail rate for DTE customers under NREL recommended value-of-solar

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ref	$ -	$ 0.49	$ 1.09	$ 1.84	$ 2.77	$ 3.91	$ 5.33	$ 7.08	$ 9.23	$ 11.87	$ 15.12	$ 19.12	$ 24.02	$ 30.04	$ 37.42
High Scenario	$ -	$ 0.49	$ 1.17	$ 2.11	$ 3.45	$ 5.32	$ 7.94	$ 11.61	$ 16.73	$ 23.89	$ 33.90	$ 47.90	$ 67.51	$ 95.01	$ 133.68
Ref (PV)	$ -	$ 0.46	$ 0.94	$ 1.46	$ 2.03	$ 2.66	$ 3.36	$ 4.13	$ 4.99	$ 5.94	$ 7.01	$ 8.20	$ 9.54	$ 11.05	$ 12.74
High Scenario (PV)	$ -	$ 0.46	$ 1.00	$ 1.68	$ 2.53	$ 3.62	$ 5.00	$ 6.77	$ 9.04	$ 11.95	$ 15.70	$ 20.54	$ 26.81	$ 34.94	$ 45.51

Table 6 Shows the increase in customer bill each year for NREL value-of-solar

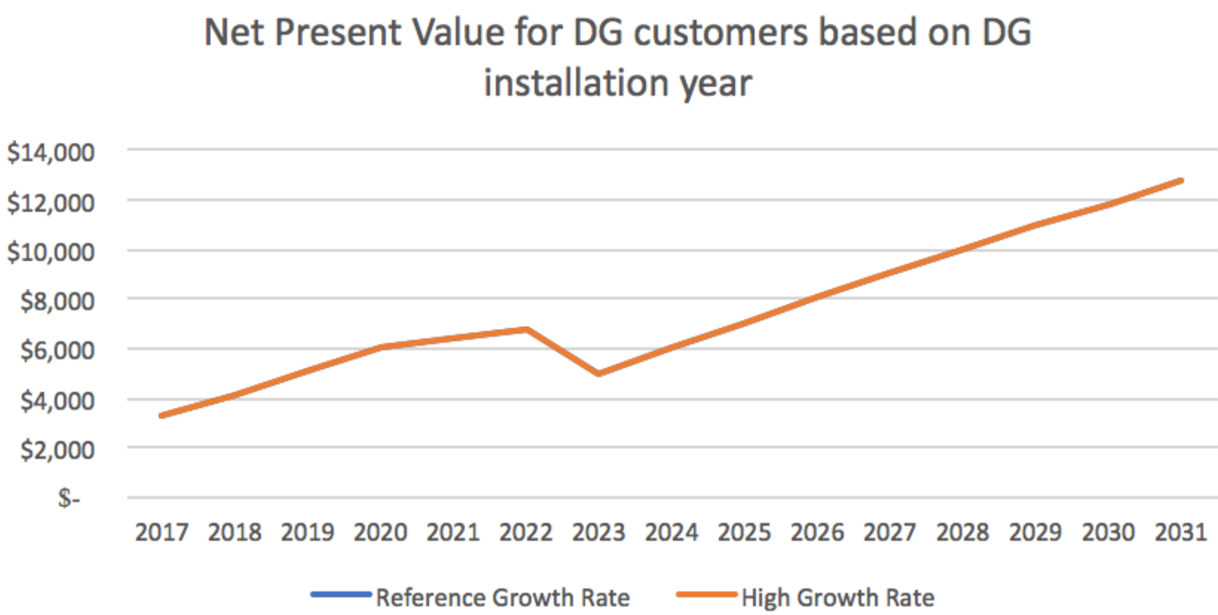

Figure 22 NPV for DG customers under NREL Value-of-Solar

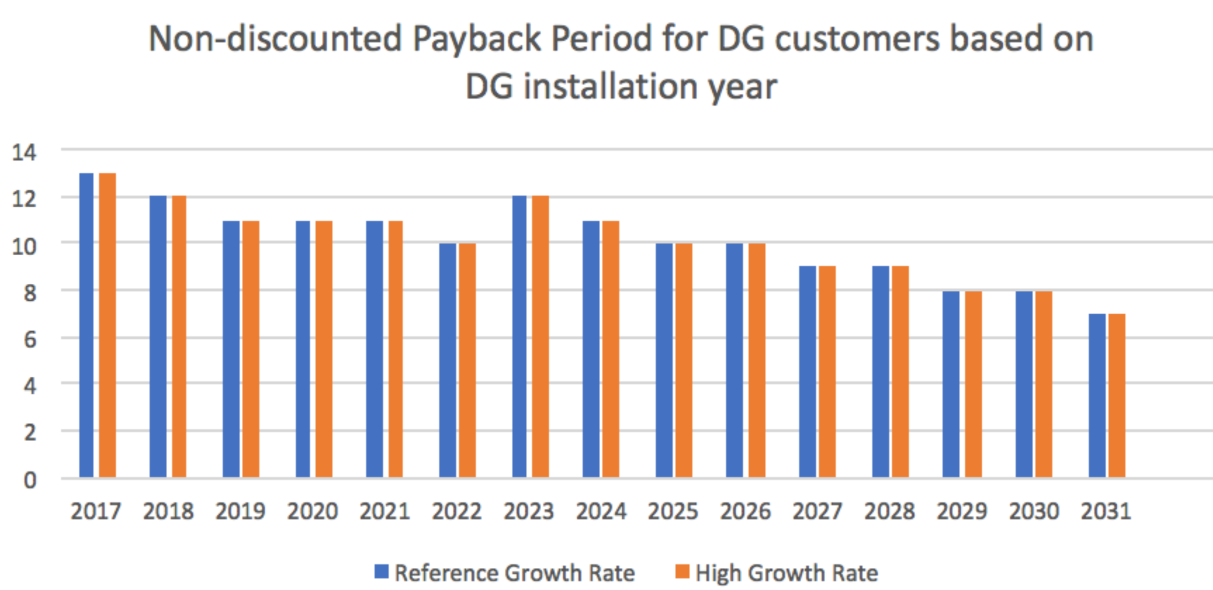

Figure 23 Payback period for DG customers under NREL Value-of-Solar

Scenario 3: Net Billing

In this case, net billing refers to the compensation policy in which all excess solar production is sold back to the utility at the wholesale rate, while generation that is consumed onsite is effectively valued at the retail rate. As can be seen in Figure 23 and Table 7, retail rates rise to a maximum of 18 cents/kWh, while the magnitude of the cross-subsidy in 2031 falls between $12 and $45 per non-DG customer.

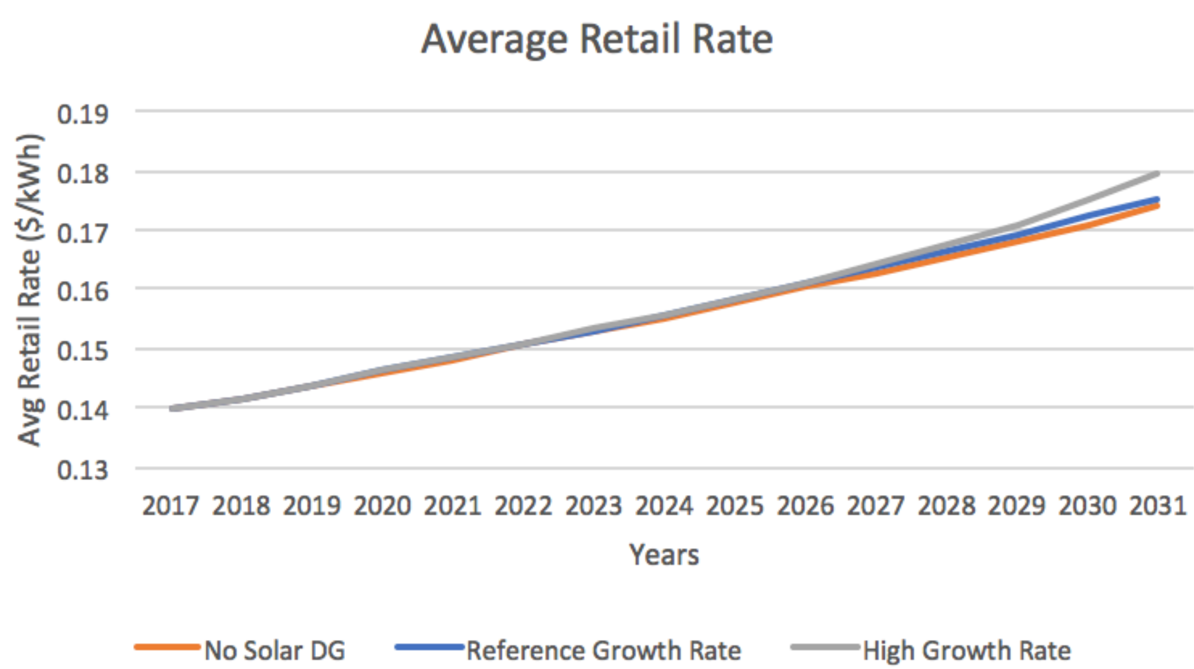

Figure 24 Average retail rate for DTE customers under Net Billing

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ref	$ -	$ -	$0.23	$0.51	$0.85	$1.27	$1.78	$2.40	$3.16	$4.08	$ 5.20	$ 6.56	$ 8.20	$10.21	$12.64
High Scenario	$ -	$ -	$0.25	$0.60	$1.08	$1.75	$2.68	$3.96	$5.73	$8.18	$11.57	$16.27	$22.80	$31.91	$44.68
Ref (PV)	$ -	$ -	$0.19	$0.40	$0.62	$0.86	$1.12	$1.40	$1.71	$2.04	$ 2.41	$ 2.81	$ 3.26	$ 3.75	$ 4.30
High Scenario (PV)	$ -	$ -	$0.21	$0.47	$0.79	$1.19	$1.69	$2.31	$3.10	$4.09	$ 5.36	$ 6.98	$ 9.06	$11.73	$15.21

Table 7 Increases in customer bill each year for Net Billing

Project NPVs would begin negative in the first, climbing slowly above water until the expiration of the ITC would bring it back down to below -$1500 in 2023. By 2031, projects are valued at between $4000 and $5000. Payback periods end at 11 years by 2031.

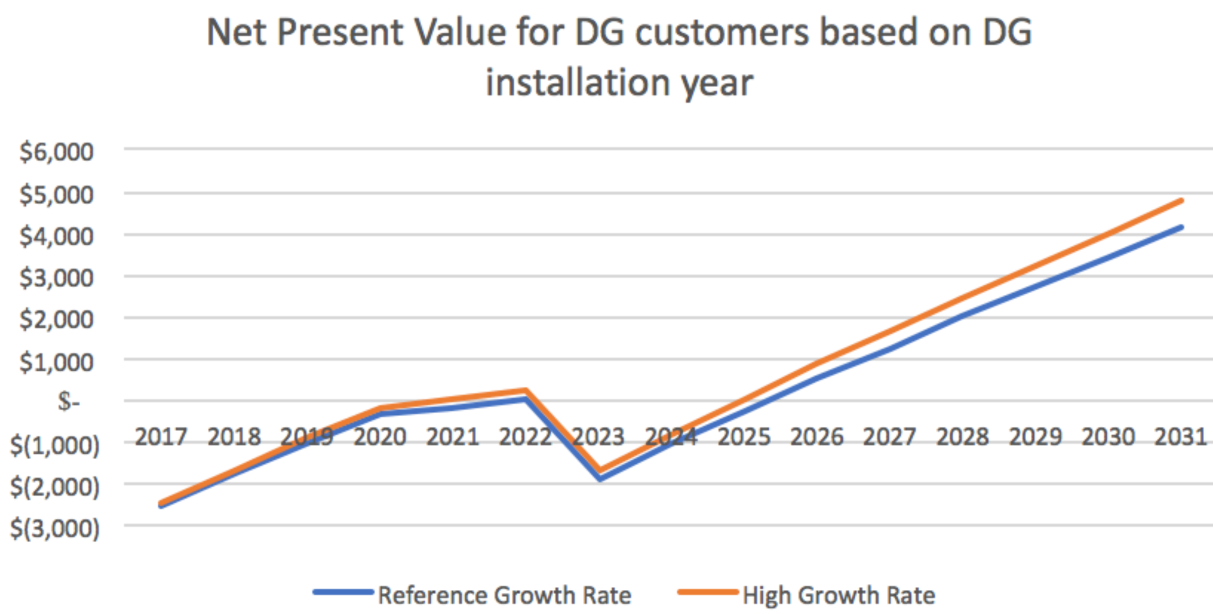

Figure 25 NPV for DG customers under Net Billing

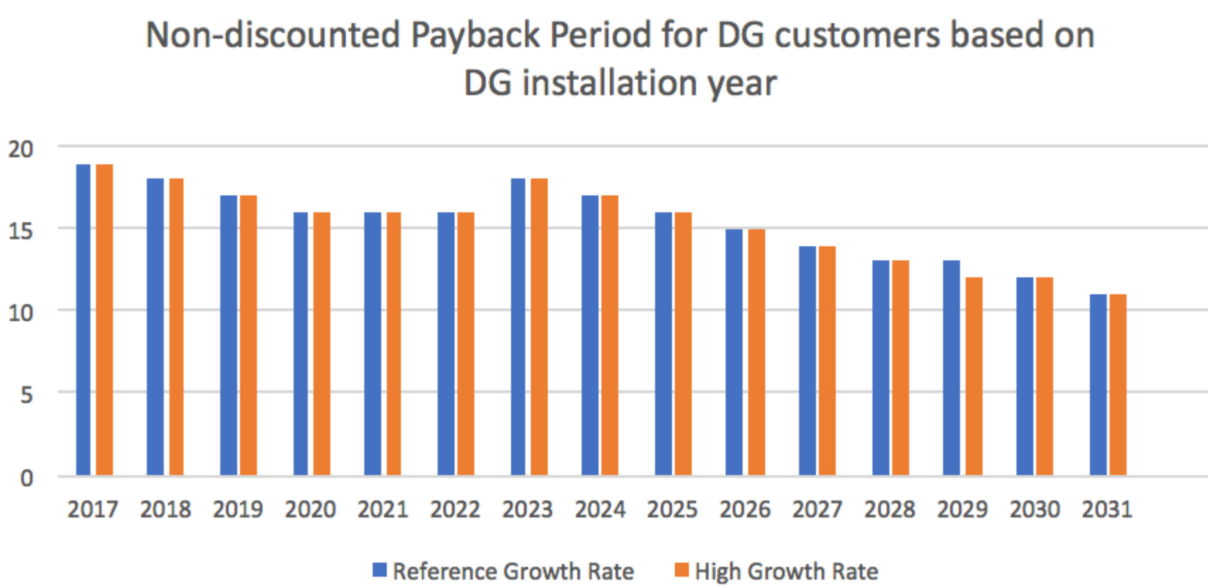

Figure 26 Payback period for DG customers under Net Billing

Scenario 4: Time-of-Use Net Metering

To model TOU rates, we used the rate structure currently in place for DTE's TOU pilot program. Those rates are 4.35 cents/kWh for off-peak on-season, 12.9 cents/kWh for on-peak on-season, 4.18 cents/kWh for off-peak off season, and 10.9 cents/kWh for on-peak off-season. We inflated each pricing tier equally. For time-of-use net metering customers, they are compensated at the going rate for the time period in which they produce.

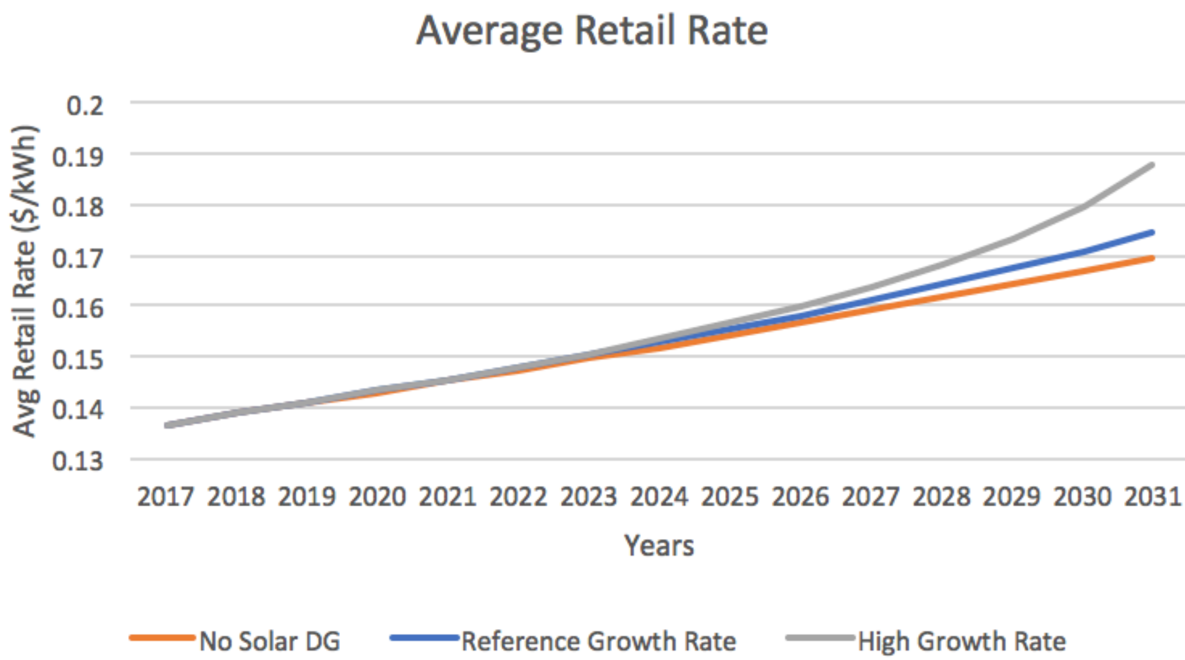

Figure 27 Average retail rate for DTE customers under Time-of-Use NEM

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ref	$ -	$ 0.57	$ 1.27	$ 2.12	$ 3.16	$ 4.44	$ 6.00	$ 7.91	$ 10.23	$ 13.06	$ 16.51	$ 20.70	$ 25.82	$ 32.05	$ 39.65
High Scenario	$ -	$ 0.57	$ 1.35	$ 2.44	$ 3.94	$ 6.03	$ 8.93	$ 12.94	$ 18.50	$ 26.22	$ 36.96	$ 51.97	$ 73.02	$ 102.79	$ 145.28
Ref (PV)	$ -	$ 0.53	$ 1.09	$ 1.68	$ 2.33	$ 3.02	$ 3.78	$ 4.62	$ 5.53	$ 6.53	$ 7.65	$ 8.88	$ 10.25	$ 11.78	$ 13.50
High Scenario (PV)	$ -	$ 0.53	$ 1.16	$ 1.93	$ 2.90	$ 4.11	$ 5.63	$ 7.55	$ 10.00	$ 13.12	$ 17.12	$ 22.29	$ 29.00	$ 37.80	$ 49.46

Table 8 Increases in customer bill each year for Time-of-Use NEM

In this scenario, retail rates rise much faster in the high growth scenario. Although the final year rates of 18.8 cents/kWh and 17.5 cents/kWh for the high growth and reference scenarios, respectively, are lower than their counterparts in the block volumetric retail rate scenario, the baseline ‘No Solar’ rate is also lower (17 cents/kWh as opposed to 17.4 cents/kWh). The final year percent increase in rates for the high and reference scenarios are 10.6% and 7.4% above the ‘No Solar’ scenario, both higher than the block volumetric scenario. The cross-subsidies fall between $39 and $146 by 2031. Figure 27 shows extremely high NPVs for TOU NEM. Under the reference scenario, NPVs hit $17,000, while climbing all the way to $24,000 in the high growth scenario. Payback periods start at 12 years and drop to between 6 and 7 by 2031.

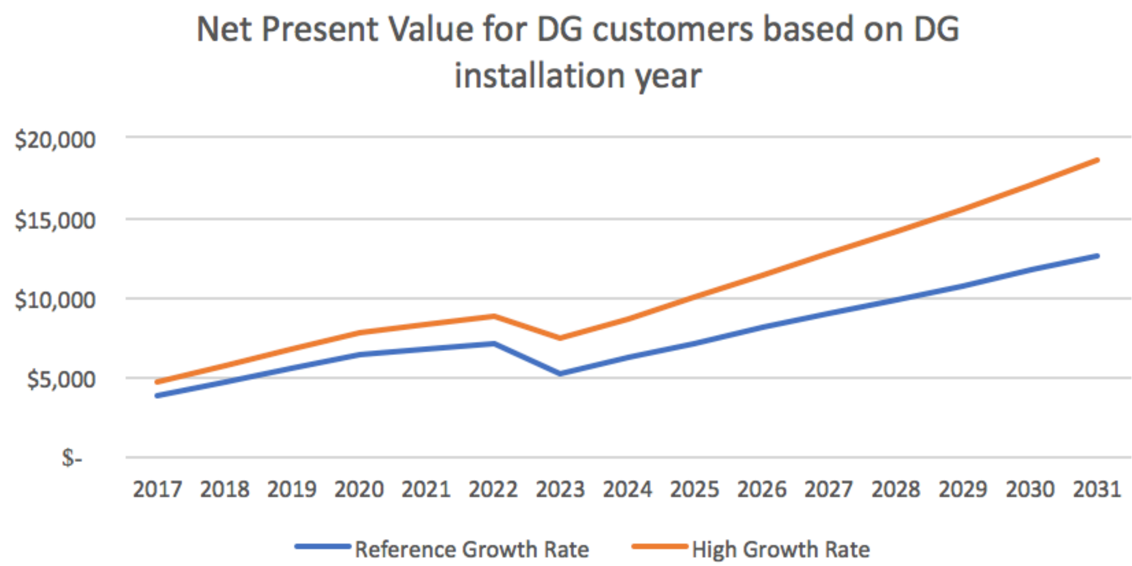

Figure 28 NPV for DG customers under Time-of-Use NEM

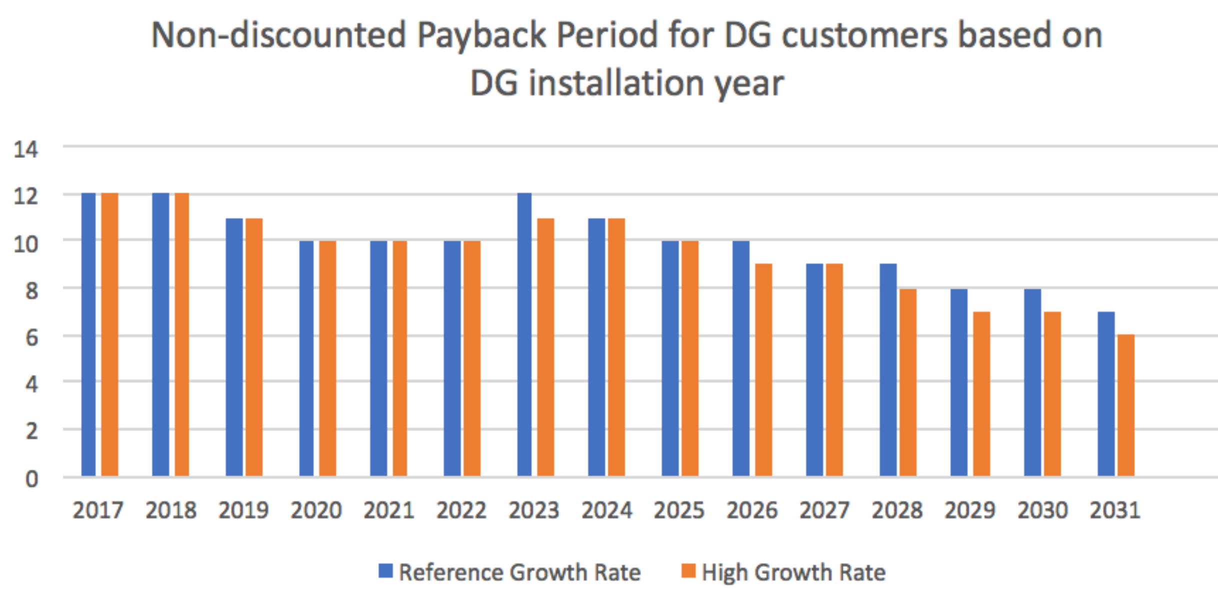

Figure 29 Payback period for DG customers under Time-of-Use NEM

Scenario 5: Time-of-Use Value-of-Solar

Low Value-of-Solar Rate

In this scenario, customers are charged for all consumption at the TOU rate, while they are compensated for all solar production at the VOS rate. Again, we will consider both the low rate and the NREL-recommended rate. As we will see, the differences between the block volumetric VOS policies and the TOU VOS policies resemble each other quite closely.

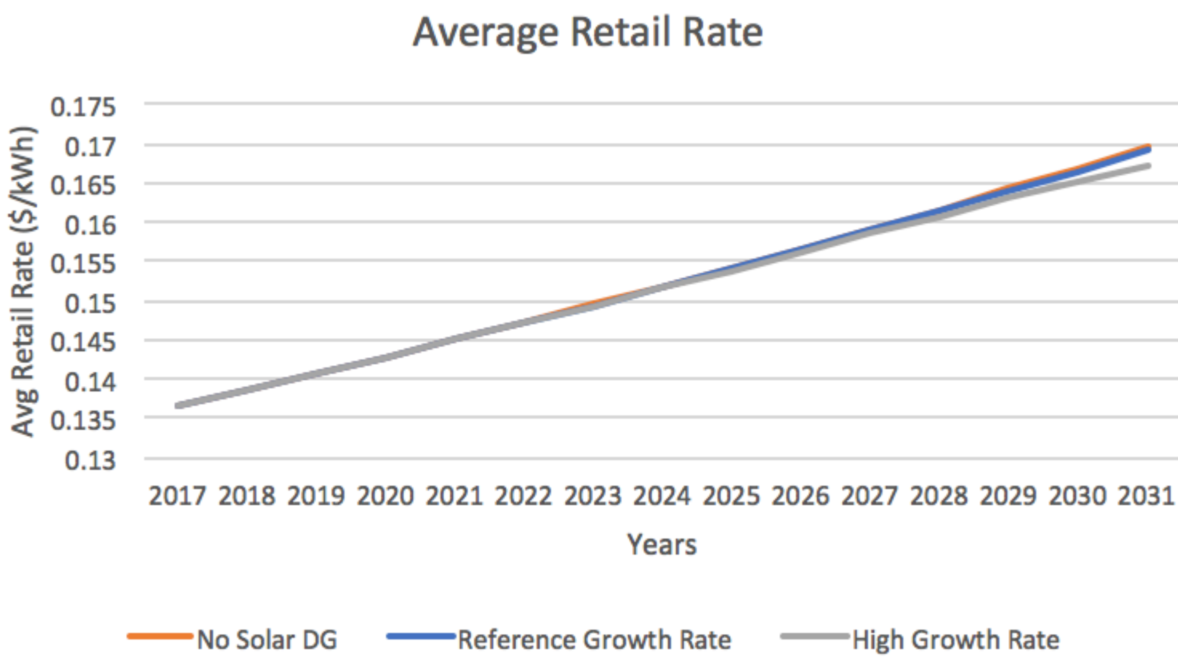

Figure 30 Average retail rate for DTE customers under Time-of-Use low value-of-solar policy

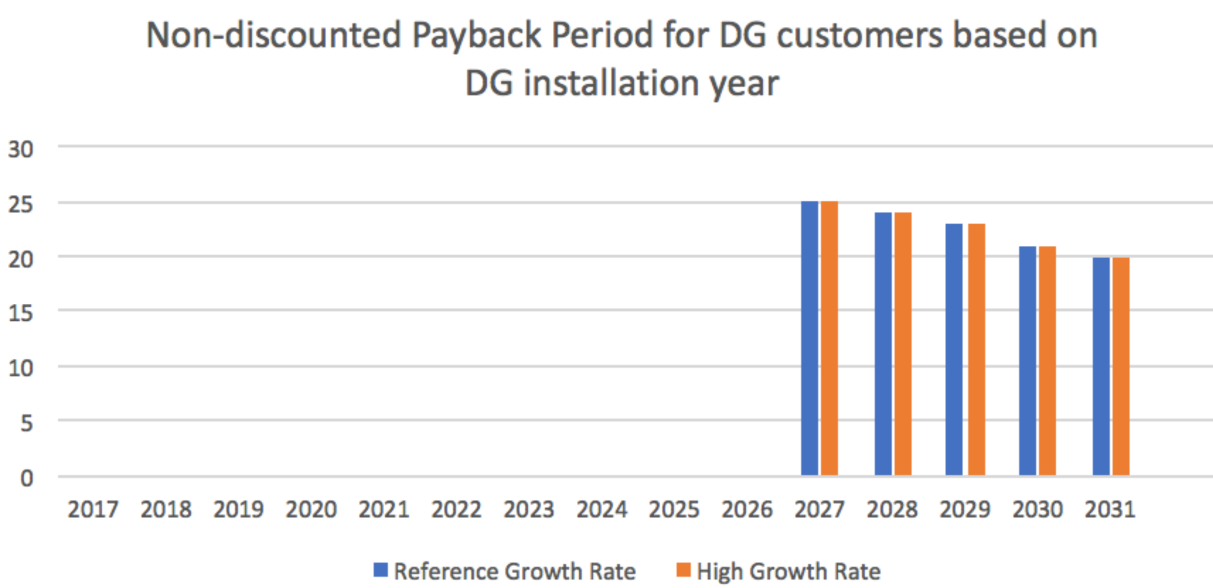

Figure 31 Payback period for DG customers under time-of-use low value-of-solar policy

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ref	$ -	$ (0.05)	$ (0.13)	$ (0.22)	$ (0.34)	$ (0.49)	$ (0.68)	$ (0.91)	$ (1.20)	$ (1.56)	$ (2.01)	$ (2.56)	$ (3.25)	$ (4.10)	$ (5.16)
High Scenario	$ -	$ (0.05)	$ (0.15)	$ (0.28)	$ (0.47)	$ (0.75)	$ (1.13)	$ (1.67)	$ (2.44)	$ (3.51)	$ (5.02)	$ (7.15)	$ (10.16)	$ (14.40)	$ (20.42)
Ref (PV)	$ -	$ (0.05)	$ (0.11)	$ (0.18)	$ (0.25)	$ (0.33)	$ (0.43)	$ (0.53)	$ (0.65)	$ (0.78)	$ (0.93)	$ (1.10)	$ (1.29)	$ (1.51)	$ (1.76)
High Scenario (PV)	$ -	$ (0.05)	$ (0.12)	$ (0.22)	$ (0.35)	$ (0.51)	$ (0.71)	$ (0.98)	$ (1.32)	$ (1.76)	$ (2.33)	$ (3.07)	$ (4.03)	$ (5.30)	$ (6.95)

Table 9 Increases in customer bill each year for time-of-use low value-of-solar

Like the block volumetric low VOS case, the TOU low VOS creates a reverse subsidy from DG-customers to non-DG customers. This results in rates that drop by up to half a cent/kWh by 2031, and subsidizes non-DG customers by $5.16 to $20.42 dollars per year by 2031. Project NPVs begin at less than -$7000 and end at -$2000, while payback only exists for projects installed in 2027 or later and reach a low of 20 years in 2031.

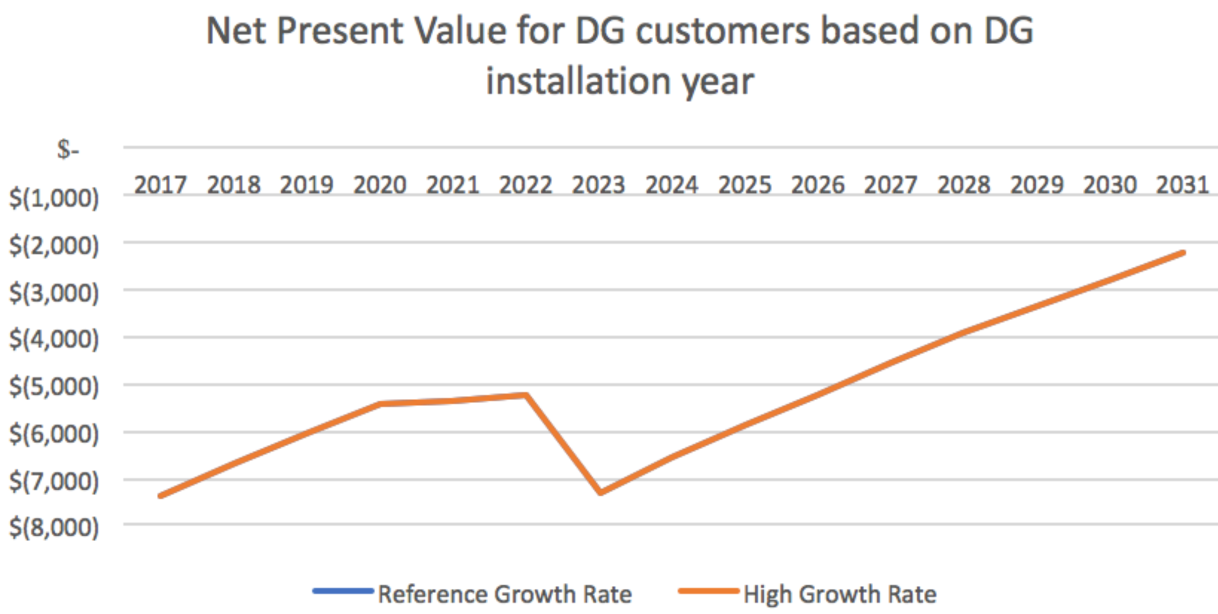

Figure 32 NPV for DG customers under time-of-use low value-of-solar policy

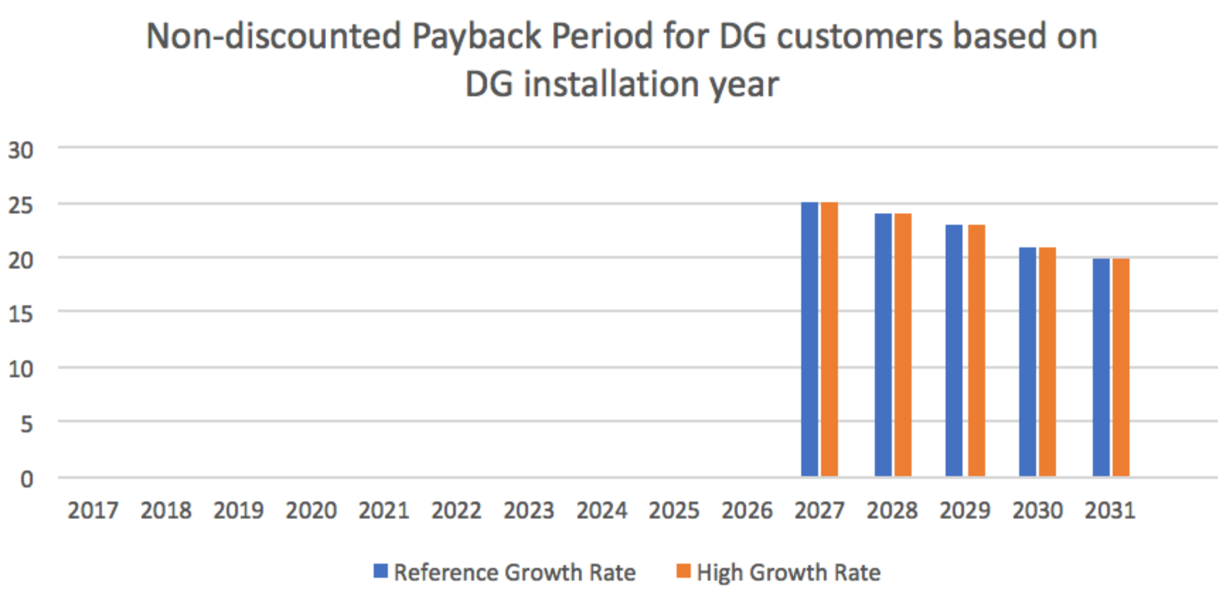

Figure 33 Payback period for DG customers under time-of-use low value-of-solar policy

NREL-Recommended Value-of-Solar Rate

Figures 32-34 and Table 10 show the effects of a 13.8 cents/kWh VOST combined with TOU retail rates. Retail rates inflate to between 17.2 cents/kWh and 18 cents/kWh. While the 2031 cross-subsidy falls between $25 and $86 per non-DG customer. NPVs start at over $3,000 and end at close to $13,000, while payback periods fall from 13 years to 7 by 2031.

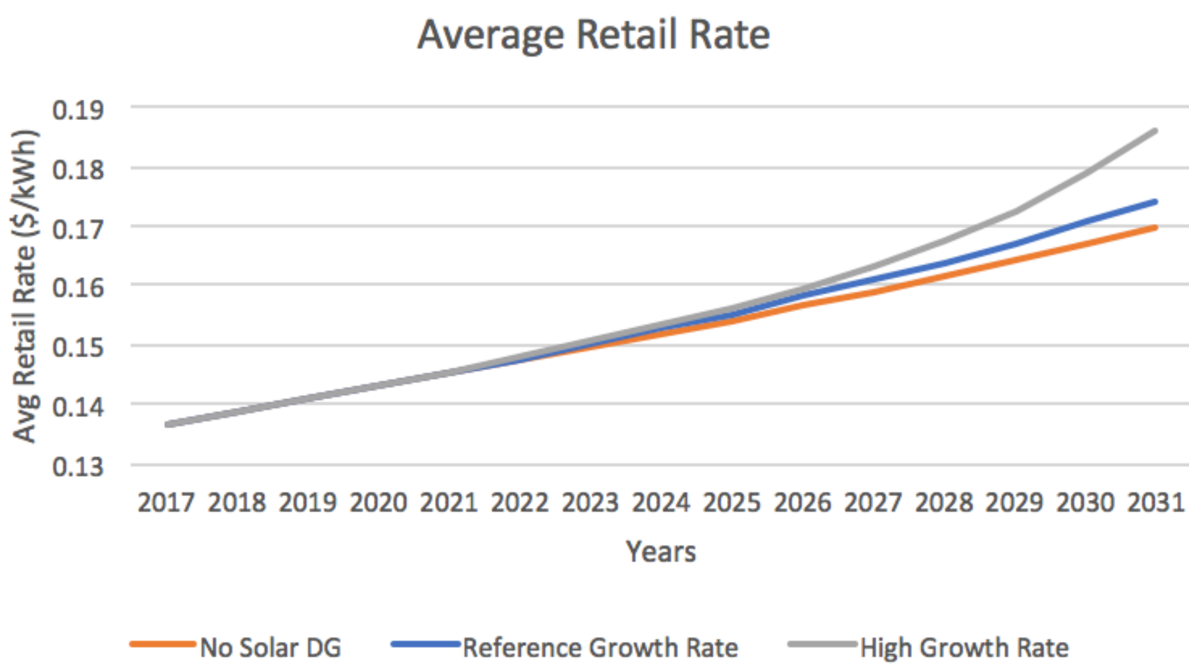

Figure 34 Average retail rate for DTE customers under NREL value-of-solar policy

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Ref	$ -	$ 0.49	$ 1.09	$ 1.84	$ 2.77	$ 3.91	$ 5.33	$ 7.08	$ 9.23	$ 11.87	$ 15.12	$ 19.12	$ 24.02	$ 30.04	$ 37.42
High Scenario	$ -	$ 0.49	$ 1.17	$ 2.11	$ 3.45	$ 5.32	$ 7.94	$ 11.61	$ 16.73	$ 23.89	$ 33.90	$ 47.90	$ 67.51	$ 95.01	$ 133.68
Ref (PV)	$ -	$ 0.46	$ 0.94	$ 1.46	$ 2.03	$ 2.66	$ 3.36	$ 4.13	$ 4.99	$ 5.94	$ 7.01	$ 8.20	$ 9.54	$ 11.05	$ 12.74
High Scenario (PV)	$ -	$ 0.46	$ 1.00	$ 1.68	$ 2.53	$ 3.62	$ 5.00	$ 6.77	$ 9.04	$ 11.95	$ 15.70	$ 20.54	$ 26.81	$ 34.94	$ 45.51

Table 10 Increase in non-DG customer bill each year under NREL value-of-solar

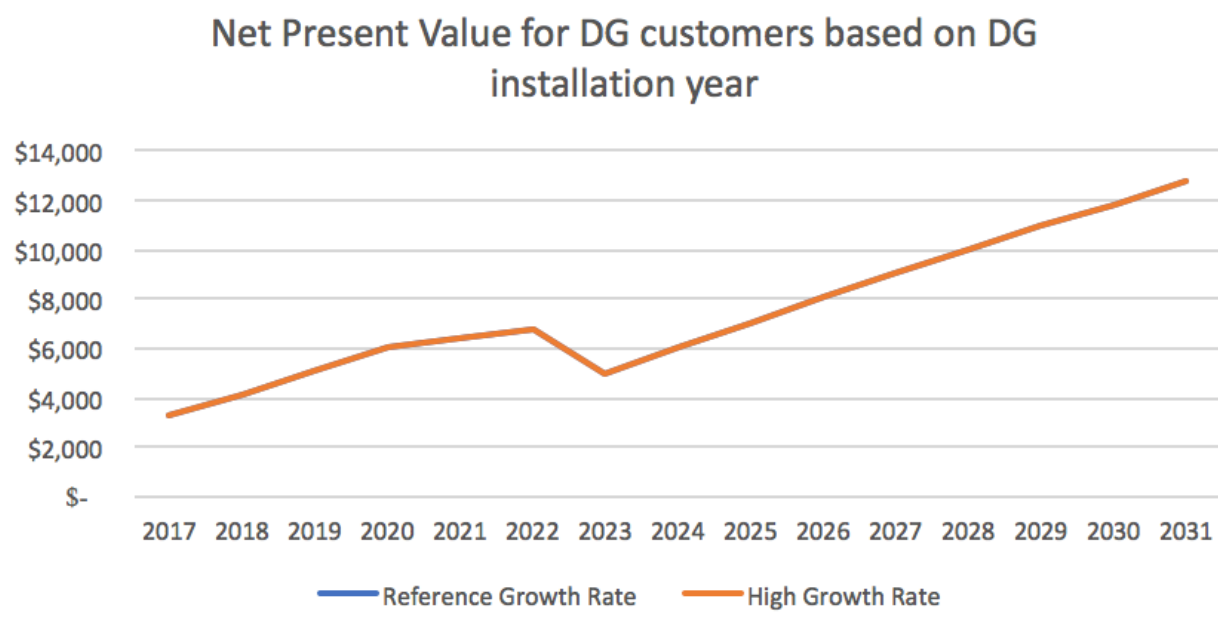

Figure 35 NPV for DG customers under NREL value-of-solar for time-of-use rate structure

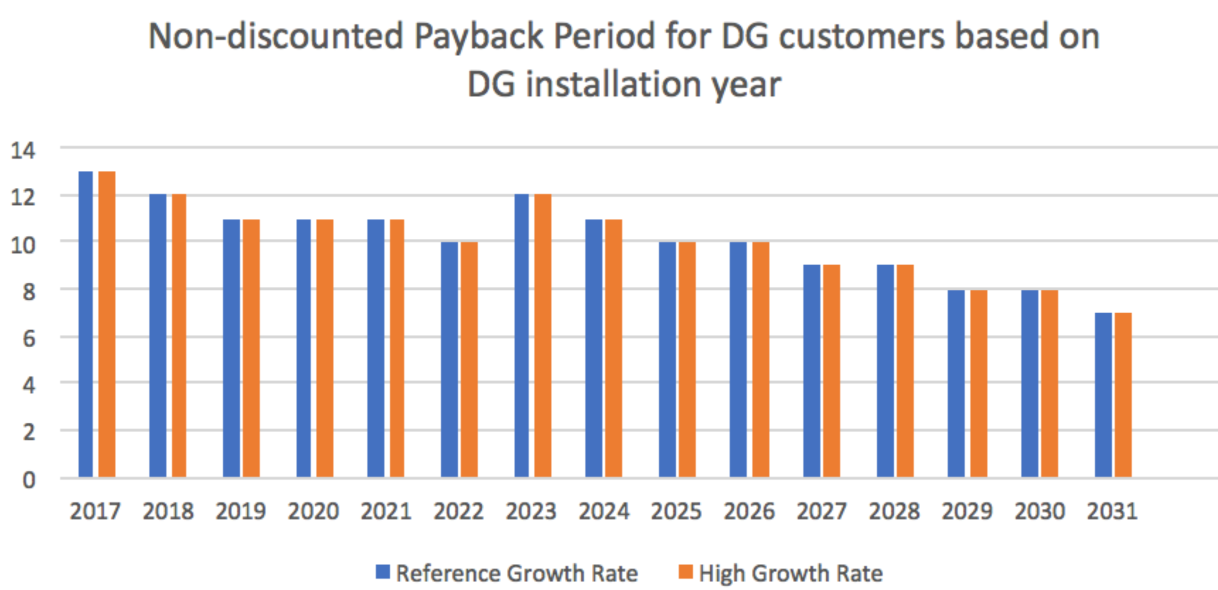

Figure 36 Payback period for DG customers under NREL value-of-solar for time-of-use rate structure

Health and Environmental Benefits Results

CO2, SO2 and NOx Emission Reductions in Both Adoption Scenarios

The two charts below show as solar adoption rates goes higher, more emissions of the pollutants will be reduced. In the reference scenario, emission reduction can be achieved by 97,548 metric ton for CO2, 133.51 metric ton for SO2 and 58.48 metric ton for NOx in 2031. In the high scenario, emission reduction can be achieved by 595,340 metric ton for CO2, 814.79 metric ton for SO2 and 356.89 metric ton for NOx in 2031, which are more than six time larger than the results under the reference scenario. Also, the reduction rates go higher when there is more electricity generated by solar energy.

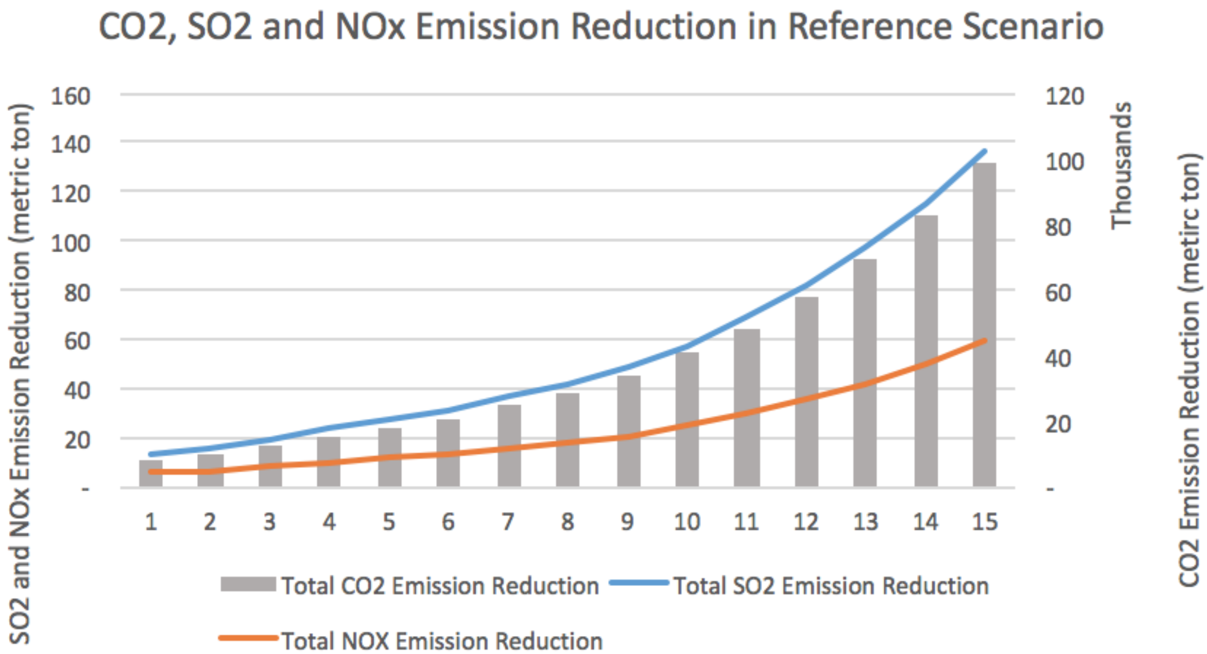

Figure 37 CO2, SO2 and NOx emission reduction based on reference scenario

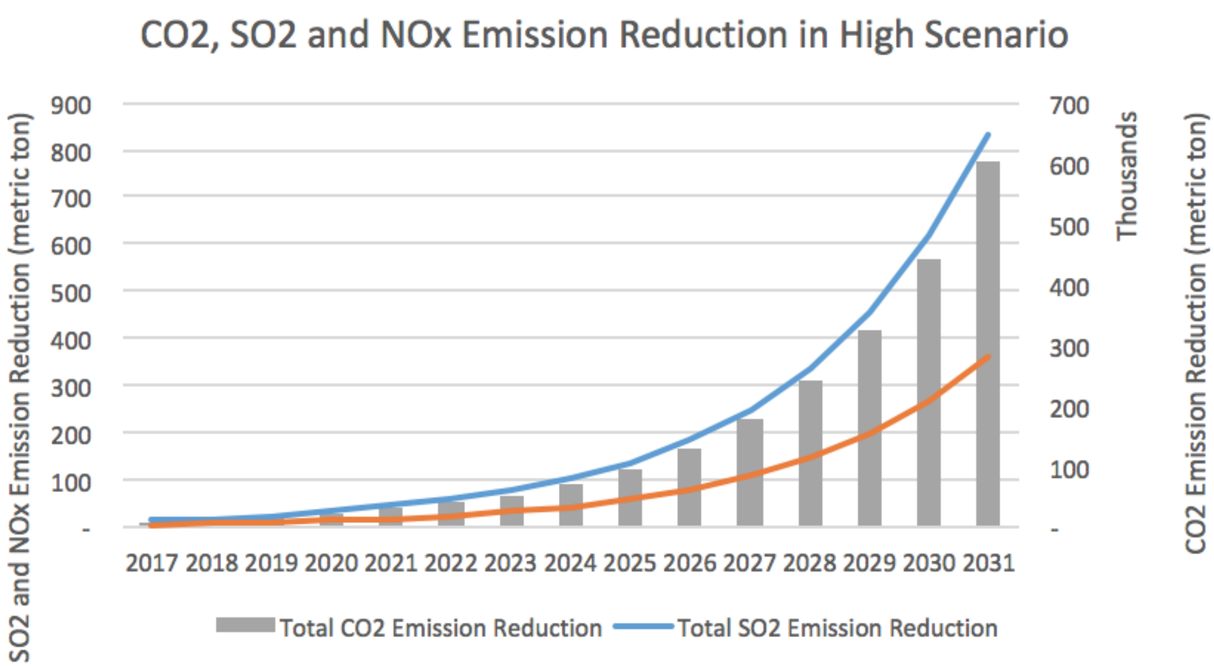

Figure 38 CO2, SO2 and NOx emission reduction based on high scenario

Here we have two offset fuel generation results under the reference and high scenarios. In 2017, the amount of coal offset is 2.19 times larger than the amount of natural gas. But, in 2031, the amount of coal offset is 1.44 times larger than the amount of natural gas as we assume the dependence on coal as a resource for electricity generation decreases. With the increase in solar energy adoption rate, it will help Michigan reduce more natural gas and coal for electricity generation, which can achieve 3,111,321 MMBTU natural gas and 4,493,208 MMBTU coal in high scenario in 2031.

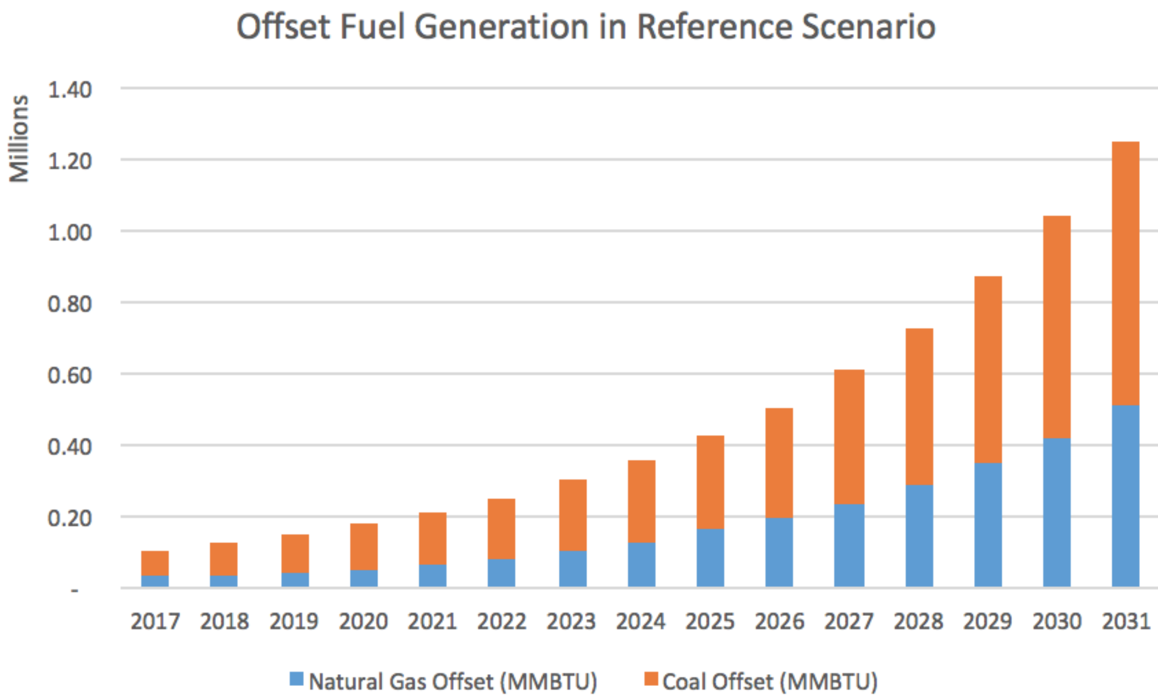

Figure 39 Offset fuel generation in the reference scenario

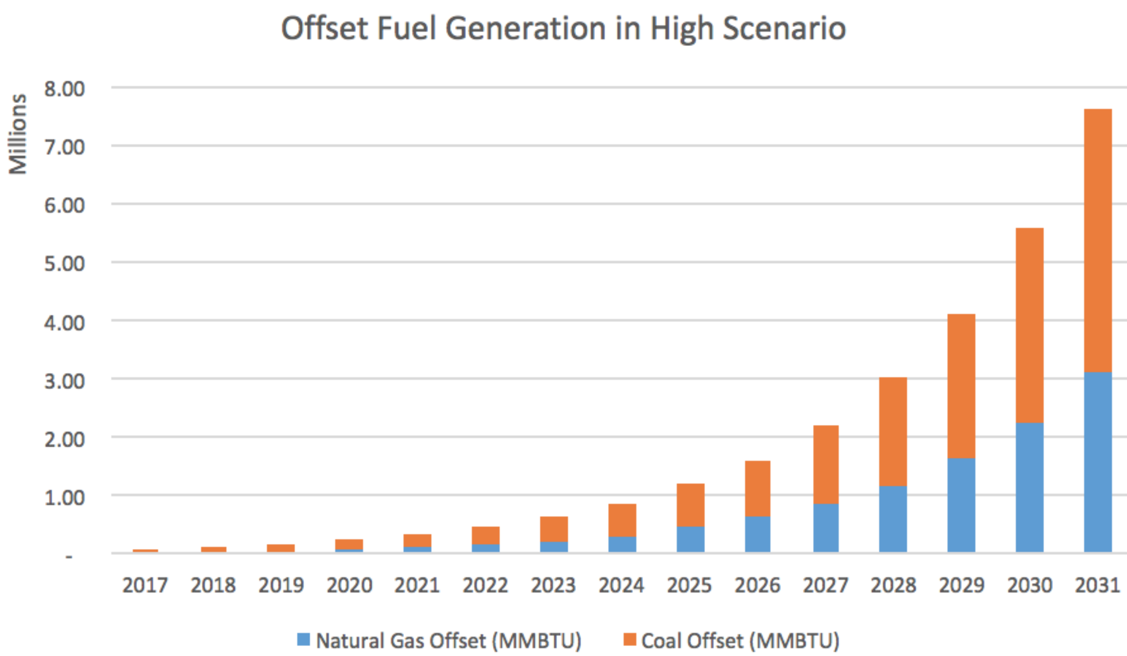

Figure 40 Offset fuel generation in the high scenario

Environmental and Health Benefits in Both Adoption Scenarios

These graphs show that the higher the solar energy adoption rate is, the higher growth rate of environmental and health benefits DTE customer are expected to get.

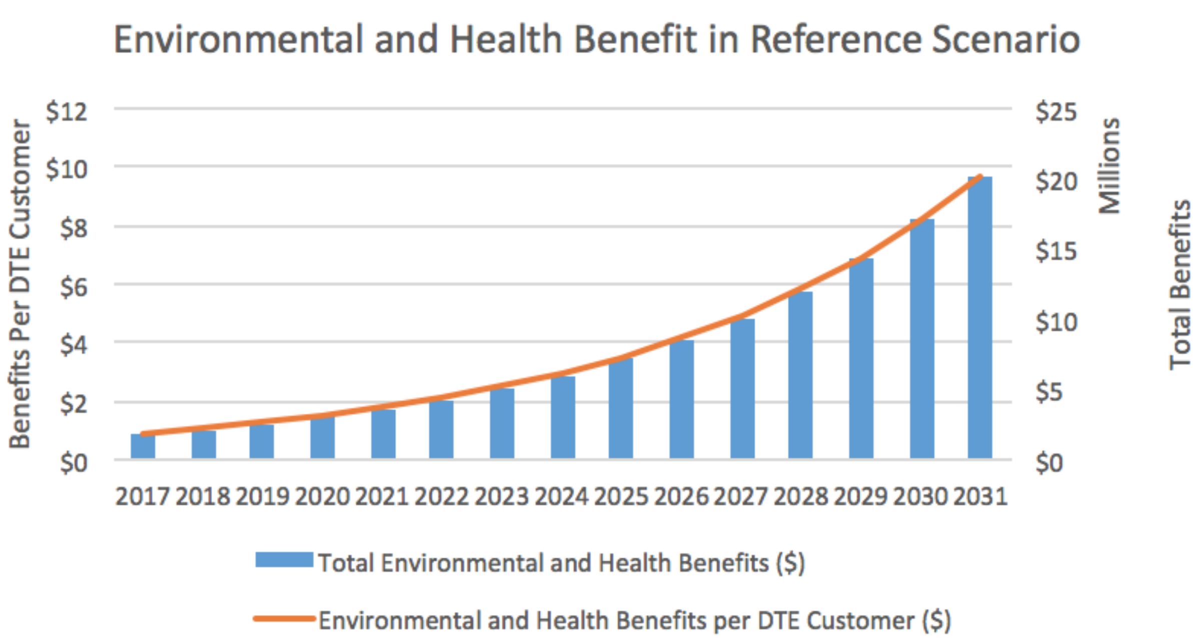

Figure 41 Environmental and health benefit in reference scenario

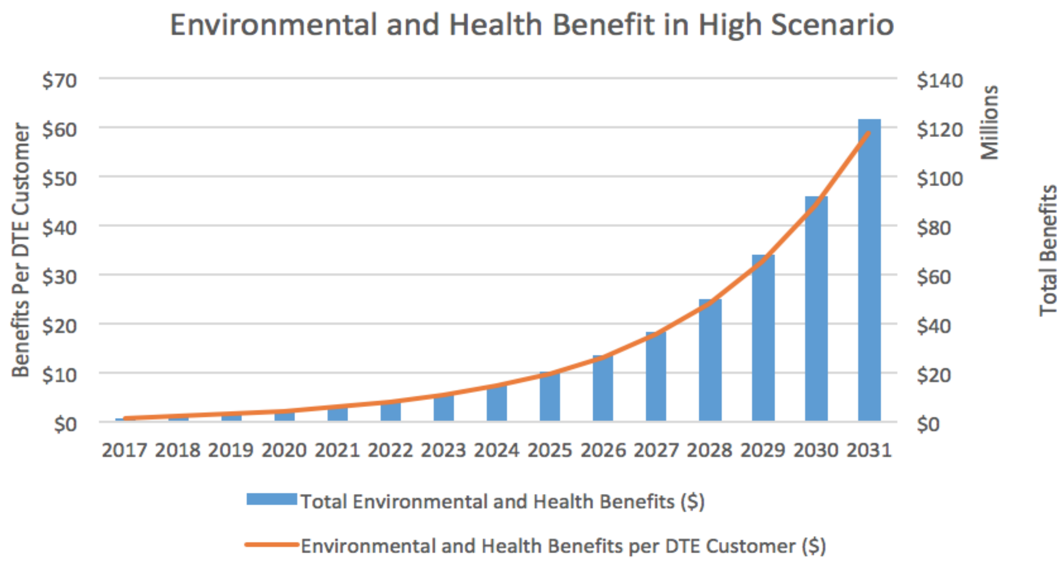

Figure 42 Environmental and health benefit in high growth scenario

Comparison Between Scenarios

Table 11 shows NPV for DG customer, average retail rate, utility bill for non-DG customers and increase in utility bill from no solar scenario. We can see that the maximum payback is for the low VOS (3.9 cents/kWh), the highest average utility rate and utility bill is for block volumetric retail rate net metering. The increase from no solar in time-of-use rate structure is for net metering.

Scenario	NPV (2031)	2017 Non-discounted Payback Period	2031 Non-discounted Payback Period	Average Retail Rate (2031)	Utility Bill (2031)	Increase from No Solar (2031)
No Solar	-		-	$ 0.1739	$ 1,399	-
Net Metering	$ 10,264.62	13	8	$ 0.1779	$ 1,431	$ 32.55
Net Metering Fixed Charge ($10)	$ 8,814.77	15	8	$ 0.1773	$ 1,426	$ 27.34
Net Metering Fixed Charge ($25)	$ 6,641.78	17	10	$ 0.1763	$ 1,418	$ 19.53
Net Billing	$ 4,126.78	19	11	$ 0.1755	$ 1,411	$ 12.92
Low VOS	$ (2,180.22)	None	20	$ 0.1732	$ 1,393	$ (5.16)
VOS NREL	$ 12,813.85	13	7	$ 0.1785	$ 1,436	$ 37.42
No Solar	-		-	$ 0.1697	$ 1,365	-
Net Metering	$ 12,521.94	12	7	$ 0.1747	$ 1,405	$ 39.65
Low VOS	$ (2,180.22)	None	20	$ 0.1691	$ 1,360	$ (5.16)
VOS NREL	$ 12,813.85	13	7	$ 0.1744	$ 1,403	$ 37.42

Table 11 Comparison of NPV, average retail rate, payback period, utility bill for non-DG customer and increase in electricity bill from no-solar scenario under different policy scenarios

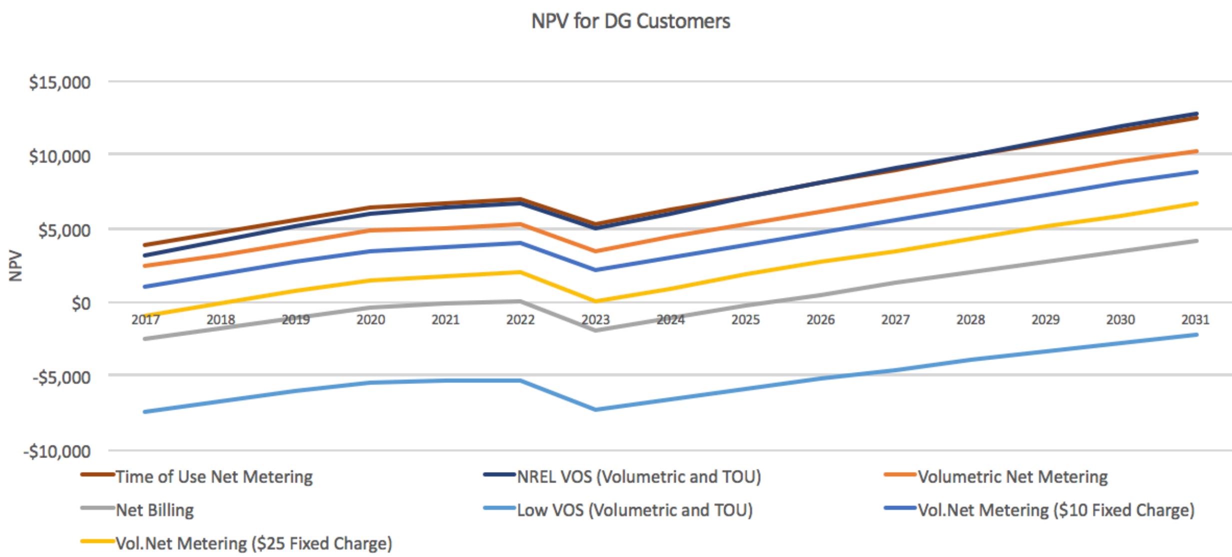

Figure 43 Comparison of NPV values under various policy scenarios

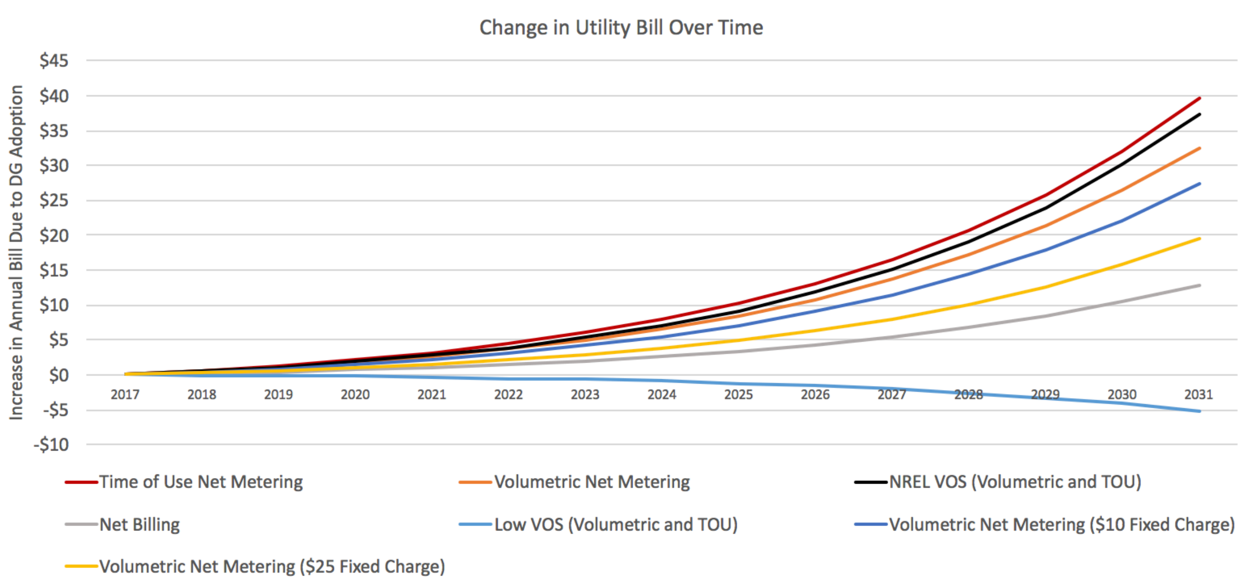

Figure 44 Comparison of change in utility bill for a non-DG customer over time under various policy scenarios

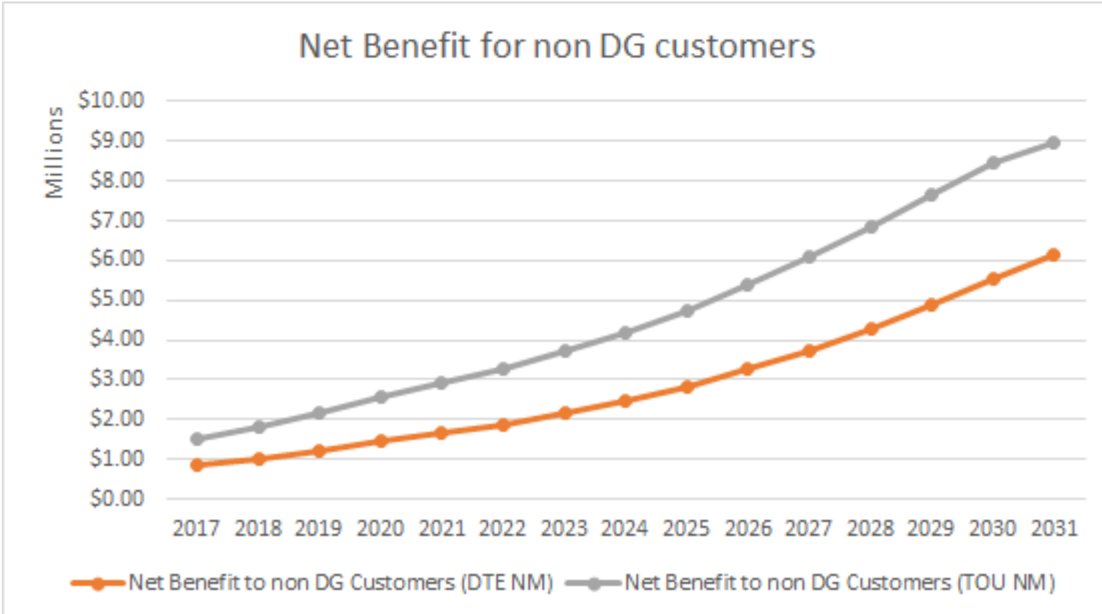

Figure 45 Net benefit (Total Benefit-Total Cost) for DTE NEM scenario and Time-of-Use NEM scenario

We quantify the total health and environmental benefits to non-DG customers and compare it with the total cost borne by non-DG customers due to the cost shift and utility escalation for the reference growth rate. The scenarios considered are DTE net metering as it is the current policy and time-of-use net metering as the increase in utility bill for non-DG customers is maximum for that scenario. We find that the health and environmental benefits exceed the increase in cost due solar DG and utility escalation in all the scenarios analyzed.

Discussion

This section will further discuss our model results and will also cover a few points of interest that fall outside of the scope of the core model. First, we discuss how the results are likely to be viewed by different stakeholder groups. We then demonstrate the sensitivity of the results to two parameters (the wholesale and retail escalation rates). The next section draws from the environmental and health modules to do a cost-benefit analysis for non-DG owners over the modeled period. We then examine the added energy burden of certain policies on low-income customers and propose a dynamic fixed charge for solar owners to compensate the lowest-income customers. Finally, we discuss alternate approaches for utilities to deal with the issues around the financial impacts of distributed solar.

Stakeholder Perspectives

It is clear from figures 42 and 43 that any solar compensation policy choice will create winners and losers. Figure 45 shows one way of comparing the effects of each policy on both DG and non-DG customers. The horizontal axis shows the 2031 bill increase over the "No-Solar" case for a single non-DG customer while the vertical axis shows the 2031 NPV of a typical residential solar project in the DTE footprint. It is clear that in general the higher the cross-subsidy, the higher the project NPV.

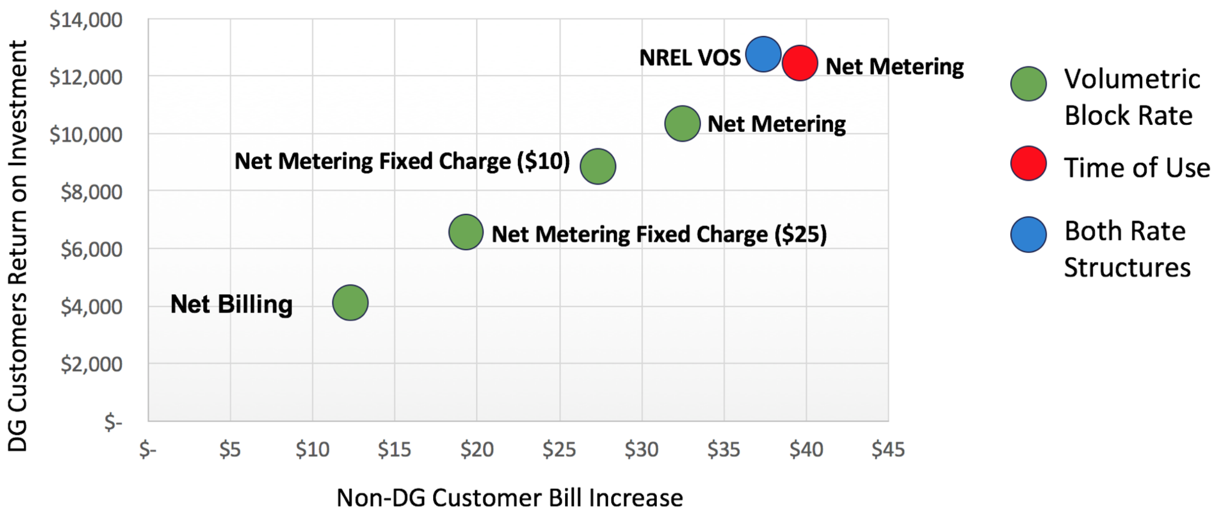

Figure 46 NPV (DG customer) vs. Bill Increase (non-DG customer) for various policy options

From the perspective of DG-owners and solar advocates, both net metering systems (block volumetric and time-of-use) and the NREL VOS compensation rate provide the greatest NPV, and presumably the greatest incentive to install solar. All four of these retail rate-compensation rate combinations result in 2031 NPVs over $10,000 with the 8% discount rate. It is notable that despite the setup of the model as a zero-sum game between DG and non-DG owning customers, the NREL VOS tariff ostensibly provides both a lower cost shift and higher NPV than time-of-use net-metering. It should be noted, however, that several factors could contribute to NREL VOS's NPV being higher, in particular the front-loading of benefits in VOS cases. It is also true that these NPVs are computed over the period of 2031-2056, while the cross-subsidy specifically reflects lost revenue from the period (in other words, there is a lag between NPVs and cross-subsidies). In these scenarios, non-DG owners each provide a subsidy of between $32 and $39 dollars, or between $2.60 and $3.25 per month.

Net billing and the low VOS estimate are the policy options that will most satisfy non-DG customers and utilities. While the low VOS estimate is not present in Figure 45, it results in a negative 2031 NPV and a non-DG customer bill decrease instead of an increase. This policy would likely appeal to non-DG customers because of this subsidy that is provided to them from DG customers. It is worth noting that it is unlikely that the Michigan Public Service Commission would allow such a policy. Net billing, on the other hand, still provides some level of subsidy to DG owners, but brings that subsidy closer to zero, a result some utilities might find more acceptable. In both of these scenarios, NPVs are low enough that solar adoption could suffer significantly. In fact, even in the net billing scenario, NPVs do not become positive until 2020 and drop below zero for two years after the ITC expires.

Finally, continuing retail-rate net metering but introducing fixed charges seems to find a middle ground between the two, though not necessarily a comfortable one. The ten-dollar fixed charge never impacts NPVs enough to make them negative, but they start relatively low (at just over

$1000). The $25 monthly fixed charge, however, does result in negative NPVs, with the maximum NPV ending at just over $6000 (compared to $10-12k for net metering cases).

Because of the linear relationship between solar project value and burden on non-DG customers, it appears a value judgment must be made about what the acceptable amount of cross-subsidy to support the residential solar industry should be. Despite this, it should be noted that this subsidy need not come directly from non-DG owning customers – these plots merely show its magnitude if it were to.

Key Drivers and Sensitivities

In an attempt to compare policies on an apples-to-apples basis, we held many parameters constant over all scenarios. These parameters can have significant effects on the measured variables. To give an example of NPV and cross-subsidy sensitivity to particular parameters, we recomputed these measures with higher and lower estimates of the utility escalation rate and the MISO escalation rate. Essentially, these parameters control the annual change in the base retail rate and the annual change in the marginal wholesale price of electricity. Currently, they are set to 2.5% and 2.81%, respectively.

The 2.5% retail rate escalation implies that year after year, DTE must collect 2.5% more revenue than the previous year to account for all of its O&M, the return-on-equity it owes its investors, debt service, etc. In reality, a utility's revenue requirement is unlikely to rise at a steady rate, but will increase and decrease depending on the status of its capital investments. The retail rate escalation is important to DG and non-DG customers because it will increase the value of every solar kWh without necessarily increasing the utility's avoided cost. This would presumably lead to higher NPVs and higher cost-shifts. On the other hand, low rate escalation would have the opposite effect, decreasing solar project value and reducing cost-shift. To obtain a range of escalation rates, we used the lowest and highest average annual state retail escalation over the past decade. This was estimated to be 6.11% for Hawai'i and 0.66% for Louisiana **[91]**.

For wholesale rate inflation, we made the simplifying assumption that natural gas would always be the fuel on the margin. The MISO escalation rate was originally set at 2.81% per year to match EIA's forecast for natural gas prices, but higher and lower estimates also exist. According to the World Bank's October 2016 Commodity Markets Outlook, natural gas prices will inflate at an uneven rate over the next eight years, starting at 17% in 2018 and gradually tapering down to roughly 4% in 2025 **[92]**. At the other end of the spectrum, IMF's commodity price forecasting has no increase in natural gas prices throughout the modeled period (until 2022) **[93]**.

Using both the low and high estimates of each of the above parameters, we recomputed NPVs and cost-shifts for the block volumetric retail-rate net metering case. Figure 46 shows the results for NPVs. As expected, the high utility escalation scenarios result in very high NPVs (reaching up $27,500) and the low utility escalation scenarios result in very low NPVs. The wholesale rates do not seem affect the NPV of projects in any appreciable way, indicating that the retail rate is the primary driver. All in all, the entire range of possible 2031 NPVs falls between $5000 and $27,500.

Likewise, Figure 47 shows the range of cost-shifts incurred by each escalation rate scenario. In this case, the utility escalation rate is not the only significant driver (though it does seem to have a larger effect than the wholesale rate escalation). The maximum cost-shift is, expectedly, the case in which the wholesale rate escalates slowly while the retail rate escalates quickly (leading to the biggest gap between a utility's revenue and their revenue requirement), while the minimum cost-shift comes from the scenario in which the retail rate escalates slowly while the wholesale rate escalates quickly. The entire range of 2031 cost burdens for individual non-DG customers is between $18 and $58 dollars.

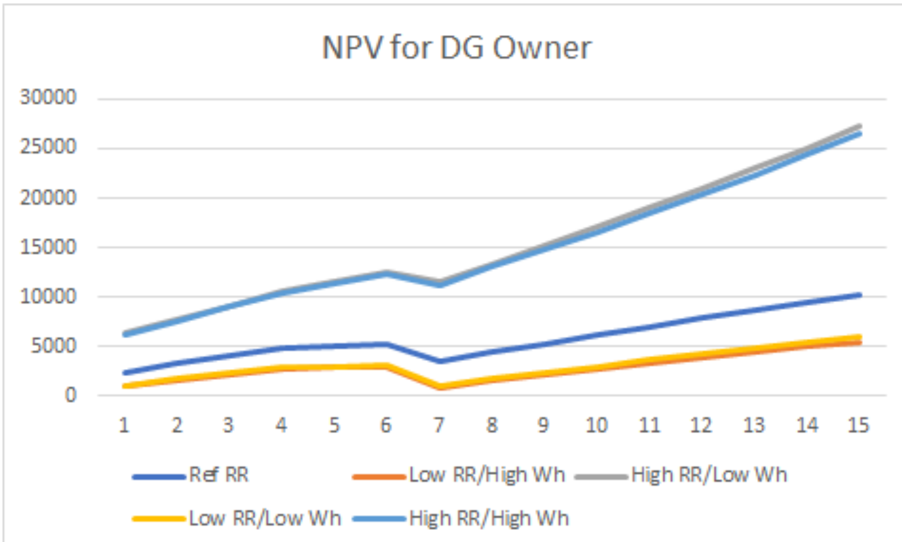

Figure 47 NPVs ($) for solar projects under high and low wholesale and retail escalation rates

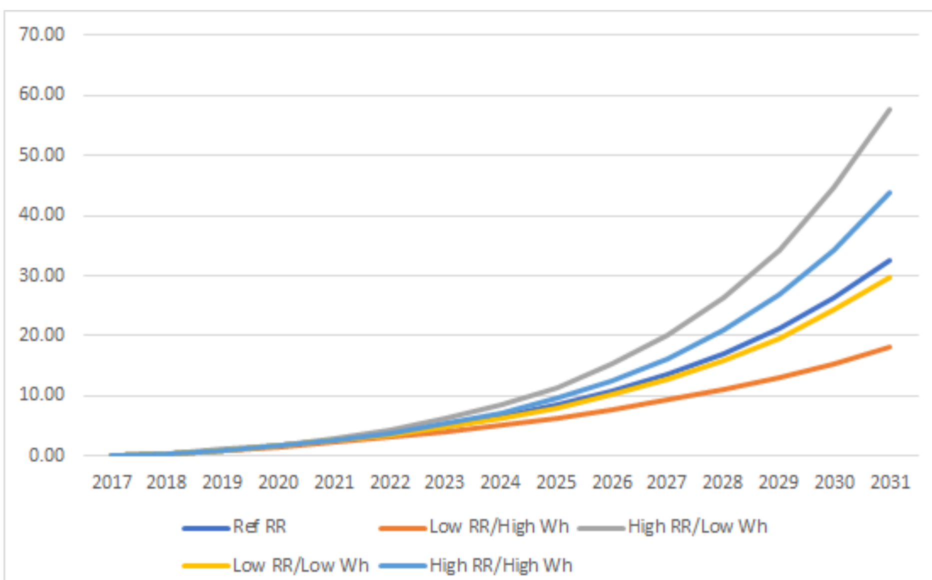

Figure 48 Additional utility bill burden to a non-DG customer due to solar-related cost-shift

Cumulative Cost-Benefit Analysis For Non-DG Customers

Incorporating some measures of the environmental and health benefits of solar electricity, we conducted a cumulative cost-benefit analysis for individual non-DG customers over the fifteen-year period. Cost to a non-DG customer here refers to the incremental cost increase in a utility bill compared to a scenario in which there is no solar on the market. The benefits are the total environmental and health benefits from reduced CO2, SO2, NOx, and particulate matter emissions. The results of this analysis under the time-of-use NEM and block volumetric rate NEM scenarios shows net benefits are positive in both cases. The compensation mechanism that presumably results in highest bill increase to non-DG customer is TOU NM, implying that all policy options will result in net benefits.

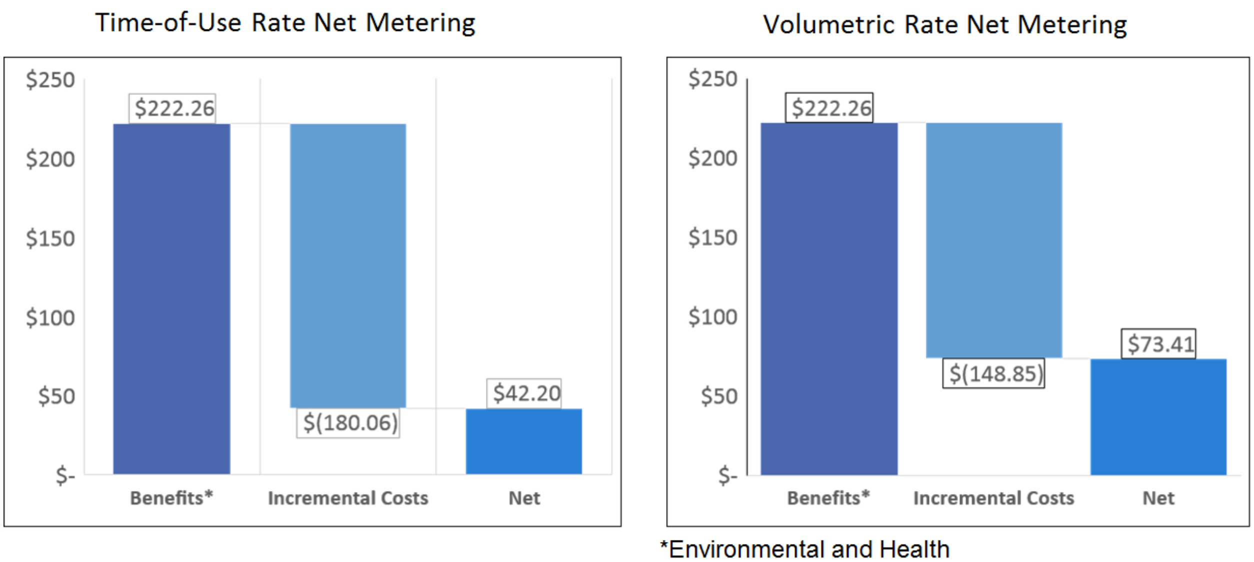

Figure 49 Cumulative cost-benefit analysis over 2017–2031 per non-DG customer (undiscounted)

As can be seen in Figure 48, if DTE continues to implement NEM under their standard block volumetric rate, a non-DG customer is expected to receive a net benefit of $73.41 from 2017 to 2031. If DTE chooses a Time-of-Use Rate as its new retail rate structure, a non-DG customer is still expected to earn $42.20 as net benefits during the same 15 modeled years. Though the net benefit amount under the time-of-use NEM is over $30 less than the business as usual case, the net benefit is still positive. Therefore, we believe considering the total environmental and health benefits from the increased solar electricity, the incremental costs are offset and non-DG customers also receive net benefits from the clean energy.

In our model, the total environmental and health benefits are consistent under different retail rate structures and policies due to the same number of DG customers. However, the different retail rate structures with NEM will result in different net benefits. Different levels of net benefits may affect the number of non-DG customers and the net benefits per non-DG customers will also be affected.

It should be noted that this brief analysis assumes that non-DG customers each receive a *pro-rata* share of the environmental and health benefits produced. To some degree, this assumption is justified for health benefits, as displaced emissions of PM and other pollutants from coal plants will primarily affect the communities that surround these plants. On the other hand, the environmental benefits (here measured only as the social cost of carbon), has global effects, making it very difficult to say with certainty how much of that benefit a DTE residential customer would receive.

Cross-Subsidy Mitigation for Low-Income Customers

While the cost-shift predicted by our model may not be a problem at low adoption rates for most Michiganders, low-income customers, who have difficulty paying their utility bill already, may be affected. Out of DTE's 1.9 million residential customers, around 125 thousand participate in assistance programs for payment of utility services **[94]**.

An ideal solution would create the health and environmental benefits received from solar without causing undue burden on low-income non-DG customers. This could be accomplished by proposing a monthly fixed fee to DG owners that would completely offset the increase in utility rates for customers on assistance programs that would happen because of solar DG adoption.

We attempted to quantify that fixed charge. We assumed that number of low income customers in assistance programs rises at the same rate as the rise in total number of residential customers. Using this assumption, we calculated a monthly fee for DG customers which escalates each year based on DG adoption. Figure 49 shows the value of that fee for the period modeled. As can be seen, the fee begins at a modest $3 per month in 2018, eventually leveling off to about $22 per month in 2031.

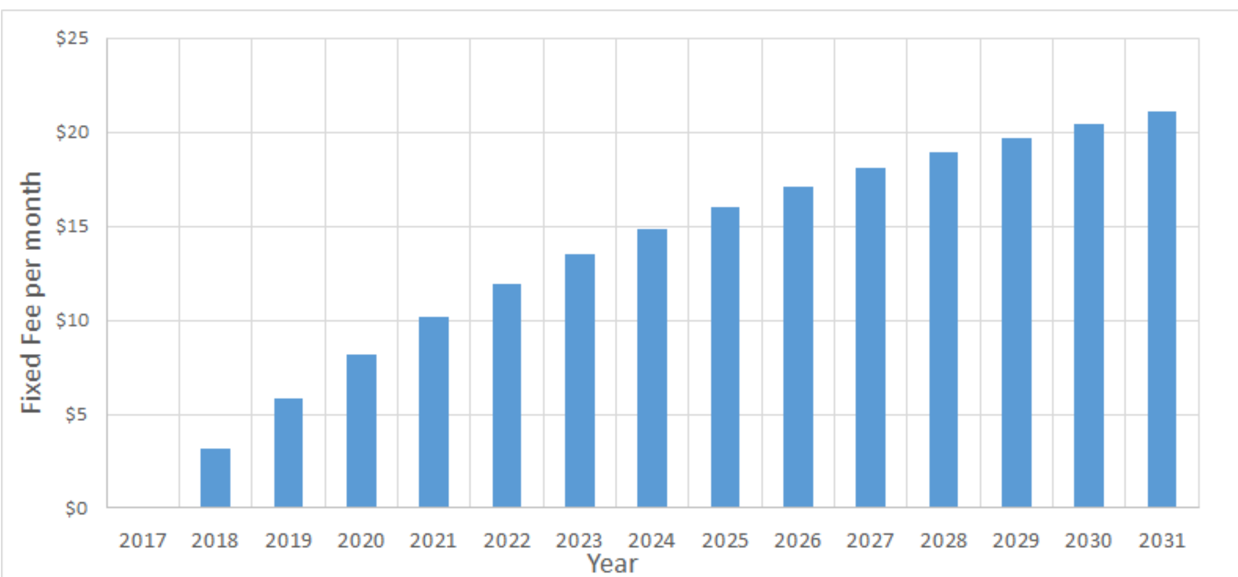

Figure 50 Proposed monthly dynamic fixed charge

NPVs under such a policy is shown in Figure 50. This fee affects project NPVs in the initial few years more significantly than in later years and could potentially reduce solar DG adoption. The

NPV is lower for all years than the NPV under net metering but the NPV remains positive throughout the timeline. In the later years, as the NPV is higher due to decreasing solar costs and increasing costs of grid electricity, solar adoption will not be affected. NPVs in later are, however, highly sensitive to the number of customers in assistance programs, so if relative proportion of such customers grows rather than shrinks, as we have predicted, project value in later years could be lower.

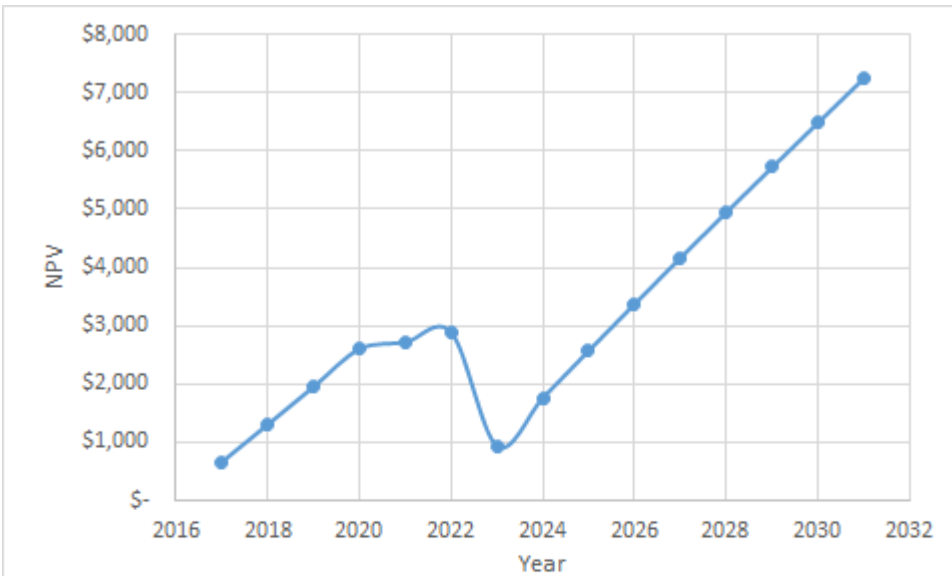

Figure 51 NPV for DG customer based on installation year under annually changing fixed costs

Such a solution would prevent cost-shifting to the most financially vulnerable non-DG customers. Some elements of the approach would be limiting, as many low-income customers are not necessarily on assistance programs, but may still feel the burden of the cost-shift.

Alternative Policy Approaches

This project focused on one aspect of net metering reform: the magnitude of the subsidies to DG owners and the cross-subsidies from non-DG owners. As a result, the proposed solutions have primarily centered on finding the 'correct' level of subsidy. However, there are several other approaches to net metering reform that could help shift net metering debates away from the zero-sum game they are often portrayed to be. NREL has proposed four distinct approaches to addressing utility financial concerns with net metering policy **[95]**. We will briefly discuss these four options. Because the first option among these is to reduce compensation to DG customers, we will not spend additional time on it (this section is based on the referenced article) **[96].**

The second option is for utilities to help get DG deployed in the times and places at which they will bring the highest value. Such efforts have begun in several places. California has already required their net-metering successor tariff (due in 2019) to factor time and location in, and Vermont has proposed siting credits for DG owners who adopt in locations that could provide distribution grid services **[97]**. While such programs are promising for solar valuation, there remains significant technical challenges to determining the locational value of small distributed solar projects. Beyond offering financial incentives for customers to install solar systems in high-value locations, utilities can take the reins and install or finance PV systems on high-value rooftops or yards, or extend such an approach to community solar programs. Utility ownership of distributed PV was famously implemented by three Arizona utilities at the end of 2014 **[98]**.

The third option is to help more customers adopt distributed solar. The purpose of this strategy is to reduce the cross-subsidy by allowing those for whom rooftop solar is too expensive to participate in community solar programs or gain access to solar financing. It is worth noting that such an approach could have unintended effects for any individual customer that remains without solar access because it does not address the issue of reduced utility revenue. Implementation strategies for such an approach have been formalized in a Utility Dive playbook for community solar **[99]**.

The fourth approach is to attempt to "align utility profits" with DG **[100]**. The solutions in this category are more radical and would require significant regulatory reform. One option within this category would be decoupling, or breaking the link between a utility's revenue and their electricity sales, or a 'lost fixed cost revenue' program which compensates a utility for the energy-efficiency programs that eat into their revenue. At least 15 states have begun to experiment with options like this **[101]**. Another option is to create performance-based incentives for utilities (as opposed to cost-of-service incentives) which reward utilities for meeting certain goals, one of which could be support for distributed energy resources **[102]**.

Future Work

There are many ways the model could be expanded to better achieve its goal of measuring the impacts of DG compensation policies on utility customers. For one, the model assumes utility rate escalation as an input rather than a variable. Even though a small sensitivity analysis is undertaken to understand the impact of retail rate escalation, explicitly modeling the utility's revenue requirement would help users understand the range of factors that can affect retail rates, and allow more consistency in the model (e.g., natural gas prices could affect both wholesale rates and the revenue requirement simultaneously).

Adoption rate is also included as an input to the model even though it is clearly related to the customer financials. This is due to lack of relevant research on the impact of NPV or payback period on solar adoption rates. Further research must be done on what factors motivate customers to invest in DG and how to model DG adoption based on those factors.

Conclusions

The first point we would like to emphasize is simple enough: compensation policies for distributed energy resources matter. Policies that are within the realm of possibility for many states (i.e. have been proposed or implemented somewhere) have the power to significantly affect solar value, and presumably adoption, in the short term, and shift noticeable costs onto low-income and other non-DG customers in the medium-to-long term. If a utility or regulator has decided that compensating solar results in a net cost and that that cost will be recovered through a rate hike, they must be aware of the consequences of such a hike. Likewise, before a regulator or lawmaker decides on an appropriate compensation policy, they should be aware of effects it could have on solar adoption and weigh the benefits of solar power to their constituents.

The second point is that, by design, this model predicts that there will always be winners and losers with any policy choice. The more value a DG-owning customer receives, the worse the cross-subsidy will be for non-DG customers. The results of this project show that a high value-of-solar tariff or net-metering combined with a time-of-use retail rate is the best financial result for a DG customer and the worst for a non-DG customer, while a low VOST or a net billing policy would be the best for non-DG customers and worst for DG customers.

The third point relates to solar adoption rates. As far as the magnitude of the subsidy, it is apparent from the results that the cross-subsidy that occurs between non-DG and DG owners is highly dependent on the solar adoption rate. At higher adoption rates, the magnitude of the subsidy is significantly higher. Based on the projections under the reference growth rate, residential DG generation would contribute to less than 1% of the total residential load, i.e. 17,000 solar customers out of 2 million total residential customers in 2031. This creates a small cross-subsidy of less than $2.70 per month for a non-DG customer under the business-as-usual net metering scenario. However, under the high growth scenario, which results in roughly 5% of all DTE residential customers owning solar panels, the monthly cross-subsidy from each non-DG customer rises to almost $10 by 2031. Given the disconnect within the model between project value and solar adoption, it is important for decision makers to consider how best to encourage and control market growth in different circumstances.

Fourth, we would like to point to the benefits of the business-as-usual case. The current net metering program helps support the residential solar industry and creates a net benefit for all customers when environmental and health benefits are considered. This is true for our reference growth scenario where residential DG generation serves around 0.9% of the total residential load. If the price of solar falls faster than expected and solar DG adoption increases, it may be prudent to reconsider the net metering policy. In such cases, net metering with fixed charges to reduce cross subsidy may be a simple policy to execute. Alternate policies such as net billing or lower value-of-solar could also be considered to prevent significant cross-subsidization, though both would lower solar project NPVs dramatically in the short term. In the long term, when DG forms a bigger part of the overall generation mix, a more detailed accounting of the costs and benefits must be performed. Many states with high penetrations have begun to pursue this through temporal and locational valuation of solar energy (e.g. time-varying rates and siting credits).

As a final point, while a $2.70 per month cross-subsidy in 2031 may not create substantial difference for the average non-DG customer, it could impact low-income customers. Hence, the authors' proposed solution to mitigating the regressive cross-subsidy is to implement a dynamic fixed fee for solar owners as DG adoption continues to grow. The cross-subsidy issue for low-income customers could also be addressed by expanding access to solar for low-income customers through utility-ownership models or community solar.

Appendix

Key Distributed Solar Energy Policies, Alphabetical by State

This appendix contains policy briefs on recent actions in roughly twenty states. The briefs are a selection of the briefs we prepared in preparation for the modeling portion of this project. They are current as of July 2016. The briefs included here tend to include states with the most significant policy actions from 2015-2016.

State: Arizona

Policy Name: Arizona Public Service Electric Company (APS), Tucson Electric Power (TEP), UNS Net Metering Rate Cases

Type of Policy: Fixed charges, Net-Excess Generation, Demand Charges

Date Proposed to Legislature: TEP proposal in November 2015; UNS in May 2015; APS in June 2016

Sponsored By: TEP, UNS, and APS utilities

Status: Pending. TEP decision expected by Dec. 2016. Others uncertain.

Generation Type: Rooftop solar

Customer Type: Residential

Summary: In November 2015 Tucson Electric Power filed a rate case with the Arizona Corporation Commission (ACC) to credit Net Energy Metered customers with the going utility-scale rate (ie. the wholesale rate TEP uses in contracts with utility-scale solar providers). They also requested an increased fixed charge (from \$10 to \$20) and a residential demand charge on rooftop solar customers. The proposal has been met with a backlash from solar advocates. A decision on the case is expected in December 2016. TEP has recently been in the news for piloting rooftop-rental programs in which they install solar panels on customers' roofs in exchange for a lower retail electric rate.

The Arizona Corporation Commission (ACC) has not set a firm kilowatt (kW)-based limit on system size capacity. Instead, systems must be sized to not exceed 125% of the customer's total connected load. If there is no available load data for the customer, the generating system may not exceed the customer's electric service drop capacity.

The ACC has not set an aggregate capacity limit for all net-metered systems in a utility's territory. The utility must instead demonstrate to the ACC why such a cap should be allowed. Under the ACC rules, each utility must file an annual report listing the net metered facilities and their installed capacity for the previous calendar year.

UniSource Energy Services (UES; also known by its parent company UNS) proposed an almost identical rule change. Hearings were held in March 2016 and a decision is pending with no expected date.

In June 2016, APS surprised many by filing a rate case which proposed to increase fixed charges, decrease volumetric charges, introduce demand charges, and reduce the net metering credit to the avoided-cost rate **[103]**.

In the background of these rate cases is a battle between APS and SunCity over rival ballot initiatives to either lock in retail rate net metering for twenty years or allow utilities to set net metering rates. As of June 2016, attempts at negotiations between the two parties have stalled. A value-of-solar study through the ACC is also ongoing.

Trico has proposed replacing net metering with avoided-cost credit for all customer exports.
The solar industry opposes any changes to the net metering rates.

State: Arkansas

Type of Policy: Net-Excess Generation

Date Enacted: 03/31/15

Policy: HB 1004 & Docket No.15-015-U

Primary Sponsor: Public Service Commission

Status: In progress

Generation Type: Renewables (Geothermal Electric, Solar Thermal Electric, Solar Photovoltaics, Wind (All), Biomass, Hydroelectric, Wind (Small), Hydroelectric (Small), Fuel Cells using Renewable Fuels, Microturbines)

Customer Type (inc. System Capacity Limit): Residential: Capped at 25 kW or, at 100% of the customers highest monthly usage in the previous 12 months. Commercial: 300kW (unless otherwise allowed by the PSC).

Summary: This legislation proposes to revise the net-metering rules to modify provisions for excess generation, to provide options for increasing the net metering cap for non-residential customers, and to open a docket to determine appropriate fees and terms for net metering customers in March 2015 **[104]**.

HB 1004 (which passed as Act 827) increases the allowable size of net metered systems and gives customers the option to sell their excess generation credits to the utility at the avoided-cost (wholesale) rate after they expire (24 months after being generated). It also directs the Arkansas Public Service Commission (APSC) to open a docket studying net metering rates. 16-027-R was opened with the APSC in May and is currently taking comments **[105]**.

Under current policy, at the net-metering customer's discretion, an electric utility may apply net-metering credits from a net-metered facility to the bill for another meter location if the net-metering facility and the separate meter location are under common ownership within a single electric utility's service area. Net-metering credits can be carried forward to subsequent billing cycles indefinitely. Utilities must compensate net excess generation after two years of accumulation at annual average wholesale avoided cost **[106]**.

State: California

Policy Name: Decision Adopting Successor to Net Energy Metering Tariff

Type of Policy: Time-of-use rates, Interconnection Fees, Solar Surcharge

Date of PUC Order: Jan. 28th, 2016, but proceeding remains open **[107]**.

Sponsored By: Rules developed by PUC in accordance with A.B. 327

Status: Passed by PUC in January, a rehearing was requested by the three major California utilities in March 2016. The PUC has 120 days to respond to the request for a rehearing **[108]**.

Generation Type: Solar

Customer Type: Residential

Summary: Pursuant to A.B. 327, the California PUC proposed rules for net-metering successor tariffs. These rules largely preserve net-metering with a few additional changes, and will take effect in 2017. Residential rooftop solar owners who install after that date will be required to pay a one-time interconnection fee (not yet specified), and then pay a surcharge on every kWh consumed from the utility. Installations are allowed to exceed 1 MW if the customer pays all interconnection and interconnection study fees. Customers who take part in this plan will be required to use Time-of-Use rates should those become available in their service region. Current net-metering customers will not have to change their plan, and all utility-wide net-metering caps were removed. California has a cap which limits distributed generation projects eligible for net metering to 5% of a utility's peak demand. Finally, customers can participate in the NEM successor tariff plan for 20 years.

The plan was met with opposition from IOUs for failing to address the core issue of cross-subsidization and instead bolstering net energy metering for years to come. The three primary IOUs: PG&E, San Diego, and Southern Cal., all submitted rehearing requests which are currently pending. The bill was supported by California governor Jerry Brown.

Under CPUC's January decision, new net metering customers will be able to keep retail rate remuneration for energy exported to the grid after the cap is hit, but they will also pay a one-time interconnection fee between $75 and $150, a non-bypassable monthly charge ranging from $0.02/kWh to 0.03/kWh, will be moved onto time-of-use rates **[109]**.

State: Colorado

Type of Policy: Net-Excess Generation

Date of Decision: August 2015

Sponsored by: Xcel Energy

Status: Rejected

Generation Type: All DG

Customer Type: All customer classes

Summary: Net metering in Colorado is applicable to all utilities with more than 5,000 customers. The system capacity limit is 120% of customer's average annual consumption for Investor-Owned Utilities (IOUs) and 25 kW for non-residential and 10 kW for residential in the case of Municipality and co-op customers. No aggregate capacity limit has been specified.

Net excess generation is credited to customer's next bill and if the customer's generation exceeds consumption in a calendar year then the utility must reimburse the customer at utility's average hourly incremental cost (the cost of energy: fuel plus economic transaction costs) over the most recent calendar year. Customers can have their credits carried forward month-to-month indefinitely.

Xcel petitioned the PUC for the net metering rate be reduced from the current residential rate of 10.5 cents/kWh to 4.6 cents/kWh to reflect the variable energy cost as they determined it.The Commission voted 3-0 in August 2015 to keep the current form of net-metering **[110]**.

State: Florida

Type of Policy: Net Metering

Date Enacted: In Progress

Status: Pending ballot in November 2016

Generation Type: Renewables

Customer Type: All customer types

Summary: Florida Public Service Commission (PSC) adopted rules for net metering and interconnection for renewable energy systems which are 2 MW or less in capacity. Net excess generation (NEG) is carried forward at the utility's retail rate (i.e. as a kilowatt-hour credit) to a customer's next bill for up to 12 months. At the end of a 12-month billing period, the utility pays the customer for any remaining NEG at the utility's avoided-cost rate. Renewable Energy Credits (RECs) are property of the system owner, and customers may sell RECs back to the utility **[111]**.

The Florida PSC ended the solar rebates to individuals in 2015 citing two reasons: cost and the fact that consumers have continued to install solar-energy systems even without rebates **[112]**.

Florida does not have a renewable portfolio standard and does not allow power purchase agreements, two policies that have driven solar in other states **[113]**.

In Florida, a utility-backed coalition called "Consumers for Smart Solar" has gotten a constitutional amendment on the November ballot which, among other things, gives non-solar consumers the right to not subsidize the fixed costs of solar customers. It will be interesting to see how easy or difficult of a time retailer will have in reducing net metering rates if this amendment passes. A Jacksonville muni, for example, has halted their petition to lower their solar remuneration rate from the retail until after the vote.

State: Hawai'i

Policy Name: Net Energy Metering Successor Policy

Type of Policy: Net excess generation, Interconnection Fee, Minimum Monthly Bill

Date of PUC Decision: October 2015

Sponsored By: PUC in response to high levels of DER and extremely high retail electricity prices

Status: PUC ruling sustained Jan. 2016 after being challenged by SEIA and TSAC in a lawsuit

Generation Type: All DG

Customer Type: All customer classes

Summary: Excellent solar resource combined with favorable net metering policies has made Hawaii the state with the highest penetrations of solar power, with capacity exceeding 53% of peak system load. In October of 2015, the Hawai'i PUC (HPUC) officially capped retail-rate net metering programs at the then-current level. Buildings with solar or other DG installations will be allowed to continue with retail-rate net metering for as long as their contract specified. New DG installations are allowed to subscribe to one of two remuneration options: a "grid-supply" option and a "self-supply" option. Both of these options are intermediate solutions for a NEM successor tariff that will result from Phase 1 of HPUC's DER Proceedings.

The grid-supply option prices electricity sent back to the grid at the avoided cost of fossil-generated electricity (based on averages from 2014 and 2015), with a minimum monthly bill of

$25 for residential customers. The grid-supply tariff is guaranteed for two years, at which point any successor tariffs proposed in Phase 2 would come into effect. The self-supply option does not allow any sale back to the grid, but offers an expedited application and approval process. Additionally, the PUC order requires utilities to formulate optional time-of-use rates according to PUC-set guidelines **[114][115]**.

State: Idaho

Type of Policy: Net Metering, Aggregate Cap

Date Docket Opened with PUC/Date Bill Proposed in State Legislative Body: AVU-15-05, June 2015; CASE NO. PAC-E-16-07, application received by the Idaho PUC in February 2016

Generation type: Solar Thermal Electric, Solar Photovoltaics, Wind (All), Biomass, Hydroelectric, Fuel Cells using Non-Renewable Fuels, Wind (Small), Hydroelectric (Small), Fuel Cells using Renewable Fuels

Summary: Avista Utilities proposed a residential fixed charge increase to $8.50, in its general rate case. In December the Idaho Public Utilities Commission approved a settlement between Avista and other parties to keep fixed charges unchanged at $5.25/month **[116]**.

In the case of Rocky Mountain Power (RMP), as of December 31,2015 the company had 161 customers with 1,049 kW of interconnected capacity. In February 2016, RMP requested the Idaho PUC to increase, rather than remove, the net metering cap in Electric Service Schedule No. 135 - Net Metering Service, from 714 kilowatts to 2,000 kilowatts for a May 1, 2016 as an effective date "to provide for ample growth and recognizing that the cap is not a hard ceiling for participation **[117]**. RMP is not changing/ addressing net metering rates in this application, but plans to do so in its next general rate case (2018) **[118]**.

State: Iowa

Policy Name: Eagle Point Solar Net Metering Rule Change

Type of Policy: Customer class restrictions

Date Docket Opened: November 2015

Sponsored By: Eagle Point Solar

Status: Awaiting PUC decision

Generation Type: Distributed Generation

Customer Type: Commercial and Industrial

Summary: Though it seems there have been many attempts to add fixed charges and propose lower net metering rates in Iowa, none have moved beyond proposals by single parties. There is an ongoing conflict between the utility Interstate Power and Light (IPL) and Eagle Point Solar over the legality of IPL's refusal to allow large commercial or industrial customers to net meter - and the PUC has agreed to take up the case to determine whether such customers should always be allowed to net meter or not **[119]**.

State: Louisiana

Type of Policy: Aggregate cap, Real time excess generation

Date Rulemaking Initiated: December 2015

Primary Sponsor: Public Service Commission

Status: In progress

Generation Type: All DG eligible for net metering

Customer Type: All customer classes

Summary: The objectives of rulemaking is first to modify the current net metering rules to address compensation for new solar customers once a utility reaches the net metering cap, and to examine appropriate changes to solar policies in the state **[120]**. Under the Commission staff's proposed rules (attached to the notice of proposed rulemaking), once a utility reaches 0.5% of its monthly retail peak load, any electricity exported to the grid by a net-metered customer would be credited at the avoided cost rate. No grandfathering for existing net metering customers **[121]**. Entergy **[122]** Louisiana and Southwestern Electric Power Company have reached the cap and ended net metering for new solar customers in 2016 **[123]**.

State: Maine

Policy Name: An Act to Modernize Maine's Solar Power Policy and Encourage Economic Development, L.D. 1649 **[124]**

Type of Policy: Market-based alternative to net metering

Date Proposed to Legislature: April 2016

Sponsored By: Maine PUC in accordance with LD 1263 (Maine Legislative Bill resolving to study alternatives to Net Energy Billing)

Status: Vetoed by Governor. Veto sustained (April 29th 2016)

Generation Type: Solar only

Customer Type: Bill is intended to drive 196 MW of solar capacity split between residential, industrial/commercial, community, and utility-scale customers/producers.

Summary: The Maine Legislature issued LD 1263 during its 2015 legislative session, requiring the PUC to open a stakeholder process to study alternatives to Net Energy Billing. The PUC was required to submit a report to the legislature by January 30th, 2016 that included any new solar billing policies, rules and policies needed for implementation, areas the stakeholders were not able to reach a consensus, timelines for implementation, and barriers to adoption.

The result of the process was the proposal L.D. 1649. Under the bill, IOUs would act as aggregators, buying solar power from residents at a PUC-set rate to resell in wholesale markets. Profits from the sale would go back to the ratepayers. Residents who currently own solar will have the option to continue net metering for 12 years or can switch to the standard proposed 20 year contract. Utility scale and large commercial/industrial installations will be bid on competitively amongst prospective owners. The terms of the bill would be reviewed after 21 MW are installed **[125]**.

The bill enjoyed utility support, as it would presumably decrease the overpaying to solar customers (in the long term) while allowing them to more efficiently reap the full market value of the solar energy, capacity, and renewable energy credits associated with DG. The solar industry also lent the bill lukewarm support. It will continue to value solar near the retail rate (probably beginning above the retail rate and decreasing slowly as more capacity is installed), and spur significant additions to solar capacity in the state. The bill was opposed by Republicans in the state legislature and ultimately vetoed by the Governor for failing to address the issue of cross-subsidization.

State: Massachusetts

Policy Name: An Act Relative to Solar Energy

Type of Policy: Aggregate cap, net excess generation

Date Signed Into Law: April 2016

Sponsored By: Compromise agreement between the state House and Senate

Status: In Effect. The first phase will remain in effect until 1600 MW of capacity is added.

Generation Type: Solar

Customer Type: All customer types

Summary: Massachusetts approached its net metering caps in 2015, spurring a fight between the two state legislative bodies and an large increase in lobbying from the solar industry. The Massachusetts House recommended caps be lifted by 2% and net metering remuneration be lowered from the retail rate to the wholesale rate of electricity. The Senate produced a counterpart bill opting for retail rate remuneration (the current practice is slightly below this). The two parties reached a compromise in April 2016 in which the cap would be raised by 3% (from 4 and 5% of a utility's private and municipal peak to 7 and 8%). The compensation rate would remain the retail rate until 1600 MW of total solar is installed, at which point the rate will drop by roughly 40% for non-government or municipal consumer-generators **[126]**.

State: Mississippi

Type of Policy: Net metering introduction

Date Enacted: 12/03/2015

Generation Type: All renewables

Customer Type: Residential, Commercial, Industrial, and Agricultural

Summary: The PSC order defines this new policy as net-metering, but customers are not credited at the retail rate. Instantaneous generation and use is credited at the retail rate while the electricity exports are credited at the utility's avoided cost plus a premium **[127]**. The aggregate capacity limit is set at 3% of the utility's total system peak demand of the prior calendar year. The credit rate between 7 to 7.5 cents/kWh was a compromise between Mississippi's regulated utilities (Entergy and Mississippi Power) and solar industry advocates proposed credit rate for excess generation **[128]**. The utilities argued for a rate of 4 - 4.5 cents/kWh against the pro-solar groups advocated rate of 10 cents/kWh. The commission will reassess the rates in three years.

State: Nevada

Type of Policy: Net metering rules; increase in fixed charges

Date Docket Opened with PUC: 07/31/15

Primary Sponsor: Public Utilities Commission of Nevada

Status: Date of final decision was February 2016.

Stakeholders For: NV Energy

Stakeholders Against: Solar Companies (e.g. SolarCity, Sunrun and Vivint) & net metering customers

Generation Type: Rooftop solar

Customer Type: Creates a separate rate class for all small and residential net metering customers and a time-of-use pricing option for all.

Summary: In February 2016, the PUC of Nevada finalized their decision to decrease the rate paid to solar customers from the retail rate of the electricity to the avoided-cost rate and increase fixed charges over a 12-year span. Under the new system, *all* excess generation will be credited at the avoided-cost rate - it will not 'roll the meter back'. The regulators also denied requests of grandfathering current net metering customers into the old rates and the new net metering policies are retroactive. Major solar companies ceased operations and solar applications have plummeted more than 90% compared to the year before **[129]**. The aggregate cap, 235 MW, was hit several months after the state legislature passed legislation of clarification.

State: New Hampshire

Name of Policy: Cap Extension, Interconnection Rules, and Tariff Proposals

Date of Decision: March 2016

Sponsored By: New Hampshire Legislature, Solar Industry

Status: Cap extension and interconnection rules passed by both houses, PUC has opened docket on net metering alternatives

Generation Type: All DG

Customer Type: All Customer Types

Summary: As New Hampshire approached its old 50 MW net metering cap in 2015, the three state utilities, the republican-led legislature, the solar industry, and the Democratic governor collaborated to pass legislation that lifted the cap to 75 MW. As interconnection requests began to pile, the solar industry launched an ultimately successful petition to double the cap to 100 MW. Within two months of the bill's passage in March 2016, one utility had already received enough applications to meet the 10 MW cap on installations larger than 100 kW.

The bill also called for a PUC working group to recommend alternative net energy metering tariffs. While no stipulations have been set as to what should be contained in this tariff, the PUC was instructed to consider the value that solar provided the grid. Typical battle lines between the utilities and solar companies and advocacy groups have been drawn, but the utilities have claimed they are not interested in a compensation rate as low as the ISO-New England spot electricity rate. The PUC was given ten months to present results. Additionally, the state has revamped its interconnection queue process **[130]**.

State: New Jersey

Name of Policy: Renewable Energy and Energy Efficiency Proposed Amendments **[131]**

Date of Enactment: Not yet enacted

Sponsored By: New Jersey Board of Public Utilities (BPU)

Status: Seeking public comments

Generation Type: Renewable, Distributed Generation

Customer Type: All Customer Types

Summary: In addition to offering net metering, New Jersey allows qualifying distributed energy resources to directly own renewable energy credits needed for utilities to meet state RPS standards. When a distributed energy resource produces enough energy, the owner earns a REC that they may then auction off in a market administered by the state. The BPU has offered some potential rules that may affect these RECs by limiting them to facilities installed in accordance with particular labor standards, and expanding them to allow particular forms of small hydro. Perhaps most importantly, the rules propose allowing ‘grid supply’ facilities to earn RECs. These are non-net metered generation facilities connected directly into the distribution system only for the purpose of grid supply **[132]**.

State: New York

Type of Policy: Net Metering Aggregate Cap

Date Enacted: October 2015

Docket Number: 15-E-0407

Status: In Effect until Reforming the Energy Vision (REV) Initiative sets the cap at the end of 2016 (Expected)

Generation Type: All DG

Summary: Governor Cuomo has directed the PSC to establish a new Clean Energy Standard mandating that 50% of the electricity consumed in NY must come from clean energy sources by 2030 **[133]**. The Reforming the Energy Vision (REV) initiative will lead to regulatory changes that promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, wider deployment of distributed energy resources, such as microgrids, rooftop solar and other on-site power supplies, and storage. It will also promote markets to achieve greater use of advanced energy management products to enhance demand elasticity and efficiencies. These changes, in turn, will empower customers by allowing them more choice in how they manage and consume electric energy **[134]**.

New York is planning to address the issue of net metering and distributed resource valuation as part of the REV process. Until then, the New York Public Service Commission (PSC) has temporarily lifted its aggregate cap on retail rate net metering for rooftop solar. Owners of DG will continue to receive retail remuneration for electricity until the valuation process is completed by REV at the end of 2016 **[135]**.

The PSC also rejected ORU (Orange and Rockland Utilities)’s proposal to replace NEM with a plan that remunerates DG owners at a wholesale rate instead of the retail rate at which the owners buy the electricity from the grid.

State: Ohio

Policy: Proposed Net Metering Deregulation

Date Docket Opened: Rules proposed by PUC of Ohio (PUCO) in November 2015, stakeholder comments submitted January 2016. Docket technically opened in 2011.

Sponsored By: The result of a PUCO initiated workshop to re-examine state net-metering rules.

Status: Stakeholder review process ongoing

Generation Type: Distributed Generation

Customer Type: All (the rules do not state it explicitly, but seem to account for all customer types)

Summary: As Ohio is in the midst of a State Supreme Court battle over the legality of PUCO's net metering mandate, PUCO has began a stakeholder process (initiated by requests from utilities) to review new rules for net metering. The court case has been extended as both parties negotiate the proposed rules, which as of now: extend the period for which excess generation credits can be rolled forward (to 36 months from 12) and allow utilities more flexibility in how they compensate customers. While the actual proposed rule requires utilities develop their own 'net metering tariffs and contracts', there is no formal definition provided for net metering, and it is unlikely that utilities will be limited to traditional retail-rate net metering if the rule proceeds **[136]**.

State: Oklahoma

Name of Policy: Oklahoma Gas and Electric Rate Proposal

Date Docket Opened: March 2016

Sponsored By: Oklahoma Gas and Electric

Status: Rate case testimony in progress

Generation Type: All Demand (No generation necessary)

Customer Type: All customers

Summary: This is indirectly related to net metering, but Oklahoma is a representative case of a state proposing fixed demand charges for all customers. The party in question is an IOU called Oklahoma Gas and Electric (OGE), who has applied to the Oklahoma Corporation Commission (OCC) for a rate case. The new rate proposal would break customer fees up into three categories: a fixed charge, a demand charge, and an energy charge. The demand charge would be designed to account for the impact on the grid of a consumer's peak load. The fixed service charge of $13 was also set to double to $26. In April 2016 the OCC rejected the methodology with which OGE calculated the fixed charges born by distributed generation owners. The burden is now on the utility to change the methodology or respond **[137]**.

State: Pennsylvania

Name of Policy: Proposed Net Metering Rules

Date of Enactment: Awaiting Approval from Independent Regulatory Review Commission (IRRC)

Sponsored By: PUC with stakeholder input

Status: New Draft Rules Proposed after June 2nd 2016

Generation Type: All Distributed Generation

Customer Type: All Customer Types

Summary: The Pennsylvania PUC released draft net metering rules in 2014 under its mandate to administer the state's alternative energy portfolio standards (AEPS). The rules controversially included a cap on the capacity of a net metered system at 110% of the load's annual usage. The primary motivation for the new rules was to prevent "merchant-generators" - those posing as net metering facilities who have the intention of selling back to the grid - of taking advantage of the generous net metering retail rate. After several comments from those seeking exceptions, the PUC increased this cap to 200%. The PUC submitted those final rules to the IRRC in the spring of 2016 and were rejected on June 2nd. The IRRC claimed the PUC had no mandate to change the final form rules to a 200% cap when the original AEPS rules specified hard caps on the wattage of net metered systems. The PUC is currently preparing responses to the IRRC decision **[138]**.

State: South Carolina

Type of Policy: Net Metering Settlement Agreement

Primary Sponsor: Office of Regulatory Staff ("ORS")

Status: In Effect until 2022

Generation Type: All Renewables

Customer Type: All customer classes

Summary: The South Carolina legislature unanimously created a voluntary Distributed Energy Resource Program in April 2014. In March 2015, the PUC approved a settlement agreement that stipulated that utilities will offer net metering at full retail rates, and no new charges or fees distinctly separate from the new net metering rates will be imposed upon customer generators until the expiration of the agreement on January 1, 2021. The system capacity limit is 20 kW for residential and 1000 kW for non-residential customers. The aggregate capacity limit is 2% of the average retail peak demand for previous 5 years **[139]**. The Distributed Energy Resource Program allows utilities to recover costs connected to meeting a 2021 target of 2% aggregate generation capacity through renewable sources **[140]**.

State: Vermont

Name of Policy: Proposed Net Metering Rule Changes

Date of Decision: Pending Results of Public Hearing

Status: Pending

Generation Type: All distributed generation

Customer Type: All customer types

Summary: Over February, March, and April of 2016, the Vermont Public Service Board proposed significant net metering rule changes. The recommended rule changes were the result of a VPSB review of net metering ordered by the Vermont legislature. The rule works as follow: At the end of each billing period, the total number of kWhs produced by the net metered system are multiplied by a sum of the blended residential retail rate (either the retail rate or the average price per kWh sold under an increasing block rate model), a locational credit (for units sited in strategic locations), and a REC credit (in return for giving up RECs earned from installation of the system). This amount is then subtracted from the total residential retail cost (gross kWhs consumed multiplied by the standard retail rate). If the amount is positive, it represents the customer's final bill. If it is negative, the utility will credit the customer that amount. Siting credits can be positive or negative, and are meant to incentivize the development of solar resources in strategic and neglected areas. It should be noted that Vermont has also stayed a rate case from one of its utilities (Green Mountain) who has exceeded their net metering capacity cap and requested to extend it **[141]**.

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