LSU Center for Energ

The Future of Solar in Louisiana

Executive Summary

that installed a system before their utility hit their 0.5% cap and are eligible for 1:1 full retail net metering and unlimited carryover versus (2) newer customers who can still zero out their bill, but are credited at avoided cost for any excess energy beyond their monthly usage. The Louisiana PSC has an active rulemaking on net metering and is awaiting commission action on a recommendation from its sta to again modify the net metering rules. Thus, the solar industry in Louisiana is truly at a crossroads.

The economic section of this report will assess the extent to which changes in solar tax credits and net metering policies might impact the economics of solar installations from a household's or business' perspective. We will consider this economic information alongside the engineering results to make a number of recommendations associated with the relative impact of the subsidy in spurring solar PV growth, the appropriate utility rate design mechanism for behind-the-meter solar, as well as provide insights into the types of distribution grid planning that utilities should be conducting in order to plan for the future of this industry.

Major results are as follows:

- The distribution grid begins to experience significant power quality issues when 20% to 30% of households within a specific feeder install solar PV. One feeder began experiencing power quality issues between 10% to 20% penetration. If solar PV installation is spatially clustered, problems might begin to arise at lower levels of penetration.
- We find that batteries can theoretically be used to mitigate these problems and allow for higher solar penetration levels. But there are not currently commercially available batteries that are programmed to dispatch in the manner described in this report. Further, for batteries to compete in the marketplace, the LPSC will need to take actions that modify existing tariffs for solar customers to incorporate time-of-use pricing for electricity sold back to the grid and valuing the capacity benefit provided by the battery. The current LPSC rulemaking on net metering is laying the groundwork for this to be possible.
- At low levels of solar penetration, solar energy provides a capacity benefit of around 33% of installed capacity. But, there are significant diminishing returns to solar capacity. We estimate that if every customer were to install a 7kW behind-the-meter solar system, this would reduce the total capacity the utility should be prepared to meet by 9%. In other words, the utility would still need to be prepared to meet more than 90% of its current residential load requirement if every residential customer were to install solar.

In light of these findings, we make the following specific recommendations:

- The Louisiana Public Service Commission should encourage all utilities to track the level of solar penetration by feeder within their system. The utility should take the feeders with the top vulnerability taking into account (a) the penetration in the feeder and (b) engineering expertise on the potential vulnerability of that feeder and produce a report showing the potential engineering impact if solar PV continues to grow on that feeder.[1] n~« ¦{§ª¥u¬§¦ xu¦ wz -«zy¬§ ¦{§ª¥ ¬~z -¬₤¬± u¦y fjm\ ¯~z¬~zª ¦®z«¬¥z¦¬« ¬§ ¬~z y«¬ªw-¬§¦ }ªy¬§ ¥¬ }u¬z z¦} ¦zzª ¦} x§¦xzª¦« uªz ¯uªªu¦¬zy
- The LPSC should make a number of changes to its rate design for solar customers.

[3] Utilities have commented that a rural feeder, for instance, might be impacted very dierently than a downtown network in New Orleans or Baton Rouge. For instance, Entergy does not allow solar on its downtown underground networks. Thus, the utilities should have latitude in using the knowledge of these specific systems alongside the solar penetration by feeder to identify the plausibly most vulnerable.

- The LPSC should continue the current process of modifying net metering rules.
- In the case where a bi-direction meter is not already installed, solar customers should install a bi-directional meter as part of the solar installation cost such that the utility can understand the impact of solar growth on its system.
- As a successor net metering policy, solar customers should be credited at the utility's avoided cost for any excess electricity delivered to the grid.
- Solar customers should also be appropriately credited for any capacity benefit they provide to the grid. Although, this should be done on a per capacity basis, and should not be accomplished by adjusting the utility's avoided cost rate.
- The LPSC should encourage rate design that allows for batteries to be incorporated by valuing the battery. This can be done in three ways:
  - Two-channel billing can allow batteries to avoid pushing energy back to the grid (and therefore consuming behind the meter).
  - Hourly avoided cost can allow for customers to send electricity back to the grid at higher price hours.
  - Providing a capacity benefit for the battery in addition to any capacity benefit of solar without a battery installed.

- The Louisiana Public Service Commission and/or Attorney General's office should look into the extent to which solar installers might have provided misleading estimates of solar production to customers.

Acknowledgments

We wish to recognize faculty and staff assistance from the LSU Center for Energy Studies, especially Marybeth Pinsonneault and Ric Pincomb for editorial expertise and the students who worked on this project.[4] We also thank Stephen Radcliffe for the formatting of this document. In addition, we thank those listed below who provided invaluable thoughts and critiques of our work. While we gave serious consideration to their varying, and sometimes conflicting, responses, the conclusions we put forth in this white paper are our own.

- The Louisiana Board of Regents provided generous financial support for this project. LEQSF(2016-18)-RD-B-05. Without this support, this project would not be possible.
- All SWEPCO employees who provided both feedback, data, and other information during this process. While there are too many specific individuals to mention by name, we give special thanks to Brian Bond (Vice President of External Affairs), Malcolm Smoak (Vice President of Distribution), Emile Cordaro (Government Relations Director), and Ron Cosby (Distribution Planning Engineer).
- Richard Ross, Director of RTO Regulatory West, American Electric Power (AEP).
- Andrew Owens, Director, Regulatory Research for Commercial Development & Innovation (CD&I), Entergy.
- Jessica Hendricks, State Policy Director, Alliance for Affordable Energy.
- A number of Southwest Power Pool (SPP) employees provided feedback. While there are too many specific individuals to mention by name, we give special thanks to Gary Cate (Manager of Market Design), Yasser Bahbaz (Supervisor of Market Forensics), Gunnar Shaffer (Engineer in Market Forensics) and Thomas Burns (Research Engineer).
- Daniel Groft, Economist, Louisiana Department of Revenue.
- Kenneth Gillingham, Associate Professor of Economics, Yale University.
- Brian Prest, Postdoctoral Associate, Resources for the Future.
- Two anonymous volunteers who live approximately 1 mile from LSU's campus in Baton Rouge who provided the data associated with their behind-the-meter solar systems.
- Several other representatives from both solar installers and solar industry advocacy groups in Louisiana were contacted, but chose not to provide feedback.

[4] We would also like to recognize the graduate students who worked on this project including Johnathon Angers (Environmental Sciences) and Morteza Dabaghmanesh (Electrical Engineering).

Tables

1 | Introduction

In 2008, the Louisiana Legislature adopted a series of income tax incentives directly aimed at increasing rooftop solar. Prior to December 31, 2017, Louisiana households had access to two relatively generous income tax credits they were able to call upon to provide financial support for their solar energy installations: a 50% state income tax credit and a 30% federal income tax credit; which on a combined basis and depending on a homeowner’s tax situation, amounted to up to an 80% credit on all Louisiana solar installations less than $25,000 in total value.

Figures 1-1 and 1-2 show [illegible]

Figure 1–2: Louisiana Behind-the-Meter Solar Capacity

project this broad in scope cannot be completed in a vacuum. This project was completed with partnership from industry, academic researchers, and the state of Louisiana.

Industry participation was crucial for a number of reasons. First and foremost, scalability of a resource in an electrical system is highly dependent upon the specifics of that system. While there has been significant academic literature that focuses on the scalability of renewable resources in a theoretical distribution grid (Babacan, Torre, & Kleissl 2017; Liu et al, 2008; Enslin 2010; Wang et al. 2017; Kandasamy et al, 2017), in practice, a utility must deal with its actual system. These "real world" systems, many times, are not as "clean" as a theoretical system. In reality, modern distribution grids have evolved, and continue to evolve, over the course of many decades. Thus, modeling a theoretical system is good for identifying areas of concern, these results are unlikely to guide the specific planning process for a utility, especially associated with a specific part of the utility's system.

While industry comes to the table with practical problems and real data, academic researchers, on the other hand, come to the table with an intimate understanding of mathematical modeling of distribution grid systems and the economics of these systems from the household's perspective. Further, in this particular application, LSU researchers have been tracking detailed, in the time frame of seconds, solar generation data on a research panel located at the Renewable Energy and Smart Grid Laboratory on LSU's campus that will be combined with company-provided data.

Finally, state policymakers are needed to review information presented and make difficult decisions that take all perspectives into account. We are appreciative of the Louisiana Board of Regents' support for this project that will allow us to present this information to stakeholders within the state and make pragmatic policy recommendations. Furthermore, we thank all stakeholders who provided feedback on this report.

1.2 Louisiana Solar Policies

The growth of the solar industry in Louisiana has been the result of two key policies; (1) net metering, and (2) a 50% state income tax credit coupled with expanded federal incentives.

In 2003, the Louisiana Legislature passed Act 653 that called upon the Public Service Commission (hereafter "the Commission" or "LPSC") to establish appropriate rates, terms and conditions for net metering contracts. More specifically, Act 653 states that the Commission:

> Shall authorize an electric utility to assess a net energy metering customer a greater fee or charge, or any type, if the electric utility's direct costs of interconnection and administration of NEM outweigh the distribution system, environmental, and public policy benefits of allocating the cost among the electric utility's entire customer base. The [NEM] customer shall reimburse the utility for any costs in excess of those to serve a traditional customer.

During the 2007 regular session the Legislature passed Act 371 that created a new tax incentive to stimulate solar investment in Louisiana. The Act created a refundable income tax credit for the purchase and installation of a wind or solar energy system for residential location. The credit was for 50% of the first $25,000 of the cost of each system.

Shortly after Louisiana put this tax incentive in place, the United States entered into what is now commonly referred to as the “Great Recession.” In order to stimulate the economy, the federal government passed the American Recovery and Reinvestment Act of 2009, known as “ARRA” or the “Stimulus” that extended the 30% federal tax credit that had already been in place since January of 2006.[10]

Louisiana households had access to two relatively generous income tax rebates they could call upon to provide financial support for their solar energy installations: a 50% state income tax credit and a 30% federal income tax credit, which, on a combined basis, amounted to an 80% credit (depending on the taxpayer’s circumstances)[11] on all Louisiana residential solar installations less than $25,000 in total value.

In 2010, the LPSC took further action to revise its NEM policy. As part of Rulemaking Docket No. R-31417, that was initially intended to address questions on commercial and agricultural [illegible]

In November of 2017, the first draft of the proposed modified rules was filed before the Public Service Commission. Hereafter this will be referred to as the “Proposed Rule.” Stakeholders were given the opportunity to file comments on the Proposed Rule, and in January of 2018, 10 stakeholders chose to do so. These stakeholders included (a) utilities such as Entergy Louisiana, SWEPCO and Cleco, (b) environmental and industry advocate groups including the Alliance for Affordable Energy (AAE), The Association of Louisiana Electric Cooperatives, Inc (ALEC), Gulf States Renewable Energy Industry Association (GSREIA), and the Sierra Club, and (c) private companies including PosiGen, Walmart, and Wilhite Energy.

The Proposed Rule marks a significant change away from the historic 1:1 full retail credit Net Metering (NEM) policy that has been in place. While the purpose of this document is not to provide a detailed explanation, the Proposed Rule can be summarized as having the following characteristics:

- **Two-channel billing:** The Proposed Rule requires all new distributed generation resources (including solar) to move to a system of two-channel billing.
- **Avoided Usage:** According to Section 4.1, “DG customers will be billed for electrical use consistent with the applicable utility’s current standard rate schedule with appropriate riders.” Under this new regime the solar customer will, in effect, receive a full retail rate credit for all avoided usage. In other words, if a customer uses 5 kW of electricity consistently over the course of an hour, and the solar system produced a consistent 3 kW of electricity over this same time period, the customer will be billed as if they used 2 kWh of electricity. Thus, for the 3 kWh of avoided usage in this example, the solar energy is valued in the same way as the prior NEM policy.
- **Electricity Fed Back to the Electric Utility:** Also according to Section 4.1, “for electricity generated and fed back to the electric utility, the customer shall be billed at a rate consistent with the utility’s approved avoided cost rate . . .”[12] This is where the Proposed Rule differs from the prior NEM policy. Under the historic 1:1 full retail credit NEM policy, the customer would be credited at the full retail rate for all electricity generated, regardless of whether it avoided usage or was sent back to the utility. In this Proposed Rule, a solar customer will be credited for any excess electricity sent back to the grid at the utility’s avoided cost, and therefore be treated more in the spirt of a “Qualifying Facility” that has been longstanding policy both in Louisiana and across the United States as laid out by the Public Utility Regulatory Policies Act of 1978 (PURPA).[13]

conducted if changes are detected in sun irradiation. So, for instance, in the middle of the night (with no solar production), data might not be recorded for hours. But during the day, there will often be an observation every four seconds. We aggregate up this data into 21,600 four second intervals throughout the day. We scale the size of our solar panel (which is a 140w system) to a 7kW unit, the typical system size that is currently being installed in Louisiana given current prices.[17]

We then take the total number of load buses, which is approximately the number of households, within the feeder and scale the solar generation to the penetration level of interest. For purposes of this report, penetration level refers specifically to the percentage of households in a feeder who install a 7kW solar system. While many engineering studies define penetration based on a percentage of the amount of the active power load connected to a residential bus, we specifically choose to define this as a share of households so that a non-engineering audience can interpret easily.

Next, we merge the solar generation data from our solar panel at the RESG Lab, which varies approximately every four seconds, with load data provided by the utility. Load data is provided in 15-minute intervals over the course of a year for each given feeder.[18] We then linearly interpolate this 15-minute load data into four second intervals and merge with the solar generation data discussed above. The result is (1) load, (2) solar generation, and (3) net-load at four second intervals.

Next, we categorize the days of the year based on differing (a) net load and (b) variability. Due to computational burdens, we are unable to run the load flow analysis for each feeder across all days of the year. Thus, instead of arbitrarily choosing days (such as the first or fifteenth day of the month), we categorize each day of the year into one of nine categories. We calculate the total net load (load – solar generation) and the standard deviation of net load for each day in the calendar year.[19] We calculate the 33.3rd and 66.6th percentile of each measure and categorize each day into high, medium, or low net load and high, medium, or low variability in net load. We then randomly choose one day from each category as a representative day to run our engineering analysis. The categories and the number of days by month in each category are listed in Table 2-1.

We next combine this net load data with the feeder specific configuration data. The feeder configuration data provides the system's admittance matrix which is basically used for the power flow analysis. By utilizing power flow equations one can determine the steady-state voltages along with active and reactive powers at any point in the feeder including lines and buses.

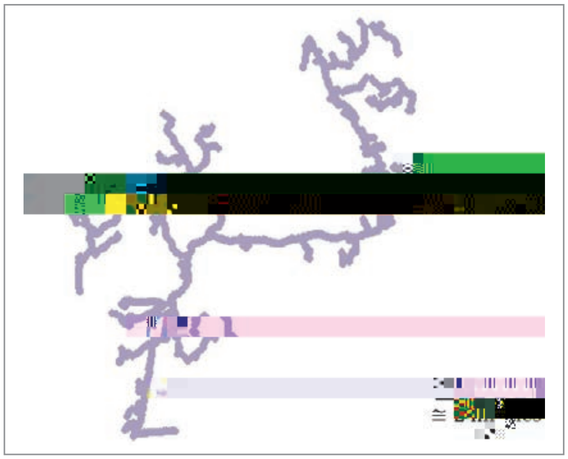
We then run a Newton Raphson (NR) based continuous power flow at four second intervals in order to observe the steady-state voltages as time passes. In this way, voltage violation can

	Representative Day Categories								
	High Load			Medium Load			Low Load		
Variability	High	Medium	Low	High	Medium	Low	High	Medium	Low
January	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
February	2	3	3	2	1	7	3	2	5
March	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
April	0	0	0	5	1	0	8	8	8
May	2	1	0	6	6	0	6	3	0
June	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
July	12	14	4	0	0	1	0	0	0
August	9	3	4	5	5	5	0	0	0
September	6	8	2	1	8	3	1	1	[illegible]
October	[illegible]	0	0	2	7	9	4	4	5
November	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
December	0	2	5	4	4	6	4	4	2
Total	45	43	31	34	41	40	[illegible]	38	[illegible]

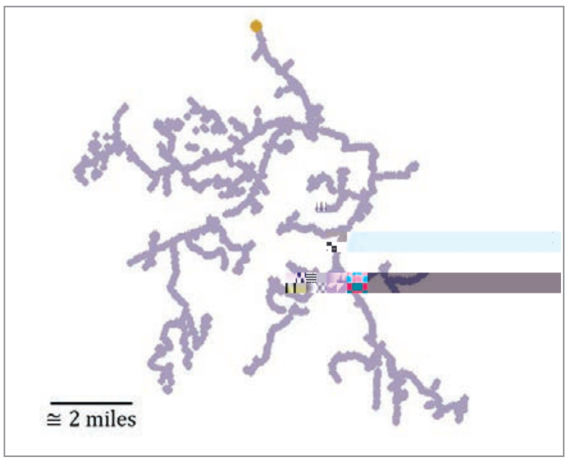
Note: Days of year do not add up to 365 because some days of solar generation data contained errors. These days were removed. High, medium, and low load and variability are defined as [illegible] 0 to 33.3rd, 33.3rd [illegible] 66.6th, and 66.6th to 100th percentile of total net lo[illegible] the standard deviation of net load by day.

Table 2-1: Solar Generation from 7kW System and Load of Average Household

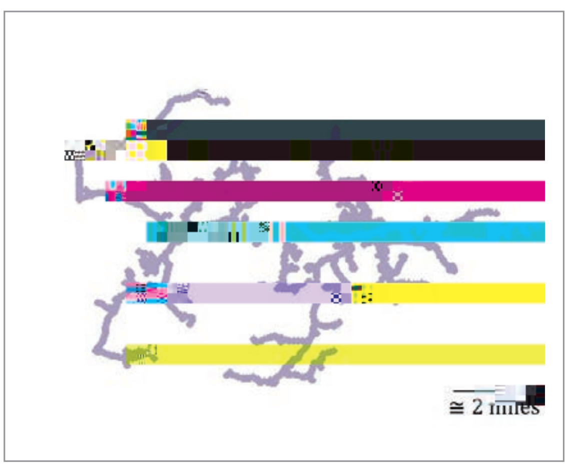
Source: Author's calculations using data from Renewable Energy and Smart Grid Laboratory and SWEPCO



Feeder A



Feeder B



Feeder C

Figure 2–1: Feeder Map

Source: SWEPCO

2.3 Incorporating Battery Storage

Next, we want to assess the extent to which battery storage can be used to mitigate

2.3.1 Dispatch Algorithm

transmission and distribution levels if the solar is able to reduce the peak load that a customer demands throughout the year. In other words, there are two potential benefits of solar. First, a rooftop solar system produces electricity that can avoid electricity generation at a traditional generation facility. But also, solar might mitigate the total amount of infrastructure needed to generate, transmit, and distribute the electricity at peak time periods. If the solar resources are able to defer, or in some instances even avoid, these expensive investments, this has the potential to provide significant value to the grid.

While the value of any capacity benefit will be assessed in the economic analysis, the engineering analysis will assess the degree to which this capacity benefit exists. And the dispatch algorithm should be created in a way that creates and/or enhances this capacity benefit. We will assess the capacity benefit of solar with no battery and compare to the capacity benefit of solar with batteries of differing sizes.

2.3.1.3 Dispatch at High Demand (and High Electricity Price) Times

Wholesale electricity prices are not constant throughout hours of the day and months of the year. Electricity prices are generally higher during high demand time periods; namely the summer months in the late afternoon and early part of the evening. Figure 2-2 below shows the average load per residential customer on one of the three feeders provided by SWEPCO alongside the average wholesale electricity price. As can be seen, prices generally follow positive relationship with demand; high [illegible] the highest price time period is in the late afternoon and early evening when solar production is declining.

In this way, the goal of dispatching at high price time periods and creating a capacity benefit are very much compatible with one another. The highest price electricity time is during the peak demand time. Thus, dispatching the battery during these high price times also allows for a reduction in capacity.

2.3.1.4 Mathematical Representation

Given the stated goals of the dispatch algorithm, next we show the specific dispatch algorithm that will be implemented.

The first step in the algorithm will be to estimate the predicted load of a given household based on historical data. In order to do this, we start with the total load profile of the entire feeder in which that house is located, and scale to the average kWhs used in a year for a home.[22] Specifically, the following regression will be run, and coe□cient estimates will be obtained:

$$L_t = \gamma_{m,h} \sum D_m \times D_h$$

where L_t is load at time

where $\widehat{L_t}$ is the predicted load in a given hour of a given month. For instance, $\widehat{L_t}$ will be the same for 8:00 a.m. for each day in January.

Now that we have the estimated load profile, we will next calculate the "optimal" level of the battery's charge at each time, which will, in essence, be the inverse of the estimated load. For instance, at peak time, the battery should be dispatching its energy and therefore driving down the battery's charge. But at times of the day with low load, the battery is better off allowing the solar panel to charge, instead of dispatching. We model this tradeoff as $\widehat{B_t}$, which is the optimal estimated battery amount that we are aiming to achieve where:

[redacted]

where P[illegible] is the maximum of $\widehat{L_t}$ by month, or the average load during the highest load hour of the day. Conversely, $\widehat{Base_m}$ is the base load (i.e. the minimum load) during the lowest average load hour of the day in a given month.

The dispatch algorithm is then:

[redacted]

where $\sum_m \widehat{Solar_t}$ is the estimated total solar production (in kWhs) in a given month and $\sum_m \widehat{Load_t}$ is the estimated total load (in kWhs) in a given month. So, if a solar system is installed that will produce about the same amount of energy as will be consumed, this ratio will be one. If the total solar production is estimated to be less than the household's total energy consumption (as will be the case in this application), this ratio will be less than one.

B_t is the battery charge at a given time period and $\widehat{B_t}$ is the predicted (i.e. "optimal") battery charge. So, if the battery has more charge than predicted charge on a typical day, $\widehat{B_t}$, then this ratio $B_t/\widehat{B_t}$ will be greater than one, and therefore the battery will increase its dispatch. If, on the other hand, the battery's actual charge is lower than predicted on a typical day, then the battery will reduce its discharge. If the battery is sufficiently large, and the solar will produce enough energy for the household's entire demand over the course of a year, then the battery will simply dispatch the load. In this case, the house will be "off the grid."[23]

The result of the dispatch algorithm for each of the nine representative days is shown in Figure 2-4. As can be seen, the algorithm successfully mitigates much of the variability in load—especially on days with high variability. Furthermore, there is a noticeable pushing of solar generation into the later hours of the day, thus creating coincidence with peak. We will assess the extent to which this will mitigate reliability concerns with solar PV integration and create capacity and energy arbitrage benefits in subsequent sections.

[23] It should also be noted that at times of high solar generation, the battery might reach maximum capacity. In this event, we created decision rules that ramped up the dispatch of the battery in a smooth manner. In these scenarios, though, the intermittency of the solar is pushed onto the grid. Other tweaks are made to the algorithm to get it to produce results that balance both the engineering concerns and (later) the economic benefits of the battery. Please contact the authors for more details on this process.

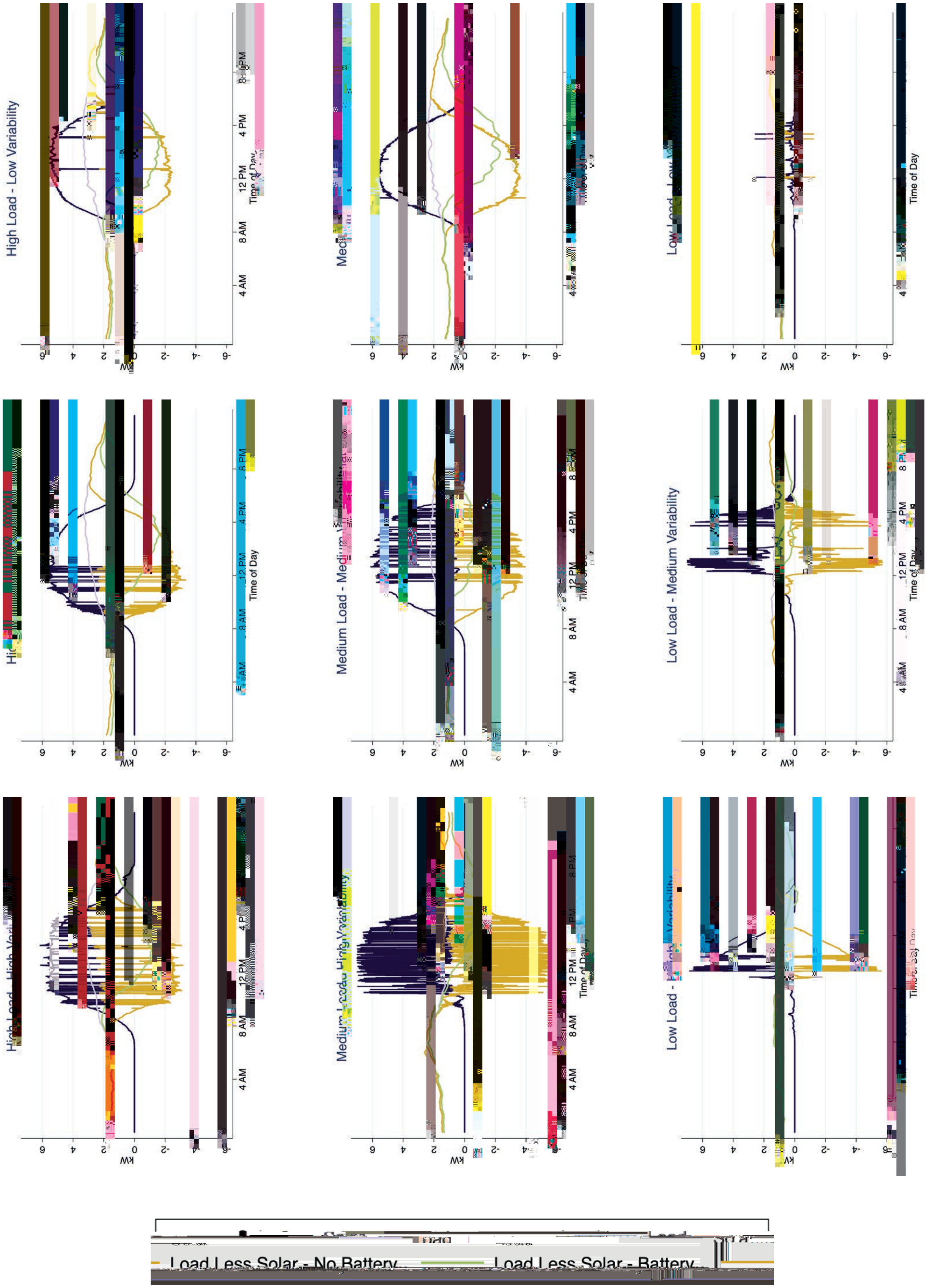


Figure 2–4: Results of Dispatch Algorithm

Source: Author's Dispatch Algorithm alongside solar generation data from Renewable Energy and Smart Grid Laboratory and load data from SWEPCO.

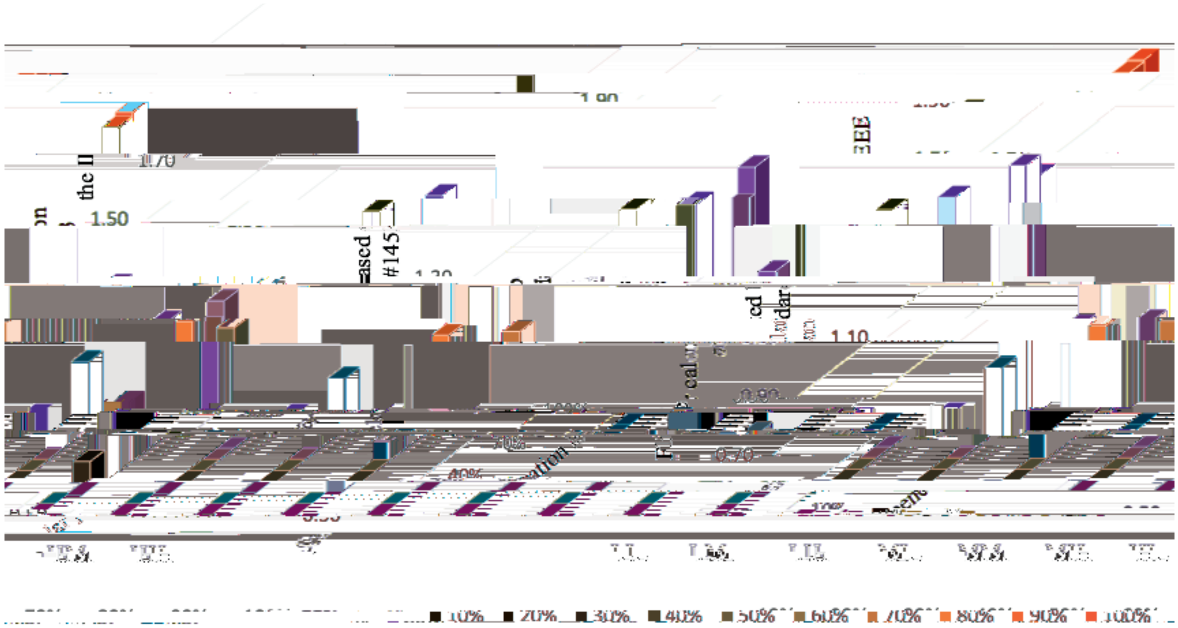


Figure 2–6: Flicker Occurrences by Penetration Level
Feeder A — No Battery

Second, problems begin to arise, especially for flicker, on days of high variability, where problems with voltage rise primarily begin to arise on days of lower load.

Third, different feeders experience problems at very different levels of penetration. In particular, Feeders A and B in this analysis became susceptible to flicker problems before voltage rise. On the other hand, Feeder C became susceptible to voltage rise problems at relatively lower levels of penetration, while flicker problems were not observed until significantly higher penetration levels. For this reason, in the event that utilities do make distribution grid upgrades to accommodate higher levels of solar growth, the types of problems being mitigated, and therefore the type of investments needed, might vary. Thus, it is unlikely that a one-size-fits-all approach will be sufficient for mitigating these problems. Special attention will need to be paid to the specifics of the feeder.

Figure 2–7: Voltage Rise by Penetration Level
Feeder B – No Battery

Figure 2–8: Flicker Occurrences by Penetration Level
Feeder B — No Battery

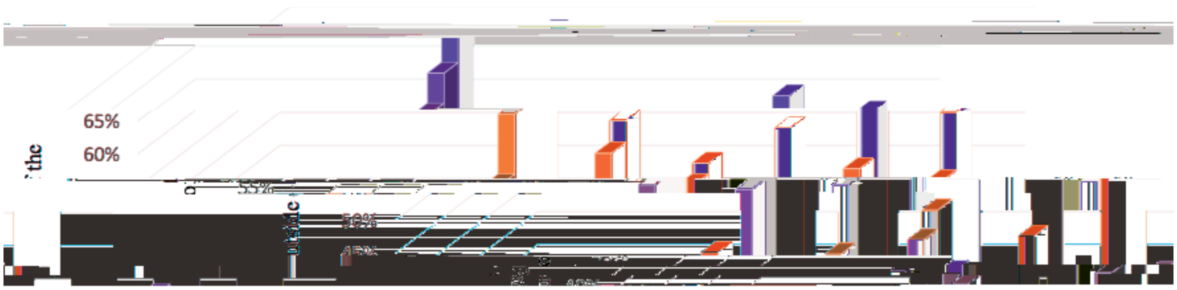


Figure 2–9: Voltage Rise by Penetration Level
Feeder C — No Battery

Figure 2–10: Flicker Occurrences by Penetration Level
Feeder C — No Battery

2.4.2 Incorporation of Solar with Battery

Next, we rerun the load flow models with the battery incorporated. We utilize the dispatch algorithm above[24] and observe the results for both voltage rise and flicker. These results are presented in Table 2-5. Corresponding figures illustrating these results are shown in Figures 2-11 and 2-12.

As can be seen, the battery reduces the amount of voltage rise and flicker considerably, and in six of the nine representative days actually allows for 100% solar penetration without any

Figure 2–11: Voltage Rise by Penetration Level
Feeder A — With Battery

Figure 2–12: Flicker Occurrences by Penetration Level
Feeder A — With Battery

in each home with a rooftop solar PV system might not be enough to shield the grid from all of the potential problems. Thus, in practice, if the goal is for solar penetration to reach high levels, there will likely need to be some combination of households implementing techniques

3.1 Review of Prior Literature

Both the diffusion of and effectiveness of renewable energy policies have been studied extensively in the academic literature[29] (Nicholson-Crotty 2009; Carley 2009; Upton & Snyder 2017; Upton & Snyder 2015). Potentially the most comprehensive peer reviewed study on the engineering and economic costs/benefits of distributed solar PV that is most complementary to this research is a two-part economic and engineering analysis, respectively Cohen & Callaway (2016) and Cohen, Kauzmann & Callaway (2016)—hereafter CC (2016) and CKC (2016). CC (2016) quantifies the physical impacts of spatially heterogenous PV over a year of distribution system operation in different climates. These studies are able to take advantage of [illegible]

[illegible]

credit, will it be economical for households to invest in solar? In order to answer this question, we will consider the solar investment from the perspective of the household, not necessarily a societal perspective.

But, under a rate design regime that properly credits households with behind-the-meter solar, including all societal benefits and costs, then the household's economic decision should coincide with maximizing societal welfare. For this reason, it will be important to quantify both the costs and benefits of solar PV and design a rate design policy that incorporates these costs and benefits. While we will not provide a definitive societal cost benefit analysis, we will provide some thoughts and insights into what the economics of solar might look like under alternative regulatory regimes that are aimed at aligning societal costs and benefits.

3.1.1 Potential Benefits

There are broadly three potential benefits of solar PV to the electric grid; (1) energy benefit, (2) reduced line losses and (3) a capacity benefit. The energy benefit is the foregone dispatching of traditional power generation sources such as nuclear, coal, or natural gas. Reduced line losses, as it is commonly called to non-engineering audiences, is some percentage of power produced by a generator that will be lost in the delivery to final customers. Because solar PV is generated on-site, the majority of line losses involved with moving the power to the location of the household will be avoided. Third, solar has the opportunity to reduce the system level peak demand which can potentially defer, or in some cases even offset, investments in generation, transmission and distribution assets.

3.1.1.1 Energy Benefit

The most obvious, and straightforward to calculate, benefit of solar PV is the fuel savings from traditional power plants (or reduced purchased energy). Fortunately, these fuel savings are relatively easy to calculate as there are real-time energy markets in the United States. SWEPCO is located in the Southwest Power Pool (SPP), which provides locational marginal pricing across all hours of the year. We will utilize the average locational marginal price in the zone in which SWEPCO is located.

3.1.1.2 Reduced Line Loss

Line loss, or voltage loss as referred to in the engineering literature, is the loss in electricity that occurs between where electricity is generated at a centralized power plant and where it is consumed at a home or business. As discussed in Borenstein (2008), transmission and distribution line losses vary over time and are proportional to the square of the flow of the lines. Borenstein (2008) shows that in California, aggregate line losses are about 7% of the power generated and range from 4.3% in low generation times to 12% in high generation times. Thus, just as power produced at peak demand time periods sells for higher values, so too can behind-the-meter solar create an additional line loss benefit, as line losses are higher at the high demand time periods

Similarly, CC (2016) find that increasing PV penetration decreases system loss, with diminishing effects at high penetration levels. These line loss estimates range from 7% to 28% at 100% solar penetration. Unsurprisingly, longer feeders have higher line losses, and therefore the PV-associated reductions in line loss associated with PV are also highest for longer feeders. We should note that this result is in contrast to a number of other studies that find that resistive losses actually increase with solar penetration (Quezada, Abad, and Roman, 2006; Widen et al., 2010; Navarro, Ochoa, and Randles, 2013; Thompson and Infield, 2007). CKC (2016) quantifies this benefit to be between 0.52¢/kWh and 0.54¢/kWh[31] or approximately 18% more than the average locational marginal price received by generators, a value consistent with findings of Borenstein (2008).[32]

Dismukes (2015) uses a line loss of 6.44% that represents the annual average line loss calculated by EIA for the years 2008 to 2012.[33] Thus, avoiding 6.44% of the line loss multiplied by the average wholesale price of electricity used in this study (about 2.3 ¢/kWh) yields an estimated avoided line loss benefit of 0.148¢/kWh. Dismukes (2015) does not take into account the coincidence of line loss with solar generation, which is a potential reason for the estimated benefit on the low end of Borenstein (2008) and CKC (2016).

3.1.1.3 Capacity Benefit

When total peak system load is reduced, this has the potential to either preclude or delay investments in generation, transmission and distribution assets.

CC (2016) find that the capacity benefit of solar varies widely across areas. They estimate that if solar PV installations were to be 100% of the peak capacity, system wide peak load would be reduced from approximately 8% to 3c [illegible]

Thus, this is the equivalent of a yearly capacity value of $220.64 for a 7kW solar system on a residential customer. Levelized to the generation of a typical system, this comes out to about 2.1¢/kWh, or about 91% of the average wholesale price of electricity. Thus, while the estimated avoided line loss in Dismukes (2015) was on the lower range of estimates from Borenstein (2008) and CKC (2016), the estimated capacity valuation is orders of magnitude larger than the estimates in both studies.

3.1.2 Potential Costs

3.1.2.1 Transformer Aging

If the prevalence of behind-the-meter solar PV increases fluctuations, there is potential for transformers to experience accelerated aging, therefore increasing the cost of maintaining the electric grid. Results from CC (2016) suggest that most transformers' aging is minimally impacted by behind-the-meter PV especially at relatively low (and current) levels of penetration. But, as penetration increases above 30%, there were a small number of transformers that experienced significantly accelerated aging, up to 166 times the normal rate. Unsurprisingly, these problems were experienced in locations with relatively high solar penetration and lower loads. Neither Borenstein (2008) nor Dismukes (2015) includes this cost.

3.1.2.2 Voltage Regulators

CC (2016) find that voltage readings outside of the permissible range do not exceed 0.5%, even in scenarios with high penetration. Thus, while voltage exceeding the permissible range is a problem in theory, they find that in practice, this is likely to become a problem only with very high levels of solar penetrations. In contrast, our engineering analysis showed voltage exceeding the permissible range at levels between 10% and 20% penetration. The likely reason for this di erence is that CC (2016) average voltage over a 15-minute interval, while our analysis considers four second time intervals. Thus, there can be significant variation of voltage outside of the permissible limits that is averaged out over longer time periods. Another potential but weaker reason is that variations in solar irradiance is assumed to occur at the same time over the entire feeder in our study while in practice this concurrence is more likely in smaller regions.

CKC (2016) suggest that a utility could upgrade voltage regulators in order to address this issue, and that the cost of doing so would be about $442,000 per year, or less than 9¢ per residential customer for its entire system. As will be discussed below, this analysis does not consider second-to-second variation and is therefore likely significantly understating the extent of this problem. Neither Borenstein (2008) nor Dismukes (2015) include this cost.

3.1.2.3 Reverse Power Flow

Finally, CC (2016) test for reverse power Brevec6Sntl,c7n4cat thae1r B5o.Tircb60ar T

3.1.2.4 Second-to-Second Flicker Regulation

CC (2016) and CKC (2016) do not consider second-to-second intermittency, i.e. voltage flicker, into their analysis. If solar PV is to increase in penetration, we show that utilities will need to be prepared to accommodate this new source of intermittency that occurs at the time interval of seconds, not minutes, as is considered in CC.

As previously mentioned, CKC (2016) suggest that a utility could upgrade voltage regulators in order to address minute-to-minute voltage rise, and that the cost of doing so would be about $442,000 per year, or less than 9¢ per residential customer for its entire system. While upgraded voltage regulators can handle these voltage changes on the scale of minutes, second-to-second variation in voltage outside of these ranges likely cannot be accommodated by upgraded voltage regulators, as traditional voltage regulators work in the scale of 30 to 45 seconds (Hartung, Baerthlein et al., 2014). In order to deal with fluctuations on the time scale considered in this analysis, a solid-state regulator would likely be needed (Ekstrom, Thomas and Leijon 2014). The replacement of these regulators requires an upfront capital expenditure but also can lead to increased power loss (Mailah, Bashi and Meng, 2003).

Both the up-front cost and power loss are contingent on the specific feeder, load profile, and solar penetration level. While estimating these specific costs is beyond the scope of this analysis, we can get a “back of the envelope” estimate of the cost in one of the feeders considered in this analysis. In Feeder A of the engineering analysis, there are 9 to 12 regulators[37] that would likely need to be repl3b7costTd i ne8 mentioned, the installed cost considered in Borenstein (2008) is more than double what is currently the installed cost in Louisiana today.[41]

Dismukes (2015), a much more recent analysis, considers a number of costs and benefits[42] and finds that in net from a societal perspective, the costs of solar energy in Louisiana are significantly higher than the benefit. But, this cost-benefit analysis considers a time period where (a) the state provided a generous 50% up front tax credit and (b) full 1:1 net metering. Potentially, if a less generous tax credit and a different rate design regime was in place, some solar investment might have still occurred and the net cost/benefits might have been different.

All of the previous studies, though, omit notable potential engineering problems created by behind-the-meter solar. While many of these technical challenges have been discussed generally and might be the reasons solar PV does not make up a larger share of electricity generation worldwide today (Sivaram, 2018), it is very difficult to quantify the actual cost of mitigating these issues as high penetration levels.

Perhaps a synopsis of this literature is best presented in a recent book titled *Taming the Sun: Innovations to Harness Solar Energy and Power the Planet*, where it states:

> "Some argue that rooftop solar power brings additional benefits to the grid, for example by reducing power losses over transmission lines when solar produces power near where it is used, or by avoiding the need to invest in expensive new grid infrastructure by lightening the load on the grid. These benefits are possible in theory, but in reality, rooftop solar is often more likely to increase rather than relieve strain on the grid."

Our study will not focus on the net benefit or cost to the grid, but instead we will present a cost-benefit analysis from the perspective of a household given the change in the solar tax credit and rate design in Louisiana.

3.2 Estimating Solar Production

Before running the economics of solar production from the household's perspective, we must first consider estimated production of behind-the-meter solar. Clearly, higher estimates of production will yield more favorable economics. Therefore, we consider seven estimates of solar production.

First, we will consider the production of the solar panel at the Renewable Energy and Smart Grid Laboratory (RESG Lab) scaled up to a 7kW system. As described in the engineering analysis, this is a 140-w solar PV panel located on the roof of the building that houses the Department of Electrical and Computer Engineering on LSU's campus. This solar panel is attached to a 2.30hm resistor that measures the electricity generated. Every four seconds, or when a change in power occurs the solar production data is recorded.

Next, we consider two publicly available online tools that allow location-specific estimated solar production; (1) NREL's "PVWatts" Calculator and (2) Google's "Project Sunroof." Both of these tools provide the estimated kWhs produced by a solar PV system in a specific location

[41] Benefits include: avoided generation energy, avoided generation capacity, avoided transmission and distribution solar installation economic benefits, solar operational and maintenance benefits. Costs include: unrecovered interconnection costs, solar net metering administrative costs, rate impacts of net metering credits, rate impacts of lost revenues, and government incentive costs.

[42] We should also note, though, that electricity prices in California were significantly higher than they are in Louisiana today (even non-inflation adjusted prices). We will present sensitivities of the economics to the electricity price.

over the course of a year. NREL's PVWatts also provides estimated solar production for each of the 8,760 hours of the year, while Google's Project Sunroof only provides an aggregate yearly estimate.[43]

In order to compare our results to actual residential solar systems, two volunteers who live approximately one mile from LSU's campus provided researchers with data from their actual systems that had been installed within the past two years. For each system, we collected data on both the advertised estimated solar production in the first year alongside the actual production that was achieved during that year. Thus, we have two data series per system—actual solar production and estimated based on the information the customer was given from the company when they purchased the solar system.

Table 3-1 shows the total capacity, kWhs produced, and implied capacity factor for each of these series in the first year of each respective units' operation. There are a few notable items.

First, the LSU solar panel has an implied capacity factor of 13.1%, compared to the two residential systems that had an 11.1% and 11.3% capacity factor. Thus, the small research panel had better capacity factor than two actual systems. This is not surprising given it is installed in a location with no shade any time of day and is not constrained to the pitch and direction of a resident's specific roof.

Second, though, we notice that the two online tools, NREL's PV Watts and Google's Project Sunroof, both have higher estimated capacity factors than both the LSU solar panel and the two residential systems. Thus, we find evidence that these online tools likely overestimate likely solar production, at least in Baton Rouge, Louisiana. We should note that this result is a bit anecdotal, as we do not have a representative sample of installations across the city or state.

The third, and potentially most troubling, result is that both residential systems produced

Impl[illegible]

S[illegible]rce		Gener[illegible]	[illegible]	Im[illegible]ied Capac[illegible] Factor
LSU Sola[illegible]		1,151	1	13.1%
NREL: PV Watts		9,221	7	15.0%
Google: Project Sunroof		8,69[illegible]	7	14.2%
Residential 1	Projected	[illegible]	[illegible]	[illegible]
	Ac[illegible]	7,788	[illegible]75	11.1%
Res[illegible]ntial 2	Projected	7,849	5.56	16.1%
	Actual	[illegible]522	[illegible]	11.3%

Note: Impli[illegible]pacity facto[illegible] ca[illegible]lulated as Generation (kWhs) / Capacity (kW) x Ho[illegible]

assumes that the inverter will be replaced in year eight and 16 for cost of $5,790 to 6,806 per replacement.[47] Dismukes (2015) does not include inverters specifically but does consider operation and maintenance costs on a levelized basis.[48]

For all analysis, we will also assume a degradation factor of ½% based on the lower of the two estimates provided by the solar providers who installed actual systems on our two volunteer households close to LSU. We assume that the panels do not become "dirty" over time, or that the owners clean the panels regularly. These assumptions are also generous relative to Borenstein (2008) that assume a 1% degradation per year and notes that a "soiling adjustment" of 5% would be appropriate (Hammond et al., 1997; Kimber et al., 2006), although also does not include in the analysis. The two installers of the residential systems presented an estimated 0.8% and 0.5% degradation. Therefore, the assumed 0.5% degradation per year is the most conservative. Dismukes (2015) also uses a degradation rate of 0.5% in all calculations.

We also note here our choice of discounting. In all analysis, in lieu of assuming some real discount rate similar to other analysis,[49] we instead report the real internal rate of return. In doing so, we make no assumptions about future electricity price escalation. Nor do we opine on whether one should consider the societal discount rate vs. a private household's discount rate. We will leave these debates up for our readers and policy makers. We will present a straightforward real internal rate of return and make no assumptions about future relative price escalations.

3.3.1 No Tax Credits

First, we consider the scenario where customers do not receive a tax credit for installing

3.3.3 Louisiana Tax Credit Expired

In the first scenario, we considered the economics of solar in the event of no up-front tax credits to subsidize the installation cost. In the second, we considered the very generous 80% combined state and federal tax credits. In this third scenario, we will consider the case where Louisiana has now removed its 50% tax credit, but the federal 30% tax credit persists. These actual residential systems, as in all tax credit combinations, have the lowest rates of return with –0.14% and -0.63% respectively.

Household Economics of Solar Investment — Federal Tax Credit (30%) - Full Retail Net Metering							
		Online Tools		Resident 1		Resident 2	
Source	LSU Lab	PVWatts	Project Sunroof	Predicted	[illegible]	[illegible]	[illegible]
Year 1	$ (16,694)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Year 2	802	917	865	80[illegible]	[illegible]	[illegible]	[illegible]
Year 3	798	913	860	805	683	978	723
Year 4	794	908	856	[illegible]	679	973	720
Year 5	790	904	852	797	676	[illegible]	[illegible]
Year 6	786	899	848	793	672	964	712
Year 7	[illegible]	895	843	789	669	959	[illegible]
Year 8	778	890	[illegible]	785	[illegible]	[illegible]	[illegible]
Year 9	774	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Year 10	[illegible]	[illegible]	831	777	659	945	[illegible]
Year 11	[illegible]	[illegible]	[illegible]	773	656	940	695
Year 12	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Year 13	759	868	818	766	649	930	688
Year 14	755	[illegible]64	814	762	646	926	68[illegible]
Year 15	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Year 16	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Year 17	[illegible]	[illegible]	802	750	636	912	674
Year 18	740	847	798	747	633	907	671
Year 19	736	843	794	743	630	903	[illegible]
Year 20	733	838	790	739	[illegible]	[illegible]	[illegible]
Year 21	729	834	786	735	624	[illegible]94	661
Year 22	725	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Year 23	722	826	778	[illegible]	[illegible]	[illegible]	[illegible]
Year 24	718	[illegible]	[illegible]75	725	[illegible]	[illegible]	[illegible]
Year 25	715	818	771	721	[illegible]	[illegible]76	[illegible]648
Years to Payback	[illegible]	20	22	23	Never	19	Never
IRR	0.71%	1.94%	1.39%	0.79%	[illegible]	[illegible]	[illegible]

No[illegible] etail electricity prices [illegible] per kWh. Electricity pr[illegible] are not [illegible] installation cost is [illegible] used in all calculations. "LSU Lab" Solar production [illegible] University. Online tools from the National Renewable Energy Laboratory's *PVWatts* and Google's *Project Sunroof*. [illegible] actual residents w[illegible] approximately 1 mile of LSU's campus in Baton Rouge.

Table 3–4: Economics of Solar – 30% Tax Credit + Full Retail Net Metering

the state tax credit has been sunset, the installed costs will need to be reduced before more investment in behind-the-meter solar can be justified from a financial perspective.

Next, Figure 3-2 shows the sensitivity of solar economics to changes in electricity prices. As can be seen, at current prices of 10¢/kWh, both the federal and state tax credits are needed to incent behind-the-meter solar investment. Now that the state tax credit has been sunset, significant increases in electricity prices will be needed to spur additional investment. Even if electricity prices double to 20¢/kWh, investment in solar still will be less attractive than 6¢/kWh but with the state tax credit. Thus, without the state solar tax credit, even large changes in the electricity prices are unlikely to spur significant investment in solar.

Rate of Return and Cost per kW of Installed Capa

Full NEM - 10¢ Electricity Pri

We should note that a combination of these two factors might occur and spur additional solar investment even in the absence of the state tax credit. A decrease in the installed cost of solar alongside an increase in electricity prices could improve the outlook for future solar investment. For this reason, even if solar growth slows in coming years, utilities should continue to monitor the relative economics of behind-the-meter solar and be prepared to adopt policies that will accommodate this growth if they become economic while mitigating reliability concerns discussed in the engineering analysis in this report.

3.4 Economics by Rate Design

Next, we consider the impact that different rate regimes might have on the economics of solar installations from the household's perspective. For this analysis, we consider the current tax regime in which a 30% federal tax credit is available (but the state tax credit is not available). For these results we will also consider the solar generation from the residential system with hourly production data available.

We will consider three different potential rate design regimes. The first is the 1:1 full retail rate credit net metering (NEM) policy that has existed in Louisiana since 2008. This is the most generous rate design regime that credits each kWh of solar production at the full volumetric retail rate of electricity. While beyond the scope of this research, this creates significant problems of shifting costs to other customers (Dismukes, 2015).

The second regulatory regime considered is, albeit, unlikely to be implemented in a practical application, but nonetheless interesting for comparison purposes. In this regime, the solar customer is treated similarly to any other small qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA), in that they will have the right to deliver electricity to the grid and be paid at the utility's LPSC-approved avoided cost rate. We consider three different avoided cost rates: an average wholesale rate over the entire year, a monthly wholesale rate, and a wholesale rate that varies by the hour. All wholesale rates are from the Southwest Power Pool (SPP) and are averaged over 2015 and 2016 prices by hour of the year. While an actual utility scale QF would be eligible to sell its power at the hourly price, reimbursing a residential customer at this level of granularity would be likely more administratively burdensome. For this reason, we consider the three wholesale prices and provide a comparison and some context. For all of these calculations, we will escalate the amount of energy sold back to the grid by 7% to credit the customer for the avoided line loss.[51]

The third regulatory regime is what the LPSC is currently moving towards, namely two-channel billing. Under this regime, customers will be credited at the full retail rate for all generation that is used behind the meter and reduces their usage. And only when the power is sent back to the grid will they be credited at the utility's avoided cost rate. For this analysis, we reimburse the hourly wholesale rate (that we will show is actually most advantageous for the customer).

therefore that will be what is utilized here. Specifically, the customer will receive a rate credit of $216 per year, or about $30 per installed kW of solar capacity. Thus, while the customer will not receive the full retail rate for energy sent back to the grid (as with 1:1 full retail credit net metering), the customer will receive a capacity benefit. Thus, the net effect of the two is an empirical question and will depend on the relative capacity benefit and wholesale electricity price used to set the utility's avoided cost rate.

Next, we will consider the economics with a two-channel billing (with capacity benefit included) alongside a battery. Consistent with the engineering analysis, we consider a 13.5 kWh Tesla Powerwall. Unlike the engineering analysis, we will run this dispatch algorithm over the year at an hourly interval, in lieu of the four second interval that is needed for the voltage rise and flicker analysis.[52] Again, for all power sent back to the grid, we will again escalate by 7% to give the customer credit for avoided line loss. The battery will also generate an additional benefit, namely, it will increase the capacity benefit per estimates discussed in Section 3.8 below.

Results are presented in Table 3-5. As can be seen, with no state tax credit and full retail net metering, the most generous rate regime, the internal rate of return on the solar investment is 0.71%, and the system has a 23 year payback. Next, we compare the average wholesale,

When reviewing the literature on quantification of capacity of intermittent resources, it quickly becomes apparent that there is no standard method. Furthermore, when reviewing the methods, it also becomes apparent that different methods will yield very different capacity benefits. This poses a significant challenge for policy makers, as significant under or over valuation of intermittent renewable resources can significantly impact both the economics of renewable resources and the stability of the electric grid. Further, over (under) valuing capacity of renewable resources at a utility scale level can lead to under (over) investment in capacity. Therefore, valuing capacity consistently and properly is of the utmost importance for

Table 3–7: Capacity Benefit as Percent of Installed Capacity

accepted definition of a resource's contribution to system "capacity," in general one of the goals of any market is to ensure that there will be enough generation capacity to meet demand at the highest demand hour of the year. The question at hand is whether the investment in a renewable energy resource, like behind-the-meter solar, can preclude additional investment in generation, transmission and distribution infrastructure at some point in the future. Precluding this investment will save money, and therefore provide value to the system.

One might argue that because the resource cannot be dispatched on demand, and the system needs to have enough capacity to meet peak demand, these intermittent resources cannot be included in planning to meet peak demand. Clearly, though, if enough renewable resources are scattered throughout enough area, at the peak hour of the year the probability that *all* of these renewable resources are producing zero power is, for all intents and purposes, zero. Thus, *some* capacity benefit should, at least in theory, exist for these resources.

On the other hand, one might argue that if the capacity value of natural gas, coal, or nuclear power plants is considered in the cost-benefit analysis of these resources, then so too should a renewable resource. In the short run, when renewables are a relatively small share of total energy generated, counting the capacity for resource adequacy planning might not cause operational problems from a practical standpoint. But, in the long run, if renewable energy sources grow to a significant share of total generation on the electric grid, then the overvaluing of this capacity will lead to reductions in investment in dispatchable generation sources and potentially lead to time periods where demand exceeds generation, causing brown outs.

The truth, like most things in life, falls somewhere between these two extremes. It is likely possible for renewables to provide some capacity benefit, therefore mitigating the need to build additional infrastructure at some point in the future. But, it is simply implausible that these renewables will count for 100% of their nameplate capacity for planning purposes, as these sources simply cannot be depended on during peak time periods. The goal of this analysis is are possible. A risk averse utility would need to consider these low probability events with little solar during peak hours. Thus, this corroborates the prior point that using this method from one, or even a few, sources of solar generation might not be prudent. Instead, the utility should average many solar generation sources across an area, and potentially consider a more modest estimate of the coincident peak reduction in capacity.

Table 3-6 also shows the results of the reduction in residential coincident peak demand when a battery is included with the solar PV system. Consider the Max Load Hour for the LSU solar panel. The percent reduction in the household's coincident peak demand is approximately 37% without a battery. But with the battery installed and the dispatch algorithm employed, the household's demand for electricity in the max load hour was actually reduced by 100%. Thus, there is significant opportunity for the battery to produce a capacity benefit.

Next Table 3-7 presents these results as a percent of installed capacity (as compared to a percent of household's peak coincident demand as shown in Table 3-6). We find that capacity benefits of solar with no battery range from an estimated approximately 19% to 43% depending on the hours considered (top load hour, five hours or 20 hours) and which solar generation source is used. When averaged across the solar generation sources we find a capacity benefit ranging from between 31% and 36% of installed capacity. Table 3-7 also presents the incremental benefits of the battery. We find that the incremental benefit of the battery ranges from 12% to 18%.

The results presented in Tables 3-6 and 3-7 provide reasonable estimates of the capacity benefit of solar and batteries when there is a relatively small amount of solar energy generated. If solar is produced in relatively small volumes, then the production in the system peak hour provides a reasonable estimate of the capacity benefit. But, as more and more solar is installed, the load curve itself can be changed.

To see this, consider the following example. The maximum average residential energy consumption per customer in one hour in our data is 3.63 kWh. This occurs at 3:00 p.m. on August 4. But after subtracting the 1.35 kWh of solar produced in this hour (using the LSU Solar data), the "net load" is 2.28 kWh. Thus, if all households were to install solar PV (and this PV were to follow this generation pattern) this particular hour of the year would no longer be one of the peak hours. Specifically, the peak net load hour of the year using the LSU solar data is view the top load hour of the system as a percent of the top load hour of the system in the event that no households installed solar. Results are presented in Figure 3-3.

As can be seen, if 100% of residential households were to install solar, this would reduce the maximum load hour the utility would need to be prepared to meet by about 9%. Further, by the time 10% of households installed solar, the maximum load hour faced by the utility would be reduced by about 5.7%. In other words, most of the capacity benefit from solar production comes from the early installers of solar. As more systems are installed, the capacity benefit reduces substantially. In Louisiana, currently less than 1.5% of residential households have installed behind-the-meter solar, so the coincident peak approach is likely reasonable for the purposes of valuing the capacity benefit of solar in the meantime. But if behind-the-meter solar grows, this capacity benefit will need to be reduced as the marginal benefit of each system declines, as more systems are installed.

Estimating the theoretical reduction in peak demand with the battery is significantly more challenging and is beyond the scope of this research. While we have shown that the battery has the potential to significantly improve the capacity benefit of solar, the dispatch algorithm used would significantly impact the incremental capacity benefit. Would the algorithm's goal be to reduce the peak demand of the household itself? Or would the goal be to reduce coincident peak of the system? What size battery would a household decide to install given the rate design regime chosen? Such questions can only be answered once a specific rate design regime is adopted and dispatch algorithms are designed to respond to these regulatory regimes.

[53] For the solar generation, we scale the residential system, PV Watts and the LSU solar system to a 7kW system and take the simple average.

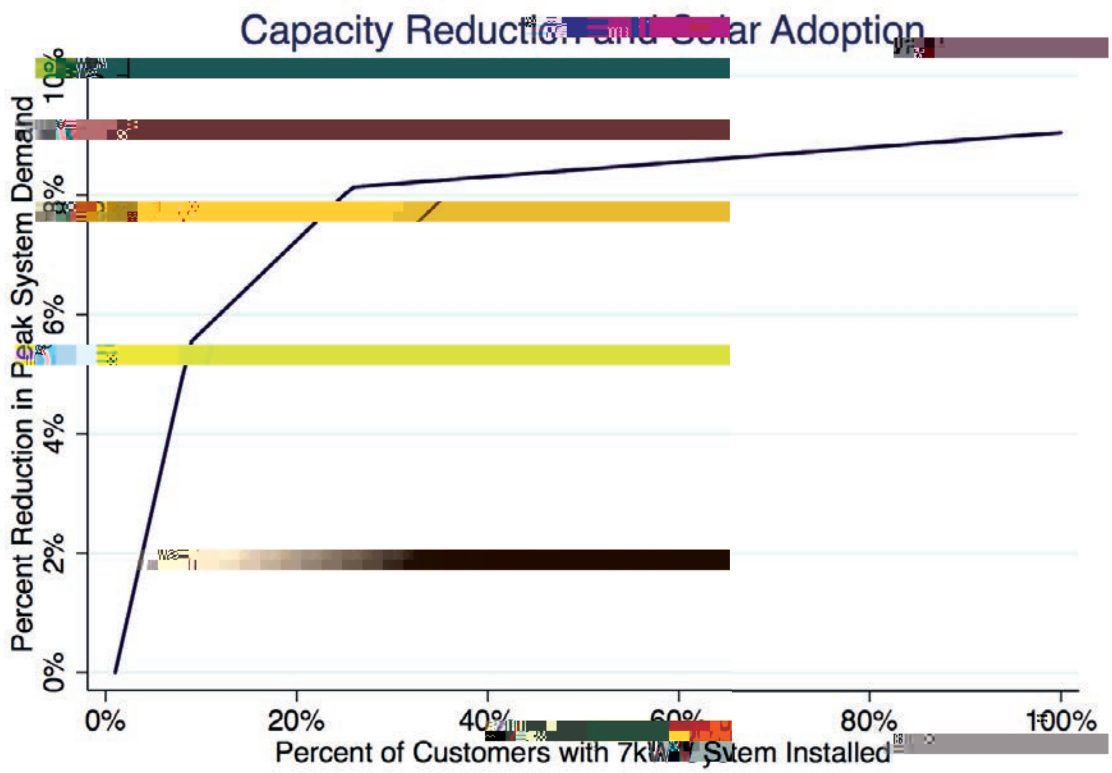


Figure 3–3: Marginal Contribution to Coincident Peak Reduction of Additional Behind-the-Meter Solar Penetration

3.6 Valuing Batteries

Next, we assess the extent to which a household might choose to install a battery given the up-front cost of the battery alongside the capacity and increased value of energy the battery provides. For this analysis, we consider three different tax credit regimes—no tax credit, a 30% federal tax credit, and an 80% state plus federal tax credit. These presume that the tax credit would cover both the cost of the solar and the battery. All calculations consider a 13.5 kWh Tesla Powerwall using the dispatch algorithm in this analysis alongside a 7kW solar system. The economics presented here is on the marginal value of the battery added to the 7kW solar system.

The battery will create value in two ways. First, it can increase the value of the energy for the household. Under a two-channel billing regime, the household is paid full retail rate for all energy produced and consumed behind the meter. In other words, just as someone would be paid retail rate for reducing their demand by installing energy efficient appliances or insulation, a solar customer will be credited at the full retail rate for reducing the number of kWh they purchase from the utility. But under a two-channel billing regime, the customer will only get credited at the avoided cost for any excess energy sent back to the grid. Thus, if a customer

[54] We also explored the option of using actual real-time prices of the collection of nodes nearest the load center. While this, in theory, would be preferable, this creates significant variability including negative prices. Furthermore, charging a customer for sending power back to the grid during an hour of negative pricing might be problematic from a public policy perspective, therefore some type of averaging can be done in practice.

can store the solar energy and dispatch it when the household needs it, this will increase the value of the energy produced. We should note that under the current regulatory regime of net metering in Louisiana, a battery cannot provide this economic incentive to the customer, as the customer is allowed to send energy back to the utility and receive a full retail rate credit on their utility bill.

The second value the battery can create is the capacity benefit. As discussed previously, a utility needs to be prepared to meet the peak load of the entire year. Thus, it must have access to the generation, transmission and distribution assets that will allow for this power to be produced and transferred to customers in the highest load hour of the year. If a battery can reduce the household's demand during this highest load hour of the year (i.e. the household's coincident peak demand), this too can create value for the grid. A regulatory regime that allows for the valuation of capacity can send the proper signal to a household to reduce its peak demand, and therefore send the appropriate market signal to allow for the installation of a battery.

The choice for the household, therefore, is whether the installation of the battery alongside its solar system will create enough value to pay for the battery. Therefore, it is important that regulators and utilities choose a rate regime that aligns incentives of both the utility and the customer and allows the customer to be credited for the benefit that the battery can provide

Thus, under current market conditions and with the two-channel billing regulatory regime, it is unlikely that batteries will see significant economic opportunity in the near future.

While this is a hypothetical exercise based on a hypothetical rate design regime that is unlikely to be implemented in this specific way in practice, these results show that if a proper rate design regime is chosen, batteries can have the opportunity to compete economically. And the economics of the battery can actually be similar to the economics of the solar itself. Thus, batteries do have the opportunity to play an important role in behind-the-meter solar. But it is up to policymakers and utilities to choose a regulatory regime that will allow these batteries to compete by offering both an energy and capacity value that the customer can be credited for appropriately.

Househ[illegible]

Two Channel Billing - Includes Capacity and Energy Benefit

	LSU Lab			PVWatts			Residential System		
Install Cost	$6,500	$4,550	$1,3[illegible]	$6,500	$4,550	$1,300	$6,500	$4,550	$1,300
Tax Credit	0%	30%	80%	0%	30%	80%	0%	30%	80%
Year 1	[illegible]	(4,394)	(1,144)	(6,151)	(4,201)	(951)	(6,287)	(4,337)	[illegible]
Year 2	155	155	155	347	347	347	212	212	212
Year 3	155	155	155	346	346	346	211	211	211
Year 4	154	[illegible]	154	344	344	344	210	210	210
Year 5	154	154	154	343	343	343	209	209	209
Year [illegible]	153	153	153	[illegible]	341	341	208	208	208
Year [illegible]	[illegible]	152	152	[illegible]	340	340	208	208	208
Year 8	152	152	152	338	338	338	207	207	207
Year 9	151	151	151	[illegible]	337	337	[illegible]	206	206
Year 10	151	151	151	[illegible]	335	335	205	205	205
Year 11	150	150	150	334	334	334	204	204	204
Year 12	150	150	150	332	332	332	203	203	203
Year 13	149	149	149	331	331	331	203	203	203
Year 14	[illegible]	148	148	329	329	329	202	202	202
Year 15	148	148	148	328	328	328	201	201	201
Year 16	147	[illegible]	147	326	326	326	200	[illegible]	[illegible]
Year 17	147	147	147	325	325	325	199	199	199
Year 18	146	146	146	323	323	323	198	198	198
Year 19	14[illegible]	146	14[illegible]	322	322	322	198	198	198
Year 20	145	145	145	321	321	321	197	197	197
Year 21	145	145	145	319	319	319	196	196	196
Year 22	144	144	144	318	318	318	195	195	195
Year 23	144	144	144	316	316	316	194	194	194
Year 24	143	143	143	315	315	315	194	194	194
Year 25	143	143	143	314	314	314	193	193	193
Payback	Never	Never	9	20	14	4	Never	23	7
IRR	-4.21%	-1.62%	12.46%	2.[illegible]7%	5.98%	30.05%	-2.00%	0.93%	18.[illegible]%

Note: Electricity [illegible] are average wholesale price from SPP averaged between 20[illegible]5 and 2017. Ele[illegible]ity prices are not escalated, thus IRRs represent a real return. Total installation cost is $6,500 fo[illegible]ll batteries based on the price of the *Tesla Po[illegible]rwall*. Degradation [illegible]e of .5 percent used in all calculation[illegible] LSU Solar production from the [illegible]le Energy and Smart G[illegible]ratory [illegible] Laboratory's. Resident is an actual resident within approximately 1 mile of LSU's campus in Baton Rouge, LA.

Table 3–8: Valuing Batteries

4 | Policy Recommendations

There are a number of results in this report that we think are important for policy makers to consider. We review and summarize these here.

4.1 Outlook on Behind-the-Meter Solar PV Installations

a study that collects data on the estimated pay-back of behind-the-meter solar systems and compare to ex-post paybacks. This is especially important given the fact that taxpayers have paid half of the cost of these installations. If any companies are found to have purposefully misrepresented information to consumers, the state should take appropriate legal action.

4.7 Environmental Externalities

A case can be made that solar PV can abate the burning of fossil fuels and therefore reduce the amount of carbon dioxide, and other pollutants like NOX and SO2, emitted into the atmosphere. While the purpose of this study is not to estimate these environmental benefits, as this is beyond the scope, we do believe that such environmental benefits can be credited

5 | Conclusions

The solar industry in Louisiana is truly at a crossroads. With the sunsetting of the state tax credits alongside changes to net metering policy, Louisiana now has a unique opportunity to set regulatory policies that better align incentives of customers (both those that install solar PV systems and those that don't), utilities, and taxpayers in Louisiana. A regulatory regime should be careful to balance two objectives: (a) proper valuation of the energy and capacity benefits provided by behind-the-meter solar while (b) avoiding the shifting of costs to non-solar customers. Further, utilities should be given clear guidance on how and when to move forward with distribution grid resilience measures that stem from the growth of behind-the-meter solar. Any distribution grid upgrades that result from this research, and that are specifically made to accommodate behind-the-meter solar growth, should be paid for by solar customers recognizing that there are policy challenges with charging customers after the fact.

On the other hand, though, solar customers should be credited for the benefits they provide, namely avoided electricity generation and avoided capacity additions. These benefits can be further enhanced by batteries if and when they become economical. The LPSC should focus on setting ratemaking processes that align incentives and send appropriate price signals and then allow the market to decide. Environmental benefits of solar can also be included in this process to the extent such benefits can be quantified.

From the outside, it might appear that solar installers and utilities have very different incentives in terms of which policies they pursue. But we push back against this notion and believe that proper ratemaking is in the long-term interest of all parties involved: customers, utilities, and the local business community. It is sometimes easy to look at every proposed ratemaking change and ask whether it will improve or diminish the economic viability of

Kandasamy, Nandha Kumar, King Jet Tseng, and Soong Boon-Hee. “Virtual storage capacity using demand response management to overcome intermittency of solar PV generation.” *IET Renewable Power Generation* 11, no. 14 (2017): 1741-1748

Kimber, A., L. Mitchell, S. Nogradi, and H. Wenger. “The Effect of Soiling on Large Grid-Connected Photovoltaic Systems in California and the Southwest Region of the United States.” Conference Record of the 2006 IEEE 4th World Conference on Photovoltaic Energy Conversion, Volume 2, 2391-2395, May 2006.

LSU | Ce