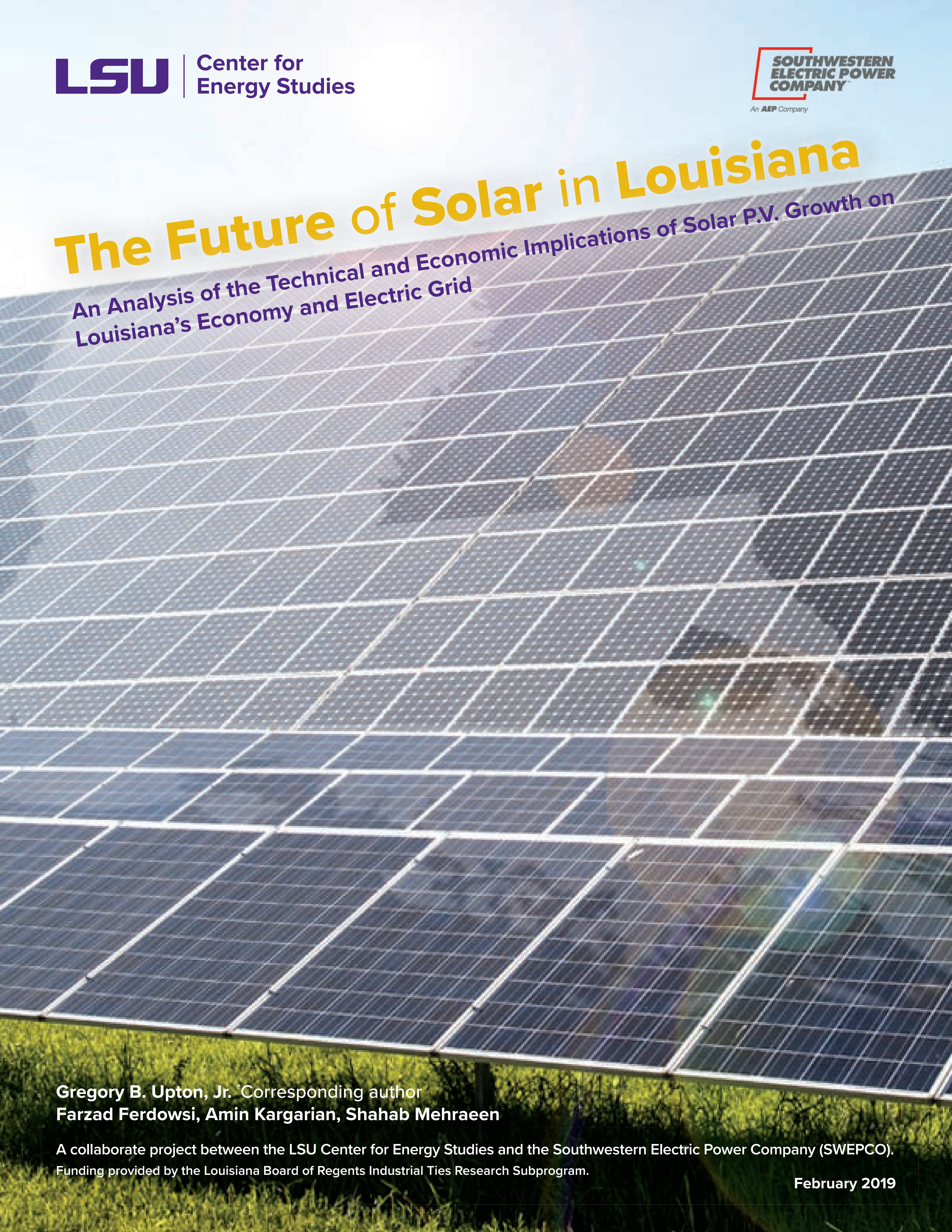

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SOUTHWESTERN ELECTRIC POWER COMPANY
An AEP Company

The Future of Solar in Louisiana

An Analysis of the Technical and Economic Implications of Solar P.V. Growth on Louisiana's Economy and Electric Grid

Gregory B. Upton, Jr. [*]Corresponding author
Farzad Ferdowsi, Amin Kargarian, Shahab Mehraeen

A collaborate project between the LSU Center for Energy Studies and the Southwestern Electric Power Company (SWEPCO).
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Executive Summary

In June of 2016, the Louisiana Board of Regents appropriated $117,051 as part of its Industrial Ties Research Subprogram (ITRS) to study how solar could be incorporated into the electric grid and whether the incorporation of battery storage could enhance the scalability of this resource in an economical way. The Southwestern Electric Power Company (SWEPCO) was the industry partner providing over $40,000 of in-kind contribution to this project, including specific distribution grid data and a significant investment of its employees' time. This collaborative effort between the LSU Center for Energy Studies, the Louisiana Board of Regents, and SWEPCO has resulted in a report that assesses both the technical and economic implications of the solar industry in Louisiana.

This report is largely divided into two distinct, but related, analyses. First, we assess the degree to which solar growth can cause challenges to the distribution grid that SWEPCO, and all electric utilities for that matter, are responsible for maintaining in order to provide safe, reliable and affordable electricity to Louisiana's residents. Using specific load and network data on three feeders within SWEPCO's service territory alongside solar production data from the Renewable Energy and Smart Grid Laboratory on Louisiana State University's campus, we are able to identify the level of solar penetration that can create significant engineering issues on the distribution grid.

Next, we assess the economics of behind-the-meter solar. 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. The Louisiana tax credit is no longer available, but the federal 30% Investment Tax Credit is still available, but begins to phase out starting in 2020. As a result, solar installations in Louisiana went from essentially zero in 2008 to today having over 140 MW of installed solar capacity.

In the 2015 session, in light of budgetary constraints, the Louisiana Legislature instituted separate $25 million caps on purchased and leased solar systems, respectively. The Legislature capped the purchased system solar credits at $10 million in FY 2015-2016 and FY 2016-2017. In the FY 2017-2018 this dropped to a cap of $5 million, for a total of $25 million in credits. But, by March of 2016 all $25 million of credits were granted to taxpayers.[1] On the leasing side, the full $25 million capped amount was not fully used before sunsetting at the end of 2017. Thus, today, the state solar tax credits are expired. The total cumulative cost of these solar subsidies to Louisiana taxpayers has been $204 million.[2] Between 2013 and the present, each Louisiana Public Service Commission (LPSC) jurisdictional utility has reached the maximum amount of solar capacity that it must allow on its system that is eligible for 1:1 full retail "net metering." Rooftop solar systems installed today are eligible to receive a full retail credit for energy used behind the meter and exported in a month up to the amount of usage. Any energy delivered to the grid in excess of usage is credited at the utility's Louisiana PSC-approved avoided cost rate. In effect, customers fall into one of two regimes: (1) those

[1] Revenue Information Bulletin No. 17-012. July 24, 2017. Income Tax. Act 413 of the 2017 Regular Session of the Louisiana Legislature Solar Energy Systems Tax Credit.

[2] Thanks to Daniel Groft, economist at the Louisiana Department of Revenue, for providing these numbers.

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 staff 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.[3] This information can be used to inform the utility and LPSC whether investments to the distribution grid to mitigate engineering concerns are warranted.
- 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 differently 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).
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- 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).

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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 the growth of behind-the-meter solar installations and capacity from 2010 until the end of 2016. As can be seen, solar installations in Louisiana went from essentially zero in 2008 (the year that the solar subsidy was passed), to today having over 24 thousand households with behind-the-meter solar, summing to almost 140 MW of installed solar capacity. This research will examine this timely and important energy research question by ascertaining the extent to which the growth of rooftop solar is scalable from the standpoint of the electric grid and whether battery systems can be used to enhance the scalability of this resource on a forward-going basis.

Unlike conventional power generation sources, solar power cannot be dispatched when needed if not accompanied by proper storage and, unfortunately, solar energy does not necessarily peak at the same time as electricity demand, which in Louisiana occurs most often on summer weekdays between 4:00 p.m. and 7:00 p.m. Thus, it is not clear whether solar power without the incorporation of battery storage can preclude investment in traditional generation, transmission, and distribution assets (i.e. create a "capacity benefit").

In addition to questions of whether solar can be used as a substitute for traditional investment in power generation, the intermittent nature of solar power can create significant technical challenges on the electric grid. More specifically, solar has the potential to cause voltage flicker, power transmission interruption, or voltage instability. As we will show, for all intents and purposes, these potential problems occur only when the renewable resource accounts for a significant share of generation in an area. But little is known about what share needs to be reached before significant problems begin to arise. Further, this threshold could be very different for different areas within the same state, and even the same utility. Thus, it is not clear that a "one size fits all" approach that sets some specific limit on solar will be sufficient to safeguard against these issues.

If policymakers are committed to a future where renewable resources are to be scaled to a significant share of Louisiana's electricity production, these issues should be anticipated and potential solutions should be identified. A "wait and see" approach might seem attractive in that it pushes difficult decisions into the future, but as we will show, such an approach might significantly increase future costs of incorporating behind-the-meter solar into the grid at significant quantities.

In fact, due to concerns raised by utilities, the Louisiana Public Service Commission (LPSC) set a cap on solar production such that net metering purchases should not exceed 0.5% of a utility's retail peak load for these very reasons.[5] Today, every utility in the state has reached this cap.

[5] Specifics of this cap are discussed below.

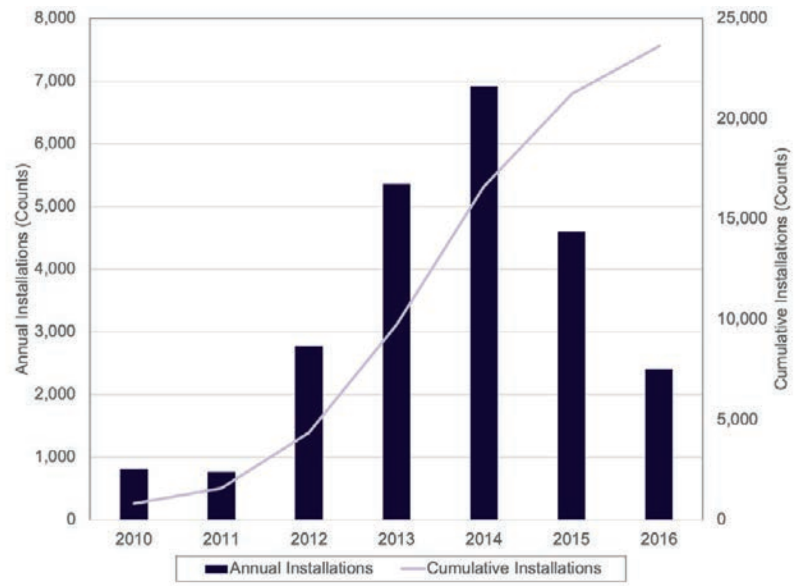


Figure 1–1: Louisiana Behind-the-Meter Solar Installations

Source: EIA 861, supplemented by data reported to LPSC.[6]

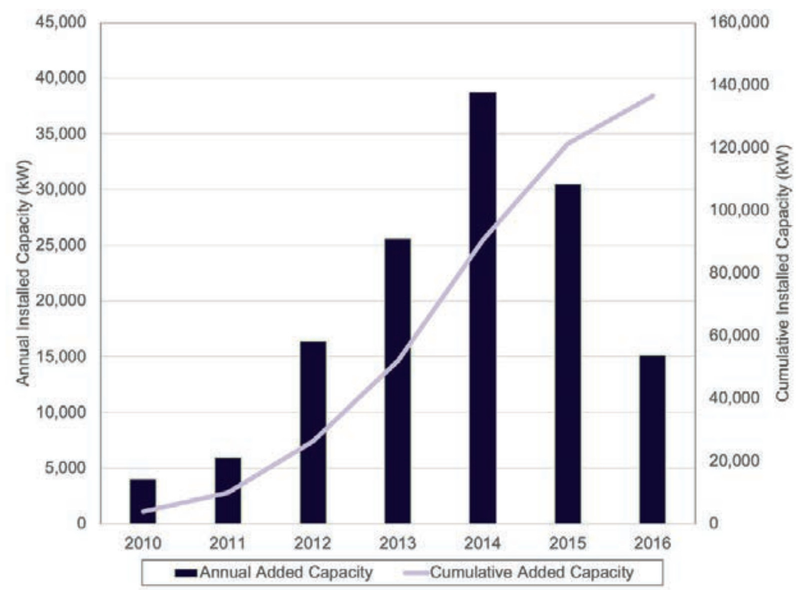


Figure 1–2: Louisiana Behind-the-Meter Solar Capacity

Source: EIA 861, supplemented by data reported to LPSC.[7]

[6] A special thanks to Andrew Owens at Entergy for compiling this data.
[7] Ibid.

While there are no utilities, to our knowledge, that have turned down customers from installing rooftop solar PV systems, and the LPSC has instituted an interim policy for net metering, it is time for these issues to be addressed and long-term predictable policies to be adopted to mitigate uncertainty for both the solar industry and electric utilities. At the time of this writing, the LPSC is in the process of a rulemaking to determine how behind-the-meter distributed resources, such as solar, will be treated for the purposes of ratemaking into the future.

But net metering policy changes are not the industry's only source of uncertainty. In light of budgetary constraints, the Louisiana Legislature capped state's solar tax credits—that offset 50% of the up-front installation cost—to $10 million in FY 2015-2016 and FY 2016-2017. In the FY 2017-2018 the cap is further dropped to $5 million. In total, $25 million in credits were available over this three-year period on a "first-come, first-served" basis to homeowners purchasing their solar systems. The Louisiana Legislature instituted a separate $25 million capped amount for leased systems. By March of 2016 all $25 million of credits were granted to taxpayers who had purchased their systems.[8] On the leasing side, the $25 million set aside by the Legislature was not fully utilized. Thus, today, the state solar tax credit is essentially expired until further action is taken. The total cumulative cost of these solar subsidies to Louisiana taxpayers has been $204 million.[9]

The Louisiana solar industry is at a crossroads. The cap for 1:1 full retail net metering has been met by each utility and the state solar tax credits have sunset. Understanding the scalability of this resource is necessary if the state is to continue to invest in rooftop-scale solar energy. For instance, both Entergy Louisiana and Entergy New Orleans are separately pursuing approvals for 150 MW in aggregate across multiple projects. Over-investment in a resource without understanding the ramifications on the state's electricity grid can lead to increased costs to ratepayers and end up harming the state economically in the long run. On the other hand, renewables can provide a source of both fuel savings and diversity to Louisiana's power portfolio, therefore hedging against potential future fuel cost changes. Also, behind-the-meter solar installation might create a significant benefit in helping defer, or possibly in some cases eliminate, investment in future generation, transmission, and distribution assets, and this energy resource is conveniently produced in the location that it is consumed.

This whitepaper will proceed in two major sections. First, a technical engineering analysis will be presented that specifically identifies these distribution grid issues associated with growing behind-the-meter solar. Next, an economic analysis is conducted to assess the implications of changing state tax credits and potential rate design regimes (in lieu of net metering). Based on the results from these two very different, but related, analyses, we will conclude with broad policy recommendations for the governor, Legislature, and Public Service Commission. We will also provide recommendations to utilities on how to plan for the future of solar growth on their distribution grids and how policy decisions might impact their actions.

1.1 Partnership

Undertaking a project with the scope of this one requires a number of partners to produce valid results that can lead to practical and pragmatic policy recommendations. Simply put, a

[8] Revenue Information Bulletin No. 17-012. July 24, 2017. Income Tax. Act 413 of the 2017 Regular Session of the Louisiana Legislature Solar Energy Systems Tax Credit.

[9] Thanks to Daniel Groft, economist at the Louisiana Department of Revenue, for providing these numbers.

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 system size limits, the LPSC revised Section 5.02 that required the LPSC to revisit its NEM rules once a utility determines that its net metering purchases exceed more than 0.5% of retail peak load. Due to reliability and other concerns raised by utilities, the LPSC revisited its NEM rules again in 2012 and 2013, and ultimately converted the 0.5% threshold into an official "hard cap" on net metering for each utility in its General Order dated July 26, 2013. In subsequent utility-specific NEM cap proceedings, the LPSC had to address issues related to terminology in its June 2013 order. Ultimately, the LPSC clarified the methodology that was to be utilized, but also affirmed that customers seeking to install rooftop solar systems could continue to do so albeit under different terms.

By 2014, a number of utilities in Louisiana were either close to, or had already reached, their caps on NEM solar. Then, in May of 2014, the LPSC hired a private consulting firm to conduct an evaluation of the total cost and benefits of net metering in the state of Louisiana. In September of 2015, the final report titled "Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers" was released. The report concluded that the "estimated costs associated with solar NEM installations outweighs their estimated benefits to ratepayers of LPSC-jurisdictional utilities."

In December of 2015, the LPSC began a new rulemaking procedure (Docket R-33929) that consisted of two phases. Phase I of the rulemaking was to create an interim rule that would be in effect for new solar customers until Phase II could be completed, that would provide a permanent rule. Specifically, in Phase I of the rulemaking, the LPSC required utilities to continue accepting new distributed generation applications after reaching the utility's net metering cap, but that the customer would be credited for any excess net metered energy delivered to the utility that was left at the end of the month after netting at the utility's avoided cost. In practice, this interim rule was no different than the previous net metering policy, as very few behind-the-meter solar customers (if any) produce sufficient excess energy over the course of an entire billing time period so as to have excess energy remaining after netting against usage. As we will show in this report, a typical customer with average usage and a 7kW solar system will produce about 55% of their power throughout the year. Phase I is currently in the process of being replaced by the permanent rule set forth in Phase II; however, at the time of this writing the LPSC has yet to take action on recommendations from its staff.

[10] Unlike the state tax credit that is capped at 50% of the first $25,000, the 30% federal tax credit has no cap. But, in Private Letter Ruling 09-108, the Louisiana Department of Revenue ruled that the same taxpayer could purchase multiple "systems," therefore exceeding the $25,000 limit.

[11] If a homeowner itemized their federal taxes, they had to pay federal tax on the state tax credit. On the other hand, if the homeowner did not itemize, then they got the full 80% in combined tax credits. In addition, while the state tax credit was refundable, the federal ITC is not.

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]
- Today, there is still considerable uncertainty about the future of rooftop solar in Louisiana. What is the future of the state tax credits? While the days of very generous up-front credits are likely behind us now, will any state tax credit be available at some point into the future? How will the economics of solar be changed under new tax and rate regimes assuming the Louisiana PSC does enact revisions to its NEM policy? Will the installed cost of solar continue to fall in the future? The future of the solar industry in Louisiana, at least in part, lies in the answers to these questions. This report will address many of these questions and make practical policy recommendations.

[12] There is an exception for grandfathered customers that is discussed in Section 7.1.

[13] Utilities have commented, fairly, that under the Proposed Rule, net metering customers would still receive favorable treatment relative to a QF.

2 | Engineering Analysis

Before assessing the economic future of the solar industry, we first present an engineering analysis that describes potential technical challenges with behind-the-meter solar incorporation and assesses the practical levels at which these problems begin to arise. This information will then be incorporated into the economic analysis in Section 3 of this report.

2.1 Conceptual Challenges with Behind-the-Meter Solar Integration

Conceptually, engineering concerns associated with integrating a large share of solar power into the distribution grid are well known and researched in the academic literature. Specifically, concentration of solar power generation can impose operational problems on local electricity distribution grids largely due to the resource's intermittence and its spatially correlated production.

For instance, a large number of solar power generators may reduce electricity production simultaneously when the weather changes, such as increases in cloud cover or even localized precipitation (Hill et al. 2012). These solar installations may also dramatically increase electricity production on sunny days leading to excess power that is dumped onto the local electric distribution grid, potentially leading to undesirable overvoltage situations (Liu et al, 2008). The mildest effect of these solar-induced power production surges includes voltage flicker and subtle power quality degradation (Hama, Kanokbannakorn & Sirisukprasert, 2017). More severe cases of excess and concentrated solar electricity production can include wider-spread voltage instability and localized system collapse (Tan & Kirschen, 2007). The power generated by solar energy can cause excessive reverse power flow that in turn interferes with the protective mechanisms and may cause overload or unexpected circuit disconnections and voltage instability (Woyte et al, 2006). And these excess power flows have been shown to age specific transformers quite rapidly. In fact, Cohen & Callaway (2016) find that PV penetrations of above 30% aged some transformers quite rapidly, up to 166 times their normal rate with no solar PV.[14]

At the bulk power system level, intermittent solar electricity production, if large enough, can lead to the reduction of power generation from conventional resources which, in turn, can lead to various thermal efficiency losses depending upon the marginal resource impacted by the incremental solar generation increase (Chowdhury & Sawab, 1996; Srisaen & Sangswang, 2006). In addition, due to solar generation uncertainty, adequate power reserves are required to balance generation and demand and control system frequency. This is a significant challenge for the grid when solar penetration is high (Halamay et al, 2011).

In short, these potential engineering considerations are well known in the electrical engineering field. But, what is less clear is how these concerns apply to a specific utility in a specific geographic area given that utility's level of current solar penetration and expected solar PV growth.

In order to assess this question, the engineering analysis will proceed in two sections. First, we will model the impact of solar PV growth on specific feeders on SWEPCO's distribution

[14] In contrast to our analysis, Cohen & Callaway (2016) defined PV penetration as the sum of PV system rating as a share of peak feeder load.

grid. We will therefore identify (a) the levels of penetration for which reliability issues begin to emerge and (b) the specific areas of the feeder where these problems begin to arise.

Consistent with prior studies, we will show that the growth of solar PV has the potential to create significant reliability problems on the power grid. The good news is that these modeling results suggest that significant reliability problems do not begin to arise until a specific "feeder" (i.e. group of around 500 to 1,000 houses that are interconnected) reaches a penetration between 10% and 20%. Two of the three feeders analyzed did not begin to experience problems until penetrations of over 20%. For purposes of this report, penetration will be defined as the percentage of households that install a 7kW solar system. Today, in Louisiana there are an estimated 24,000 customers with solar installation—or about 1.5% of total households in the state.[15] Thus, in aggregate we are not approaching this limit. But, this does not mean that individual feeders in high penetration areas are not approaching this limit. Unfortunately, detailed feeder level data on solar penetration is not available statewide.

2.2 Modeling Impact of Solar PV Growth on the Grid

In order to model the impact of solar PV growth on the grid, we utilized detailed engineering data associated with actual feeders in the Southwestern Electric Power Company's (SWEPCO's) distribution grid. SWEPCO is located in northwestern Louisiana and serves approximately 225,000 customers in 13 parishes.

This feeder-specific data includes detailed engineering data, including bus geographical coordination, substation transformer characteristics, active and reactive powers consumed by each customer (load-bus), resistance (R), Reactance (X) and Capacitance (C) for each distribution line along with the line length and conductor specifications.

Electric utilities, such as SWEPCO, typically do not have information on the amount of power generated by behind-the-meter solar systems.[16] While the utility will observe the net load of a household over the course of a month alongside whether the household has behind-the-meter solar installed, the utility does not observe the total electricity load and total solar generated separately. As shown in the equation below, the utility typically observes the net load of a household over the course of a month but does not observe the load and solar generation directly.

Net Load = Load — Solar Generation

In addition, the time scale needed for examining the extent to which solar might cause engineering problems on the distribution grid is in the range of seconds. SWEPCO collects data on the net load data for a specific household over the course of month. For an entire feeder (~500 to 1,000 households) SWEPCO tracks net load data in fifteen-minute intervals.

For these reasons, and in order to model the solar generation at the household level, we utilized data from the Renewable Energy and Smart Grid Laboratory (RESG Lab) at Louisiana State University. The solar panel, installed on the roof of the building that houses the Division of Electrical and Computer Engineering, records the voltage each time a change occurs, with a minimum time between observations being four seconds. Four second samplings are

[15] Specifically, there are an estimated 24,598 solar installations, and 1,656,053 households in Louisiana.

[16] Hopefully, this will not be the case in the future. For instance, one utility in Louisiana is currently working on updating meters that will provide more detailed information about solar production, demand, and net production. But at the time of writing this report, this is still not common across most utilities in the United States. SWEPCO specifically, does not have this information.

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 be monitored and detected. Additionally, the flicker computation unit calculates the Short-Term flicker (PST) every 150 time steps or 10 minutes based on the IEEE standard 1453.[20] The layout of feeders A, B and C are shown in Figure 2-1. The location of the substation transformer shows where the feeder is connected to the upstream system that delivers the main power.

[17] More information on the economics will be discussed in subsequent sections.

[18] For some feeders, 15-minute interval load data was not available. Therefore, we took other feeders' load patterns and scaled to the size of the feeder. While not presented here, load patterns are (unsurprisingly) very similar across feeders because they are in geographically similar areas experiencing the same weather conditions, etc.

[19] There are several days for which the solar panel in the LSU lab was down for technical reasons. This mainly occurs due to a technical failure in the LabVIEW platform (the voltage measurement unit) or an accidental disconnection at the load side. These days include January 3-6, March 20, and May 12-18.

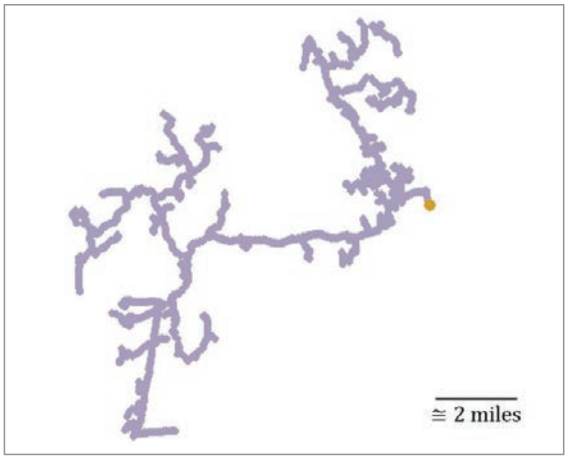
[20] Technical details on power flow models and flicker computation can be found in Ajjarapu & Christy (1992) and IEEE standard 1453, 2015 respectively.

	Representative Day Categories								
	High Load			Medium Load			Low Load		
Variability	High	Medium	Low	High	Medium	Low	High	Medium	Low
January	3	2	11	1	2	5	0	1	2
February	3	3	3	2	1	7	3	2	5
March	0	0	0	3	1	2	10	6	8
April	0	0	0	5	1	0	8	8	8
May	2	1	0	6	6	0	6	3	0
June	10	10	0	3	5	1	0	1	0
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	0
October	0	0	0	2	7	9	4	4	5
November	0	0	2	2	1	1	8	8	8
December	0	2	5	4	4	6	4	4	2
Total	45	43	31	34	41	40	44	38	38

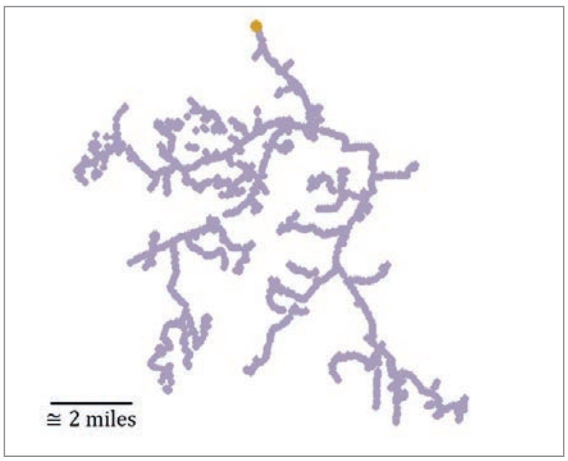
Note: Days of year do not add up to 365 because some days of solar generation data contained errors. These days were removed. High, medium, and low load and variability are defined as the 0 to 33.3rd, 33.3rd to 66.6th, and 66.6th to 100th percentile of total net load and the standard deviation of net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

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

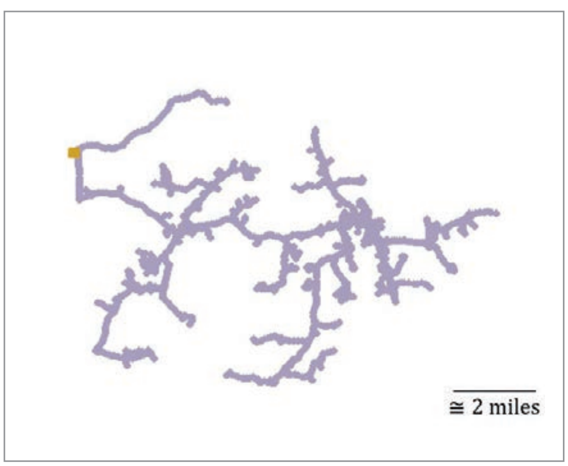
Source: Author's calculations using data from Renewable Energy and Smart Grid Laboratory and SWEPCO



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 reliability problems associated with incorporating solar PV into the grid. Therefore, we proceed in three steps.

First, we create a battery dispatch algorithm that sets a specific decision rule for how a battery will choose when to charge itself and when to dispatch (or some combination of the two). This dispatch algorithm will have three goals elaborated in the following. The first goal is associated with the engineering analysis, and the second two goals aim to create an economic benefit of the battery system. More details on these goals are discussed in section 2.3.1 below.

1. **Mitigate Engineering Problems:** The first, and foremost, goal is to mitigate engineering problems associated with voltage rise and flicker on the distribution grid. Fast and large fluctuations in solar output can occur on the time scale of just a few seconds. Additionally, during periods of high solar production, the flow of power can actually be reversed in the sub-station transformer leading to voltage rise.
2. **Reduce Peak Net Demand:** The second goal is to reduce the peak demand of the household. Later in this report we will assess the extent to which solar without battery storage might create a “capacity benefit,” i.e. whether it can defer, or in some cases even avoid, future investment in generation, transmission, and distribution. One potential benefit of the battery is that is can create or augment this capacity benefit. The valuation of this potential benefit will be assessed in the economics model.
3. **Arbitrage Energy Price Differences across Time:** Third, the battery should store energy produced by the solar power during time periods where solar generation is greater than load to recover lost charge before selling electricity back to the grid. Under a two-channel billing regime, this will increase the value of energy for the customer. In the event that energy is sent back to the grid, the battery should dispatch more power at higher wholesale price time periods relative to lower wholesale price time periods. Due to the laws of supply and demand, as demand increases in specific hours of the day and days of the year, this pushes up market wholesale electricity prices. The battery will have the goal of dispatching more electricity at higher price time periods, thus again, creating an economic benefit that will be valued in the economics model. It is important to note that a utility would likely require advanced metering infrastructure (AMI) in order to be able to provide more granular avoided cost-based credits to a customer.

Second, we will implement this battery dispatch algorithm using (a) the solar PV data obtained from the solar panel on LSU’s campus scaled to a 7kW system and (b) the load data provided by the utility. Subtracting the solar generation from the load will provide net load that will then be used in Step 3.

Finally, we will re-run our engineering analysis, but this time incorporating the batteries and battery dispatch algorithm above. For all engineering analysis, we will consider 5kW continuous power *Tesla Powerwall* with 13.5 kWh of available storage.

2.3.1 Dispatch Algorithm[21]

There has been a growing literature on the incorporation of battery storage into renewable energy applications. Elon Musk, CEO of *Tesla*, explained the need for batteries as follows:

> "It's really not that complicated. You need battery packs because the sun does not shine at night…During the day you fill up the battery and then at night…you use the battery. It's pretty straightforward, really."

While Mr. Musk is certainly correct that the concept is pretty straightforward, he is only addressing one purpose of the battery. It is true that if a house were to disconnect from the grid (i.e., becomes a miniature "micro grid"), it would need a battery to power the home at night. But the second type of intermittency the battery needs to be prepared to handle is on the order of magnitude of seconds—not necessarily minutes or hours. Further, every battery will need to make a decision of how to dispatch in real time given uncertainty about future load and future solar generation. And not mentioned by Musk, in the event that homes are connected to the grid (as is the focus of this research), these batteries should be able to shield the grid from this inherent second-to-second variability of solar PV generation if PV penetration continues to grow. Simply put, a battery might be able to mitigate these concerns, but at the core of the battery there must be an algorithm that decides when, and how much power, to dispatch. We present a dispatch algorithm with three goals in mind.

2.3.1.1 Mitigating Grid Reliability Concerns

First, and foremost, the battery dispatch algorithm needs to smooth the variability in the net load that is exposed to the grid. As previously discussed, and as will be shown in the results of this research, there are two potential negative impacts that solar can create on the electric grid; voltage rise and flicker. Flicker generates a high level of haste and large fluctuations that can occur in the time frame of seconds. In fact, in our data we observe larger than 90% fluctuations in solar generation in just a four second interval. Furthermore, if a feeder has sufficiently high solar penetration, at times of high solar generation and/or relatively low net load, this can create a voltage drop in the distribution system due to momentary loss of solar power. Conversely, during times of consistent solar generation (e.g., clear sunny days in the fall and spring when temperatures are relatively mild), solar penetration can lead to rises in voltage on the distribution system if not compensated.

2.3.1.2 Provide Capacity Benefit

One of the largest challenges to the incorporation of renewable resources such as solar and wind energy into the electric grid is the inherent intermittency of these resources. While much of this report focuses specifically on how these resources can cause engineering problems for the distribution grid, a larger question also remains regarding the extent to which these resources can mitigate the need for additional capacity additions.

Utilities need enough power generation capacity to provide electricity to their customers during the highest demand time period. One of the potential benefits of behind-the-meter solar is that it can allow the utility to forego future capital expenditures at the generation,

[21] As will be discussed further in this report, we implement this dispatch algorithm on the 4-second interval data previously discussed. In addition, we also run a similar dispatch algorithm on hourly data over the entire year for purposes of estimating the economic benefit of the battery. We do this due to the computational burden of running the entire year on a 4-second interval (this would literally take months of computer run time). While the principles of the dispatch algorithm are similar, the actual implementation was changed as needed to allow for differences in the one-hour and four second time granularity. For this reason, before a dispatch algorithm should be used in practice, we recommend that actual batteries are dispatched in this manner.

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 demand time periods are associated with higher prices while lower demand time periods are associated with lower prices.

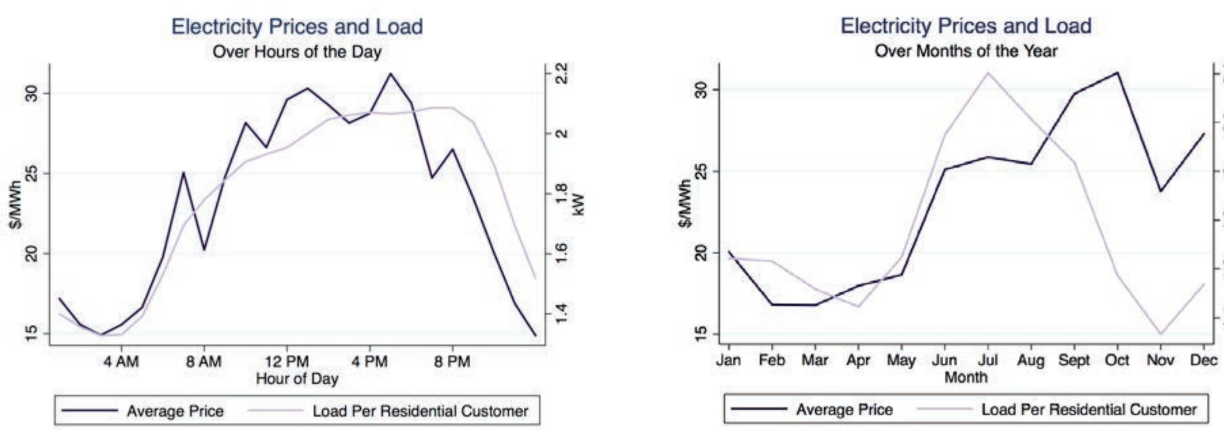


Figure 2–2: Price and Residential Load

Source: Author's Calculations using data from SWEPCO feeder and wholesale SPP Prices.

Next, Figure 2-3 shows the coincidence of solar generation with prices, both varying over the day and throughout the months of the year. Solar data are taken from three sources; the LSU Renewable Energy and Smart Grid Laboratory (i.e. "LSU Solar"), NREL's PVWatts online tool, and an actual residential solar customer approximately one mile from LSU's campus. As can be seen, across hours of the day, prices are lowest at night when solar is not producing. But

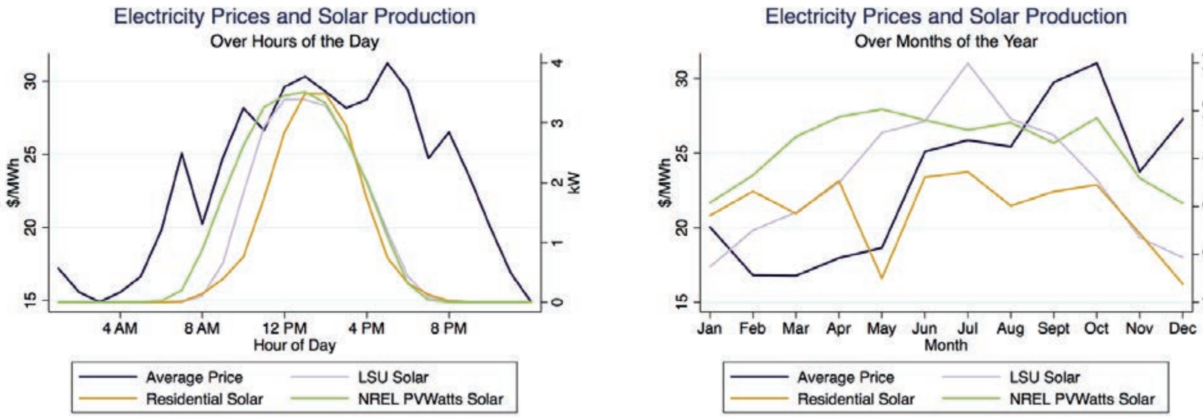


Figure 2–3: Price and Solar Production

Source: Author's calculations using data from Renewable Energy and Smart Grid Laboratory and wholesale SPP Prices.

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 coefficient estimates will be obtained:

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

where L_t is load at time t. In this application, while we only have load at 15-minute intervals, we linearly interpolate this load into four second intervals to match the solar generation data. D_m are indicator variables for each month of the year and D_h are indicator variables for each hour of the day. So, in total, there will be 288 coefficients estimated (12 months times 24 hours). $\gamma_{m,h}$ are estimated econometrically for each hour-month combination. For example, $\gamma_{1,1}$ provides the average load in hour one of month one. Next, we will use these coefficients to predict $\widehat{L_t}$.

$$\widehat{L_t} = \widehat{\gamma_{m.h}} \sum_{m,h} D_m \times D_h$$

[22] For our application, we assume that this representative house uses 15,435 kWhs per year, based on average residential electricity usage in Louisiana.

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:

$$\widehat{B_t} = \frac{\widehat{Peak_m} - \widehat{L_t}}{\widehat{Peak_m} - \widehat{Base_m}}$$

where $\widehat{Peak_m}$ 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:

$$d_t = \widehat{L_t} \times \frac{\sum_m \widehat{Solar_t}}{\sum_m \widehat{Load_t}} \times \frac{B_t}{\widehat{B_t}}$$

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.

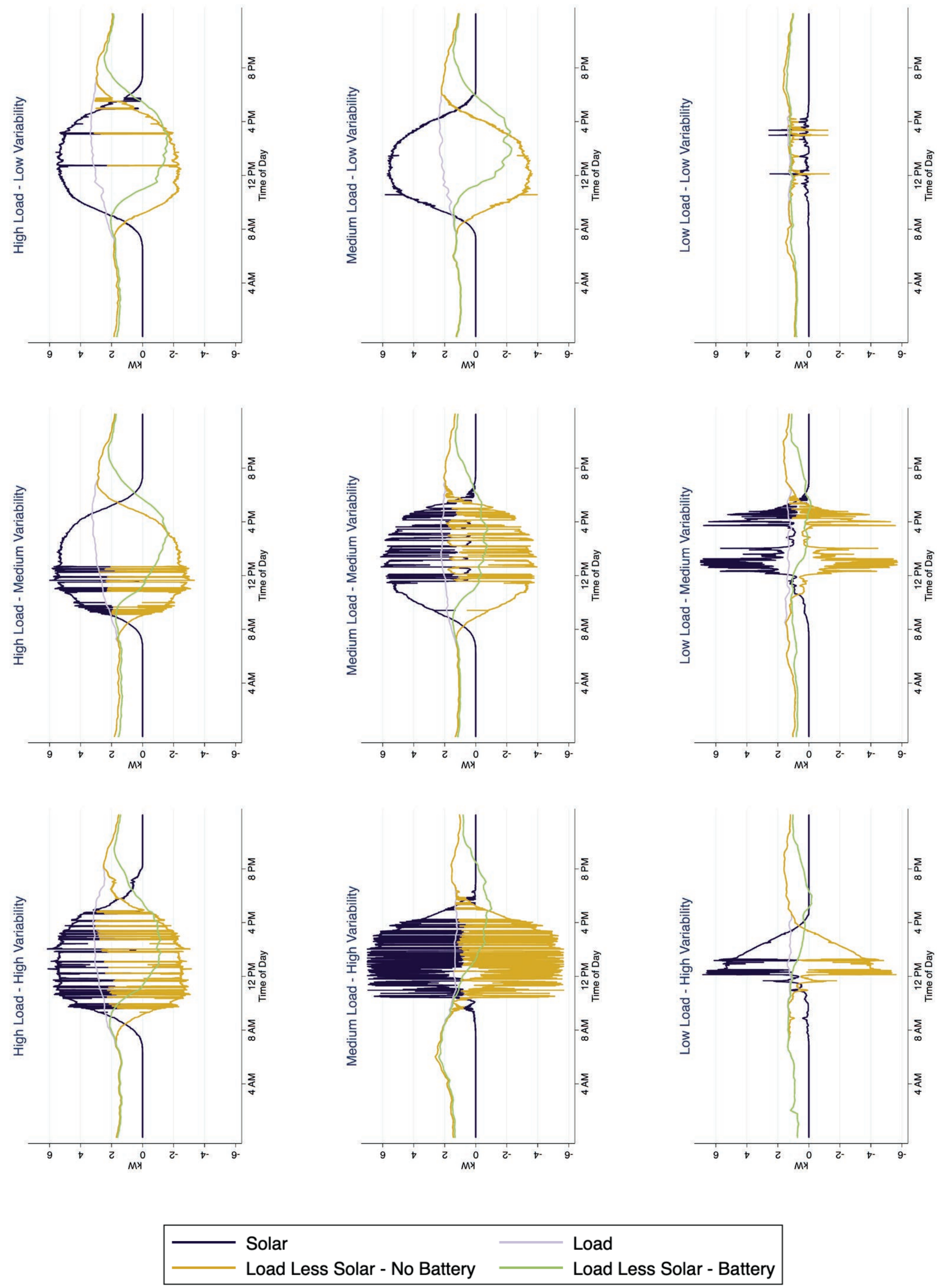


Figure 2–4: Results of Dispatch Algorithm

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

2.4 Results

2.4.1 Incorporation of Solar with No Battery

First, we present results for the baseline model using solar PV with no incorporated battery storage. We present the results for the first feeder, Feeder A, in Table 2-2.

Table 2-2 shows the level voltage rise and maximum flicker detected by solar penetration level. As previously mentioned, penetration level is defined as the share of households that install a 7kW behind-the-meter solar system. So, in a feeder with 600 households, a 10% penetration means that 60 of these households have installed solar PV. We analyze the voltage rise and maximum flicker for the nine categories of days mentioned above, including high, medium, and low net load and high, medium, and low variability (and each corresponding combination).

Two results are noticeable. First, we detect no occurrences of voltage rise or flicker exceeding permissible ranges for the 10% and 20% penetration levels. This is good news, suggesting that low levels of penetration are unlikely to cause significant distribution grid reliability issues. On the other hand, though, these results suggest that if the state of Louisiana pursues the goal of achieving a significant share of the state's electricity being met by behind-the-meter solar PV, utilities will need to prepare for these problems. While we will address the potential ability of batteries to mitigate these problems in the next section, other potential solutions can also be proposed that can include upgrades to the distribution system itself.

But second, these results show that these problems arise primarily on days of higher solar variability. On days of low variability, we do not expect any problems with flicker outside of the permissible range and estimate that voltage rise will not occur until penetration levels above 60% are reached. Problems are most prevalent on days of high penetration and low and medium load. Results are also presented in Figures 2-5 and 2-6 for voltage rise and flicker, respectively, and correspond directly to numbers presented in Table 2-2.

We next present corollary results for Feeders B and C. These results are shown in Tables 2-3 and 2-4. As shown in Table 2-3, Feeder B begins to experience flicker problems between the 10% and 20% penetration levels. In particular, it begins experiencing these problems on the representative day with medium load and high variability. Voltage rise does not begin to be detected until penetration levels between 30% and 40% are reached. After the 40% threshold is met, the distribution grid experiences significant occurrences of voltage rise and flicker in five of the nine representative days of load and variability.

For Feeder C, voltage rise begins between 20% and 30% and begins on days of high variability and medium load. But on Feeder C, we do not begin to see problems associated with flicker until between 40% and 50% penetration. Corollary figures for Feeders B and C for voltage rise and flicker are shown in in Figures 2-7 to 2-10.

There are a few important policy implications associated with these results. First, we begin to see problems between these three feeders at levels as low as between 10% and 20% penetration. As previously mentioned, penetration in this analysis is defined as the percentage of households that have installed a 7kW behind-the-meter solar system on a feeder.

Flicker, Voltage Rise and Solar PV Penetration - Feeder A - No Battery

Voltage Rise Detected

Flicker Above Threshold

Penetration Level	Engineering Parameter	Low Load: Low Variability	Low Load: Medium Variability	Low Load: High Variability	Medium Load: Low Variability	Medium Load: Medium Variability	Medium Load: High Variability	High Load: Low Variability	High Load: Medium Variability	High Load: High Variability
10%	Voltage Rise	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Flicker	0.02	0.01	0.02	0.16	0.01	0.18	0.03	0.08	0.02
20%	Voltage Rise	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Flicker	0.02	0.07	0.09	0.16	0.07	0.40	0.03	0.08	0.09
30%	Voltage Rise	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Flicker	0.02	0.15	0.20	0.16	0.16	0.61	0.03	0.14	0.19
40%	Voltage Rise	0%	0.57%	0.44%	0%	0%	3.04%	0%	0%	0%
	Flicker	0.03	0.25	0.33	0.16	0.26	0.77	0.03	0.22	0.31
50%	Voltage Rise	0%	2.04%	2.74%	0%	0%	12.71%	0%	0%	0%
	Flicker	0.05	0.37	0.47	0.16	0.39	0.98	0.05	0.34	0.45
60%	Voltage Rise	0%	3.16%	6.65%	0%	0%	20.72%	0%	0%	0%
	Flicker	0.06	0.46	0.58	0.16	0.49	1.04	0.06	0.43	0.56
70%	Voltage Rise	0%	4.88%	12.55%	2.69%	2.27%	24.62%	0%	0%	0%
	Flicker	0.11	0.77	0.93	0.16	0.79	1.32	0.11	0.74	0.90
80%	Voltage Rise	0%	6.93%	16.70%	4.93%	3.88%	27.09%	0%	0%	0%
	Flicker	0.13	0.87	1.06	0.16	0.89	1.41	0.13	0.85	1.02
90%	Voltage Rise	0%	8.74%	18.78%	20.08%	15.48%	29.88%	0%	0.05%	0.01%
	Flicker	0.19	1.22	1.51	0.16	1.23	1.68	0.18	1.23	1.38
100%	Voltage Rise	0.01%	10.51%	20.82%	29.62%	23.39%	31.97%	0.29%	2.26%	1.66%
	Flicker	0.19	1.24	1.52	0.16	1.21	1.69	0.18	1.23	1.31

Note: Voltage rise shows the percent of voltage readings outside of the ANSI standard. Flicker is shown as the per-unit flicker voltage where one per-unit is noticeable and annoying light flicker perceived by 50% of the human population. PV penetration level defined as the percent of nodes within the feeder that have a 7-kW behind-the-meter solar system.

Table 2–2: Flicker, Voltage Rise and Solar PV Penetration Feeder A — No Battery

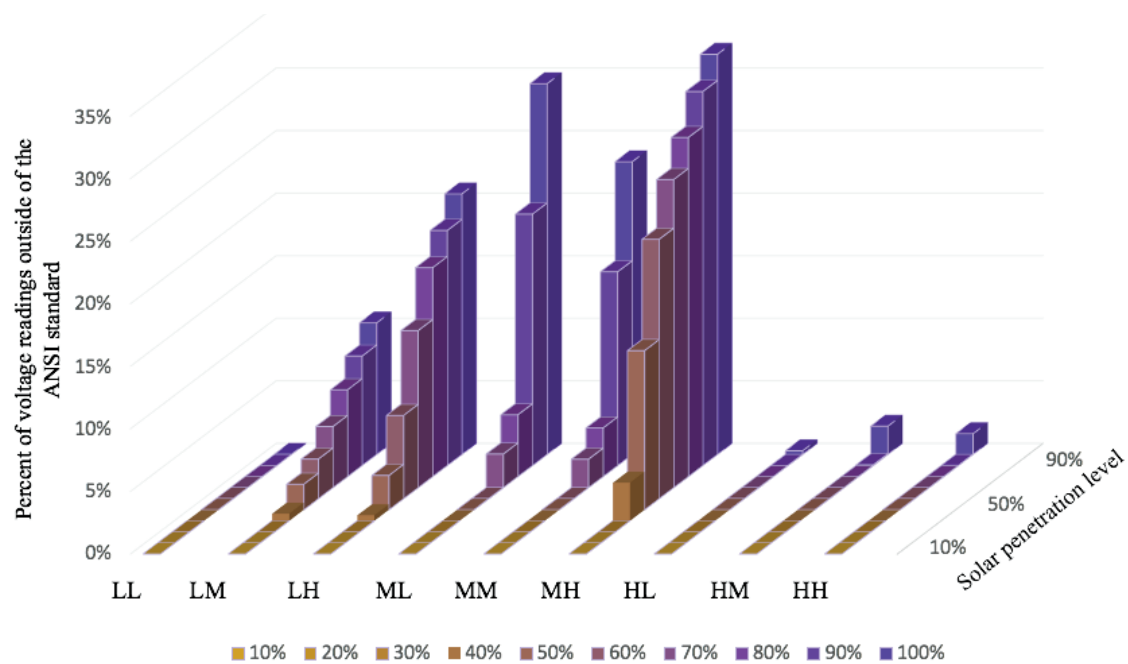


Figure 2–5: Voltage Rise by Penetration Level Feeder A — No Battery

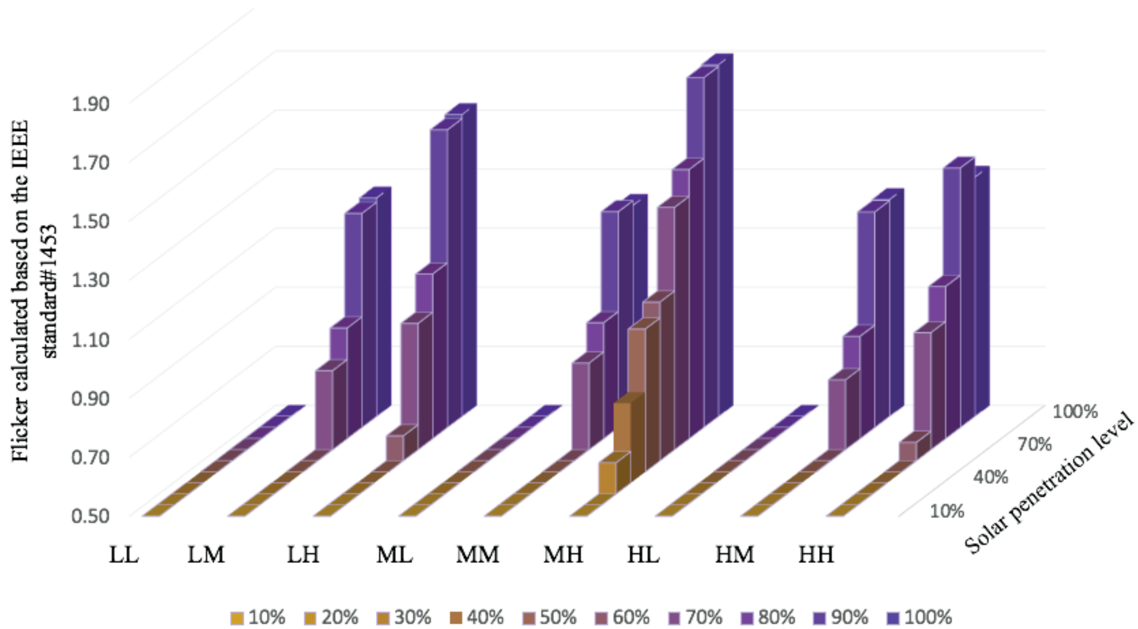


Figure 2–6: Flicker Occurrences by Penetration Level Feeder A — No Battery

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.

Flicker, Voltage Rise and Solar PV Penetration - Feeder B

Voltage Rise Detected

Flicker Above Threshold

Penetration Level	Engineering Parameter	Low Load			Medium Load			High Load		
		Low Variability	Medium Variability	High Variability	Low Variability	Medium Variability	High Variability	Low Variability	Medium Variability	High Variability
10%	Voltage Rise	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Flicker	0.02	0.03	0.04	0.19	0.04	0.28	0.04	0.09	0.04
20%	Voltage Rise	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Flicker	0.02	0.12	0.16	0.19	0.15	0.55	0.04	0.14	0.20
30%	Voltage Rise	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Flicker	0.03	0.26	0.32	0.19	0.30	0.78	0.04	0.29	0.39
40%	Voltage Rise	0%	0.84%	0.67%	0%	0%	4.61%	0%	0%	0%
	Flicker	0.06	0.43	0.52	0.19	0.51	1.01	0.06	0.52	0.61
50%	Voltage Rise	0%	2.91%	3.64%	0%	0%	20.14%	0%	0%	0%
	Flicker	0.08	0.52	0.63	0.19	0.61	1.10	0.08	0.63	0.70
60%	Voltage Rise	0%	4.55%	10.12%	0.17%	0.07%	22.55%	0%	0%	0%
	Flicker	0.15	0.87	0.96	0.19	0.97	1.39	0.17	1.11	1.04
70%	Voltage Rise	0%	6.37%	16.99%	1.41%	0.75%	28.32%	0%	0%	0%
	Flicker	0.16	0.91	1.00	0.19	1.03	1.43	0.19	1.21	1.06
80%	Voltage Rise	0%	8.93%	20.36%	14.90%	12.18%	31.71%	0%	0%	0%
	Flicker	0.16	0.91	1.00	0.19	1.03	1.43	0.19	1.21	1.06
90%	Voltage Rise	0%	10.92%	22.49%	30.45%	23.84%	34.46%	0%	0.22%	0.03%
	Flicker	0.21	1.12	1.21	0.19	1.21	1.57	0.26	1.50	1.18
100%	Voltage Rise	0.01%	12.51%	23.73%	40.95%	31.76%	36.18%	0%	1.03%	0.23%
	Flicker	0.27	1.34	1.38	0.19	1.36	1.68	0.32	1.83	1.12

Note: Voltage rise shows the percent of voltage readings outside of the ANSI standard. Flicker is shown as the per-unit flicker voltage where one per-unit is noticeable and annoying light flicker perceived by 50% of the human population. PV penetration level defined as the percent of nodes within the feeder that have a 7-kW behind-the-meter solar system.

Table 2–3: Flicker, Voltage Rise and Solar PV Penetration Feeder B — No Battery

Flicker, Voltage Rise and Solar PV Penetration - Feeder C

Voltage Rise Detected

Flicker Above Threshold

Penetration Level	Engineering Parameter	Low Load			Medium Load			High Load		
		Low Variability	Medium Variability	High Variability	Low Variability	Medium Variability	High Variability	Low Variability	Medium Variability	High Variability
10%	Voltage Rise	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Flicker	0.00	0.01	0.02	0.03	0.01	0.17	0.01	0.01	0.01
20%	Voltage Rise	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Flicker	0.00	0.03	0.04	0.03	0.03	0.27	0.01	0.02	0.04
30%	Voltage Rise	0%	1.86%	1.93%	0%	0%	10.47%	0%	0%	0%
	Flicker	0.01	0.08	0.10	0.03	0.08	0.42	0.01	0.06	0.09
40%	Voltage Rise	0%	4.50%	11.79%	0%	0%	25.26%	0%	0%	0%
	Flicker	0.01	0.10	0.13	0.03	0.10	0.48	0.01	0.08	0.12
50%	Voltage Rise	0%	7.50%	18.63%	9.20%	7.41%	29.89%	0%	0%	0%
	Flicker	0.03	0.25	0.32	0.03	0.24	0.76	0.03	0.22	0.28
60%	Voltage Rise	0%	10.35%	21.95%	32.11%	24.53%	33.87%	0%	0.03%	0%
	Flicker	0.04	0.31	0.40	0.03	0.30	0.85	0.03	0.27	0.34
70%	Voltage Rise	0.03%	14.15%	24.77%	45.54%	35.08%	37.25%	8.40%	14.44%	13.89%
	Flicker	0.03	0.25	0.33	0.03	0.25	0.77	0.03	0.22	0.29
80%	Voltage Rise	0.06%	17.55%	27.25%	54.64%	43.22%	40.10%	16.71%	27.64%	26.26%
	Flicker	0.05	0.34	0.44	0.03	0.33	0.90	0.04	0.30	0.37
90%	Voltage Rise	0.09%	20.98%	29.24%	59.17%	47.07%	42.31%	34.60%	44.74%	42.92%
	Flicker	0.08	0.61	0.77	0.03	0.57	1.19	0.07	0.52	0.57
100%	Voltage Rise	0.18%	23.90%	30.48%	62.95%	50.37%	43.95%	49.31%	54.12%	51.67%
	Flicker	0.11	0.83	1.05	0.03	0.75	1.38	0.10	0.68	0.72

Note: Voltage rise shows the percent of voltage readings outside of the ANSI standard. Flicker is shown as the per-unit flicker voltage where one per-unit is noticeable and annoying light flicker perceived by 50% of the human population. PV penetration level defined as the percent of nodes within the feeder that have a 7-kW behind-the-meter solar system.

Table 2–4: Flicker, Voltage Rise and Solar PV Penetration Feeder C — No Battery

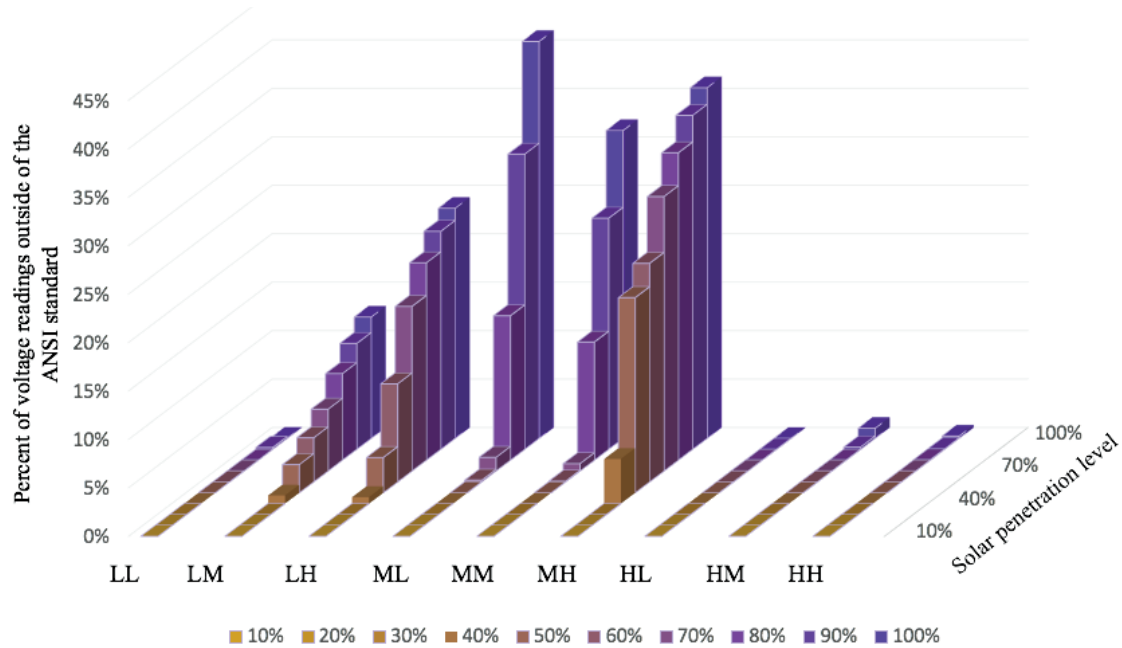


Figure 2–7: Voltage Rise by Penetration Level
Feeder B – No Battery

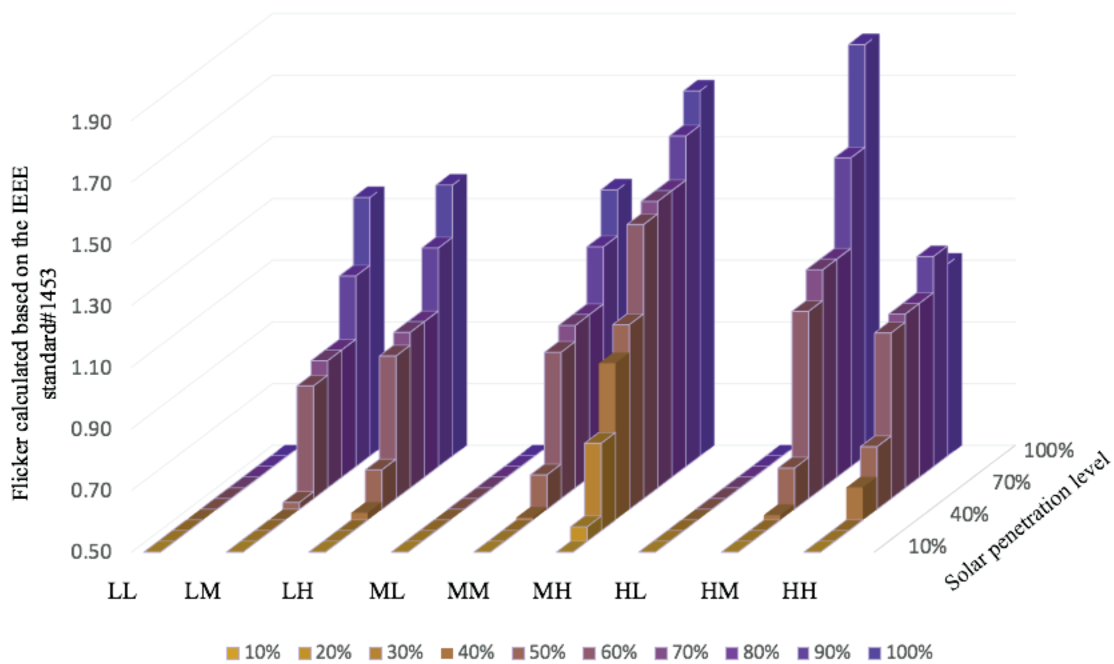


Figure 2–8: Flicker Occurrences by Penetration Level
Feeder B — No Battery

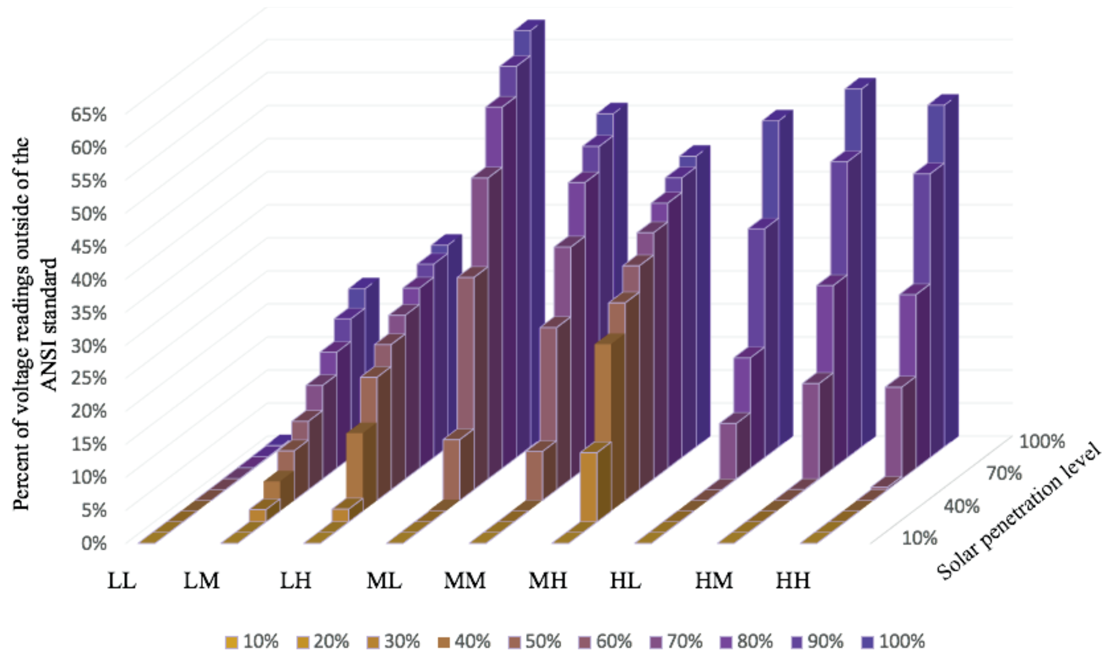


Figure 2–9: Voltage Rise by Penetration Level
Feeder C — No Battery

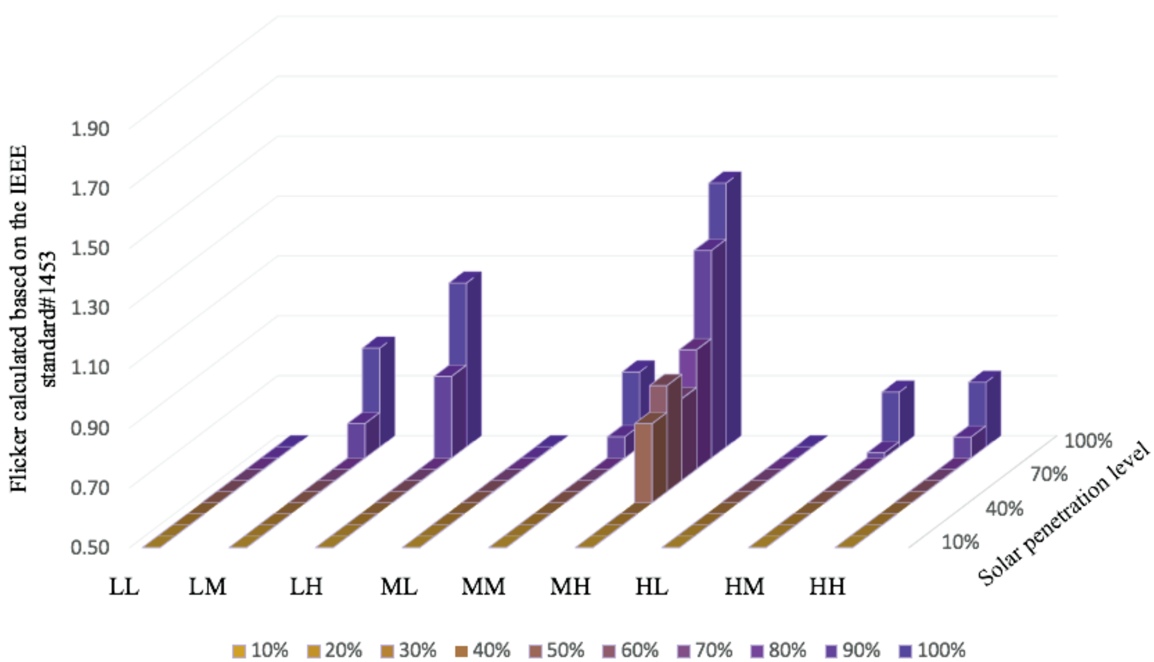


Figure 2–10: Flicker Occurrences by Penetration Level
Feeder C — No Battery

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 unacceptable voltage rise and flicker. For voltage rise, we begin to see problems starting between 30% and 40% penetration in the medium load and high variability scenario. For flicker, we do not see problems until between 50% and 60% penetration in the low load and high variability scenario.

Flicker, Voltage Rise and Solar PV Penetration - Feeder A - With Battery

Voltage Rise Detected

Flicker Above Threshold

Penetration Level	Engineering Parameter	Low Load: Low Variability	Low Load: Medium Variability	Low Load: High Variability	Medium Load: Low Variability	Medium Load: Medium Variability	Medium Load: High Variability	High Load: Low Variability	High Load: Medium Variability	High Load: High Variability
10%	Voltage Rise	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Flicker	0.02	0.00	0.02	0.16	0.00	0.05	0.03	0.08	0.00
20%	Voltage Rise	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Flicker	0.02	0.00	0.09	0.16	0.00	0.05	0.03	0.07	0.00
30%	Voltage Rise	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Flicker	0.02	0.01	0.20	0.16	0.01	0.10	0.03	0.07	0.01
40%	Voltage Rise	0%	0%	0%	0%	0%	0.08%	0%	0%	0%
	Flicker	0.02	0.01	0.33	0.16	0.01	0.16	0.03	0.07	0.01
50%	Voltage Rise	0%	0%	0%	0%	0%	1.10%	0%	0%	0%
	Flicker	0.02	0.02	0.47	0.16	0.01	0.26	0.03	0.07	0.02
60%	Voltage Rise	0%	0%	0%	0%	0%	3.34%	0%	0%	0%
	Flicker	0.02	0.02	0.58	0.16	0.02	0.31	0.03	0.07	0.02
70%	Voltage Rise	0%	0%	0%	1.20%	0%	4.61%	0%	0%	0%
	Flicker	0.02	0.04	0.93	0.23	0.03	0.54	0.03	0.07	0.04
80%	Voltage Rise	0%	0%	0%	2.39%	0%	5.28%	0%	0%	0%
	Flicker	0.02	0.06	1.06	0.27	0.05	0.66	0.03	0.07	0.06
90%	Voltage Rise	0%	0%	0.11%	10.78%	0%	6.41%	0%	0%	0%
	Flicker	0.02	0.08	1.50	0.36	0.06	0.91	0.03	0.07	0.07
100%	Voltage Rise	0%	0%	0.56%	18.60%	0%	9.61%	0%	0%	0%
	Flicker	0.02	0.09	1.52	0.37	0.07	0.98	0.03	0.07	0.08

Note: Voltage rise shows the percent of voltage readings outside of the ANSI standard. Flicker is shown as the per-unit flicker voltage where one per-unit is noticeable and annoying light flicker perceived by 50% of the human population. PV penetration level defined as the percent of nodes within the feeder that have a 7-kW behind-the-meter solar system.

Table 2–5: Flicker, Voltage Rise and Solar PV Penetration
Feeder A — Battery-connected condition

These results provide us with two useful conclusions. First, and foremost, if dispatched properly, batteries can mitigate problems created by solar on the distribution grid and can increase the maximum penetration of solar PV before problems begin to arise. But second, these results suggest that batteries might not be the only answer. And on specific days, particularly days of high variability and low and medium loads, a 13.5 kWh Tesla Powerwall

[24] Note that the description of the dispatch algorithm provides the overall methodology, but there are a number of technical alternations that are made in practice to make sure the battery does not dispatch more than its power rating, that the battery charge stays within the bounds of the battery, etc.

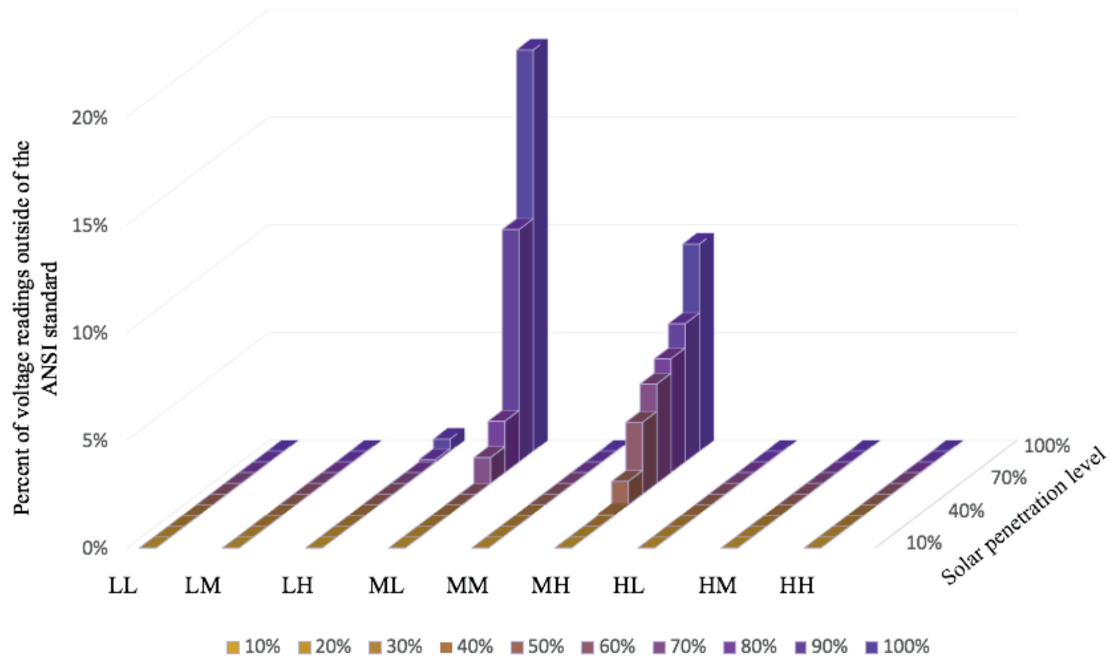


Figure 2–11: Voltage Rise by Penetration Level
Feeder A — With Battery

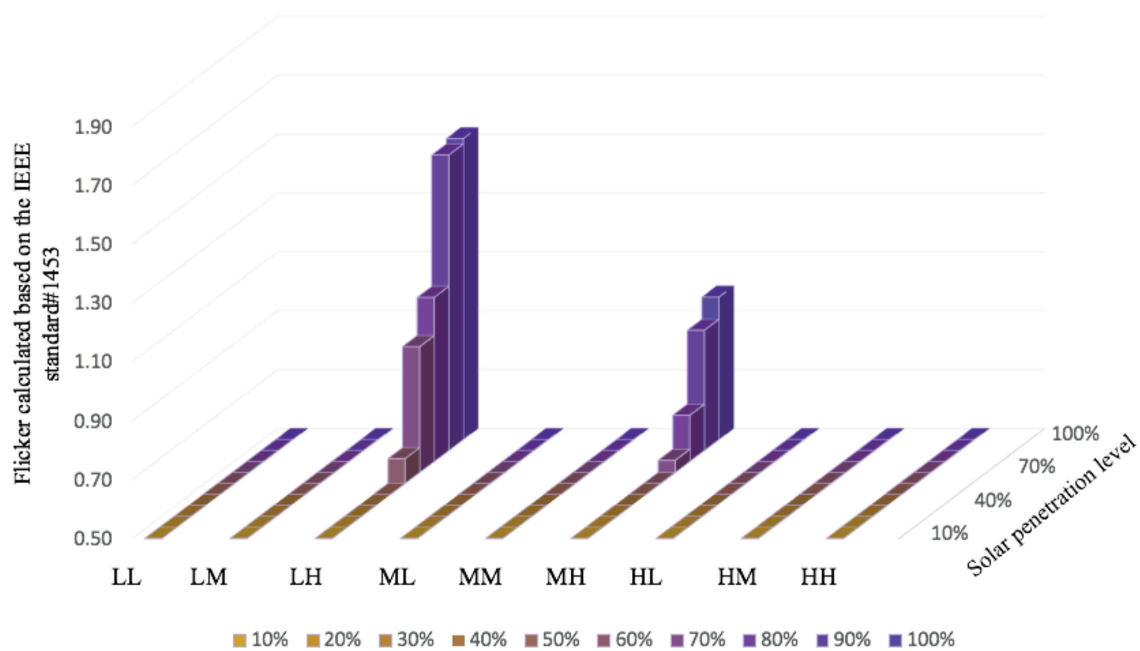


Figure 2–12: Flicker Occurrences by Penetration Level
Feeder A — With Battery

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 to shield the grid from adverse solar impacts, but simultaneously, upgrades to the distribution grid itself will likely need to be made.

2.5 Engineering Conclusions and Policy Recommendations

We urge caution to policymakers when considering the extent to which batteries can mitigate these problems. First, these results are based on theoretical simulations. Before a utility would implement specific policies around batteries, we recommend that actual field tests be run where batteries with a dispatch algorithm are run on specific sources of load and the net load and variability be actually observed over some time.

Second, these results utilize the engineering specs for a Tesla Powerwall as provided by Tesla's website. In practice, we are unable to tell whether this battery will be able to change dispatch on a four second interval basis without compromising the life of the battery. Furthermore, we are unaware of any way for a household to use a dispatch algorithm similar to the one presented in this research in their home.

Finally, while we did do considerable testing on variations of the dispatch algorithm we present here, there are surely alterations and improvements that can be made when implementing this real time algorithm on an actual battery. Potentially, after testing and tweaking the algorithm, we might be able to mitigate the voltage rise and flicker to an even greater extent. Or, on the other hand, these field tests might reveal that a very different algorithm is needed due to the technical ability of the battery, ability of a computer to dispatch at this rate, or any other number of technical reasons.

Thus, all in all, batteries might be an integral part of incorporating large shares of renewable energy into our electric grid in the future, but as of today, battery technology with these capabilities are not currently available to consumers. Therefore, at this time, policy makers should consider other options for shielding the distribution grid from the inherent grid reliability issues that behind-the-meter solar can create. Nonetheless, we hope that these results can encourage future development of battery algorithms for the purpose of mitigating voltage rise and flicker on the distribution grid. The potential economics of battery installations will be discussed below.

3 | Economic Model

The engineering analysis yields three main results. First, that on aggregate, Louisiana does not have high enough solar penetration to create wide-scale grid instability problems. But second, we have shown that (a) concentrated solar investment in specific areas can cause localized issues and (b) if solar growth continues, these problems will likely become more prevalent. Third, though, this analysis shows that incorporating batteries into behind-the-meter solar can mitigate these issues. But, of course, there is a tradeoff in that implementing battery storage will be costly for the homeowner. Thus, how a utility chooses to conduct distribution grid planning will greatly depend on the rate at which solar investment is expected to continue into the future and whether batteries will be incorporated into the behind-the-meter systems or whether the utility's distribution grid will be responsible for handling these changes in voltage and flicker.

On one hand, solar PV costs have been falling substantially over the past decade (Barbos, Galen et al. 2014). Specifically, estimates suggest that from 2009 to 2013, Chinese (and non-Chinese) solar panel costs declined from $7.9 ($8.4) per installed watt to $4.4 ($5.0)—a reduction of 44% (41%). For modeling purposes in this research, we will assume a household can install a 7kW system for $25,000, or about a cost of $3.57 per watt of installed capacity, consistent with actual installations that we are observing in Louisiana.[25] To illustrate this cost reduction, Borenstein (2008), assumed a cost per installed watt of behind-the-meter PV of $8 (which was considered "possibly a bit optimistic" at the time), more than double what we use in our analysis just a decade later. Thus, while predicting future costs of solar is beyond the scope of this research, utilities should consider the possibility that solar PV costs will decline further in coming years for purposes of distribution grid planning.[26] [27]

But, simultaneously, utility planning should also consider that Louisiana has weaned off of its generous 50% state tax credit. Therefore, moving forward, unless a change to the tax code is implemented, homeowners will have access to only the 30% federal tax credit unless that also begins to decline in 2020, before it phases out entirely for homeowners (businesses, including those that lease residential systems, will be eligible for a 10% federal investment tax credit).

Therefore, the economics models presented in this section will consider the relationship between (1) installed costs of behind-the-meter solar PV, (2) tax credit availability and (3) electricity prices. It is the relationship between these three factors that will drive consumers' decision to adopt solar.[28] The economic modeling will also value the capacity benefit that solar might provide and then consider the extent to which a battery can create/augment this capacity benefit.

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[25] Some have commented that some installations are even less, more in the $3 range. We will use the $25,000 for a 7kW system, as we have documented specific Louisiana systems installed in the last two years with this cost.

[26] We will present sensitivity analysis showing the economics from the household's perspective in the event that installation costs decline.

[27] We should also note that the comparison of utility scale vs. distributed renewable has inherently created questions over whether economies of scale exist in these renewable technologies (Junginger et. al., 2005; Ederer, 2015; Dismukes & Upton, 2015) and whether costs have declined over time (Williams, et al. 2017, Wiser et al 2016, Voormolen et al. 2016). Our approach will remain agnostic to differing views on the potential for future cost declines and technological progress.

[28] The capacity factor of a system also can drive this analysis. We will not consider this explicitly in this analysis. Instead we will consider a range of capacity factors based on different sources. All baseline results will use the implicit capacity factor of the solar panel installed on LSU's campus.

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 the variation in climate across the geographically large state of California and consider feeders in Berkeley, Los Angeles, and Sacramento. Further, feeders in urban, suburban, and rural areas are considered. Concurrently, CKC (2016) quantifies the economic benefits (primarily associated with capacity) and costs (primarily associated with voltage regulation) to assess the net cost or benefit that behind-the-meter solar customers provide to the system.[30]

In contrast to our study, though, the maximum time granularity of the solar generation data utilized in these studies is a one-minute interval, compared to the four second interval used in this analysis. To illustrate the importance of this time granularity, in one day in April, we observe 84 changes of over 50% within four second intervals. In some instances, more than a 90% change in PV generation is observed in a four second interval.

Another notable study is Borenstein (2008). In contrast to CC (2016) and CKC (2016), Borenstein presents a market valuation of solar PV that incorporates both coincidence with high demand time periods and reductions in line losses. This study finds that “the market benefits of installing current solar PV technologies, even after adjusting for its timing and transmission advantages, are calculated to be much smaller than the costs.” But, as previously mentioned, the cost per installed kW was more than twice what is considered in this analysis consistent with current installed costs being observed in Louisiana.

The third notable study, and previously mentioned in this report, was commissioned by the Louisiana Public Service Commission for the express purpose of quantifying the costs and benefits of solar in Louisiana (Dismukes, 2015). The analysis includes benefits of solar including avoided generation, transmission, and distribution costs but also considers costs such as unrecovered interconnection and utility administrative costs, lost revenues, and the cost to the state of Louisiana that provided generous up-front subsidies. The study finds that the costs of behind-the-meter solar are about 1.5 times the benefits in Louisiana. Thus, solar in Louisiana fails a cost-benefit analysis from a societal perspective. This does not necessarily, though, mean that solar is uneconomic from an individual household’s perspective under a specific tax credit and rate design regime. But it does conclude that in total, Louisiana’s solar policies have been a net cost on society—not a benefit.

In many ways our economic analysis is at the intersection of these prior studies, but we differ in one key way. Specifically, the purpose of this analysis is to answer the following question: *Given the new potential rate design regime in Louisiana and discontinuation of the state tax*

[29] While this literature is large, examples of policy adoption and diffusion include Huang et al. (2007), Matisoff (2008), Nicholson-Crotty (2009), Lyon and Yin (2010), Carley and Miller (2012), Yi and Feiock (2012), Matisoff and Edwards (2014), Schaffer & Bernauer (2014), Upton & Snyder (2015). Examples of effectiveness of policies include Lipp (2007), Carley (2009), Delmas and Montest-Sancho (2011), Popp et al. (2011), Jenner et al. (2012), Upton and Snyder (2017).

[30] This analysis is technical in nature and does not consider potential shifting of costs between solar and non-solar customers from a rate design perspective. Thus, these estimates are independent of whether a utility has a net metering policy compared to a two-channel billing avoided cost policy, for instance.

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 35%.[34] To put this into perspective, a 100% penetration level as defined by CC (2016) is equivalent to approximately 80% of households installing a 7kW PV system.[35] CC (2016) also find that the capacity benefit of solar reduces as additional solar is installed. Therefore, at low levels of penetration, the capacity benefit of solar will be highest and the capacity benefit will diminish as penetration increases.

Thus even if all households were to install solar PV, the utility would still need to be prepared to meet in excess of 90% of the current peak load. CKC (2016) quantifies this capacity benefit on a levelized per kWh basis as 0.05¢/kWh and 0.21¢/kWh, or between 1.6% and 7% of the average locational marginal price received by generators.

Thus, in sum, the reduced voltage loss and capacity benefit are estimated to provide a levelized per kWh of solar produced ranging from 0.57¢/kWh to 0.75¢/kWh. This ranges from 19% to 25% of average wholesale market prices in California during the time period being analyzed.

Borenstein (2008) finds that actual installations of solar PV systems in California have not significantly reduced the cost of transmission and distribution infrastructure and is unlikely to do so in other regions. Specifically, Borenstein (2008) estimates that the capacity transmission value is about 1% of the wholesale electricity prices and assigns zero distribution capacity value. Borenstein (2008) estimates that the sum of benefits of solar to the transmission and distribution network (T&D) is between 0% and 20% of the average wholesale price.

Dismukes (2015) estimates the value of offset capacity in Louisiana. In total, the estimated benefit on a per kW of installed capacity of behind-the-meter solar is $30.88 per year.[36]

31 Calculations based on results on page 143. $0.0349 - $0.0297 = $0.0052; $0.0351 - $0.0297 = $0.0054.

32 Results of Borenstein (2008) were met with significant critiques. A response was issued and is available on Severin Borenstein's website.

33 See U.S. Energy Information Administration, 2012 State Electricity Profiles – Louisiana; Table 10: Supply and disposition of electricity, 1990-2012 (million kilowatthours).

34 These percentages are based on a visual inspection of Figure 2.

35 Based on "back of envelope" engineering estimates for general comparison.

36 This includes avoided generation, transmission and distribution capacity investments. It should be noted, though, that the Southwest Power Pool (SPP) does not have a capacity market for generation, while the Midwest Independent System Operator (MISO) does. In the case of SPP, the capacity value, therefore, is embedded entirely in the energy cost. Different stakeholders have given different feedback on whether and how this should be included in this analysis. For purposes of this report, that is interested in the entire state of Louisiana, we will include this benefit. But individual utilities should deal with this appropriately based on their market.

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 difference 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 flows. They find that these effects can be large, especially at higher levels of penetration. Specifically, at 50% penetration, they find that twelve of the 24 scenarios considered exhibited backflow at up to 1% of the time. When penetration is increased to 100%, all scenarios experience backflow at least 4% of the time. The voltage rise analysis (in the engineering analysis) also considers reverse power flow but does not report this specifically. Neither Borenstein (2008) nor Dismukes (2015) includes this cost.

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 replaced with an estimated cost to replace of between $1 and $1.3 million dollars,[38] or a cost of $1,600 to $2,200 per customer.[39] While significant additional analysis would be needed to understand the full cost of upgrading the distribution system to accommodate high levels of penetration, simple back of the envelope calculations suggest that costs will far exceed those presented in CKC (2016).[40]

Borenstein (2008) mentions this second-to-second variation, but states that it "is more difficult to quantify without a detailed engineering specification." Therefore, his economic estimates do not include potential mitigation of this second-to-second variation, which causes voltage flicker on the distribution grid.

Dismukes (2015) does not explicitly take into account this, or any of the prior mentioned, potential engineering costs associated with solar growth. In the context of his analysis, these engineering costs would lead to both economic benefits of the installation and upgrading of feeders but also costs to ratepayers. Thus, the net effect in his cost benefit analysis of this additional piece is ambiguous.

3.1.3 Potential Economic Net Cost/Benefits

Two of the prior mentioned studies present what can be considered a cost-benefit analysis. Borenstein (2008) finds that the net present cost of installing solar PV technology in 2008 far exceeded the net present value of benefits under a wide range of assumptions about the interest rate used and estimated change in the real cost of electricity. But, as previously

[37] This is based on the engineers' analysis of the specific distribution system data.

[38] These numbers are adapted from Exposito and Berjillos (2007) and Gaudreau and Kempkes (2007).

[39] There are approximately 600 customers in this node. Due to confidentiality reasons, we cannot provide the specific customer number; therefore we provide this range that is rounded.

[40] CKC (2016) estimate that the cost would be $442,000 annually for all circuits in PE&G's entire system with 5.2 million residential customers, or a yearly cost of less than 9 cents per customer per year.

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 2.3Ohm 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

Implied Capacity Factors				
Source		Generation (kWh)	Capacity (kW)	Implied Capacity Factor
LSU Solar		1,151	1	13.1%
NREL: PV Watts		9,221	7	15.0%
Google: Project Sunroof		8,692	7	14.2%
Residential 1	Projected	9,234	7.975	13.2%
	Actual	7,788	7.975	11.1%
Residential 2	Projected	7,849	5.56	16.1%
	Actual	5,522	5.56	11.3%

Note: Implied capacity factor calculated as Generation (kWhs) / Capacity (kW) x Hours in Year.

Table 3–1: Implied Capacity Factors

[43] Unfortunately, we are unable to observe actual solar generation that would occur at the specific location of the feeders being considered. Because the solar generation data comes from different locations and across different time periods of the load data provided by SWEPCO, there will be unobserved correlation between prices and solar PV production. Borenstein (2008) discusses this issue in depth in the context of California data. He presents an upper bound estimate of this bias and finds that such bias is small. For this reason, we have decided to not address this issue directly within this analysis, as it would require a number of different assumptions that could, in turn, open up different potential sources of bias.

significantly less energy than the advertised amount by their installer. Specifically, the first resident, who installed a 7.975 kW system with an estimated 13.2% capacity factor, only actually produced an 11.1% capacity factor. During the first full year of production, the solar system produced about 1,400 kWhs less of electricity than projected. Assuming a volumetric utility rate of 10 cents/kWh, this is more than $140 less in electricity, or about 15% of the estimate. The second resident installed a 5.56 kW system that was advertised as having a 16.1% capacity factor (the resident told me personally that the installer claimed that these were "high efficiency" solar panels). But in fact, the actual capacity factor in the first year was only 11.3%. Thus, the homeowner produced about 2,200 kWhs less than advertised, for a total lost value of almost $220 in the first year.

The implied capacity factor in Dismukes (2015) was 17%—significantly higher than any of the numbers presented here.[44]

Results of this exercise have significant potential policy implications. First, actual solar systems tend to generate less electricity than online tools might predict. And second, that homeowners should be aware that actual solar production might be significantly less than advertised by installers. We recommend that the Public Service Commission and/or the Louisiana Attorney General's Office research the extent to which installers knowingly presented false information to homeowners. In fact, there has been at least one lawsuit accusing solar companies of false advertising.[45] While these results indicate that such activity might be occurring, we are in no way opining on this or any specific claim or lawsuit and recommend that many more than two households should be observed before reaching concrete conclusions to the extent to which purposeful misrepresentation of production might be occurring, and which companies might be responsible. Furthermore, there could be significant heterogeneity across companies. Companies that base their estimates on sound analysis and therefore provide realistic estimates of production will likely welcome efforts to prevent competitors from presenting estimates that are unrealistic. We recommend the state conduct a study to assess the extent to which homeowners are experiencing the level of generation advertised by sellers.

3.3 Economics by Subsidy Level

Next, we present three sets of estimates of the internal rate of return of a behind-the-meter solar PV system from the standpoint of the household who is making the purchasing decision. In each of these scenarios, we consider an electricity price of $0.10/kWh (the current average in Louisiana ignoring the fixed monthly charge portion) and assume 1:1 full retail credit net metering with unlimited carryover. Thus, the household will be credited a full $0.10 per kWh of electricity produced.[46] Sensitivities to different production estimates are shown.

Before presenting these results, we should note here that there is an obvious cost omitted from this analysis. Namely, we assume that the inverter installed alongside the solar system will last the full 25-year life of the panels. After speaking with several people in industry, this is unlikely to be the case. A generous estimate is that the inverter will need to be replaced once during the system's 25-year life, with an estimated cost of about $5,000. Borenstein (2008)

[44] Thus, the economic benefits in Dismukes (2015) are therefore likely overstated in this regard. We were not able to extrapolate a specific capacity factor for Borenstein (2008) or CKC (2016).

[45] U.S. District Court for the Eastern District of Louisiana Case number 2:16-cv-14431.

[46] In reality, there might be fixed and variable charges on a customer's bill. Thus, the "marginal cost" of an additional kWh consumed might be less than the average cost. Thus, this analysis likely provides a generous estimate of the IRR for a household. Of course, the actual values for an individual customer within a specific utility's jurisdiction will vary.

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 behind-the-meter solar PV, and therefore all of the up-front cost of the system is incurred by the household. These results are presented in Table 3-2. In our baseline model using the generation from the LSU solar panel this system will not pay for itself within its estimated 25-year lifespan and will have a -2.2% internal rate of return. None of the estimates have a payoff period within the 25-year life of the system, nor do any estimates provide a positive rate of return. Unfortunately, the two worst estimated rates of returns are for the actual residential solar customers that range from -2.94% to -3.36%. Thus, with no tax credits and even with full retail net metering, solar PV has consistently negative rates of return. In other words, even with full retail net metering, behind-the-meter solar is not economic at current retail electricity prices and current installation costs.

3.3.2 Full Louisiana and Federal Tax Credits

Next, we consider the subsidy regime that Louisiana existed under from 2008 until recently when the tax credits expired. As previously mentioned, the Louisiana Legislature adopted a series of income tax incentives directly aimed at increasing rooftop solar in 2008. Louisiana households had access to two relatively generous income tax rebates that could provide financial support for their solar energy installations: a 50% state income tax credit and a 30%

[47] As noted previously, solar PV installation costs have declined substantially over the past decade. For comparison, Borenstein (2008) considered an installed cost of $8,000/kW, compared to the approximately $3,500 installed cost assumed in this analysis. So, the economics of the panels should be significantly better in our analysis given the fact that (a) the installed cost has been reduced by more than half and (b) we assume (generously) that the inverter will last the life of the system.

[48] Dismukes (2015) considers the operation and maintenance costs from NREL's Jobs and Economic Development (JEDI) Model. In Dismukes (2015), the economic benefits of this operation and maintenance are included.

[49] For instance, Borestein (2008) considers four real discount rates; 1%, 3%, 5% and 7%, where the lower two are argued to be more appropriate for evaluation using a social discount rate and the higher two more appropriate for an evaluation of market cost of capital. Dismukes (2015), Cohen, Kauzmann and Callaway (2016), and Fares and Webber (2017) utilize the utility's weighted average cost of capital, as is standard practice used in utility ratemaking.

Household Economics of Solar Investment No Tax Credit - Full Retail Net Metering							
		Online Tools		Resident 1		Resident 2	
Source	LSU Lab	PV Watts	Project Sunroof	Predicted	Actual	Predicted	Actual
Year 1	$ (24,194)	$ (24,078)	$ (24,131)	$ (24,187)	$ (24,311)	$ (24,012)	$ (24,270)
Year 2	802	917	865	809	686	983	727
Year 3	798	913	860	805	683	978	723
Year 4	794	908	856	801	679	973	720
Year 5	790	904	852	797	676	969	716
Year 6	786	899	848	793	672	964	712
Year 7	782	895	843	789	669	959	709
Year 8	778	890	839	785	666	954	705
Year 9	774	886	835	781	662	949	702
Year 10	770	881	831	777	659	945	698
Year 11	766	877	827	773	656	940	695
Year 12	763	873	823	769	652	935	691
Year 13	759	868	818	766	649	930	688
Year 14	755	864	814	762	646	926	684
Year 15	751	860	810	758	643	921	681
Year 16	748	855	806	754	639	917	678
Year 17	744	851	802	750	636	912	674
Year 18	740	847	798	747	633	907	671
Year 19	736	843	794	743	630	903	667
Year 20	733	838	790	739	627	898	664
Year 21	729	834	786	735	624	894	661
Year 22	725	830	782	732	621	889	657
Year 23	722	826	778	728	617	885	654
Year 24	718	822	775	725	614	881	651
Year 25	715	818	771	721	611	876	648
Years to Payback	**Never**	**Never**	**Never**	**Never**	**Never**	**Never**	**Never**
IRR	**-2.21%**	**-1.16%**	**-1.63%**	**-2.14%**	**-3.36%**	**-0.60%**	**-2.94%**

Note: Retail electricity prices $0.10 per kWh. Electricity prices are not escalated, thus IRRs represent a real rate of return. Total installation cost is $25,000 for all systems and all systems scaled to 7kW for appropriate comparison. Degredation rate of .5 percent used in all calculations. "LSU Lab" Solar production from the Renewable Energy and Smart Grid Laboratory at Louisiana State University. Online tools from the National Renewable Energy Laboratory's *PVWatts* and Google's *Project Sunroof*. Residents are actual residents within approxmately 1 mile of LSU's campus in Baton Rouge.

Table 3–2: Economics of Solar – No Tax Credit + Full Retail Net Metering

federal income tax credit, which, on a combined basis, amount to as much as an 80% credit on all Louisiana residential solar installations less than $25,000 in total value.

Results of this scenario are presented in Table 3-3. The baseline rate of return is 18.3% with an estimated seven years to payback. These results vary from 14.9% to 23.9% IRR and six- to eight-year payback period. Again, the two lowest IRRs/highest payback times are with the actual solar PV systems installed by the two residential customers. Nonetheless, these results show that under a regime of 1:1 full retail credit net metering, and a combined 80% up-front tax credit, it is no wonder that Louisiana experienced significant solar investment during the time period that these subsidies were in place.

Household Economics of Solar Investment Federal and State Tax Credit (80%) - Full Retail Net Metering							
		Online Tools		Resident 1		Resident 2	
Source	LSU Lab	PV Watts	Project Sunroof	Predicted	Actual	Predicted	Actual
Year 1	$ (4,194)	$ (4,078)	$ (4,131)	$ (4,187)	$ (4,311)	$ (4,012)	$ (4,270)
Year 2	802	917	865	809	686	983	727
Year 3	798	913	860	805	683	978	723
Year 4	794	908	856	801	679	973	720
Year 5	790	904	852	797	676	969	716
Year 6	786	899	848	793	672	964	712
Year 7	782	895	843	789	669	959	709
Year 8	778	890	839	785	666	954	705
Year 9	774	886	835	781	662	949	702
Year 10	770	881	831	777	659	945	698
Year 11	766	877	827	773	656	940	695
Year 12	763	873	823	769	652	935	691
Year 13	759	868	818	766	649	930	688
Year 14	755	864	814	762	646	926	684
Year 15	751	860	810	758	643	921	681
Year 16	748	855	806	754	639	917	678
Year 17	744	851	802	750	636	912	674
Year 18	740	847	798	747	633	907	671
Year 19	736	843	794	743	630	903	667
Year 20	733	838	790	739	627	898	664
Year 21	729	834	786	735	624	894	661
Year 22	725	830	782	732	621	889	657
Year 23	722	826	778	728	617	885	654
Year 24	718	822	775	725	614	881	651
Year 25	715	818	771	721	611	876	648
Years to Payback	**7**	**6**	**6**	**7**	**8**	**6**	**7**
IRR	**18.32%**	**21.82%**	**20.21%**	**18.53%**	**14.91%**	**23.88%**	**16.10%**

Note: Retail electricity prices $0.10 per kWh. Electricity prices are not escalated, thus IRRs represent a real rate of return. Total installation cost is $25,000 for all systems and all systems scaled to 7kW for appropriate comparison. Degredation rate of .5 percent used in all calculations. "LSU Lab" Solar production from the Renewable Energy and Smart Grid Laboratory at Louisiana State University. Online tools from the National Renewable Energy Laboratory's *PVWatts* and Google's *Project Sunroof*. Residents are actual residents within approxmately 1 mile of LSU's campus in Baton Rouge.

Table 3–3: Economics of Solar – 80% Tax Credit + Full Retail Net Metering

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 results are presented in Table 3-4.

In the baseline scenario, we estimate a 23 year payback and a rate of return of 0.71%. Results range from –0.63% to 2.61% and a 19-year payback to the system never paying back. The two actual residential systems, as in all tax credit combinations, have the lowest rates of return with –0.14% and -0.63% respectively.

While there are significant policy implications of this result, conclusions reached might be very different depending on one's perspective. First, these results suggest that the state's 50% tax credit was significant in driving solar adoption. In other words, without the state's tax credit, even as solar installation costs have been falling, it is unlikely that many households would install solar in Louisiana. The economics are simply not sufficient without the state tax credit.

But on the other hand, others might argue that if behind-the-meter solar is not economic even with the federal tax credit and full retail net metering, then Louisiana taxpayers should not be investing in this form of energy. We will leave this policy debate to policy makers and their constituents to decide through the democratic process.

We note a few caveats when considering the future viability of behind-the-meter solar in Louisiana. The internal rate of return considered in this analysis might not be the only reason a household chooses to install solar. First, a customer might view an investment in solar as a hedge against future electricity price increase. Thus, if one believes that electricity prices are going to increase faster than the rate of return on an alternative investment into the future, purchasing solar panels will be one way to hedge against this. As previously discussed, this analysis is agnostic to future electricity price increases and considers no change in the real cost of electricity in the future.[50] Second, and more simply, consumers might have a preference toward solar panels. Maybe they enjoy the aesthetics of panels on their home, find pleasure in the concept of generating their own electricity, or believe that this investment will benefit the environment. In this way, solar panels might be considered a consumption good, not necessarily a financial investment, for the household. All of these factors considered, we cannot conclude that no solar investment will occur if the internal rate of return is low or even negative. In fact, utilities tell us that they continue to have seen systems installed, but at levels closer to levels seen in Texas, Mississippi, and Arkansas that have never had a state tax credit. But we can reasonably conclude that the amount of solar investment will likely slow considerably in the absence of these subsidies.

3.3.4 Sensitivity Analysis

In the prior section we showed that behind-the-meter solar installations are uneconomic from the household's financial perspective unless very generous tax credits are provided. Next, we analyze the sensitivity of this result to both changes in electricity prices and changes in the installed cost per installed kW of solar. While we remain agnostic in terms of how these respective prices will change in coming years, we can assess the impact of these market changes on the economics of solar installations in Louisiana.

First, Figure 3-1 shows the sensitivity of the internal rate of return (IRR) experienced by a solar installer (i.e. the household or business) to changes in the installed cost per kW with full retail net metering and 10¢ per kWh retail electricity prices. As can be seen, at $3,500 per installed kW (the approximate current cost) households will only see a positive rate of return when both the state and federal tax credits—totaling 80% of the upfront cost—are available. Now that

[50] We should note that the two local residents provided us with the company's estimated rate of return on their solar investment. In both cases, the installer assumed a 3.5% and 4% increase in electricity prices. Therefore, the electricity price increase actually more than offset the decrease in efficiency of the units over time. Our analysis assumes constant real prices into the future, i.e., we specifically choose to be agnostic to the relative price of electricity and other goods and services into the future. Therefore, our results might be considered a "real" rate of return, while the rates of return estimated by the solar producers when selling their units can be thought of as a "nominal" rate of return assuming electricity prices escalate at 3.5% and 4%, respectively, into the future.

Household Economics of Solar Investment
Federal Tax Credit (30%) - Full Retail Net Metering

Source	LSU Lab	Online Tools: PV Watts	Online Tools: Project Sunroof	Resident 1: Predicted	Resident 1: Actual	Resident 2: Predicted	Resident 2: Actual
Year 1	$ (16,694)	$ (16,578)	$ (16,631)	$ (16,687)	$ (16,811)	$ (16,512)	$ (16,770)
Year 2	802	917	865	809	686	983	727
Year 3	798	913	860	805	683	978	723
Year 4	794	908	856	801	679	973	720
Year 5	790	904	852	797	676	969	716
Year 6	786	899	848	793	672	964	712
Year 7	782	895	843	789	669	959	709
Year 8	778	890	839	785	666	954	705
Year 9	774	886	835	781	662	949	702
Year 10	770	881	831	777	659	945	698
Year 11	766	877	827	773	656	940	695
Year 12	763	873	823	769	652	935	691
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Year 16	748	855	806	754	639	917	678
Year 17	744	851	802	750	636	912	674
Year 18	740	847	798	747	633	907	671
Year 19	736	843	794	743	630	903	667
Year 20	733	838	790	739	627	898	664
Year 21	729	834	786	735	624	894	661
Year 22	725	830	782	732	621	889	657
Year 23	722	826	778	728	617	885	654
Year 24	718	822	775	725	614	881	651
Year 25	715	818	771	721	611	876	648
Years to Payback	**23**	**20**	**22**	**23**	**Never**	**19**	**Never**
IRR	**0.71%**	**1.94%**	**1.39%**	**0.79%**	**-0.63%**	**2.61%**	**-0.14%**

Note: Retail electricity prices $0.10 per kWh. Electricity prices are not escalated, thus IRRs represent a real rate of return. Total installation cost is $25,000 for all systems and all systems scaled to 7kW for appropriate comparison. Degredation rate of .5 percent used in all calculations. "LSU Lab" Solar production from the Renewable Energy and Smart Grid Laboratory at Louisiana State University. Online tools from the National Renewable Energy Laboratory's *PVWatts* and Google's *Project Sunroof*. Residents are actual residents within approxmately 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.

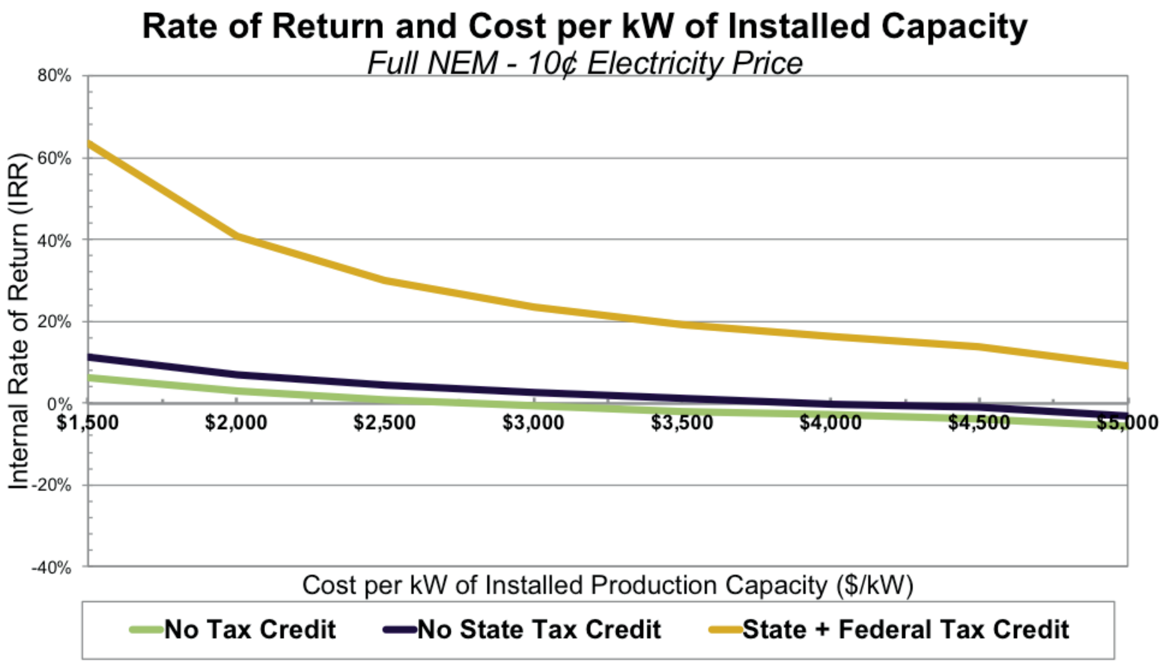

Figure 3–1: Sensitivity of Solar Economics to Installed Cost

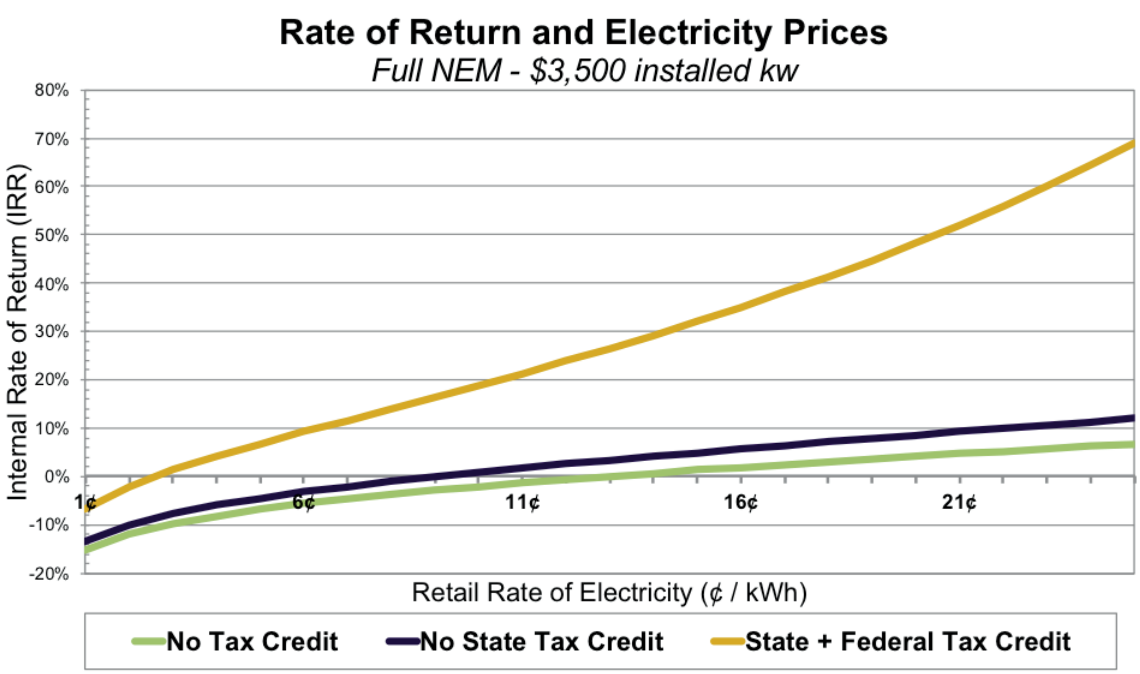

Figure 3–2: Sensitivity of Solar Economics to Electricity Prices

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).

We present two results associated with a two-channel billing regime. First, we simply show a movement to two-channel billing with no capacity benefit added. Next, we compare these results to a regime where the customer is reimbursed a yearly fixed capacity benefit credit. Of the estimates discussed above, the most generous comes from Dismukes (2015), and

[51] See discussion of line loss above. When a wholesale power generator sells to the grid, some share of that power will be lost in the transmission and distribution network. Therefore, solar that is produced at the point of consumption, will avoid that line loss.

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, monthly wholesale, and hourly wholesale prices. As can be seen, these all yield between an approximately -7% and -9% internal rate of return. As more time granularity is added the IRR improves due to the coincidence of solar production to demand (and therefore higher prices).

Finally, we consider the case with two-channel billing. With a two-channel billing regime alongside no capacity benefit, the system is estimated to not pay back within the 25-year life and have a IRR of -0.5%. Interestingly, when the capacity benefit is added, the rate of return is almost identical to the case of full retail net metering. Namely, the internal rate of return is 0.77%. Using the battery dispatch algorithm, we are able to increase the IRR to about 2.41%. Thus, the battery is able to arbitrage price differences, and therefore increase the value of electricity sold. It should be noted that this analysis does not consider the cost of actually installing a battery (that will be assessed in a later section). This is simply meant to illustrate the (a) increase in value of electricity sold and (b) additional capacity benefit if the battery is installed with the dispatch algorithm in place.

3.5 Capacity Benefit

In the prior section, for purposes of the solar economics, we simply considered the capacity value as provided in Dismukes (2015). In this section we delve further into plausible valuation of this capacity as well as estimate the capacity benefit based on the data used in this study. A utility (or Independent System Operator (ISO) / Regional Transmission Organization (RTO)) will forecast the maximum load that needs to be met over a time period and make sure there is enough generating capacity that can be dispatched to meet this load.

But estimating the capacity factor of intermittent renewable energy sources has not proved to be a straightforward process. In fact, of all of the issues dealt with in this report, based on stakeholder feedback from a number of groups, the issue of valuing capacity of solar has been the most controversial. Unlike a traditional power generator that can be dispatched, the system

[52] In theory, we could run this analysis across all four second intervals of the year and then aggregate up to the year, but this creates significant computational constraints. Therefore, all economic analysis of the dispatch algorithm will be run on hourly intervals.

Comparison of Household Economics Under Different Rate Regimes
LSU Solar - Federal Tax Credit (30%)

Install Cost	$17,500.00						
Rate Regime	**Full NEM**	**Average Wholesale**	**Monthly Wholesale**	**Hourly Wholesale**	**Two Channel Billing**	**Two Channel Billing + Capacity**	**Two Channel Billing with Battery**
Year 1	$ (16,694)	$ (17,299)	$ (17,297)	$ (17,224)	$ (16,800)	$ (16,701)	$ (16,546)
Year 2	802	200	202	275	696	796	951
Year 3	798	199	201	273	693	793	947
Year 4	794	198	200	272	689	790	944
Year 5	790	197	199	270	686	787	941
Year 6	786	196	198	269	682	784	937
Year 7	782	195	197	268	679	781	934
Year 8	778	194	196	266	676	779	930
Year 9	774	193	195	265	672	776	927
Year 10	770	192	194	264	669	773	924
Year 11	766	191	193	262	666	770	920
Year 12	763	190	192	261	662	767	917
Year 13	759	189	191	259	659	765	914
Year 14	755	188	190	258	656	762	910
Year 15	751	187	189	257	652	759	907
Year 16	748	186	188	255	649	756	904
Year 17	744	185	187	254	646	754	901
Year 18	740	184	186	253	643	751	897
Year 19	736	183	185	251	639	748	894
Year 20	733	182	184	250	636	746	891
Year 21	729	181	183	248	633	743	888
Year 22	725	180	182	247	630	740	885
Year 23	722	179	181	246	627	738	881
Year 24	718	178	180	244	624	735	878
Year 25	715	177	179	243	620	733	875
Years to Payback	**23**	**Never**	**Never**	**Never**	**Never**	**23**	**19**
IRR	**0.71%**	**-8.90%**	**-8.82%**	**-7.05%**	**-0.50%**	**0.77%**	**2.41%**

Note: Solar production data from Renewable Energy and Smart Grid Laboratory at Louisiana State University. Degredation rate of .5 percent used in all calculations. Two channel with battery does not include cost of battery. Two channel billing with and without battery include capacity benefit of solar with and without battery, respectively. Full NEM and wholesale calculations do not include capacity benefit. Wholesale and two channel billing credit customer for a 7% avoided line loss.

Table 3–5: Sensitivity of Solar Economics to Rate Regimes

cannot just assume that the renewable resource will necessarily be running at the time of peak system load. In this application, behind-the-meter rooftop solar PV will create a capacity benefit to the extent to which its production is coincident with system wide peak.

In order to assess the capacity benefit, we sum the 15-minute interval load for each of the 8,760 hours in the year. We aggregate approximately 10 residential feeders' load data provided by SWEPCO. Next, we scale down this hourly load to the size of a typical household's demand (15,435 kWs per EIA).

Next, we combine this load data with solar production data. For solar production, we consider three sources (1) LSU Lab, (2) PVWatts, and (3) a resident with actual solar installation approximately one mile from LSU's campus. While we have data on two residential solar systems, only one provided access to hourly production data in an accessible manner. All solar data is scaled to a 7kW system to allow for consistent comparisons.

Capacity Benefit as Percent of 7kW Solar System *Residential Class Coincident Peak*	Max Load Hour	Top 5 Hours	Top 20 Hours
Average Residential Load	3.60	3.53	3.44
Reduction in Net Load from 7kW System at System Peak Hours			
LSU Solar			
No Battery	1.35	2.15	2.62
Battery	3.60	3.53	4.06
Percent Reduction - No Battery	37.4%	60.9%	76.2%
Percent Reduction - Battery	100.0%	100.0%	117.8%
PVWatts Solar			
No Battery	2.71	2.86	1.91
Battery	3.60	3.53	3.45
Percent Reduction - No Battery	75.1%	80.9%	55.6%
Percent Reduction - Battery	100.0%	100.0%	100.3%
Residential Solar - 2016			
No Battery	3.01	2.64	1.93
Battery	3.60	3.18	2.70
Percent Reduction - No Battery	83.6%	74.7%	56.0%
Percent Reduction - Battery	100.0%	90.1%	78.5%
Average (Solar)	**65.4%**	**72.2%**	**62.6%**
Average (Solar + Battery)	**100.0%**	**96.7%**	**98.9%**

Note: Solar System refers to kWh reduction from a 7 kW solar system. Battery refers to a 13.5 kWh battery.

Table 3–6: Reduction in Coincident Peak Demand with 7kW Residential PV System

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 stakeholders from state policy makers, utilities, ISO/RTOs and households.

On one, one might argue that an intermittent renewable resource by its very nature does not have a capacity value because it cannot be dispatched on demand. While there is no universally

Capacity Benefit as Percent of Solar Capacity *Residential Class Coincident Peak*	Max Load Hour	Top 5 Hours	Top 20 Hours
LSU Solar			
No Battery	19%	31%	37%
Battery	51%	50%	58%
Incremental Benefit of Battery	32.2%	19.8%	20.5%
PVWatts Solar			
No Battery	39%	41%	27%
Battery	51%	50%	49%
Incremental Benefit of Battery	12.8%	9.6%	22.0%
Residential Solar			
No Battery	43%	38%	28%
Battery	51%	45%	39%
Incremental Benefit of Battery	8.4%	7.8%	11.0%
Average (Solar)	**33.6%**	**36.4%**	**30.8%**
Average (Incremental Battery)	**17.8%**	**12.4%**	**17.8%**

Note: Solar System refers to kWh reduction from a 7 kW solar system. Battery refers to a 13.5 kWh battery.

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 to estimate a capacity benefit for solar PV in Louisiana in the hopes that this can inform how utilities can value this capacity with the goal of passing this benefit on to the customer who installs behind-the-meter solar systems.

In order to estimate a capacity benefit, we consider the top 20 load-hours of the year. We will break these down into (a) the top load-hour of the year, (b) the top five load-hours and then (c) the top 20 load-hours. We will observe both the load and the solar generation in those hours. The idea is straightforward—during the highest load-hours of the year, we simply observe how much solar generation is available. Thus, any behind-the-meter solar production during these top load-hours is decreasing the max load of the system.

Results are presented in Table 3-6. We look at the solar production from the three solar sources in the maximum load hour, average production in the top five load-hours and 20 load-hours, respectively. The LSU solar scaled to a 7kW system produced 2.62 kWhs per hour on average over the top 20 load-hours of the year, and 1.35 kWhs in the maximum load hour of the year. Thus, the peak hour and average of 20 peak hours load were reduced by 37.4% and 76.2%, respectively. While results vary across solar generation data, the average reduction in coincident residential load from a 7kW system ranges from 62% to 72%.

There are a few notable lessons from this exercise. The first is that the solar generation that happened to occur in this hour drives the estimated capacity benefit. Thus, just an intermittent cloud cover during the top load-hour of the year can significantly impact the estimated capacity benefit. For this reason, we do not recommend utilities use only one solar production data set in order to estimate this capacity benefit. Instead, utilities should collect hourly production data scattered across the service territory of interest in order to estimate capacity benefits. Simply taking the solar generation estimate from one source—being NREL's PVWatts, a research solar panel, or a residential household—will lead to significant changes in the estimated capacity benefit. This type of approach inherently allows for gamesmanship in the regulatory process by allowing stakeholders to pick and choose the solar generation estimate used.

Second, a utility should be prepared to meet the peak load in the worst case scenario. Thus, observing the solar generation at the time of peak load for one source only informs utilities of the reduction in peak load that happened to occur in that historical hour. But what the utility, and ISO/RTO, should be concerned about is the ability to meet peak load in a low probability, high peak load event. If solar generation across units is positively correlated across time (which is clearly the case), then there will be a broad range of possible net load levels during the peak period—both with significant solar generation as well as very little solar generation 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 now July 21 at 7:00 p.m. Thus, the peak load time period has now been shifted to later in the evening. This is the commonly described "duck curve".

Thus, in the long run, as more and more households install behind-the-meter solar, the peak of the system will get pushed later in the evening, until eventually, if all households were to install solar, the new peak time period would be around 7:00 p.m. (instead of 3:00 p.m. using this specific example). Thus, for capacity planning, the utility will now focus on the later peak time period. The empirical question is therefore: What is the reduction in the highest net load hour of the year?

Thus, next we ask the following question. *If all residential customers were to install a 7kW behind-the-meter solar system, by how much would it reduce coincident residential peak demand?* In order to calculate this, we consider 1,000 representative households. We incrementally subtract off the solar generation from one household's load curve.[53] We then 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.

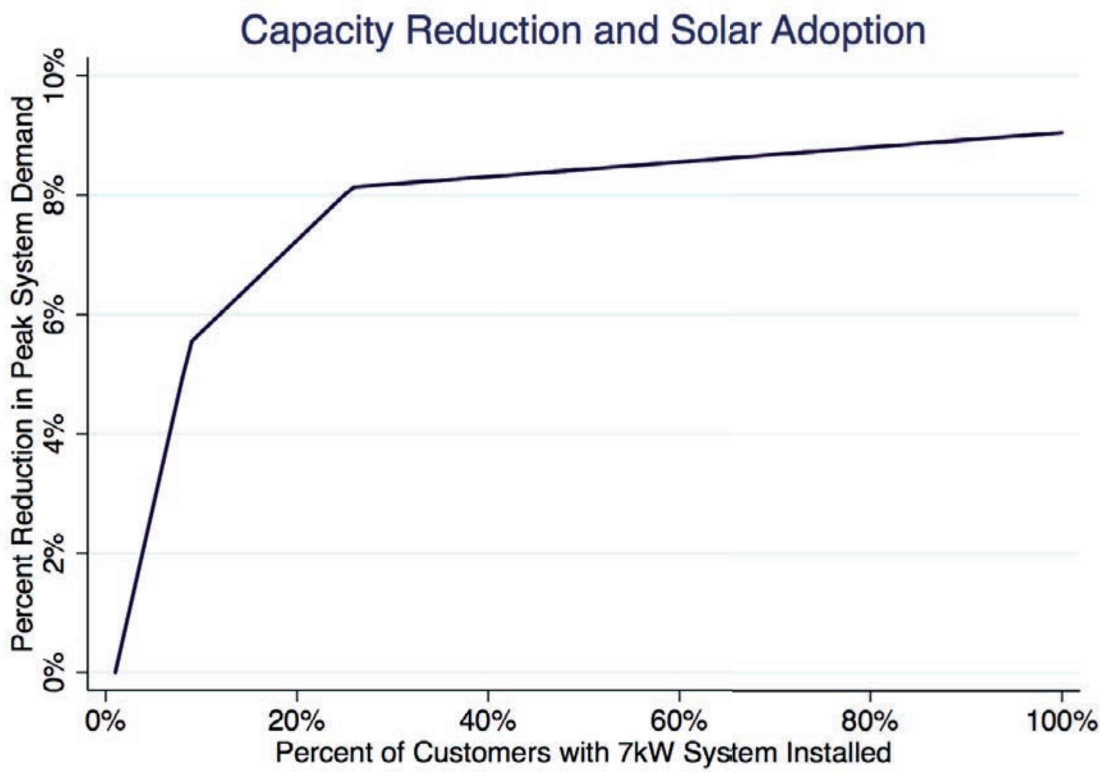

Figure 3–3: Marginal Contribution to Coincident Peak Reduction of Additional Behind-the-Meter Solar Penetration

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 to the system. If the capacity and energy benefit provided by the battery is over-valued, customers will be incentivized to install batteries that will in essence be subsidized by other non-solar and non-battery customers. On the other hand, if the capacity and energy benefit provided by the battery is under-valued, then solar customers will decide not to install a battery when the cost of the battery in actuality is lower than the benefit the battery could provide.

The controversy, of course, is how this energy and capacity benefit will be valued. For the energy value, we will assume that the customer is credited at the full retail rate for all electricity produced and consumed behind the meter. In other words, this energy can be thought of as avoided usage. The capacity value, though, is a bit more controversial in how it is valued. Consistent with the prior two-channel billing economics of solar in this report, we will use the capacity benefit from Dismukes (2015). Specifically for purposes of our analysis, the customer will receive a rate credit of $216 per year, or about $30 per installed kW of solar capacity. We will use this value for two reasons. First, and most obviously, this number is derived from actual estimates of Louisiana utilities and this report was commissioned by the Louisiana Public Service Commission for the purposes of informing Louisiana policies. But second, Dismukes (2015) provides, by far, the most generous capacity benefits for solar of any of the studies that were analyzed. We credit this capacity benefit to the customer as a fixed monthly credit on their bill.

These results are shown in Table 3-8 on the next page. There are a few notable results. First, under the 80% combined tax credit regime, the batteries have a 4-to-9-year payback time period. This is similar to the payback time period of the solar system itself under a scenario of full retail net metering and the 80% tax credit that ranges from 6 to 8 years. With the 30% tax credit, the payback time period ranges from 14 years to not paying back in the 25 year threshold. Of course, this assumes that the life of the battery will continue for that time period. With no subsidy, the battery's minimum estimated payback time period is 20 years.

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.

Household Economics of Battery Investment
Two Channel Billing - Includes Capacity and Energy Benefit

	LSU Lab			PV Watts			Residential System		
Install Cost Tax Credit	$6,500 0%	$4,550 30%	$1,300 80%	$6,500 0%	$4,550 30%	$1,300 80%	$6,500 0%	$4,550 30%	$1,300 80%
Year 1	(6,344)	(4,394)	(1,144)	(6,151)	(4,201)	(951)	(6,287)	(4,337)	(1,087)
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	154	154	344	344	344	210	210	210
Year 5	154	154	154	343	343	343	209	209	209
Year 6	153	153	153	341	341	341	208	208	208
Year 7	152	152	152	340	340	340	208	208	208
Year 8	152	152	152	338	338	338	207	207	207
Year 9	151	151	151	337	337	337	206	206	206
Year 10	151	151	151	335	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	148	148	148	329	329	329	202	202	202
Year 15	148	148	148	328	328	328	201	201	201
Year 16	147	147	147	326	326	326	200	200	200
Year 17	147	147	147	325	325	325	199	199	199
Year 18	146	146	146	323	323	323	198	198	198
Year 19	146	146	146	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 IRR	Never -4.21%	Never -1.62%	9 12.46%	20 2.17%	14 5.98%	4 36.05%	Never -2.00%	23 0.93%	7 18.79%

Note: Electriciry prices are average wholesale price from SPP averaged between 2016 and 2017. Electricity prices are not escalated, thus IRRs represent a real rate of return. Total installation cost is $6,500 for all batteries based on the price of the *Tesla Powerwall*. Degredation rate of .5 percent used in all calculations. "LSU Lab" Solar production from the Renewable Energy and Smart Grid Laboratory at Louisiana State University. *PV Watts* is an online tool from National Renewable Energy Laboratory's. Resident is an actual resident within approxmately 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

At current electricity prices and installed costs of solar PV, it is unlikely that we will see significant increases in behind-the-meter solar investment in the next few years. While solar PV investments were economic from the household's perspective with the combined state and federal tax credit that covered 80% of a household's up-front installation cost, now that the state tax credit has been removed, it will be difficult for households to justify solar investment from a financial perspective. Nonetheless, utilities tell us that households are still continuing to install rooftop solar PV systems in Louisiana.

It should be noted that a combination of (a) decreasing installed costs and (b) increasing electricity prices could change the economics in coming years. Thus, we are in no way saying that solar does not have a bright future in Louisiana. Instead, we are simply stating the fact that under current market conditions and regulatory environment, households will have a difficult time justifying investment in solar from a strictly financial perspective.

4.2 Investment in Grid Modernization to Accommodate Solar

Due to the unlikely aggressive growth of solar under current market conditions and the current level of solar being approximately ½% of the state's load, we do not find it prudent for electric utilities to engage in large investments in distribution grid modernization for the sole purpose of mitigating issues with solar growth. We do, though, recommend that the LPSC encourage each utility to provide a list of all feeders with more than 1% of customers with solar. Utilities should model these feeders and assess the extent to which problems might occur specifically on those feeders with high penetration. In the short run, these studies can simply be paid for out of the utility's operational and maintenance budget, that is absorbed in rates by all rate payers. But if these studies become significantly costly, and investments in the distribution grid are needed specifically to mitigate the engineering problems associated with behind-the-meter solar, the LPSC should create a monthly charge to all solar PV customers. Any distribution grid upgrades to accommodate this growth should be approved by the LPSC, and the cost of these upgrades should be added to the monthly solar charge. If customers are able to show that their solar system does not contribute to a grid reliability problem, say through the installation of a battery, the customer should be exempt from contributing to the distribution grid upgrades through the monthly charge. Batteries are just one way that these distribution grid problems can be mitigated. The LPSC should consider any proposed mitigation technique as needed, such as different inverters.

4.3 Capacity Benefit

Solar customers should be compensated for the capacity benefit they provide to the grid, in addition to the value of energy generated. Policy makers can consider different ways of valuing this capacity. For instance, Entergy has embedded the capacity benefit into a per-kWh credit to customers for all power sold back to the grid in regulatory proceedings in both Texas and Arkansas. An alternative method is to estimate a capacity benefit of the solar and provide a monthly credit.

The problem with providing a per-kWh capacity benefit for power sent back to the grid is that this is in contradiction to the incentives that we recommend for installing a battery. Therefore, we recommend that either a customer specific demand charge is used (that can be mitigated by both the solar and battery) or the customer is credited a monthly capacity credit that will be determined in the regulatory process. We do not believe that embedding a capacity benefit into a per-kWh avoided cost is consistent with the approach laid out in this research.

4.4 Valuing Energy — Time of Use Pricing

For electricity sent back to the grid, customers should get as close as possible to time of use pricing. While there are a number of ways this can be done, this analysis uses the average hourly wholesale price over the Southwest Power Pool (SPP) by month and reimburses solar customers this amount for the power sold back to the grid.[54] While specifics might vary, utilities should base this energy benefit on actual wholesale prices. This approach is consistent with the economic principles of matching prices and quantities at the time of the transaction, but also benefits solar customers whose production is coincident with demand. Further, this will send a signal to households to install PV in a way that is coincident with system demand (not necessarily in a way that just maximizes total production). While beyond the scope of this research, we have been told that households typically install solar on the south-eastern side of their house (if possible) to maximize solar production, while installation on the west side would be more coincident with system peak demand. Valuing energy sold back to the grid with more time granularity will send an appropriate price signal. Under current net metering, the household simply has the incentive to maximize energy production without regard to potential capacity benefits.

4.5 Implication of Two-Channel Billing

According to this analysis, depending on the valuation of capacity and coincidence of solar production with wholesale prices, a two-channel billing regime is not estimated to negatively impact the economics of behind-the-meter solar significantly. But, this new billing regime does align incentives of utilities, households that choose to install solar, and households that choose not to install solar. While net metering might have been an appropriate policy (as it was simple and straightforward) while the Louisiana solar industry was in its infancy, it is time for change. We do recommend that the LPSC consider providing a monthly capacity benefit (in lieu of a per kWh benefit) and value energy sent back at the most granular time possible (preferably hourly, which would require advanced metering infrastructure and related investments). We also recommend that the LPSC allow for additional benefits of batteries as those benefits are able to be demonstrated.

4.6 Consumer Protection

The state should investigate the extent to which solar installers might have purposely over-estimated solar production in order to enhance the advertised economics of their systems when selling to customers. We recommend that either the LPSC or the Attorney General fund 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 to solar customers in the ratemaking process. Such inclusion of environmental benefits can improve the economics of solar for households.

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 behind-the-meter solar. But we implore policy makers and citizens to resist this temptation. The goal of policies should not be the growth of behind-the-meter solar by itself. Instead the goal of policies should be to provide clean, affordable, and reliable electricity to the citizens and businesses of this state. If we set ratemaking policies appropriately, we can let the market decide which combination of generation sources are able to achieve this outcome.

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