THE UNIVERSITY OF CHICAGO — ABRAMS ENVIRONMENTAL LAW CLINIC OF THE UNIVERSITY OF CHICAGO LAW SCHOOL

April 28, 2020

Via E-Filing Only

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48917

RE: MPSC Case No. U-18232

Dear Ms. Felice:

Please find enclosed the Qualifications and Direct Testimony of John Farrell on Behalf of Soulardarity and accompanying exhibits SOU 57 - SOU 64, along with the proof of service, for electronic filing in the above referenced matter. Please do not hesitate to contact my office with any questions or comments.

Sincerely,

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xc: Parties to Case No. U-18232

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE Electric Company to fully comply with Public Acts 295 of 2008	Case No. U-18232 ALJ Sharon L. Feldman

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QUALIFICATIONS AND DIRECT TESTIMONY OF

JOHN FARRELL

ON BEHALF OF SOULARDARITY

Dated: April 28, 2020

I. Introduction and Summary

I respectfully submit this testimony in Case No. U-18232 regarding DTE's 2020 Renewable Energy Plan. These comments reflect a wide range of issues related to the value of distributed renewable energy resources, from economies of scale of renewable energy to distributed energy benefits to community solar policy considerations.

Q: Please state your name, occupation, and business address.

A: My name is John Farrell. I am a co-director of the Institute for Local Self-Reliance (ILSR), and I direct ILSR's Energy Democracy Initiative. My business address is 2720 E. 22nd Street, Minneapolis, MN 55406.

Q: Please describe your work experience.

A: I am the co-director of the Institute for Local Self-Reliance (ILSR), and I direct and have worked for ILSR's Energy Democracy Initiative for 14 years. I authored *Energy Self-Reliant States*, a state-by-state atlas of renewable energy potential highlighted in the *New York Times*, showing that most states do not need to look outside their borders to meet their electricity needs. I have also published studies on the economies of scale of renewable energy, distributed solar valuation, and distributed solar plus energy storage. I have also written extensively on the economic advantages of democratizing the electricity system and community renewable energy, published a rich interactive map on solar grid parity, and polished the policies (like Minnesota's solar energy standard) necessary to support locally owned renewable energy development. I have keynoted conferences like Solar Energy Focus in Washington, DC, and the Midwest Energy Fair. More information about me and my work can be found at https://ilsr.org/about-the-institute-for-local-self-reliance/staff-and-board/john-farrell/.

Q: Are you sponsoring any exhibits as part of your testimony?

A: In addition to making reference to certain exhibits sponsored by Mr. Koeppel in his Direct Testimony submitted this same day, I am sponsoring the following exhibits (continuing the numbering from Mr. Koeppel's direct testimony):

57. ANDREW SATCHWELL ET AL., NAT'L RENEWABLE ENERGY LABORATORY, FINANCIAL IMPACTS OF NET-METERED PV ON UTILITIES AND RATEPAYERS: A SCOPING STUDY OF TWO PROTOTYPICAL U.S. UTILITIES (2014), https://emp.lbl.gov/publications/financial-impacts-net-metered-pv.

58. JOHN FARRELL, INST. FOR LOCAL SELF-RELIANCE, BEYOND SHARING – HOW COMMUNITIES CAN TAKE OWNERSHIP OF RENEWABLE POWER (2016), https://ilsr.org/report-beyond-sharing/.

59. MARIA MCCOY, INST. FOR LOCAL SELF-RELIANCE, COMMUNITY SOLAR WITH AN EQUITY LENS: GENERATING ELECTRICITY AND JOBS IN NORTH MINNEAPOLIS (2018), https://ilsr.org/community-solar-equity-ler-episode-57/.

60. Marie McCoy & John Farrell, Inst. for Local Self-Reliance, National Community Solar Tracker (published quarterly), https://ilsr.org/national-community-solar-programs-tracker/.

61. Gideon Weissman & Bret Fanshaw, Environment American Research and Policy Center, Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society (2016), https://environmentamerica.org/sites/environment/files/reports/AME%20ShiningRewards%20Rpt%20Oct16%201.1.pdf.

62. Richard Perez et al., Solar Power Generation in the US: Too expensive, or a bargain? (2011), http://www.asrc.cestm.albany.edu/perez/2011/solval.pdf.

63. John Farrell, Inst. for Local Self-Reliance, Reverse Power Flow: How Solar+Batteries Shift Electric Grid Decision Making from Utilities to Consumers (2018), https://ilsr.org/wp-content/uploads/2018/07/Reversing-the-Power-Flow-ILSR-July-2018.pdf.

64. Marie Donahue, Inst. for Local Self-Reliance, Visualizing California's Booming Solar Market (2018), https://ilsr.org/visualizing-calif-booming-solar-market/.

II. Why Bigger Is Not Necessarily Best in Renewable Energy

Q: What size of renewable energy costs less, large or small?

A: If you try to answer this question, you may be fooled, because the truth is that large-scale renewable energy competes in a different market from small-scale renewable energy. A report published by the Institute for Local Self-Reliance in 2016 and re-released in 2019 reveals data that undercuts the persistent myth of big being better, particularly because the point of grid interconnection and proximity to load matter. *See* Ex. SOU-10, JOHN FARRELL, INST. FOR LOCAL SELF-RELIANCE, IS BIGGER BEST IN RENEWABLE ENERGY? (2019).

The graphic "Wind Economies of Scale" on page 14 of the *Is Bigger Best* report compares the levelized cost of wind power projects at different scales, based on 2011-2015 project data. Most projects larger than five megawatts will interconnect to the transmission system and compete with other wholesale producers. In this market, greater size does matter. But at the smallest scale—projects 5 megawatts and smaller—where size would appear as a disadvantage, projects can receive higher prices for displacing transmission losses and providing supply to meet growing load on the distribution system. As shown in the chart, distributed wind can potentially receive higher prices; the avoided cost figure came from contracts secured by a community wind developer in Minnesota.

Solar has a similar dynamic, where the price of the competition is not the same for large and small projects. On-site projects compete with delivery costs of retail electricity, which includes generation, transmission, and distribution. Large-scale solar projects are among the least cost-effective in comparison, because their transmission interconnection costs swamp any marginal economies of scale. The graphic "Solar Competes at Most Sizes" on page 26 of *Is*

Bigger Best illustrates the fact that the levelized cost of electricity production for solar projects between five and 20 MW are lower than larger solar projects, and the cost of delivered power from projects at those smaller sizes is even better due to the ability of those projects to inject power without expensive new transmission infrastructure. The graphic also suggests that requests for proposal that ignore solar projects sized one to 20 megawatts may miss the most cost-effective solar project size segment.

In fact, the perpetuation of the bigger is best myth has less to do with actual project economics and more to do with the perfectly rational financial interests of utility companies. Most vertically integrated monopoly utilities (or even those with just a distribution monopoly) earn a profit on capital expenditures. This means that large-scale power projects, especially if utility-owned, generate shareholder returns. In contrast, distributed energy projects are often not utility-owned but may also reduce the need for new capital expenditures by reducing infrastructure needs through provision of local capacity and energy. A chart, from a 2014 study by the National Renewable Energy Laboratory, illustrates how utility management and shareholder interests differ from customer interests. *See* Ex. SOU-57, ANDREW SATCHWELL ET AL., NAT'L RENEWABLE ENERGY LABORATORY, FINANCIAL IMPACTS OF NET-METERED PV ON UTILITIES AND RATEPAYERS: A SCOPING STUDY OF TWO PROTOTYPICAL U.S. UTILITIES (2014) at xi. The chart shows customer rate and shareholder return impacts for two different utilities in a hypothetical scenario of 10% of sales offset by customer-owned solar. In this model, customer electricity bills increase by 2.5% and 2.7% for the two utilities, respectively, but utility equity returns decrease by 3% and 8%, respectively. Where distributed solar is concerned, utility shareholders have much more to lose than customers. The unequal impact of widespread distributed solar penetration creates a conflict of interest for utility management because their monopoly license comes with an agreement to maximize the public interest.

Q: What benefits can accrue to consumers through the implementation of distributed energy?

A: While monopoly utilities have a vested interest in downplaying distributed energy, public regulators have a vested interest in considering it for the consumer benefits. The Minnesota Smarter Grid Study provides a potent illustration of the importance of evaluating distributed and utility-scale means for future power generation. *See* Ex. SOU-12, Vibrant Clean Energy, LLC, Minnesota's Smarter Grid (2018).

Published in 2018, the study modeled the capacity and energy (in hourly increments) required to meet Minnesota's grid demands with increasingly low-carbon energy. The study found massive savings for Minnesota's electric customers in several scenarios reducing greenhouse gas emissions by 80% by 2050.

The study also shows that widespread distributed solar adoption is feasible and economically rewarding, as much or more so than reliance on utility-scale solar. In a state that is nearing 1 gigawatt of installed distributed energy resources, the study showed that a thirteen-fold increase in distributed solar by 2050—including approximately five gigawatts by the mid-2030s––results in similar financial savings for all customers as statewide decarbonization scenarios that focus solely on utility-scale solar. The local solar scenario creates over 40,000 jobs and would provide billions of dollars in customer energy bill savings.

Charts within the Minnesota Smarter Grid Study illustrate the opportunity. The chart titled "Average Annual Household Savings in Minnesota" compares household energy savings for different decarbonization scenarios. *See id.* at 21. The Local Decarbonization scenario, featuring 13 gigawatts of rooftop solar installed by 2050, provides close to the highest financial benefit. The dot representing the scenario, in yellow, is hidden just below the purple square of the Nuclear Retirements scenario, which showed the highest annual average savings for Minnesota households. A second chart titled "Estimated Electricity Sector FTEs By Scenario" illustrates the job creation benefits of the differing scenarios, showing that the rooftop solar maximization scenario creates 40,000 jobs, more than any other scenario with comparably high levels of household energy savings. *See id.* at 23.

Utilities often ignore "local decarbonization" or rooftop solar scenarios in planning because they do not directly control deployment of these resources. Investor-owned utilities, in particular, may be reluctant to show state regulators scenarios that reduce the utility's need to spend capital, its most reliable route to earning a profit. This means that public regulators have a responsibility to ensure that the resource plans of regulated utilities accurately reflect a careful analysis of the economic and financial benefits of power generation at any scale.

III. Community Solar

Q: What is Community Solar?

A: Community solar programs provide an opportunity to capture the economic and technical benefits of distributed energy and to provide access to solar energy to customers that do not own a sunny rooftop. While programs vary, a key characteristic is that customers can subscribe to energy production from a specific solar project (potentially nearby) and receive credit on their bill in proportion to their subscription. Community solar programs provide clean power for electricity grids, energy savings for customers, and opportunities for third parties to develop and own clean energy projects. The Institute for Local Self-Reliance's Beyond Sharing Report analyzes four key components of community solar programs: tangible benefits for customers, ownership options, increasing renewable energy, and offering access to all types of customers. *See* Ex. SOU-58, JOHN FARRELL, INST. FOR LOCAL SELF-RELIANCE, BEYOND SHARING – HOW COMMUNITIES CAN TAKE OWNERSHIP OF RENEWABLE POWER (2016).

Q: Please discuss the key components of Community Solar programs.

A: Most programs provide tangible benefits in the form of a bill credit. Some programs, like Maryland, treat community solar like virtual net metering and provide a bill credit similar to that offered to customers with on-site solar. Minnesota uses the value of solar, after having used a net metering proxy called the "applicable retail rate."

Most programs also provide ownership flexibility, requiring or allowing project ownership by subscribers or third parties. This important policy allows for projects like the Shiloh Temple community solar project in Minneapolis, a gold standard for community solar. *See* Ex. SOU-59, MARIA MCCOY, INST. FOR LOCAL SELF-RELIANCE, COMMUNITY SOLAR WITH AN EQUITY LENS: GENERATING ELECTRICITY AND JOBS IN NORTH MINNEAPOLIS (2018). The project, on a local church, recruited workers from the local population, was subscribed by the church and members of the congregation and neighborhood, and is cooperatively owned by subscribers.

Almost all community solar increases renewable energy deployment, but the best programs actually tie individual subscriptions to specific projects, giving customers certainty that their investment results in new clean energy development and a sense of connection to their energy source.

Access to all is the broadest and hardest policy objective to achieve. For one, it means that community solar should be available to all customer classes, not just residential customers. A big success of Minnesota's program has been the opportunity for small and large commercial customers to participate. This did not encroach on residential participation for a key reason—Minnesota's program has no capacity cap. Therefore, high participation from commercial customers does not crowd out residential participation.

A second facet of access to all is allowing customers of any income or credit to participate. Few programs have succeeded on this measure. While Minnesota has no specific policy to increase access, the previously mentioned Shiloh Temple project has reached more low-income subscribers through an innovative "backup subscriber" model, where the church has agreed to pick up subscriptions if a customer moves or defaults on their payments. Other states have set minimum participation standards, special program phases, or other strategies to recruit low-income participants, but few have seen widespread success. Ensuring widespread access requires addressing several financial issues: inability to cover upfront costs, lack of credit to finance subscriptions, and what to do in the event the customer cannot continue their subscription.

While Minnesota's program needs to do more to ensure access, it continues to lead the nation in deployed community solar capacity. *See* Ex. SOU-60, MARIE MCCOY & JOHN FARRELL, INST. FOR LOCAL SELF-RELIANCE, NATIONAL COMMUNITY SOLAR TRACKER (published quarterly).

IV. The Benefits of Distributed Generation

Q: Please describe the unique benefits of distributed energy.

A: In the comparisons of large and small renewable energy, both share important characteristics of reduced health impacts from pollution, reducing fuel price risks, and providing price certainty. But distributed energy resources have unique values, reflected in numerous studies captured in this meta-analysis published in 2016. *See* Ex. SOU-61, GIDEON WEISSMAN & BRET FANSHAW, ENVIRONMENT AMERICAN RESEARCH AND POLICY CENTER, SHINING REWARDS: THE VALUE OF ROOFTOP SOLAR POWER FOR CONSUMERS AND SOCIETY (2016). While many of these studies did not result in use of the valuation in active market policies, one state has been applying distributed solar valuations in solar markets for several years: Minnesota.

Conceived in legislation in 2013 and adopted in 2014, Minnesota's value of solar policy captures the most common values used for distributed solar. Based on my analysis of annual filings by Xcel Energy in Docket No. 13-867 to the Minnesota Public Utilities Commission, avoided infrastructure costs have consistently been between $0.04 and $0.05 per kilowatt-hour (the total value of solar has ranged between $0.11 and $0.13). This reflects the unique value of distributed energy resources based on their interconnection point to the grid and proximity to load. It also represents the tension point between utility shareholders and customers, because it represents avoided utility capital spending (and profits) associated with otherwise needed transmission and distribution infrastructure. On-site distributed solar may have even higher avoided costs, because it interconnects even further from substations, behind the transformers serving just a few homes.

Q: What are some of the lessons learned about distributed solar valuation from Minnesota's experience?

A. Minnesota's landmark policy and its implementation provide a few lessons about the limitations of distributed solar valuation. For one, it still overlooks a number of important values, including resiliency, reliability, and job creation.

When paired with storage, for example, distributed solar can provide resilience to neighborhoods, communities, and cities that centralized power generation cannot. It can provide power to fire stations or hospitals, community cooling centers, or essential industries when grid power is unavailable due to natural disaster or public safety shutoffs.

Distributed solar can also enhance reliability. In the wake of the infamous 2003 blackout affecting the northeast United States, one study found that 500 megawatts of distributed solar could have avoided the blackout by providing enough capacity and voltage support in key locations to prevent the blackout from cascading from one grid to another. *See* Ex. SOU-62, RICHARD PEREZ ET AL., SOLAR POWER GENERATION IN THE US: TOO EXPENSIVE, OR A BARGAIN? (2011). Hundreds of megawatts of distributed energy resources on the PJM interconnection have since provided reactive power and voltage support to that region's grid due to open markets with low thresholds for market entry (100 kilowatts). *See* Ex. SOU-63, JOHN FARRELL, INST. FOR LOCAL SELF-RELIANCE, REVERSE POWER FLOW: HOW SOLAR+BATTERIES SHIFT ELECTRIC GRID DECISION MAKING FROM UTILITIES TO CONSUMERS (2018). In regions without this market access, distributed energy resources have unrecognized value, and state regulators must fill the gap in the absence of market pricing by ensuring inclusion of distributed energy resources in resource modeling and planning.

Distributed solar also creates more jobs than centralized solar. As shown in the Minnesota Smarter Grid Study, similar levels of household energy savings and reduced carbon pollution are accompanied by thousands more jobs if the deployed capacity is built at small scale. In a 2018 report on distributed energy resources, the Institute for Local Self-Reliance found similar out-sized benefits from solar plus storage compared to the proposed Puente gas peaker plant in California. *See id.* at 25. The proposed plant has since been scrapped, in lieu of renewable energy plus storage.

Minnesota's value of solar may undervalue a number of important elements of distributed solar, but it also provides an important lesson about policy design. The Minnesota policy allows for a recalculation of solar valuation each year, but the revised values only apply to new projects. Existing projects lock in the solar valuation at the time of application approval, for 25 years. This balances value accuracy with a truth of solar development—to find financing for a solar project, developers need some certainty about their expected revenue. In New York, the value of distributed energy resources has resulted in a hyper-accurate and under-utilized market for distributed solar and other resources. In particular, the attempt to identify location specific values for solar, while admirable, has made development extremely uncertain. Minnesota's policy strikes the balance between accuracy and usability.

The lesson from Minnesota for distributed solar locational value is particularly important. Many experts rightly assert that the locational value of distributed energy varies significantly, depending on the load and load profile of the distribution feeder, growth projections, substation age and capacity, and actions of other customers on the same feeder. Minnesota's policy includes the option of a locational component, but stakeholders have already spent more than a year trying to identify the right principles and procedures to provide both accuracy and certainty. Part of the problem is that few utilities collect the feeder-level data necessary to do accurate valuation. Xcel Energy's hosting capacity analysis, for example, relies on some data collected by automated SCADA systems and other data collected manually. Until the most recent filing, the estimates of available capacity on the utility's feeders did not even include projects in the interconnection queue, essential data for valuing prospective new distributed solar systems. And even if the utility and regulators develop an accurate picture of locational value, if it varies too much from year to year, it may not be possible to use it to guide new projects when developers need revenue certainty to obtain project financing.

Q: How should does distributed energy relate to integrated resource and distribution planning?

A: A final important consideration in distributed energy development is the underlying assumption that it represents an exception to the "appropriate" model of grid planning. Integrated resource planning was proposed in response to spectacular financial disasters related to large, centralized power plant development in the 1960s and 1970s. The planning presumption was the more oversight would address the shortcomings of utility planning even if it did not change the paradigm of large, central-station power generation. At the time, there was little practical experience with alternative business models. That is no longer true.

For example, in the past decade, California electricity customers have cumulatively deployed six gigawatts of power generation capacity without an approved resource plan. A graphic on the website of the Institute for Local Self-Reliance (animated in its original location at https://ilsr.org/visualizing-calif-booming-solar-market/), illustrates where the solar was built by quarter but, more importantly, it illustrates how the widespread availability of distributed energy undercuts the presumptive value of top-down resource planning. *See* Ex. SOU-64, Marie Donahue, Inst. for Local Self-Reliance, Visualizing California's Booming Solar Market (2018).

Electric utilities often focus on the marginal costs of customer-owned generation, a perspective that is uniquely applied to these resources. In contrast, when electricity demand grew in the early years of the grid, costs of service—interconnection and power generation—were socialized to allow electricity service to expand broadly. The social compact worked perfectly because utility shareholders were happy to deploy capital to address customer demands and power costs kept falling relative to inflation. California's customers have sent a clear message to utilities and regulators: we will not rely solely on a monopoly utility market to provide power. This message is a "postcard from the future" for states with less intense sunlight and lower retail electricity prices, but the delivery is imminent.

The implication for other states is significant, because it suggests that the marginal costs in resource planning are the centralized, utility-scale ones, not the distributed ones. In other words, good public utilities should design their grid to maximize these customer-capitalized resources. It will be up to public regulators to square the circle of aligning utility financial incentives with a market that no longer demands similarly high deployment of utility capital.

V. Conclusion

Q: Are you aware of any reason why the fundamental ideas of this research would not apply in Michigan?

A: No. The economies of scale of renewable power generation and the value elements of distributed energy resources are similar across all states. Community solar serves the same purpose of lowering barriers to entry for customers in every state. And regulated monopoly utilities, whether they own generation or have customers in a retail choice environment, still own and make investments in distribution infrastructure with profits reliant on capital expenditures (and more typically also have similar rewards for investments in power generation, transmission infrastructure, or even gas pipelines to serve power plants).

While the specific financial and economic values of distributed solar or community solar might vary by state or utility service territory, all of the analysis and evaluation included in this testimony applies to the Michigan electricity market and regulatory structure.

Q: Does this conclude your testimony?

A: Yes

LBNL-6913E

ERNEST ORLANDO LAWRENCE BERKELEY NATIONAL LABORATORY

Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A Scoping Study of Two Prototypical U.S. Utilities

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September 2014

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Acronyms

APS – Arizona Public Service
BAU – business-as-usual
CAGR – compound annual growth rate
CapEx – capital expenditures
CFE – Comision Federal de Electricidad
DOE – U.S. Department of Energy
EE – energy efficiency
EPE – El Paso Electric
EPRI – Electric Power Research Institute
FAC – fuel adjustment clause
FCM – Forward Capacity Market
FERC – Federal Energy Regulatory Commission
GRC – general rate case
IRP – integrated resource plan
ISO-NE – Independent System Operator New England
LBNL – Lawrence Berkeley National Laboratory
LRAM – lost revenue adjustment mechanism
NAPEE – National Action Plan for Energy Efficiency
NE – northeast
NEM – net energy metering
NEVP – Nevada Power
NPV – net present value
O&M – operations and maintenance
PACE – PacifiCorp East
PNM – Public Service Company of New Mexico
PPA – purchased power agreement
PSCO – Public Service Company of Colorado
PUC – public utilities commission
PV – solar photovoltaic
REC – renewable energy certificate
ROE – return-on-equity
RPC – revenue-per-customer
RPS – renewable portfolio standard
SEEAction – State Energy Efficiency Action Network
SEIA – Solar Energy Industries Association
SEPA – Solar Electric Power Association
SPP – Sierra Pacific Power
SRP – Salt River Project
SW – southwest
T&D – transmission and distribution
TOD – time-of-delivery
TOU – time-of-use
UOG – utility owned generation
WACC – weighted average cost-of-capital
WACM – Western Area Power Administration, Colorado-Missouri Region
WALC – Western Area Power Administration, Lower Colorado Region

Executive Summary

Deployment of customer-sited photovoltaics (PV) in the United States has expanded rapidly in recent years, driven in part by public policies premised on a range of societal benefits that PV may provide. With the success of these efforts, heated debates have surfaced in a number of U.S. states about the impacts of customer-sited PV on utility shareholders and ratepayers, and such debates will likely become only more pronounced and widespread as solar costs continue to decline and deployment accelerates. To inform these discussions, we performed a scoping analysis to quantify the financial impacts of customer-sited PV on utility shareholders and ratepayers and to assess the potential efficacy of various options for mitigating those impacts.

The analysis relied on a pro-forma utility financial model that Lawrence Berkeley National Laboratory previously developed for the purpose of analyzing utility shareholder and ratepayer impacts of utility-sponsored energy efficiency programs. Using this model for the present study, we quantified the impacts of net-metered PV for two prototypical investor-owned utilities: a vertically integrated utility located in the southwest (SW) and a wires-only utility and default service supplier located in the northeast (NE). For each utility, we modeled the potential impacts of PV over a 20-year period, estimating changes to utility costs, revenues, average rates, and utility shareholder earnings and return-on-equity (ROE). The analysis is thus focused on utility shareholder and ratepayer impacts, and thus does not consider all relevant aspects of these debates. Other important boundaries of the study scope and methods (and potential sources of misinterpretation) are highlighted in Text Box 1 within the main body of the report.

The utility shareholder and ratepayer impacts of customer-sited PV were first assessed under a set of base-case assumptions related to each utility's regulatory and operating environment, in order to establish a reference point against which sensitivities and potential mitigation strategies could be measured.[1] The base-case analyses were performed with total penetration of customer-sited PV rising over time to stipulated levels ranging from 2.5% to 10% of total retail sales (compared to current penetration levels of 0.2% for the U.S. as a whole and of roughly 2% for utilities with the highest penetrations, excluding Hawaii).[2] Each of these PV penetration cases were compared to a scenario with no customer-sited PV over the entire analysis period. Although the estimated impacts of customer-sited PV reflect an assumption of net metering, those impacts should not be attributed to net metering, per se, as some amount of customer-sited PV deployment could occur even in the absence of net metering.

Key findings from the **base-case analysis** are as follows:

- **Utility Costs and Revenues.** Customer-sited PV reduces both utility revenues and costs (i.e., revenue requirements). In the case of the SW Utility, the impacts on revenues and costs are roughly equivalent under the 2.5% PV penetration scenario. At higher PV penetration

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[1] See Sections 3 and 4 for a full description of base-case assumptions. Variations around these and other base-case assumptions are explored within the sensitivity analysis.
[2] Specifically, penetration of customer-sited PV rises from zero in year-1 to levels ranging from 2.5% to 10% of retail sales in year-10, and then remains constant as a percentage of retail sales for the latter 10 years of the 20-year analysis period. This approach was taken in order to capture end-effects that occur after PV additions take place.

levels, however, revenue reductions exceed cost reductions, in part because of a declining marginal value of PV. In the case of the NE Utility, revenue reductions exceed cost reductions across all of the future PV penetration levels considered, and the divergence is considerably wider than for the SW Utility. This occurs because the NE Utility has higher assumed growth in certain fixed costs that customer-sited PV does not reduce.

- **Achieved ROE.** Impacts on achieved shareholder ROE varied by utility and PV penetration level (see Figure ES-1). Under the scenario with PV penetration rising to 2.5% of retail sales (roughly the same order of magnitude as the current largest state markets), average achieved shareholder ROE was reduced by 2 basis points (a 0.3% decline in shareholder returns) for the SW utility and by 32 basis points (5%) for the NE Utility. Under the more aggressive 10% PV penetration scenario, average ROE fell by 23 basis points (3%) for the SW Utility and by 125 basis points (18%) for the NE Utility. These ROE reductions occur because of the proportionally larger effect of customer-sited PV on utility revenues than on utility costs, under our base-case assumptions. ROE impacts were larger for the wires-only NE utility, because of both its higher assumed growth in fixed costs and its proportionally smaller ratebase (as it does not own generation and transmission).

- **Achieved Earnings.** The impact of customer-sited PV on shareholder earnings for the SW Utility was somewhat more pronounced than the ROE impacts, because of lost earnings opportunities associated with deferred capital expenditures that would otherwise generate earnings for shareholders. Under the 2.5% PV penetration scenario, average earnings for the SW Utility were reduced by 4% (compared to a 0.3% reduction in ROE). Because of the lumpy nature of capital investments and the way in which they change the timing of general rate cases (GRCs) and setting of new rates, those earnings impacts do not necessarily scale with the penetration of customer-sited PV; under the 10% PV penetration scenario, earnings for the SW Utility were reduced by 8%. Because the NE Utility does not own generation or transmission, the lost earnings opportunities from customer-sited PV are less severe, and thus impacts on earnings are similar to impacts on ROE, ranging from a 4% reduction under the low-end PV penetration scenario to a 15% reduction in earnings at the high-end PV penetration scenario. [3]

- **Average Rates.** The ratepayer impacts of customer-sited PV were relatively modest compared to the impacts on shareholders. In the 2.5% PV penetration scenario, customer-sited PV led to a 0.1% increase in average rates for the SW Utility and a 0.2% increase for the NE Utility. Under the more aggressive 10% PV penetration scenario, average rates rose by 2.5% and 2.7% for the SW and NE Utilities, respectively. These rate impacts reflect the net impact of customer-sited PV on utility costs and sales, where reduced costs are spread over a smaller sales base. Note, though, that these impacts represent the increases in average rates across all customers, including those with and without PV, and thus do not measure cost-shifting, per se.

[3] The prototypical NE Utility in our analysis may present a case where the ROE of future investments does not cover the cost of equity, in which case the deferral of future capital investments would benefit shareholders; however, a cost of equity test, which is beyond the scope of this study, would be required to make such a determination.

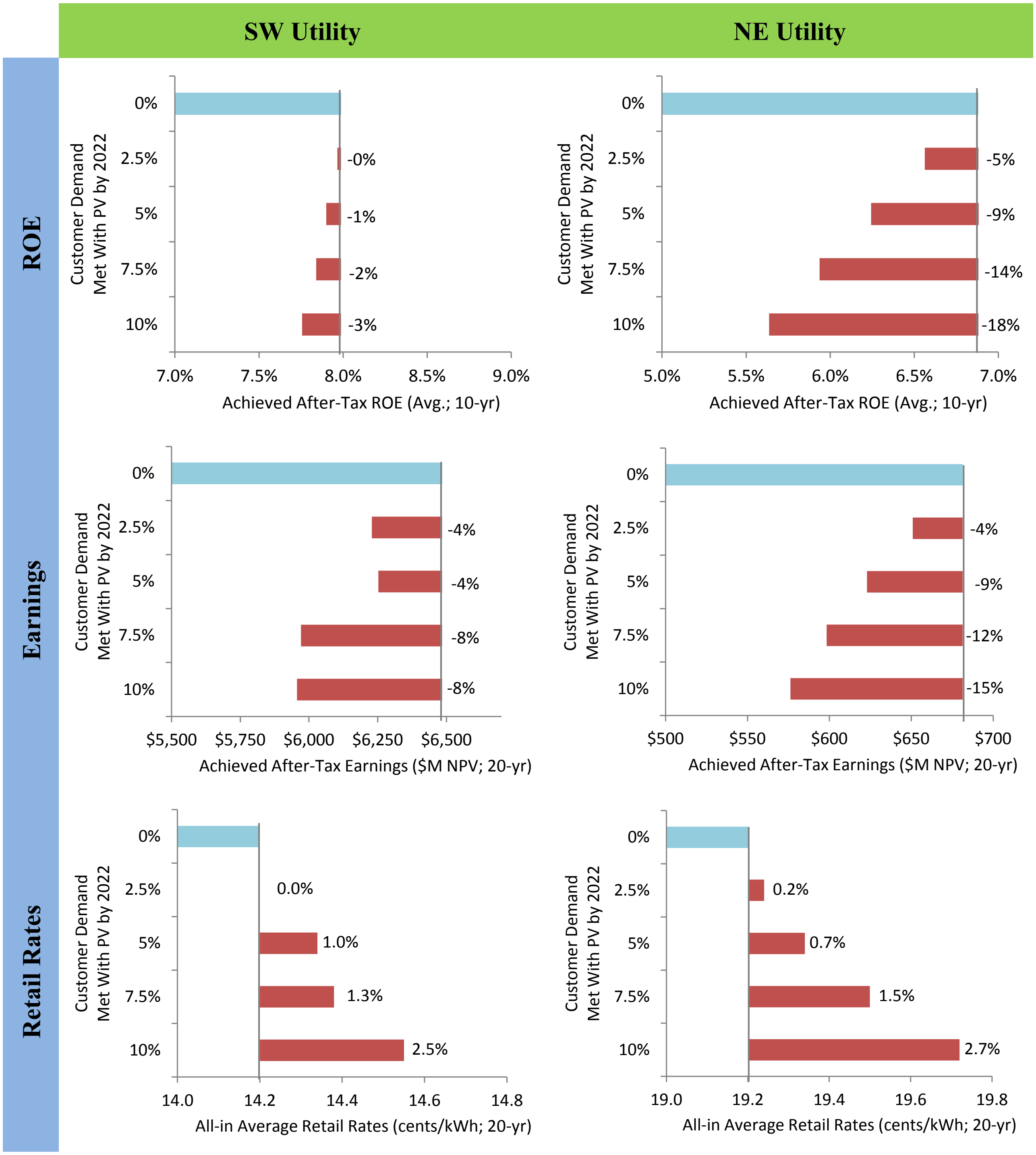

Figure ES-1. Impacts of Customer-Sited PV on Average Achieved ROE, Earnings, and All-in Retail Rates

One key objective of this scoping study was to illustrate the extent to which the potential impacts of customer-sited PV on utility shareholders and ratepayers depend on underlying conditions of the utility. To explore these inter-relationships, we compared the impacts from PV under a wide array of sensitivity cases, each with varying assumptions about the utilities' operating or regulatory environment (see Table 3 in the main body for the full list of sensitivity cases). The sensitivity cases all focus specifically on impacts from customer-sited PV at a penetration level of 10% of total retail sales. This is the highest penetration level examined within this study, and was used for the sensitivity cases in order to most clearly reveal the underlying relationships between the impacts of PV and the sensitivity variables (that is, to distinguish the signal from the noise). Were lower PV penetration levels assumed, the impacts of PV would be smaller and the ranges across sensitivity cases would be narrower, but the fundamental results would be qualitatively the same.

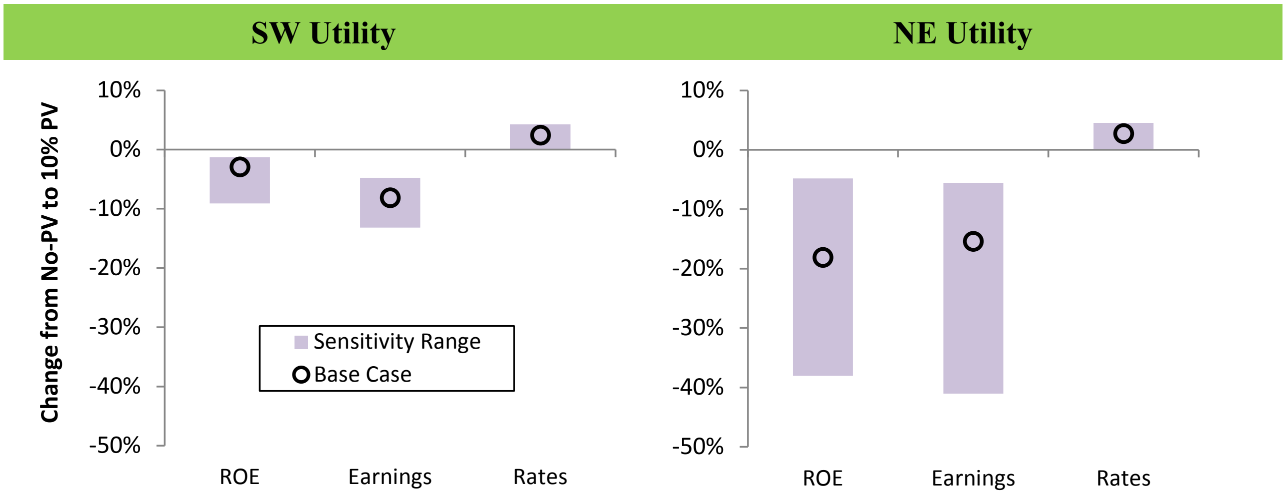

Figure ES-2. Impacts of Customer-Sited PV across Sensitivity Cases

Key themes and relationships illustrated through the **sensitivity analysis** are as follows[4]:

- The magnitude of shareholder impacts varies considerably across the sensitivity cases, as illustrated in Figure ES-2. Specifically, achieved earnings were reduced by 5% to 13% for the SW utility and by 6% to 41% for the NE utility, with similar ranges in the impacts on achieved ROE, illustrating the degree to which these impacts potentially depend on utility-specific conditions. By comparison, the ratepayer impacts were relatively stable across sensitivity cases, with increases in average rates ranging from 0% to 4% for the SW utility and from 1% to 4% for the NE utility.

- The impacts to both prototypical utilities are particularly sensitive to the capacity value and avoided T&D costs from customer-sited PV. Important to note, however, is the divergent set of implications for ratepayers vs. shareholders. The greater the capacity value and avoided T&D costs from PV, the greater the deferral of utility capital expenditures. This reduces the impacts of customer-sited PV on retail rates. Indeed, under one set of assumptions for the SW Utility, customer-sited PV results in a slight decrease in average rates. For utility shareholders, however, increased deferral of capital expenditures leads to greater erosion of earnings.

[4] The focus of our sensitivity analysis is on how the metrics vary between cases with and without PV and how the size of that difference varies depending upon underlying utility conditions, not on how the absolute level of the shareholder and ratepayer metrics varies between sensitivity cases.

- The impact of customer-sited PV on average retail rates also depends on underlying load growth (prior to the effects of PV on load). With lower load growth, as may occur in the case of a utility with aggressive energy efficiency programs, customer-sited PV results in a larger increase in average retail rates, because of the smaller base of retail sales over which fixed costs must be recovered, and because of reduced opportunity for cost savings from deferred capital expenditures. Shareholder impacts from customer-sited PV can also be sensitive to underlying load growth, though those relationships are complex and can be idiosyncratic depending upon details of the particular utility and the choice of metric used.

- The shareholder impacts of customer-sited PV tend to be more severe when retail rates rely predominantly on volumetric energy charges and also tend to be more severe when longer lags exist within the ratemaking process (e.g., longer periods between rate cases or use of historic test years). The heightened shareholder impacts in these cases occur because of greater revenue erosion associated with PV.

- The shareholder and ratepayer impacts from customer-sited PV also depend, though often to a lesser extent, on the magnitude and growth rates of various utility cost elements; however, the degree and direction of those sensitivities depend on the type of cost and how it is recovered. For example, the erosion of shareholder profitability from customer-sited PV is unaffected by fuel costs (assuming they are a pass-through), but may be highly sensitive to capacity costs for utility-owned generation.

Finally, we analyzed a number of (though by no means all) options for mitigating the possible impacts of customer-sited PV on utility shareholders and ratepayers (see Table ES-1). As in the sensitivity analysis, we again focused on the impacts under the 10% PV penetration scenario, in order to most clearly reveal the effects of the mitigation measures considered. These mitigation scenarios borrow, to some degree, from the kinds of measures that have been implemented or suggested in connection with energy efficiency programs. Most target shareholder impacts associated with either revenue erosion or lost earnings opportunities from customer-sited PV, and in some cases may exacerbate the ratepayer impacts from customer-sited PV.

Table ES-1. Mitigation Measures Examined in This Study

Mitigation Measure	Revenue Erosion	Lost Earnings Opportunities	Increased Rates
Revenue-per-Customer (RPC) Decoupling	●		○
Lost Revenue Adjustment Mechanism (LRAM)	●		○
More Frequent Rate Cases	●		○
No Regulatory Lag	●		○
Current & Future Test Years	●		○
Increased Demand Charge & Fixed Charge	●		○
Shareholder Incentive		●	○
Utility Ownership of Customer-Sited PV		●	○
Customer-Sited PV Counted toward RPS			●

● Primary intended target of mitigation measure
○ May exacerbate impacts of customer-sited PV

Key themes and findings from the **analysis of mitigation options** include the following:

- Decoupling and lost-revenue adjustment mechanisms may moderate revenue erosion from customer-sited PV, and thereby mitigate its impacts on shareholder ROE and earnings; however, the size (and even direction) of impact varies greatly depending upon the design of these mechanisms and characteristics of the utility. Depending on the utility's underlying rate of cost growth, similar outcomes may also be achieved by transitioning to more-frequent rate cases, use of current or future test years, and reduced regulatory lag. However, to the extent that these various mitigation measures serve to restore shareholder ROE and earnings, they may entail some corresponding increase in average retail rates, exemplifying the kind of tradeoffs inherent in many potential mitigation measures.

- Increased fixed customer charges or demand charges may also moderate revenue erosion, and the associated impacts on shareholder ROE and earnings, from customer-sited PV. Importantly, though, the effectiveness of those measures depends critically on the underlying growth in the number of customers or customer demand. For the prototypical NE utility in our analysis, a shift in revenue collection from volumetric energy charges towards larger fixed customer charges (when implemented for all customers, not just those with PV) actually *exacerbates* the erosion of shareholder ROE, due to the low rate of growth in the number of utility customers relative to growth in sales. Moreover, such shifts in rate design are not without other consequences, including that they dampen incentives for customers to invest in energy efficiency and PV.

- Shareholder incentive mechanisms, similar to those often implemented in conjunction with utility-administered energy efficiency programs, as well as utility ownership or financing of customer-sited PV, both offer the potential for substantial shareholder earning opportunities, though the associated policy and regulatory issues may be significant. The significance of the potential earnings boost is most pronounced for wires-only utilities with otherwise limited investment opportunities: in the case of the NE Utility in our analysis, nearly all of the earnings erosion that would otherwise occur as a result of customer-sited PV is offset in a scenario where the utility owns just one-tenth of the customer-sited PV deployed in its service territory offsets.

- Allowing utilities to automatically apply all net-metered PV towards their RPS obligations, without providing any explicit payment to the customer, has the potential to substantially mitigate the rate impacts from PV. However, such an approach is not without tradeoffs, as it effectively entails transferring ownership of renewable energy certificates (RECs) as a condition of service under net metering, and it achieves cost savings by, in effect, reducing the amount of incremental renewable generation required to comply with the RPS.

Policy Implications and Areas for Further Research

In summary, the findings from this scoping study point towards several high-level policy implications. First, even at 10% PV penetration levels, which are substantially higher than exist today, the impact of customer-sited PV on average retail rates may be relatively modest (at least from the perspective of all ratepayers, in aggregate[5]). At a minimum, the magnitude of the rate impacts estimated within our analysis suggest that, in many cases, utilities and regulators may have sufficient time to address concerns about the rate impacts of PV in a measured and deliberate manner. Second and by comparison, the impacts of customer-sited PV on utility shareholder profitability are potentially much more pronounced, though they are highly dependent upon the specifics of the utility operating and regulatory environment, and therefore warrant utility-specific analysis. Finally, we find that the shareholder (and, to a lesser extent, ratepayer) impacts of customer-sited PV may be mitigated through various "incremental" changes to utility business or regulatory models, though the potential efficacy of those measures varies considerably depending upon both their design and upon the specific utility circumstances. Importantly, however, these mitigation strategies entail tradeoffs – either between ratepayers and shareholders or among competing policy objectives – which may ultimately necessitate resolution within the context of broader policy- and rate-making processes, rather than on a stand-alone basis.

As a scoping study, one final objective of this work is to highlight additional questions and issues worthy of further analysis, many of which will be addressed through follow-on work to this study and further refinements to LBNL's utility financial model. Although by no means an exhaustive list, these areas for future research include examining: the relative impacts of customer-sited PV compared to other factors that may impact utility profitability and customer rates; the combined impacts of customer-sited PV, aggressive energy efficiency, and other demand-side measures; the rate impacts of customer-sited PV and various mitigation measures specifically on customers without PV and differences among customer classes; a broader range of mitigation options; potential strategies for maximizing the avoided costs of customer-sited PV; and continued efforts to improve the methods and data required to develop reliable and actionable estimates of the avoided costs of customer-sited PV.

[5] We do not evaluate rate impacts for individual customer classes or rate classes, and the average rate impacts described within this report may not capture more substantial impacts that could occur within individual customer or rate classes.

1. Introduction

Electricity generation from customer-sited photovoltaic (PV) systems currently constitutes just 0.2% of total U.S. electricity consumption, though it has reached higher penetration levels in various states and utility service territories, and has grown at a rapid pace of roughly 50% per year over the past decade.[6] This recent growth has been fueled by a combination of falling PV system prices, the advent of customer financing options, and various forms of policy support at the federal, state, and local levels that are premised on the range of societal benefits that PV may provide. One critical element in the value proposition has been net energy metering (NEM or simply "net metering"), a billing mechanism that allows customers to export electricity generated by their PV systems to the grid and apply that excess generation against electricity consumption at other times, in effect receiving credit for all PV generation at the prevailing retail electric rate.

Heated debates surrounding the financial impact of customer-sited PV and net metering on utility shareholders and ratepayers have surfaced in a number of states, and these will likely become more widespread as solar deployment expands, and as states approach statutory caps on the allowed amount of net-metered PV.[7] Utility executives are often concerned about revenue erosion and reduced shareholder returns when customers with net-metered PV are able to avoid charges for fixed infrastructure costs, as well as potential cost-shifting between solar and non-solar customers. At the same time, net metering is viewed as essential by customers with PV to protect their investments, by the solar industry to grow their businesses, and by states and environmental advocates to achieve climate or other environmental policy goals. To date, however, progress on these issues has been hampered by a lack of evidence about the magnitude of the financial impacts on utility shareholders and ratepayers, the conditions under which those impacts may become more or less significant, and the efficacy of potential mitigation options.

Debates about net metering are taking place against the backdrop of a larger set of discussions about existing utility business and regulatory models. One dimension of those broader discussions has focused on the poor alignment between the traditional utility business model – whereby utility profits are closely tied to their volume of sales and capital investments – and recent advances in technology and public policy driving growth of demand-side resources, which tend to reduce sales and opportunities for capital investments (Kind 2013, Fox-Penner 2010). Arguably the greatest progress on those issues has occurred with respect to utility ratepayer-funded energy efficiency (EE) programs, where the unintended consequences of the "utility throughput incentive" to increase sales and add capital investments to the utility's ratebase have been long-recognized and a variety of regulatory tools have been developed and deployed to better align utility financial interests with EE goals (Wiel 1989, Moskovitz et al. 1992, Eto et al.

[6] The highest state-level penetration rates for customer-sited PV are in Hawaii (3.8% of retail electricity sales at year-end 2013), New Jersey (1.7%), and California (1.1%), while the highest penetration rates for individual investor-owned utilities are for the three largest Hawaii utilities (5.1%-6.0%), Pacific Gas & Electric (2.3%), San Diego Gas & Electric (2.0%), and Arizona Public Service (2.0%). These values are derived from data on customer-sited PV capacity installed through year-end 2013, as reported by GTM/SEIA (2014) and by SEPA (2014).

[7] Recent challenges to existing net metering tariffs have been raised in regulatory proceedings in Arizona, California, Colorado, Georgia, Idaho, Louisiana, and Nevada (among others); and issues related to the potential rate impacts or cost-shifting from net metering have been prominently featured within energy policy forums (Borenstein 2013) and among major news outlets (Cardwell 2013, Tracy 2013).

1994, Harrington et al. 1994, Stoft et al. 1995, Kushler et al. 2006, NAPEE 2007). Among the goals of the present study is to leverage this base of experience and illustrate how some of the same regulatory and ratemaking strategies could also be applied in the context of distributed PV.

As the attention of policymakers and electric industry observers has turned towards customer-sited PV, studies representing a diversity of perspectives have highlighted potential misalignments between net metering and utility cost structures (Brown and Lund 2013, Cai et al. 2013, DOE 2007, Duthu et al. 2014, Graffy and Kihm 2014, SEPA-EPRI 2012, Wood and Borlick 2013). A number of those studies and several others (Bird et al. 2013, Blackburn et al. 2014, Linvill et al. 2013, Kihm and Kramer 2014, Shirley and Taylor 2009) identify regulatory and ratemaking options for mitigating adverse rate impacts from distributed PV, while many others (also) discuss possible broader changes to utility business and regulatory models that are compatible with, or that could facilitate the growth of, distributed PV (EPRI 2014, Hanelt 2013, Harvey and Aggarwal 2013, Lehr 2013, Moskovitz 2000, Newcomb et al. 2013, Nimmons and Taylor 2008, Richter 2013a, Richter 2013b, Rickerson et al. 2014, RMI 2012, RMI 2013, Wiedman and Beach 2013).

Quantitative analyses relating to the financial or economic impacts of customer-sited PV and net metering have thus far consisted mostly of cost-benefit studies performed from the perspective of utility ratepayers or society more broadly; see Hansen et al. (2013) for a meta-analysis of cost-benefit studies and E3 (2014) for a more recent example. The results of those studies hinge on the methods and assumptions used to estimate the value of distributed PV to the utility, and considerable disagreement exists around which particular sources of value to consider and how to quantify them (APPA 2014, Bradford and Hoskins 2013, Cliburn and Bourg 2013, Keyes and Rábago 2013, Stanton and Phelan 2013). Competing studies have thus often led to divergent results (E3 2013, Beach and McGuire 2013). By comparison, few analyses beyond several recent research notes by Wall Street analysts (Dumoulin-Smith et al. 2013, Goldman Sachs Global Investment Research 2013) and a limited base of theoretical work (Oliva and MacGill 2012) have sought to examine the financial implications of net metering for utility shareholders. Moreover, little if any published research has quantitatively compared possible options for mitigating any potential adverse impacts on either utility shareholders or ratepayers.

This report seeks to build upon, and address gaps within, the aforementioned body of research through a scoping analysis that quantifies the potential financial impacts of net-metered PV on utility shareholders and ratepayers. The analysis leverages a pro-forma utility financial model that Lawrence Berkeley National Laboratory (LBNL) developed for the purpose of analyzing the shareholder and ratepayer impacts of utility-sponsored EE programs (Cappers et al. 2009, Cappers and Goldman 2009a, Cappers et al. 2010, Satchwell et al. 2011). Using this model, we quantify the financial impacts of customer-sited PV for two prototypical investor-owned utilities: a vertically integrated utility located in the Southwest and wires-only utility and default service supplier located in the Northeast. For each utility and under a range of PV penetration levels, we model the impact of net-metered PV on utility costs, revenues, average rates, and utility shareholder earnings and return-on-equity (ROE). We examine the sensitivity of those impacts to various aspects of the utility operating and regulatory environment (e.g., load growth, cost growth, the frequency of general rate cases), as well as to alternate assumptions about the value of PV to the utility (i.e., avoided costs). Finally and importantly, we quantify the impact of a number of possible mitigation approaches that might be used to reduce any negative impacts to shareholders and/or ratepayers from growing amounts of customer-sited PV. These mitigation measures include alternative rate designs, utility revenue decoupling, utility ownership of distributed PV, and various other strategies. Key boundaries to the study scope and methods (and potential sources of misinterpretation) are highlighted in Text Box 1.

The remainder of the report is organized as follows. Section 2 provides an overview of the utility pro-forma financial model and describes its previous applications. Section 3 identifies key assumptions used to model the two prototypical utilities and presents base-case projections of their costs, revenues, retail rates, and profits without PV. Section 4 presents the corresponding base-case results for the two prototypical utilities under a range of PV penetration levels. Section 5 presents our sensitivity analyses, which illustrate how the utility shareholder and ratepayer impacts of PV are dependent upon various aspects of the utility operating and regulatory environment. Section 6 presents the results of the mitigation analyses, which examine the extent to which any negative financial impacts from distributed PV may be mitigated through a set of regulatory and ratemaking measures. Finally, Section 7 offers a number of policy implications and identifies areas for further research. Additional details about modeling assumptions and results are included in the appendices.

Text Box 1. Key Boundaries of the Study Scope and Methods

Issues surrounding the impacts of customer-sited PV and net metering are complex, and discussions of these issues are invariably contentious. In the interest of ensuring that the findings from this analysis are interpreted and applied appropriately, we highlight a number of important boundaries of the study scope and methods.

- First, the study is not a detailed analysis of the value of PV. It relies on a financial model, not a utility production cost or planning model. This financial model contains a relatively high level of detail in its representation of utility ratemaking and revenue collection processes, but less detail in its representation of the physical utility system. As a result, the impacts of distributed PV on utility cost-of-service are based on a coarser set of assumptions than what might be possible with utility operations or planning models. For this reason, we include sensitivity analyses to examine how the financial impacts of PV would vary with alternate assumptions related to avoided costs.
- Second, the model, as configured for this study, captures financial effects at the utility level, not at the customer-class level. As such, we do not directly quantify cost-shifting or cross-subsidization among customer classes, although the modeled impacts on average retail electricity rates may, under many of the scenarios, be considered a proxy for the impacts on non-PV customers. Future follow-up analyses may explore participant/non-participant impacts more explicitly and in greater depth.
- Third, the analysis is focused narrowly on the financial impacts of customer-sited PV on utility shareholders and ratepayers when compensated under net metering. It does not analyze costs and benefits for customers with PV systems, or for society-at-large, and therefore does not consider costs that PV customers incur for their systems nor any broader social benefits (e.g., reduced emissions, economic development, energy security). By limiting the scope of our analysis to net-metered PV, we do not address potential impacts to utility shareholders or ratepayers that may occur under other compensation schemes, nor do we address the impacts that might occur under complete “grid defection”, whereby customers with PV and distributed storage bypass utility service entirely (RMI 2014).
- Fourth, the estimated impacts of customer-sited PV are based on comparisons to scenarios with no customer-sited PV. Thus, even though these impacts reflect an assumption of net metering, they should not be attributed to net metering, per se, as some amount of customer-sited PV deployment could occur even in the absence of net metering.
- Finally, we seek to understand how PV may impact two prototypical utilities along the spectrum of electric utility operating and regulatory environments in the United States. Although our sensitivity analyses capture a broader range of assumptions about utility operating and regulatory environments, we have by no means exhausted all possible combinations of conditions that utilities may face, and thus some care must be taken in generalizing from the results.

2. Model Description

For the present analysis, we used a *pro forma* financial model that calculates utility costs and revenues, based on specified assumptions about its physical, financial, operating, and regulatory characteristics (Figure 1). The model was adapted from a tool (the Benefits Calculator) initially constructed to support the National Action Plan on Energy Efficiency (NAPEE) and intended to analyze the financial impacts of EE programs on utility shareholders and ratepayers under alternative utility business models (NAPEE 2007). LBNL has since expanded and applied the enhanced model to evaluate the impact of aggressive EE programs on utilities in the U.S. (Cappers and Goldman, 2009a, 2009b; Cappers et al., 2010; Satchwell et al., 2011). Applications of the LBNL model and analysis of model outputs have been used as part of technical assistance to state public utility commissions (PUCs) considering aggressive EE goals and/or alternative utility business models (e.g., Arizona, Nevada, Massachusetts, and Kansas). The model has also been used to support the State and Local Energy Efficiency Action Network (SEEAction), which builds on the NAPEE effort, with analysis used in workshops and trainings. Through these various applications, the overall structure of the model has been reviewed and vetted by regulators, utility staff, and EE program administrators. We chose to use this model in order to connect the much more extensive analysis of the impacts of EE on utilities to the analysis of the impact of PV on utilities.

Within the remainder of this section, we provide a brief overview of the financial model used for the present analysis, first discussing how the model calculates utility costs and revenues and then describing how changes in costs and revenues are used to evaluate the impact of PV on three stakeholder metrics. The three metrics include two utility shareholder metrics (achieved ROE and achieved earnings) and one ratepayer metric (average retail rates).[8]

The model quantifies the utility's annual costs and revenues over a 20-year analysis period. Importantly, the model performs all calculations at the total utility level, and does not differentiate among rate classes or between PV participants and non-participants. Utility costs are based on model inputs that characterize current and projected utility costs over the analysis period. Some costs are projected using stipulated compound annual growth rates (CAGRs); other costs are based on schedules of specific investments (e.g., generation expansion plans). The costs cover several categories of the utility's physical, financial, and operating environment, including fuel and purchased power, operations and maintenance, and capital investments in generation and non-generation assets (i.e., transmission and distribution investments). The model calculates the utility's ratebase, which grows with additional capital investments and declines with depreciation of existing assets. The model also estimates interest payments for debt used to finance a portion of capital investments and includes taxes on earnings. The details of how we modeled our prototypical utilities' costs are in Section 3.

The utility's collected revenues are based on retail rates that are set in periodic general rate cases (GRCs) throughout the analysis period (see Figure 1). By default, the model assumes that rate

[8] Previous analysis with the same model included a second ratepayer metric: total customer utility bills. In this report, we report utility collected revenues, which is the same as total customer utility bills.

cases occur at some specified frequency, though the model also allows the utility to file a GRC when making capital investments of a certain amount or higher.

GRCs are used to establish new rates based on the revenue requirement set in a test year (including an authorized ROE for capital investments), the test year billing determinants (i.e., retail sales, peak demand, and number of customers), and assumptions about how the test year revenue requirement is allocated among the billing determinants. The model allows for different types of test years (i.e., historical test years, current test years, and future test years).[9] The particular rate design of the utility consists of a combination of a volumetric energy charge ($/kWh), volumetric demand charge ($/kW), and fixed customer charge ($/customer). Model inputs specify the relative size of those three rate components, and can be modified to represent different rate designs. The model used for this study did not have the capability to represent more complex rate designs, such as time-of-use (TOU) pricing or tiered (i.e., inclining or declining block) rates, though future versions of the model will possess that capability.

The rates established in a GRC are then applied to the actual billing determinants in future years to calculate utility collected revenue in those years. The model accounts for a period of regulatory lag whereby rates established in a GRC do not go into effect until some specified number of years after the GRC. In between rate cases, certain costs are passed directly to customers through rate-riders (e.g., fuel-adjustment clause [FAC]). Our average all-in retail rate metric, a measure of impacts from the utility customer perspective, reflects the average revenue collected per unit of sales which accounts for periodic setting of new rates, rate-riders, and delays in implementing new rates.

The financial performance of the utility is measured by the achieved after-tax earnings and achieved after-tax ROE, both of which are commonly used by utility managers and shareholders.[10] We calculated the prototypical utilities' achieved after-tax ROE in each year as the current year's earnings divided by current year's outstanding equity (i.e., the equity portion of the ratebase).[11] Achieved after-tax ROE may – and often does – differ from the utility's authorized ROE, which is established by regulators in a GRC and is used to determine the amount of return a utility can receive on its capital investments. This is because utility rates are set such that the test-year revenue requirement (based on the test year costs and billing determinants) would produce earnings that are sufficient to reach the authorized after-tax ROE. Actual utility revenues and costs may differ from those in the test year, leading to achieved earnings, and hence *achieved* ROE, that deviates from the authorized level. In general, achieved ROE will be less than authorized ROE if, between rate cases, utility costs grow faster than

[9] Many states allow the utility to file an adjustment to its historical test-year costs during a GRC (i.e., pro-forma adjustment period) to update and correct them to better reflect expectations about normal cost levels.
[10] ROE is considered to be a measure of how well a company is performing for its shareholders. While a high ROE typically indicates efficient use of shareholder's money, it is not always the case that a high ROE indicates a stable and profitable business. ROE is dependent on several factors, including the ratio of debt to equity which may artificially inflate a company's ROE if the company is making investments mostly with debt. ROE is also a useful metric when comparing companies within an industry, because the metric is normalized.
[11] The model does not take into account cash flow and changes in financing costs that may result from under- or over-recovery of costs, which may impact ROE.

revenues. Conversely, achieved ROE will generally be greater than authorized ROE if, between rate cases, utility costs grow slower than revenues.

We calculated the prototypical utilities' achieved after-tax earnings as collected revenues minus costs in each year. Similar to achieved after-tax ROE, achieved after-tax earnings can be different than the utility's authorized earnings, because the *achieved* earnings are based on actual profitability in a given year and the *authorized* earnings are set in the GRC revenue requirement, based on the authorized ROE.

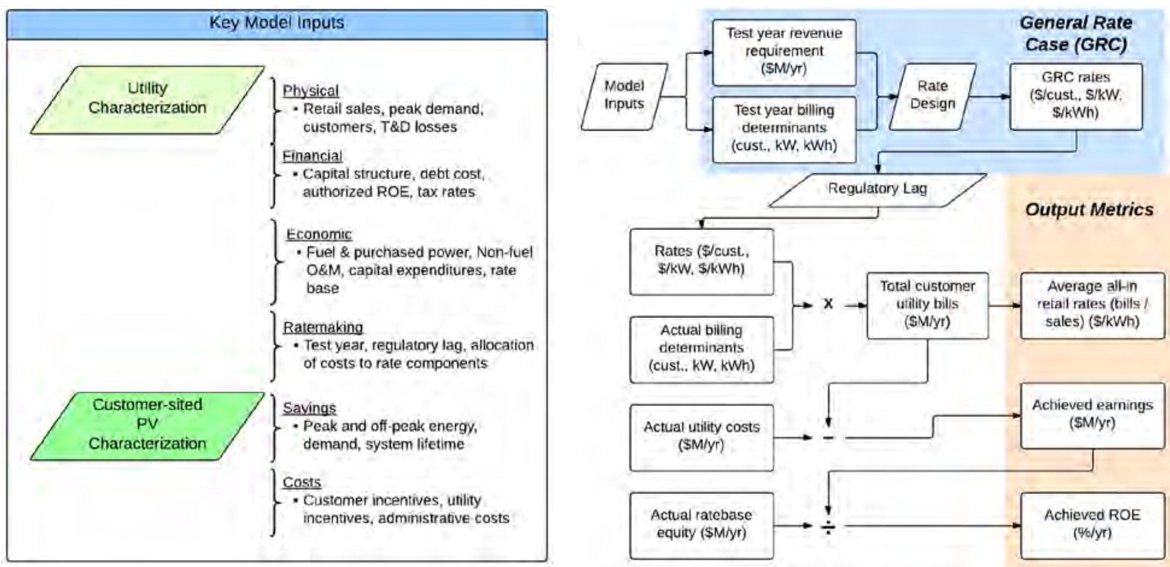

Figure 1. Simplified Representation of the Model and Calculation of Stakeholder Metrics

A key part of analyzing the impact of PV on utility profitability and customer rates is to capture how the addition of PV changes utility costs and billing determinants. In general, PV reduces fuel and purchased power costs, and it can also reduce utility costs related to ongoing and incremental capital expenditures (including return, depreciation, and taxes related to those capital expenditures). In terms of the impacts on billing determinants, PV reduces volumetric sales and customer peak demand, which reduces utility revenues collected on a volumetric basis through energy and demand charges. Changes to utility costs and billing determinants then flow through the model to calculate our key stakeholder metrics. We expand on our characterization of the impact of customer-sited PV on utility costs and billing determinants in Section 4.

Aside from the traditional cost-of-service business model, alternative regulatory mechanisms can also be implemented in the model. The model includes the ability to represent decoupling mechanisms (i.e., sales based or revenue-per-customer), lost revenue adjustment mechanisms, and shareholder incentive mechanisms. The model can also analyze alternative ratemaking approaches (e.g., high fixed customer charge) by changing the way utility revenues are collected among different billing determinants. We describe the intent and design of each of these and other alternatives in more detail in Section 6, where they are considered as options to mitigate the impact of PV on utility profitability.

3. Prototypical Utilities without Customer-Sited PV

Our analysis results are based on characterizations of two prototypical utilities: a vertically integrated utility in the southwest and a wires-only utility and default service supplier in the northeast (see Table 1). The choice of these two prototypical utilities was intended to capture both a broad spectrum of utility operating and regulatory environments, as well as two regions of the United States that have thus far seen the greatest levels of customer-sited PV deployment. In this section, we describe the key assumptions used to model these utilities (with further details included in Appendix A), and present 20-year projections of the utilities' costs (i.e., revenue requirements), average retail rates, collected revenues, shareholder earnings, and return on equity without PV. **These projections represent the base-case utility characterizations**; alternate assumptions about various aspects of the utilities' operating and regulatory environments are explored through the sensitivity analyses in Section 5.

Table 1. Prototypical Utility Characterization: Key Inputs

Key Input*	Southwest Utility	Northeast Utility
Utility type	Vertically integrated	Wires-only
Asset Ownership	Generation, Transmission, and Distribution	Distribution only
2013 Retail Sales Level (CAGR)	30,460 GWh (2.1%)	21,957 GWh (1.4%)
2013 Peak Demand Level (CAGR)	6,531 MW (2.1%)	5,655 MW (1.5%)
2013 Retail Customer Count (CAGR)	1,094,658 (2.7%)	1,239,682 (0.3%)
Average Fuel and Purchased Power Costs CAGR	5.6%	6.6%
Non-fuel Operations & Maintenance (O&M) Costs CAGR	2.6%	3.4%
2013 Ratebase (net accumulated depreciation)	$7.39B	$2.03B
RPS Compliance Strategy	Build & Buy	Buy
2013 All-in Retail Rate Level	11.34 ¢/kWh	12.82 ¢/kWh
Frequency of General Rate Case (GRC) Filings	Every 3 years**	Every 3 years
Regulatory Lag (i.e., period of time between filing of GRC and when new rates take effect)	1 year	1 year
Test Year	Historic	Historic
Authorized ROE	10.00%	10.35%
Debt and Equity Share (Ratio)	46%:54% (0.85)	57%:43% (1.32)
Weighted Average Cost-of-Capital (WACC)	8.33%	7.86%

* All monetary values and growth rates are expressed in nominal terms

** For the Southwest Utility, we assume that GRCs also occur after any capital investment exceeding $900M.

3.1 Southwestern vertically integrated utility

We developed long-range (i.e., 2013-2032) cost and load forecasts for the prototypical Southwestern Utility ("SW Utility") by starting with data originally provided by Arizona Public Service (APS) staff for a 2009 project (Satchwell et al. 2011) and then updated those forecasts based on information from the 2012 APS Integrated Resource Plan (IRP) and other recent regulatory filings. Various assumptions, like annual energy and peak demand growth, were then further modified in order to create a more generic prototypical southwestern utility. Thus, although data from APS were used to seed the initial utility characterization, ***the prototypical SW Utility used in this analysis is not intended to represent APS, specifically***. When modifying assumptions to reflect regionally representative data, we ensured that those changes were internally consistent with other input assumptions.

The SW Utility's costs and revenues are driven by, among other things, projected load growth, the utility's capacity expansion plan, compliance with the renewables portfolio standard (RPS), and rate design.[12] With respect to load growth, the SW Utility has retail sales of 30,460 GWh and a peak demand of 6,531 MW in 2013 (exclusive of any savings from PV), both of which are forecasted to grow at a compound annual rate of 2.1% per year over the 20-year time horizon. This load growth is representative of SW regional load forecasts (see Appendix A) and is lower than what APS forecasted in its 2012 IRP (i.e., 2.7% annual growth in energy and 2.7% annual growth in peak demand).

The SW Utility has a 2013 installed capacity of 4,797 MW of conventional generation, including nuclear, coal, mid-merit gas, and peaking gas units. The SW Utility also has existing and owned renewable generating capacity of 206 MW. The SW Utility purchases capacity through short-term capacity contracts to make up for a shortfall between the installed capacity and the peak load plus a 14% planning reserve margin. The SW Utility follows a generation expansion plan based on the APS 2012 IRP, which assumes incremental capacity additions, periodically adding additional peaking plants and additional mid-merit plants. No utility-owned generation is retired during the analysis period in the base-case, though we examine early retirements of coal generation in one of the sensitivity cases discussed in Section 5.

The SW Utility complies with a mandated RPS of 20% retail sales by 2025 through a combination of utility-owned renewable resources and renewable energy purchased power agreements (PPAs). We assumed an RPS requirement larger than the actual APS requirement to reflect more typical requirements of utilities in the southwest. Periodic investments in utility-owned renewable plants are assumed to each contribute 25 MW toward peak demand (e.g. firm capacity) and produce 219 GWh/year of renewable energy. Any remaining shortfall in the RPS requirement is met through signing new renewables PPAs at a contract price of $70/MWh. The amount of utility-scale solar added for the RPS (exclusive of customer-sited PV) varies from year to year, ultimately constituting roughly 6.5% of annual sales by 2022. Thus, the total penetration of solar from both utility-scale and customer-sited PV well exceeds the contribution from customer-sited PV alone.

The SW Utility revenue requirement allocation (i.e. the rate design) is based on typical APS customer bills from its 2011 rate case. The SW Utility collects revenues based on annual retail sales, peak demand, and number of customers. As noted previously, revenue requirements are allocated at the utility-level; we do not separately identify particular rate classes or revenue allocations thereof. Total non-fuel revenues are collected among billing determinants as follows: 16% from customer charges, 14% from demand charges, and 70% from energy charges. This percentage allocation holds constant throughout the analysis period. Total fuel and purchased power revenues are collected exclusively through energy charges, and the SW Utility is assumed to have a fuel adjustment charge (FAC) that allows all fuel and purchased power costs to be passed through to customers on an annual basis.

[12] Appendix A describes all input assumptions for the SW Utility.

The resulting SW Utility revenue requirement is $3.6B in 2013 and grows at 4.3% per year through 2032 (see Figure 2). Operations and maintenance (O&M) costs (inclusive of non-fuel O&M expenses from incremental capital expenditures) are the largest non-fuel cost component of the revenue requirement and grow at 2.6% per year from 2013 to 2032. Fuel and purchased power costs are the single largest component of the revenue requirement and grow at 5.6% per year during the 20-year analysis period.

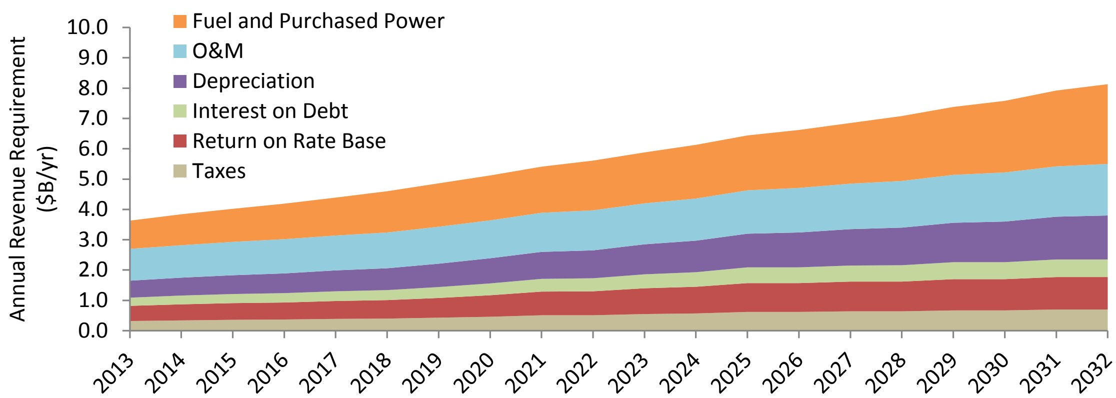

Figure 2. SW Utility Revenue Requirement

Since the SW Utility collects revenues based on its allocation among billing determinants (i.e., retail sales, peak demand, and number of customers), growth in utility collected revenues is tied to growth in billing determinants between rate cases. Non-fuel collected revenues are based on rates per billing determinant set during the SW Utility GRC. Due to assumed regulatory lag, these rates take effect one-year after the filing of a GRC. Figure 3 shows that non-fuel costs are *higher* than non-fuel collected revenues over the first half of the analysis period (prior to the addition of any customer-sited PV), due to the higher growth rate of non-fuel costs relative to growth in billing determinants. Non-fuel costs and revenues are better aligned in later years of the analysis period, because new generating investments in those years trigger more frequent GRC filings. SW Utility all-in average retail rates, reflecting fuel and non-fuel collected revenues, increase from 11 cents/kWh in 2013 to 18 cents/kWh in 2032 (2.5%/yr).

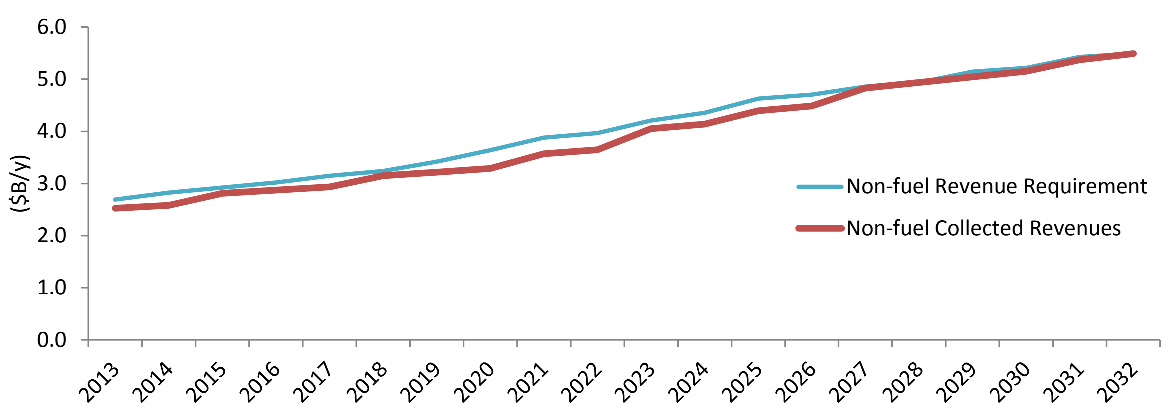

Figure 3. SW Utility Non-Fuel Collected Revenues and Non-Fuel Revenue Requirement

Text Box 2. A Note on Terminology: Fuel Costs vs. Non-Fuel Costs

Throughout this report, we distinguish between two broad categories of costs: fuel costs and non-fuel costs. When used within the context of this distinction, “fuel costs” refers to all costs that are fully passed through to customers, via annually adjusted FAC charges. These include (as applicable, depending upon the utility): fuel costs for utility-owned generation, all purchased power costs associated with long-term contracts and short-term purchases of energy and capacity, and transmission access costs. Within our analysis, utility shareholders are indifferent to fuel costs or any impact that customer-sited PV may have on these costs or the associated revenues.

“Non-fuel costs” simply refers to all remaining utility costs, which include both fixed and variable costs. These costs are recovered through retail rates established in GRCs based on test-year costs and billing determinants. We refer to revenues from those GRC-established rates as “non-fuel revenues.” Growth in those revenues between rate cases is a function of growth in the utility’s billing determinants (which, in our analysis, consist of retail sales, peak demand, and number of customers). Given the periodic nature of GRCs and the temporal lags therein, non-fuel costs and non-fuel revenues may not align with each other, which in turn affects utility earnings and ROE (either positively or negatively, depending on the direction of the misalignment). As discussed further, customer-sited PV impacts the relative growth rates of non-fuel costs and non-fuel revenues, and this is one of the key drivers for its utility shareholder impacts.

The utility achieves an average after-tax ROE of 8.0% from 2013-2022 and 8.4% from 2013-2032.[13] The utility’s achieved after-tax ROE is less than its authorized ROE of 10% in most years. Achieved after-tax earnings are $3.4B from 2013-2022 and $6.5B from 2013-2032.[14] Achieved after-tax earnings are also less than authorized earnings in most years of the analysis period (see Figure 4). “Under earning”, where levels of achieved earnings are less than authorized earnings, occurs because utility costs grow at a faster rate between rate cases than do billing determinants. The utility can increase earnings by either increasing sales or decreasing costs between rate cases. SW Utility earnings and ROE increase significantly in later years when the utility increases its ratebase equity through several generation investments. Those investments also trigger more frequent GRC filings, which in turn leads to more frequent rate increases, boosting revenue growth.

[13] We calculate average ROE on a levelized basis, using a discount rate equal to the utility’s weighted average cost of capital (WACC).
[14] We calculate earnings on a net present value (NPV) basis, using a discount rate equal to the utility’s WACC.

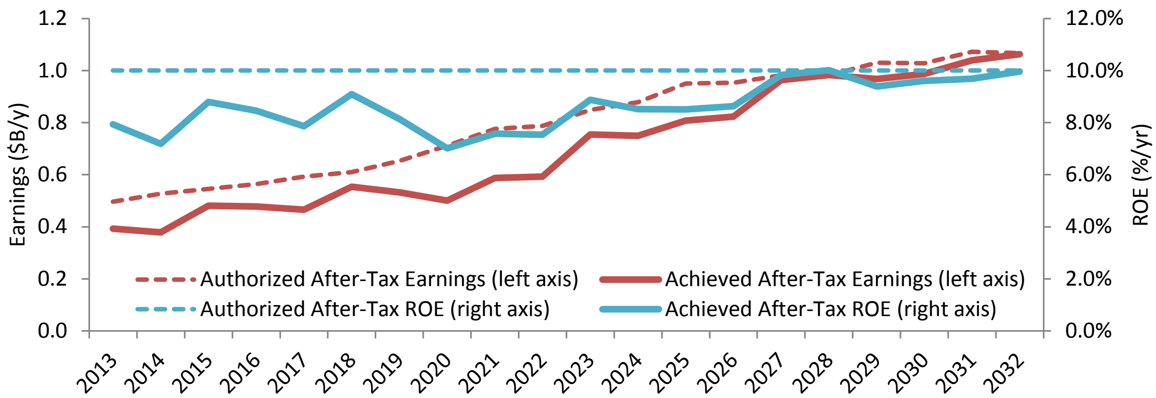

Figure 4. SW Utility Achieved and Authorized Earnings and ROE

3.2 Northeastern wires-only utility and default service provider

The prototypical Northeastern Utility ("NE Utility") is a "wires-only" utility in a restructured northeastern state, with substantially different asset ownership than the vertically integrated structure of the SW Utility. Specifically, the NE Utility owns and operates the distribution network, but does not own transmission or generation assets. The utility serves as the default supplier of generation service for customers within its distribution service territory, and all energy and generation capacity required to serve those customers is procured through market purchases.

We developed long-range (i.e., 2013-2032) cost and load forecasts for the prototypical NE Utility by starting with data provided by the Massachusetts Department of Public Utilities (DPU) for a 2009 project (Cappers et al., 2010), which are generally consistent with the Massachusetts Electric Company ("Mass Electric"). We then updated those data based on publicly available information from a 2009 rate case and FERC Form 1 data, and updated assumptions about current and future energy, capacity, and renewables prices using the 2013 Synapse Avoided Energy Supply Costs in New England (AESC) report. Thus, although data from Mass Electric were used to seed the initial utility characterization, ***the prototypical NE Utility used in this analysis is not intended to represent Mass Electric, specifically***.

The NE Utility's costs and revenues are driven by five key assumptions: the load forecast, growth in O&M costs, power supply costs, rate design, and compliance with an RPS.[15] First, the NE Utility has 2013 retail sales of 21,957 GWh and 5,655 MW of peak demand, which grow at 1.4% and 1.5% per year, respectively (exclusive the effect of PV). The retail sales and peak demand growth rates are lower than our assumptions for the SW Utility and are consistent with expected load growth in the northeast. The ISO-New England (ISO-NE) 2013 Regional System Plan forecasts 1.1% per year retail sales growth and 1.4% per year peak demand growth for the entire region through 2022.[16]

[15] Appendix A describes all input assumptions for the NE Utility

[16] ISO-NE 2013 Regional System Plan (p. 7). http://www.iso-ne.org/trans/rsp/index.html

Second, the NE Utility experiences O&M cost growth (including O&M costs from incremental generating plants) of 3.4% per year for the entire analysis period. This is higher than the SW Utility, which is assumed to experience O&M cost growth of 2.6% per year.

Third, we assume power supply costs (i.e., energy and capacity) and transmission access charges[17] are a pass-through to customers recovered through a "tracker" or bill "rider". The achieved revenues for these costs are therefore determined based on actual commodity costs each year, rather than on rates set during GRC. These power supply and transmission access costs are the largest component of the total NE Utility revenue requirement, ranging from 50% to 60% of total costs each year of the 20-year analysis period.

Fourth, similar to the SW Utility, we assume a revenue requirement allocation (i.e., rate design) for the NE Utility that is based on typical Mass Electric customer bills. We used the company's most recent cost-of-service and rate design studies to determine the percentages of total non-fuel revenues collected among energy, demand, and customer charges. Total non-fuel revenues are collected among billing determinants as follows: 23% from customer charges, 21% from demand charges, and 56% from energy charges, which are constant through the analysis period. All purchased power and transmission access charges are entirely collected from energy charges.

Fifth, the NE Utility complies with a mandated RPS obligation that starts at 8% of annual retail sales in 2013 and increases by 1% of annual retail sales each year of the analysis period (reaching 27% by 2032). The RPS obligation is met through the purchase of renewable energy credits (RECs), at an average price of $35/MWh. The RPS is also assumed to include a solar carve-out, wherein a small portion of the RPS is met with solar RECs, assumed for our purposes to consist of utility-scale solar. This utility-scale solar (which rises to 1.7% of retail sales by 2022) is additional to the customer-sited PV, though it is a substantially lower penetration of utility-scale solar than in the SW Utility.

The NE Utility revenue requirement is $2.2B in 2013 and grows at 5.7% per year through 2032. Default service customer supply costs and transmission access charges grow at 6.6% per year and are the largest component of the NE Utility revenue requirement. The revenue requirement does not include the power supply costs and transmission access costs associated with competitive suppliers who purchase power for non-default service customers (i.e., competitive supply customers), although those costs are included for reference in Figure 5.

[17] While we assume the NE Utility does not own and earn a return on transmission assets, there are instances where a "wires-only" utility may be part of a holding company that also owns and operates a separate transmission company (Transco). The Transco may be making investments in transmission assets which create earnings for the holding company. While customer-sited PV may impact the earnings of Transcos, they are outside the scope of the present analysis, which focuses only on the financial impacts to the regulated distribution utility.

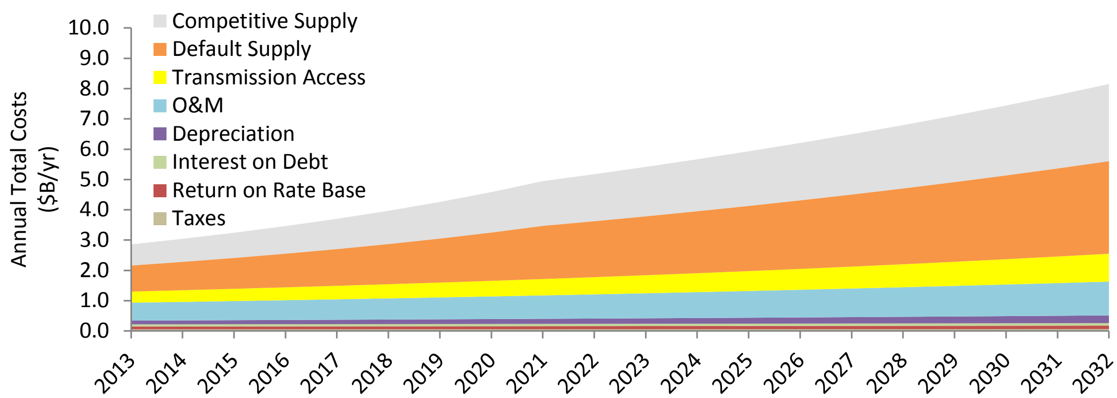

Figure 5. NE Utility Revenue Requirement

Similar to the SW Utility, the NE Utility collects revenues based on allocation among billing determinants (i.e., retail sales, peak demand, and number of customers), which ties growth in utility collected revenues to growth in billing determinants between rate cases. Non-fuel collected revenues are based on rates per billing determinant set during the NE Utility general rate case (GRC) and take effect one-year after the filing of a GRC. Figure 6 shows that non-fuel costs are *higher* than non-fuel collected revenues in all years of the analysis period, which occurs because those costs grow at a faster rate between rate cases than growth in billing determinants. NE Utility all-in average retail rates (that include fuel and non-fuel collected revenues) increase from 13 cents/kWh in 2013 to 28 cents/kWh in 2032 (4.2% per year).

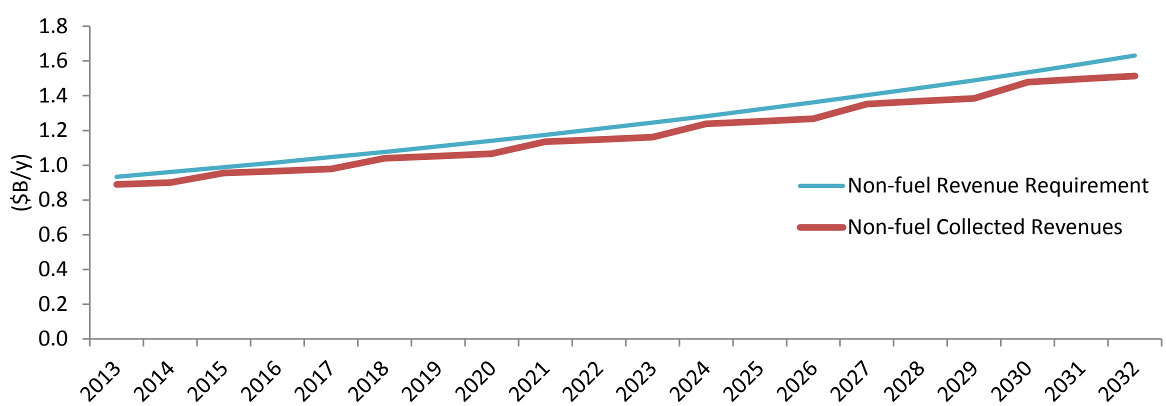

Figure 6. NE Utility Non-Fuel Collected Revenues and Non-Fuel Revenue Requirement

The NE Utility's achieved after-tax ROE and achieved after-tax earnings are below the authorized levels over the entirety of the analysis period (see Figure 7).[18] Specifically, the utility achieves an average after-tax ROE of 6.9% from 2013-2022 and 6.5% from 2013-2032, compared to its authorized ROE of 10.35%. Total achieved after-tax earnings are $461M over

[18] The "sawtooth" pattern of the annual achieved ROE and achieved earnings reflect the steady decline in both metrics during periods between each rate case, and then increases in both metrics in the year following each rate case, as rates are re-set to bring revenues and costs into closer accord.

the 2013-2022 period and are $681M over the full 20-year period from 2013-2032. Achieved earnings are less than authorized earnings for reasons similar to those discussed with respect to the SW Utility, though the gap is greater in the NE utility because of the greater underlying difference between the growth rates of non-fuel costs and non-fuel revenues. It is also worth noting that the NE Utility's earnings are 10-14% of the SW Utility's earnings, because the NE Utility does not build, own, and earn a return on generating assets under cost-of-service regulation.

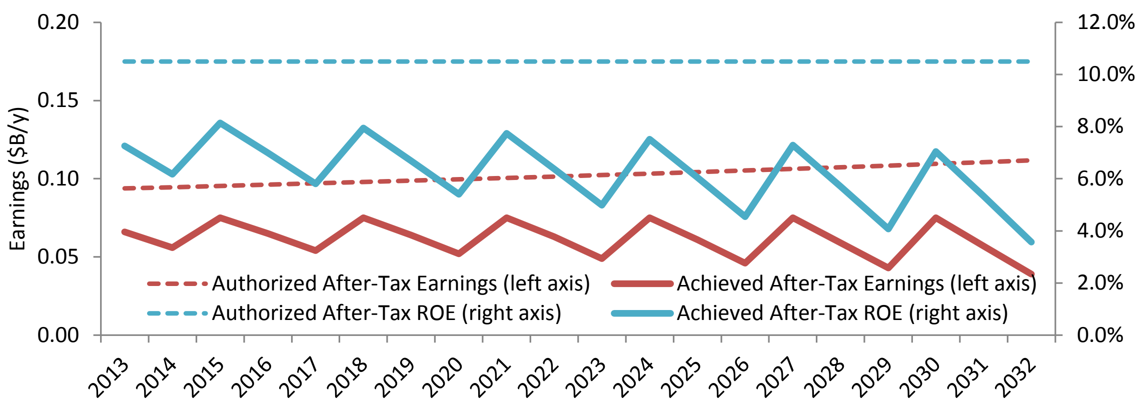

Figure 7. NE Utility Achieved and Authorized Earnings and ROE

4. Base Case Results: How does customer-sited PV impact utility shareholders and ratepayers?

This section characterizes the financial impacts of customer-sited PV on the two prototypical utilities, under our base case utility characterizations and at varying PV penetration levels. We begin by describing impacts of PV on the utilities' retail sales and peak demand, utility costs (i.e., revenue requirements), and utility collected revenues. We then describe utility shareholder impacts in terms of changes to achieved after-tax average ROE and achieved after-tax earnings, and describe ratepayer impacts in terms of changes to customer all-in average retail rates. This approach to modeling the financial impacts of PV, and the metrics used to measure those impacts, are largely analogous to those used in previous studies of the shareholder and ratepayer impacts of customer EE programs (Cappers et al., 2009a, Cappers et al., 2009b, Cappers et al., 2010 and Satchwell et al., 2011).

Importantly, the base case results should not be interpreted as representative of an "expected-case" scenario or as indicative of what any particular utility might experience. Rather, the purpose of the base case analysis is, first to provide a vehicle for explaining how changes in our modeled metrics (average retail rates and utility shareholder ROE and earnings) derive from the underlying impacts of customer-sited PV on utility revenues and costs, and how those impacts are related to the timing of GRCs. Second, the base case results serve as the reference point for the sensitivity analysis in Section 5 and the analysis of mitigation approaches in Section 6. Given these objectives, we primarily focus here on the *direction* of change in each metric; we largely defer discussion about the *size* of the impacts until the sensitivity analysis in Section 5, where the range in possible magnitude of the impacts can be appropriately framed within the context of utilities' regulatory and operating environments (and potential variations therein).

4.1 Customer-Sited PV Penetration Assumptions

Customer-sited PV adoption is a model input assumption. We specify annual capacity additions of customer-sited PV, such that the proportion of retail sales met by customer-sited PV grows linearly over the first 10 years of the analysis period (2013-2022). We examine four different PV penetration trajectories, which grow from 0% in 2012 to reach terminal penetration levels in 2022 equal to 2.5%, 5%, 7.5%, and 10% of customer sales.[19] Although the analysis period extends over 20 years, customer-sited PV is added only during the first 10 years in order to capture "end effects" (i.e., impacts on utility costs and revenues that occur in years beyond those when PV is added).

The assumed PV deployment rates, particularly in the case of 10% penetration, are aggressive compared to both current penetration levels and even to projected penetration levels over the next decade, at both state and national levels. As of year-end 2013, electricity generation from customer-sited PV in the United States was equivalent to 0.2% of total U.S. retail electricity

[19] In addition to customer-sited PV, some amount of utility-scale PV is also assumed for both of the two prototypical utilities, as described in Section 3.

sales, and was as high as 4% of retail sales in Hawaii and 1-2% in the next two largest state solar markets (New Jersey and California). Current penetration rates for individual utilities, or for residential customer classes, may be higher. In Hawaii, penetration of customer-sited PV has reached 5.1% to 6.0% of retail sales among the three investor-owned utilities, and 10-15% for residential customer classes. Outside of Hawaii, the highest utility-level penetration rates are in California, where total customer-sited PV generation has reached 2.3% of total retail sales (and 3.0% of residential retail sales) in Pacific Gas & Electric's service territory.

Projecting future growth in customer-sited PV is a highly speculative exercise. If one were to simply extrapolate average growth rates from the past five years, customer-sited PV penetration in 10 years would reach 0.8% of total U.S. retail electricity sales, and 3-5% in the largest state markets (excluding Hawaii, which would reach 20%). Projections from EIA's most recent Annual Energy Outlook anticipate lower growth in customer-sited PV, with total generation from end-use PV reaching roughly 0.6% of total U.S. retail electricity sales over 10 years (EIA 2014), while forecasts from GTM and SEIA project slightly faster growth, with residential and commercial PV penetration reaching almost 0.8% of U.S. retail sales in just four years, by 2017 (GTM/SEIA 2014). As a final point of comparison, customer adoption modeling conducted for the SunShot Vision study, which considered a 75% reduction in PV costs from 2010 to 2020, projected 3% penetration of customer-sited PV in the Northeast (or 1-8% among individual states in the region) and 7% penetration in the Southwest (with penetration levels of 3-11% among individual states) by 2030 (DOE 2012).

4.2 Impacts on Retail Sales and Peak Demand

The utilities' retail sales and peak demand with and without customer-sited PV are shown in Figure 8 for the SW and NE utilities, under the 10% PV penetration scenario. Throughout this analysis, we assume that all customer-sited PV is net-metered, with no binding limits on the amount of excess generation that can be carried over from billing period to the next. PV generation therefore reduces sales on a one-for-one basis; the difference between retail sales with and without PV thus grows proportionally with the linear growth in PV penetration over the first 10 years and then remains constant thereafter. PV generation does not, however, reduce peak demand on a one-for-one basis, but rather each kW of PV capacity reduces customer peak demand by less than one kW, because the timing of maximum PV output does not coincide perfectly with customer peak demand. Moreover, the marginal impact of PV on peak demand declines as PV penetration levels grow over the first 10 years, as the timing of the net system peak progressively shifts to early evening periods with lower solar power generation. For simplicity, we assume that the reduction in aggregate customer billing demand from PV is equivalent to the reduction in utility-wide peak demand.[20] Further details of how we model the reduction in peak demand with deployment of PV are described in Appendix B.

[20] In practice, customer peak demand used for billing of demand charges is often not the same as the customer's coincident peak demand. However, given the complexity and variety of demand charge structures, and limitations of the model, we make the simplifying assumption that the change in aggregate billing demand is equal to the change in utility peak demand.

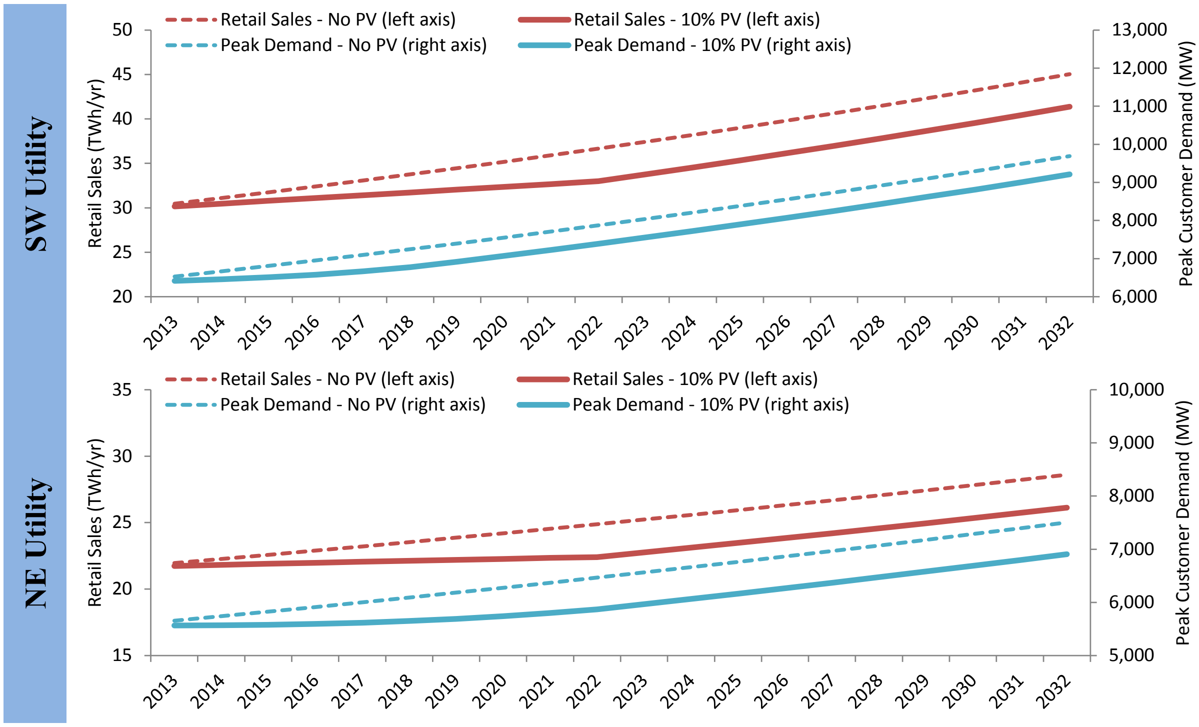

Figure 8. Utility Retail Sales and Peak Demand with and without PV Assuming 10% PV Penetration in 2022

4.3 Impacts on Utility Costs

The impact of customer-sited PV on utility costs (i.e., the revenue requirement) is a function of the changes in retail sales and peak demand described above, as well as a variety of other assumptions. The manner in which those cost impacts are modeled differs somewhat between the two prototypical utilities. We provide a high level overview of how these cost impacts are modeled for the base case analysis and describe the resulting change in total utility costs here, with additional details provided in Appendix B. Alternate assumptions related to these cost impacts are explored through the sensitivity analyses in Section 5, which includes both "high value of PV" and "low value of PV" scenarios.

The utility financial model calculates the utility revenue requirement as the sum of the six cost categories described previously (i.e., fuel and purchased power, O&M, depreciation, interest on debt, return on ratebase, and taxes). For the purpose of explaining how customer-sited PV affects revenue requirements, however, it is useful to describe the impacts in terms of the underlying changes to generation-related costs and transmission and distribution (T&D) costs.

4.3.1 Modeling the Impacts on Generation Costs

For the vertically integrated SW Utility, reductions in generation costs due to customer-sited PV are associated with reductions in fuel costs and purchased power costs, as well as the deferral of generation investments (including O&M costs associated with those deferred generation investments).[21] Fuel and purchased power costs, and the change in those costs due to customer-sited PV, are based on simplified dispatch logic. Deferrals of peaking plants (e.g., combustion turbines) are based on the number of years it takes before the peak demand with PV reaches the level of peak demand without PV for the year when the decision to build the generator would otherwise occur (see Figure 9). Similarly, deferrals of plants built primarily to supply energy (e.g., combined cycle gas turbines) are based on the number of years it takes before the sales with PV reaches the level of sales without PV for the year when the decision to build the generator would otherwise occur. Deferral of generation investment leads to reductions in depreciation costs, interest expenses (i.e., cost of debt to finance the generating plant), utility shareholder returns on the capital investment, and taxes (assessed on the shareholder returns). We refer to utility earnings foregone as a result of deferral of capital investments as the "lost earnings opportunity" effects of PV.

In addition to deferral of utility-owned generation, customer-sited PV also reduces market purchases of energy and capacity to meet residual load needs, as well as PPAs with renewable generators required to meet the utility's RPS obligation.[22] Those cost reductions are included within the model as purchased power costs. The reduction in RPS compliance costs occurs because customer-sited PV is reducing retail sales, not because it is being counted directly towards RPS obligations (though that possibility is considered within the mitigation measures evaluated within Section 6).

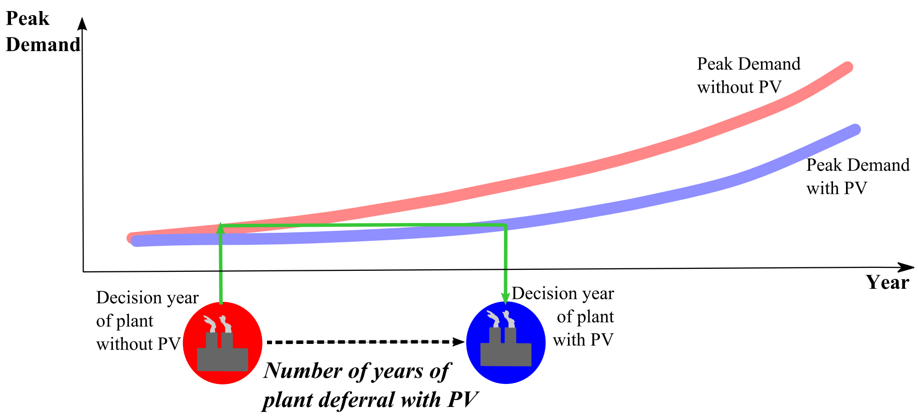

Figure 9. Illustration of the Peaker Generation Investment Logic with PV in the Model

In contrast to the SW Utility, the NE Utility does not own generating assets and is assumed to purchase all of its energy and capacity needs through wholesale contracts. Thus, generation-related costs reduced by the addition of PV consist entirely of purchased power costs for energy

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[21] We do not include any explicit "integration costs" associated with short-term variability and uncertainty of PV, though we do account for a decline in its capacity credit and energy value with increased penetration. The costs of short-term variability and uncertainty have been reported to be less than 0.5 cents/kWh of renewable generation for APS (B&V 2012, Mills et al. 2013) and are therefore of secondary importance. Accounting for these integration costs would thus lead to a slight increase in estimated rate impacts of customer-sited PV, but no change to earnings and ROE, given that they consist of fuel costs that are passed through directly to customers in the FAC.

[22] A portion of the SW Utility's RPS obligation is assumed to be met with utility-owned renewable generation facilities; however, renewable PPAs are assumed to be the marginal RPS resource.

and capacity. For RPS compliance, the NE Utility purchases fewer renewable energy credits to meet the RPS with PV than without PV, based on the retail sales reduction.

Note also that the impacts of PV on generation-related costs are based on reductions in sales and peak demand at the bulk power system level. Since customer-sited PV is located at the customer premises, reductions in sales and peak demand at the bulk power system level are greater than at the customer level due to avoided T&D losses. For the SW Utility, T&D losses are assumed to be 7% and 15% for retail sales and peak demand, respectively, and for the NE Utility, are assumed to be 4.1% and 8%, respectively.[23]

4.3.2 Modeling the Impacts on T&D Costs

Here we describe the base-case assumptions related to the impacts of customer-sited PV on T&D costs, but note in advance that this is a topic of substantial uncertainty and disagreement, and for that reason it is one key element explored within the sensitivity analysis in Section 5.

For the SW Utility, T&D capital costs are modeled as non-generation capital investments, and a fraction of those investments (20%) is assumed to be proportional to growth in peak demand on the T&D system. In the base-case, we assume that PV reduces peak demand at the T&D level by 20% of the reduction in peak demand at the bulk power level. The corresponding reductions in T&D peak demand growth thereby reduce growth-related non-generation capital investments, resulting in reductions in depreciation expenses, shareholder returns on those investments, interest expenses, and taxes. For the base-case analysis, we assume therefore that customer-sited PV leads to a net reduction in distribution system capital expenses. Within the sensitivity analyses, however, we consider a case in which distribution costs *increase* as a result of PV.

For the NE Utility, the model treats transmission costs differently than distribution costs. The NE Utility does not own transmission facilities, but rather purchases transmission service from a regional transmission operator (ISO-NE) and passes those costs through to customers via a transmission access charge. Transmission charges are included in the model as a portion of purchased power costs and are calculated based on the average monthly peak demand of the utility. We assume that customer-sited PV reduces average monthly peak demand by 20% of the reduction in annual peak demand, leading to corresponding reductions in the portion of purchased power costs associated with transmission access charges.[24] In contrast, the NE Utility does own and operate distribution facilities, and distribution costs are therefore modeled as a capital investment, some portion of which is growth related (33%). Similar to the approach used to model T&D cost impacts for the SW Utility, the addition of PV reduces growth-related distribution system capital expenses for the NE Utility, leading to corresponding reductions in returns on ratebase, depreciation expenses, interest, and taxes.

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[23] Losses for peak demand are greater than average losses due to the non-linear relationship between load levels and losses (Lazar and Baldwin 2011).

[24] The 20% assumption is based on an analysis of hourly load and PV generation in the Northeast over the span of one year.

4.3.3 Total Reduction in Utility Costs

Given the modeled relationships described above, the total reductions in utility costs (i.e., revenue requirements) resulting from customer-sited PV in the base-case analysis are shown in Figure 10, with further details on the underlying source of cost reductions listed in Table 2. For the SW Utility, customer-sited PV reduces total utility costs over the 20-year analysis period by \$0.7 B (1.3% of total utility costs) under 2.5% PV penetration and by \$2.2B (4.0% of total utility costs) under 10% PV penetration, compared to a case without any customer-sited PV. Similarly, for the NE Utility, the cost reductions range from \$0.8B (1.5% of total utility costs) at 2.5% PV penetration to \$2.3B (4.5% of total utility costs) at 10% PV penetration. As shown in the figure, the composition of the cost reductions differs significantly between the two utilities due to differences in the two utilities' physical and operating characteristics, with important implications for the shareholder and ratepayer impacts, as discussed below.

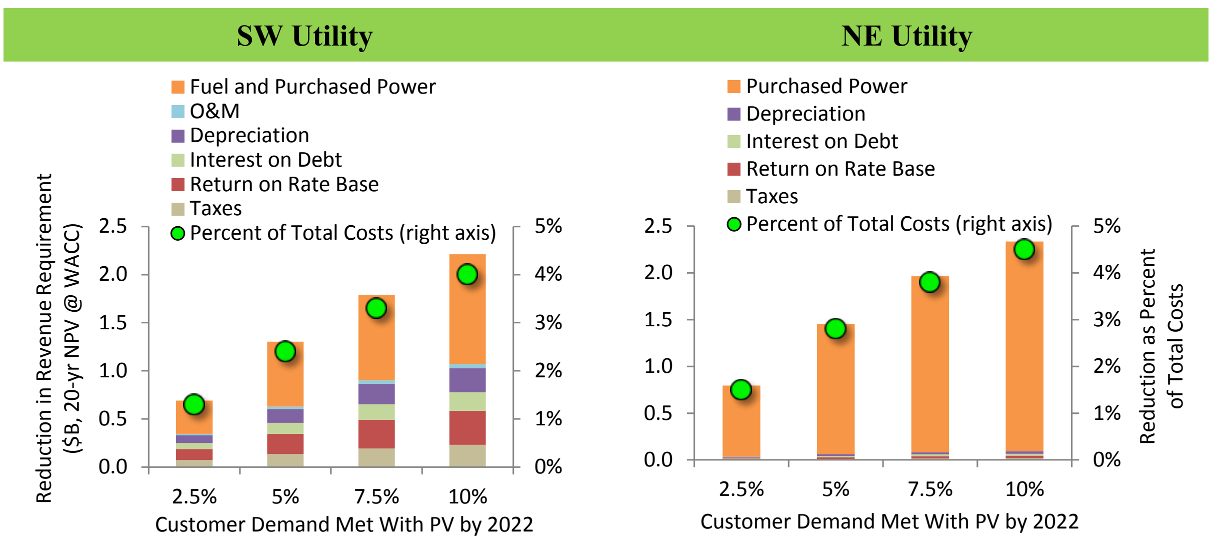

Figure 10. Reduction in Utility Revenue Requirements with Customer-Sited PV

Table 2. Sources of Modeled Reductions in Utility Costs from Customer-Sited PV

Cost Category	SW Utility	NE Utility
Fuel & Purchased Power	• Reduced fuel costs for utility-owned generation • Reduced energy and capacity market purchases and PPAs • Reduced RPS procurement costs • Reduced losses	• Reduced energy and capacity market purchases • Reduced transmission access charges • Reduced RPS procurement costs • Reduced losses
O&M	• Reduced O&M due to deferred utility-owned generation	• None
Depreciation Interest on Debt Return on Ratebase	• Deferred utility-owned generation • Reduced T&D CapEx	• Reduced distribution system CapEx
Taxes	• Deferred utility-owned generation • Reduced T&D CapEx • Reduced collected revenues	• Reduced distribution system CapEx • Reduced collected revenues

4.3.4 Implied Avoided Cost of PV

Discussions about the costs and benefits of customer-sited PV often rely on estimates or assumptions about the "avoided costs" from PV (often used interchangeably with the term "value of PV"), which is simply the reduction in costs resulting from customer-sited PV, per unit of customer-sited PV generation. Such avoided costs may be construed broadly at the societal level, or more narrowly by considering only reductions in costs for the utility, which would typically include the impact of PV on different utility cost components (e.g., energy, generation capacity, T&D capacity, losses).

For the purpose of comparison between our results and other estimates of avoided costs from customer-sited PV, we map the cost reductions from customer-sited PV estimated within our analysis to the categories often used in avoided cost calculations (see Figure 11). The simple calculations used to parse avoided costs into these categories become much more difficult when accounting for the deferral of "lumpy" investments like new generation plants. For simplicity, we conduct these approximations for 2018, the latest year before PV begins to displace lumpy investments for the SW Utility. To be clear, these avoided cost values should be considered simply for benchmarking purposes; the financial model used for this analysis does not, itself, distinguish among the specific set of cost categories in Figure 11, and more generally, the model does not contain the level of granularity in modeling the physical impacts of customer-sited PV on utility systems to be considered a refined, independent estimate of avoided costs. Additional details describing the methods used to approximate the breakdown of the value of PV are provided in Appendix B.

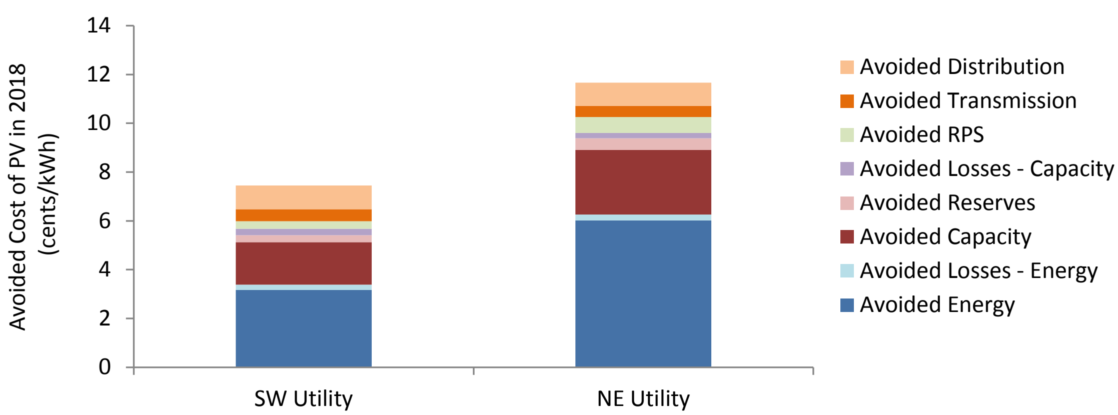

Figure 11. Estimated Avoided Costs in 2018 for the SW and NE Utilities (6% PV Penetration)

For the specific year shown, the total avoided cost value of PV is equal to 7.5 cents/kWh for the SW utility and 11.7 cents/kWh for the NE utility. For both utilities, avoided energy costs are the largest component, followed by avoided capacity costs and avoided distribution costs. These sources of avoided costs are augmented by: avoided transmission costs; reductions in the cost of planning reserves, which are based on a percentage of peak demand; avoided costs related to losses, which impact both the amount of energy purchased and the amount of generation capacity needed to meet peak demand and reserves; and avoided RPS procurement costs, resulting from the reduction in retail sales and corresponding reduction in RPS obligations (which are set as a percentage of sales).

Avoided costs are higher for the NE Utility than the SW Utility, primarily due to differences in the value of avoided energy costs and the value of avoided capacity costs. Avoided energy costs are higher for the NE Utility due to higher expected energy prices in the Northeast (primarily from natural gas) relative to the fuel costs for the SW Utility (a mix of gas and coal). The capacity value is higher for the NE Utility due to two factors: (1) customer-sited PV contributes slightly more to meeting peak demand due to the lower overall PV penetration from both utility-scale and distributed PV, compared to the SW utility; and (2) PV in the Northeast generates less energy than in the Southwest, leading to a higher capacity value in $/kWh terms in the Northeast.

As shown previously in Figure 10, reductions in utility costs from customer-sited PV do not scale in proportion to the PV penetration level, but rather exhibit diminishing returns. To more clearly illustrate this point, we plot the avoided cost per unit of PV energy, averaged over the full 20-year analysis period, for each PV penetration level considered (see Figure 12). For both the SW and NE utilities, the avoided cost of PV (per unit of PV energy) declines with increasing penetration levels. Specifically, the average value of PV for the SW Utility declines from 10.3 cents/kWh under the 2.5% penetration scenario to 8.5 cents/kWh under the 10% penetration scenario; for the NE Utility, it declines from 15.8 cents/kWh to 12.3 cents/kWh. The decline in avoided cost with increasing penetration is due to a decline in the contribution of PV to meeting peak demand (peak demand shifts into the early evening with higher PV penetration) and a decline in the cost of energy displaced by PV (PV begins to displace more efficient plants or plants with lower cost fuels). For reference, we also include the average cost of energy per unit of sales in the scenario without PV. This comparison shows that the reduction in utility costs from customer-sited PV is less than the average cost of generating and delivering electricity for both the SW and NE utility in this base-case analysis, and that this gap grows with PV penetration level.

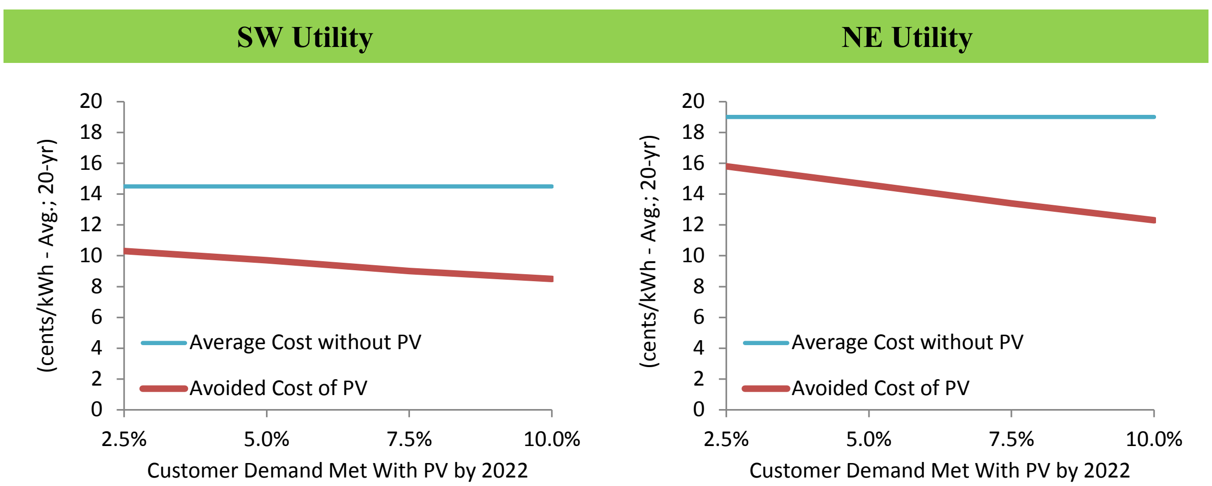

Figure 12. Avoided Cost of PV at Varying Penetration Levels and Average Cost without PV

4.4 Impacts of PV on Collected Revenues

All customer-sited PV within our analysis is net-metered under the same retail rates applicable to other customers, and without any PV-specific charges (e.g., additional fixed charges or standby charges for PV customers). The impacts of customer-sited PV on total utility collected revenues are thus a function of changes in billing determinants and in the rates for each billing determinant caused by PV. The change in billing determinants is simply the reduction in retail sales and peak demand, as described in Section 4.2, while the change in rates reflects the net effect of customer-sited PV on test-year costs (i.e., revenue requirements) and billing determinants used within each GRC.

Customer-sited PV reduces revenues related to both fuel costs and non-fuel costs (see Text Box 2 for explanation of this distinction). For the purpose of understanding how these revenue impacts ultimately translate to impacts on shareholder ROE and earnings, it is most useful, however, to focus specifically on impacts to non-fuel revenues. To illustrate, Figure 13 compares reductions in non-fuel revenues under each PV penetration scenario to the corresponding reductions in non-fuel costs. In the case of the SW Utility, the impacts on revenues and costs are roughly equivalent under the 2.5% PV penetration scenario. At higher PV penetration levels, however, reductions in non-fuel revenues exceed reductions in non-fuel costs. This occurs, in part, because of the declining marginal value of PV as penetration levels increase, as discussed in Sections 4.3.4. For the NE Utility, the divergence between reductions in non-fuel revenues and non-fuel costs is substantially wider. This is because of the greater assumed growth rate in non-fuel O&M costs for the NE Utility, as indicated previously in Table 1, and the assumption that those costs are not reduced as a result of customer-sited PV.

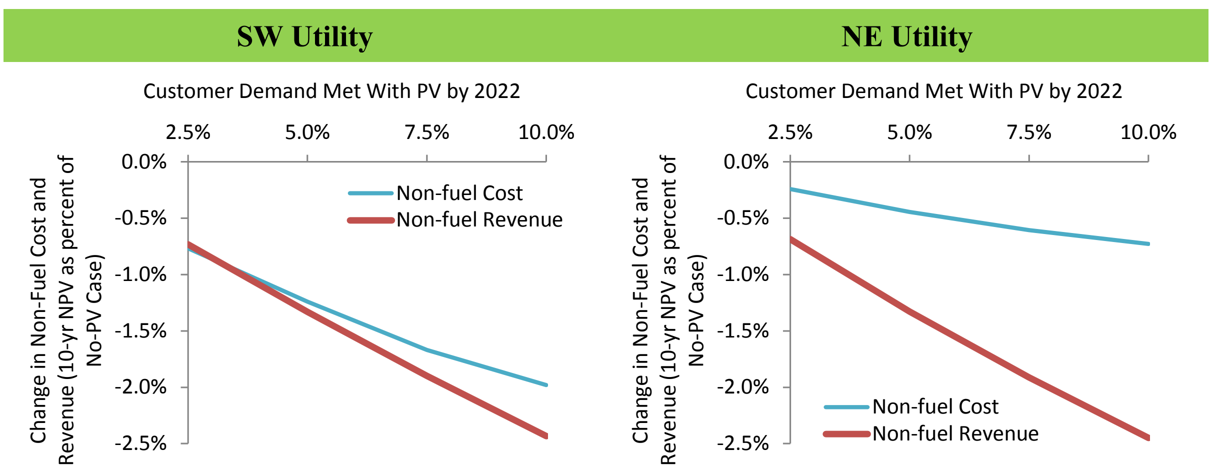

Figure 13. Reduction in Utility Non-Fuel Revenue Requirements (Costs) and Collected Revenues

4.5 Impacts of PV on ROE

Under our base-case assumptions, customer-sited PV leads to a reduction in the prototypical utilities' achieved ROE. This occurs because, as discussed in the preceding section, PV reduces collected non-fuel revenues by a greater amount than non-fuel costs (i.e., "revenue erosion effect"), which in turn reduces earnings and thereby reduces ROE. Importantly, even without PV, the utilities' achieved ROE is below their authorized ROE, because the utilities' costs grow faster than their revenues, as described earlier in Section 3. The addition of customer-sited PV exacerbates those underlying conditions, leading to further erosion of ROE. As discussed later in Section 6, there are several mechanisms (e.g., revenue decoupling) designed to reduce and/or remove the negative impact that reductions in sales growth, such as those caused by customer-sited PV, may have on shareholder ROE.

For the SW Utility, achieved average ROE over the first 10 years of the analysis period is 2 basis points lower at 2.5% PV penetration and 23 basis points lower at 10% PV penetration than it is without PV (see Figure 14). These basis point reductions represent, in relative terms, a 0.3% to 2.9% reduction in average utility shareholder returns over the first 10 years. For the NE Utility, the ROE impacts are somewhat more substantial, with a 32 basis point (4.7%) reduction at 2.5% PV penetration and a 125 basis point (18.1%) reduction at 10% PV penetration, relative to the no-PV case.

The larger ROE impacts for the NE Utility are due to two underlying factors. The first factor can be traced back to the greater assumed growth rate in non-fuel O&M costs for the NE Utility, which in turn leads to a greater divergence between the impact of customer-sited PV on non-fuel revenues and non-fuel costs (i.e., the dynamic discussed in relation to Figure 13). The other key factor underlying the difference in ROE impacts between the two utilities is the proportionally smaller ratebase (compared to retail sales) of the wires-only NE Utility, as that utility does not own generation assets. A given reduction in earnings will therefore have a proportionately larger ROE impact for the NE Utility, as ROE is equal to earnings divided by the ratebase equity.

The ROE impacts over the full 20-year analysis period are, in the case of the NE Utility, slightly smaller than the average impacts over just the initial 10 years. This is to be expected, as ROE impacts from customer-sited PV are driven chiefly by its effects on the relative growth of non-fuel costs and non-fuel revenues, and that impact occurs primarily during the initial 10 years when PV penetration is growing. In the latter 10 years, the relative growth of fuel costs to non-fuel revenues reverts largely back to the relationship that would have existed in the absence of any customer-sited PV. In contrast, for the SW Utility, the 20-year ROE impacts are slightly larger, but more irregular, than the average impacts over the initial 10 years. This phenomenon is an artifact of the irregular timing of large, lumpy capital expenditures – and the GRCs triggered by those expenditures – over the course of the 20-year analysis period. Notwithstanding those complexities, largely confined to the SW Utility in our analysis, the impacts of PV on achieved annual ROE are, in general, concentrated primarily within the initial 10 years of the analysis period and are more readily interpretable for that timeframe. Thus, throughout the remainder of this report, our discussions of ROE impacts focus solely on the first 10 years of the analysis period (though we continue to discuss earnings and rate impacts over the full 20-year period).

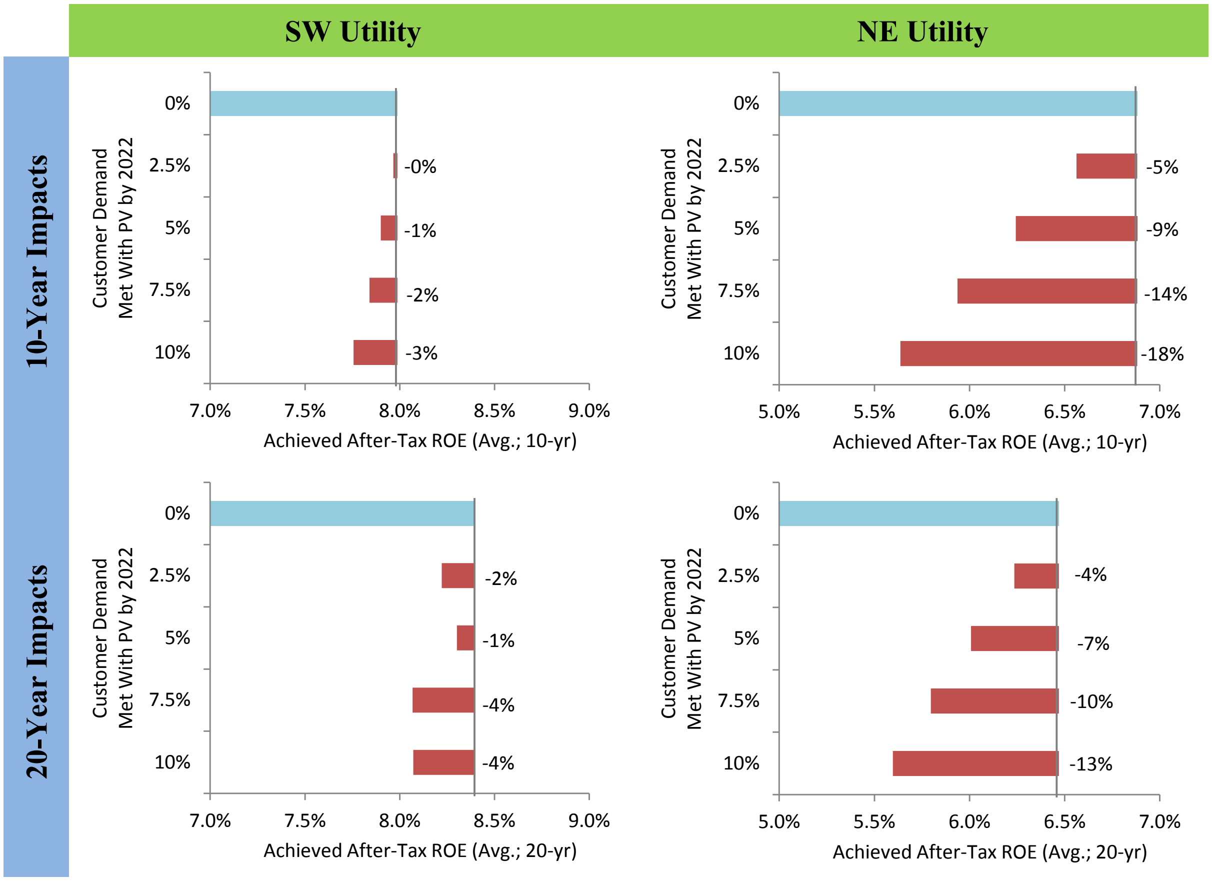

Figure 14. Reduction in Achieved After-Tax ROE

4.6 Impacts of PV on Earnings

Customer-sited PV may reduce shareholder earnings through two separate mechanisms. First, it can do so if it reduces utility revenues by a greater amount than it does costs (i.e., the "revenue erosion effect" that also drives the impacts on ROE). Second and separately, customer-sited PV may also diminish future earnings opportunities, by reducing or deferring capital investments that would otherwise contribute to the utility's ratebase (which we term the "lost earnings opportunity effect").[25] As will be explored further in Section 6, a variety of potential mechanisms exist for mitigating earnings erosion, including a number mechanisms that specifically seek to provide the utility with additional earnings opportunities.

[25] An increase in earnings is valuable to shareholders only if the return on future investments is greater than the cost of equity (see Koller et al., 2010), which presently would be the case for most utilities. The prototypical NE Utility in our analysis, however, may present a case in which the ROE of future investments may not cover the cost of equity, in which case the deferral of future capital investments would benefit shareholders. A cost of equity test is beyond the scope of this study. See Kihm et al. (2014) for the motivations of a utility to invest in capital in a future with increased EE and PV when returns on future investments are greater or less than the cost of equity.

Figure 15 shows the base-case earnings impacts for both utilities, across the range of PV penetration levels considered and over multiple timeframes. As to be expected, earnings impacts increase with PV penetration. For the SW Utility, achieved earnings over the first 10 years are $48M (1.4%) lower at 2.5% PV penetration, compared to the case with no PV, growing to $193M (5.7%) lower at 10% PV penetration. For the NE Utility, earnings over the first 10 years are reduced by $25M (5.5%) at 2.5% PV penetration and by $93M (20.2%) at 10% PV penetration. The earnings impacts are greater, on a percentage basis, than the impacts to ROE, given the additional effect of lost earnings opportunities.[26] This is especially true for the SW Utility (e.g., 2.9% reduction in ROE vs. 5.7% reduction in earnings over the first 10 years), where the potential for deferral of utility-owned generation facilities leads to relatively large lost earnings opportunities.

Additional earnings erosion occurs over the latter half of the 20-year analysis period, as deferral of capital investments continues beyond the initial 10-year period when customer-sited PV is installed. These "end-effects" are particularly pronounced in the case of the SW Utility, where PV results in deferral of generation plants in the latter 10 years (see Figure 16). Thus, at 10% PV penetration, achieved earnings over the full 20-year analysis period are $528M (8.1%) lower than with no PV, compared to the $193M (5.7%) reduction over the first 10 years, as noted above. For the NE Utility as well, additional earnings erosion occurs in years 11-20, though to a much more limited extent, given that the utility does not own generation and thus the only deferred capital expenditures are for distribution system investments. At 10% PV penetration, for example, achieved earnings by the NE Utility are reduced by 20.2% in the first ten-years, but only 15.4% over the full 20 years of the analysis period.

As with the impact of PV on achieved ROE, we see that the impact of PV on earnings, in percentage terms, is larger for the NE Utility than for the SW Utility, though the difference between the two utilities is not as large. As noted, the impact of customer-sited PV on achieved earnings is the combined result of the "revenue-erosion effect" (associated with the disproportionately larger reduction in collected revenues than in utility costs) and the "lost earnings opportunity" effect (associated with the deferral of capital expenditures). The former effect is larger for the NE Utility than for the SW Utility; as discussed previously, this is due to the larger assumed growth in non-fuel O&M costs for the NE Utility and the assumption that customer-sited PV does not reduce those costs. In contrast, the latter "lost earnings opportunity" effect is larger for the SW Utility, given that the SW Utility owns generation plants that are deferred by customer-sited PV. On net, though, the difference between the two utilities is greater with respect to the revenue erosion effect, and thus the earnings impacts are slightly greater for the NE Utility.

[26] The larger percentage impacts on earnings can also be explained mathematically: ROE equals earnings divided by the equity portion of the utility's ratebase. Customer-sited PV reduces earnings (the numerator) as well as the ratebase (the denominator), and thus the percentage reduction in ROE must necessarily be smaller than the percentage reduction in earnings.

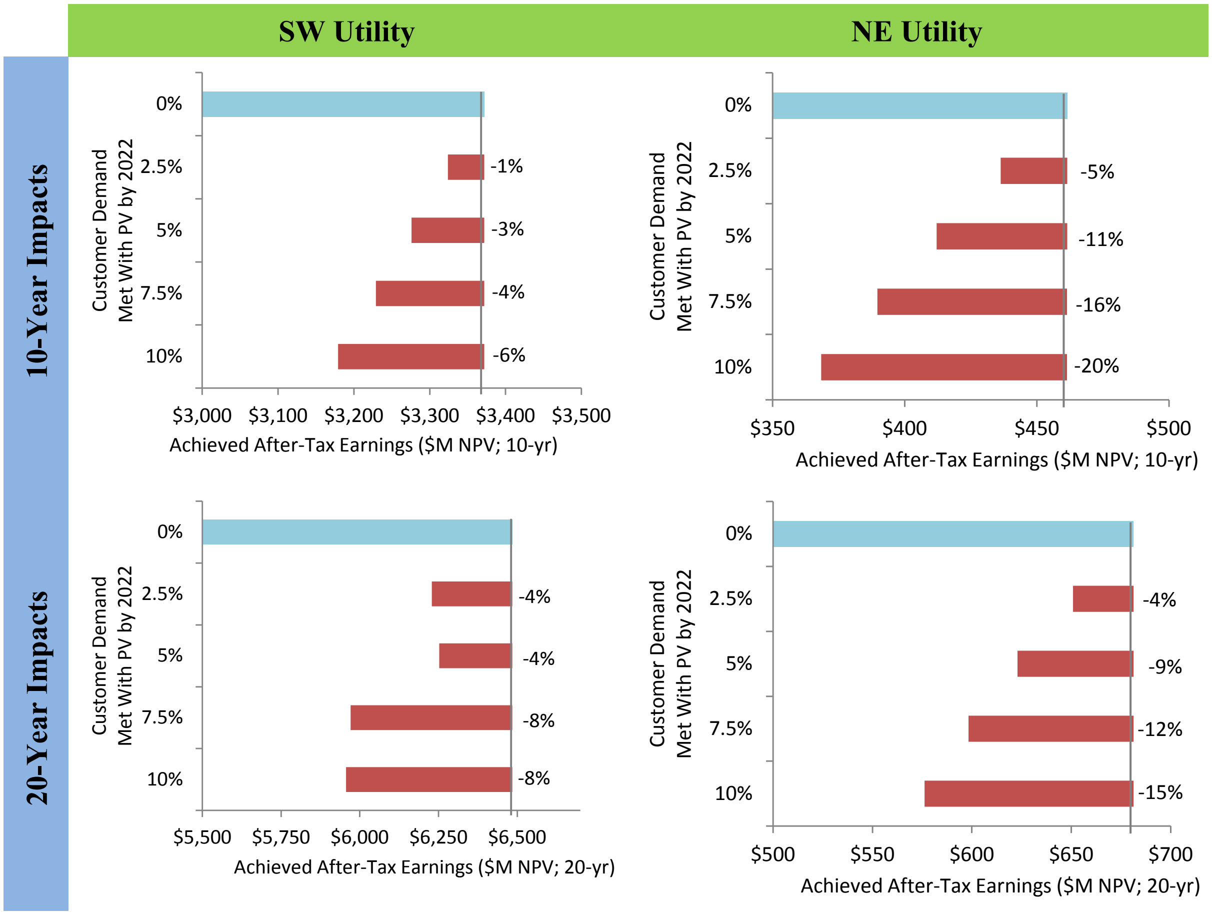

Figure 15. Reduction in Achieved After-Tax Earnings

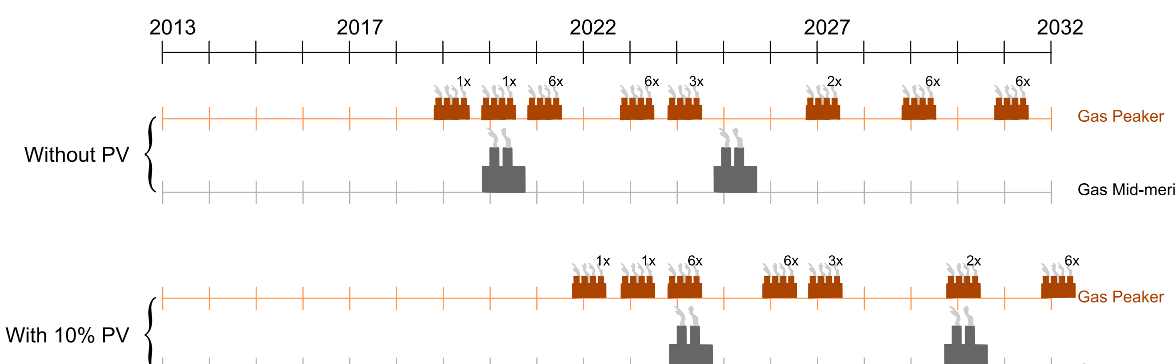

Figure 16. Generation Investment Deferral for the SW Utility with 10% PV

4.7 Impacts of PV on Average Retail Rates

Within the timeframe of our analysis, customer-sited PV impacts average, all-in retail rates in two, inter-related ways. First, it impacts the retail rates set within each GRC through the net result of reductions in the test-year utility costs and billing determinants used to establish rates.

As discussed in Section 4.3, under our base-case assumptions customer-sited PV generally reduces utility costs by less than it reduces retail sales. As a result, average retail rates established through each GRC increase with the addition of customer-sited PV. That particular dynamic is dependent on a variety of assumptions related to the ability of customer-sited PV to reduce utility cost, some of which are explored within the sensitivity analysis in Section 5. Second, customer-sited PV impacts average rates in the years between GRCs, though this effect is simply a mathematical artifact. Average rates are, by definition, equal to total collected revenues divided by total retail sales. Among customers with PV, the net-metered PV reduces both the revenues received from those customers (the numerator) and their retail sales (the denominator), but the reductions in revenues are necessarily smaller, given that some portion of revenues are derived from fixed customer charges (which are unaffected by PV) and demand charges (which are only marginally affected by PV).

The base-case impacts of customer-sited PV on average all-in retail rates over the first 10 years of the analysis period are shown in Figure 17, for both utilities and across the range of PV penetration levels considered.[27] For the SW Utility, the all-in average retail rate at 10% PV penetration is 0.23 cents/kWh (1.8%) higher over the first 10 years of the analysis period (i.e., 2013-2022) than it is without PV. The rate impacts for the NE Utility are similar, with an average rate that is 0.23 cents/kWh (1.5%) higher at 10% PV penetration than without PV. As to be expected, the rate impacts are smaller at lower PV penetration levels.

Over the entire 20-year analysis period, the impacts on average rates are generally somewhat higher than over just the first 10-year period. This is due to the fact that PV penetration is ramping up over time, and thus the average penetration level during the initial 10 years is lower than over the full 20 years. At 10% PV penetration, for example, average retail rates for the SW utility are 0.35 cents/kWh (2.5%) higher than without PV, while average rates for the NE Utility are 0.52 cents/kWh (2.7%) higher.

[27] We calculate the average all-in retail rate on a levelized basis using a customer discount rate of 5%.

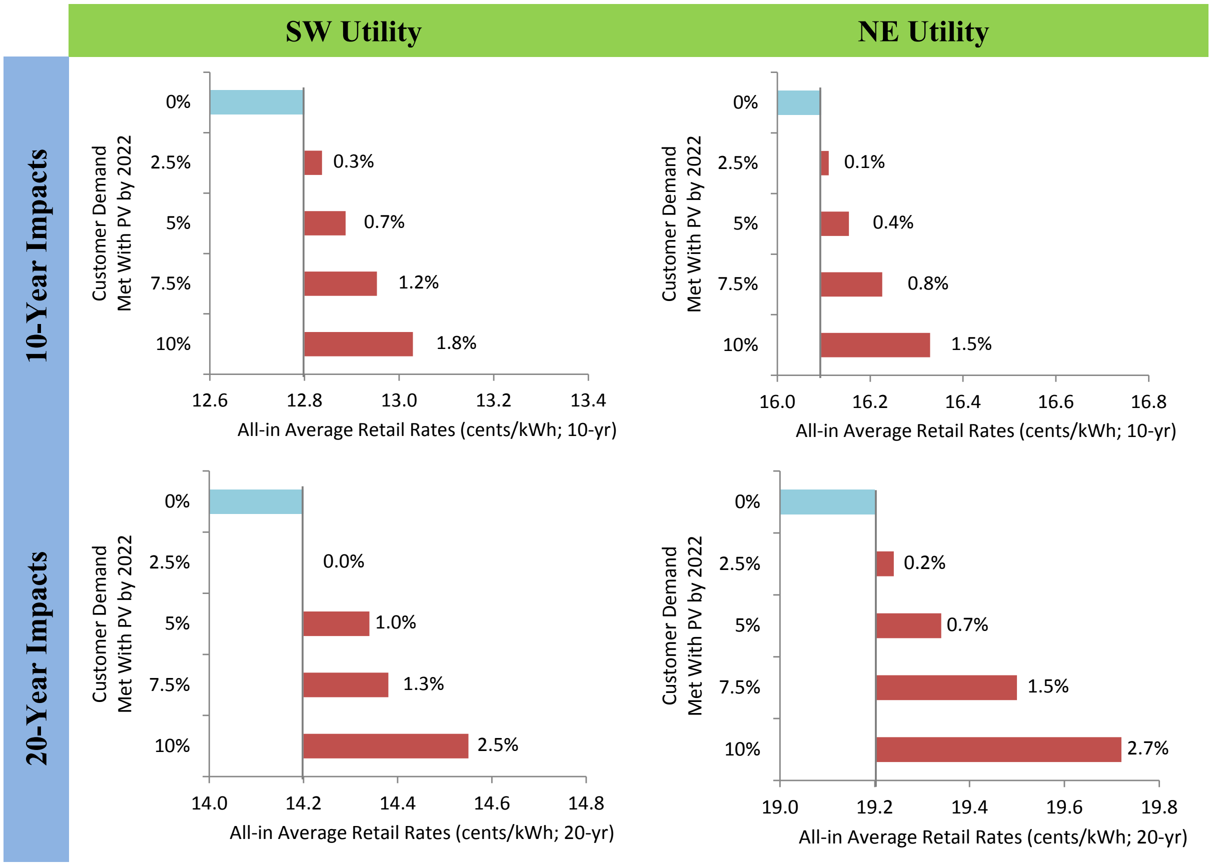

Figure 17. Increase in All-in Average Retail Rates

5. Sensitivity Results: How do the impacts of PV depend on the utility operating and regulatory environment and other key assumptions?

The base case results presented in Section 4 reflect a variety of assumptions about the two prototypical utilities. Actual conditions faced by U.S. utilities, however, vary considerably and many of the assumptions employed within our base case analysis relate to future trends that are subject to significant uncertainty. In order to examine how the impacts of customer-sited PV on utility shareholders and ratepayers may depend on assumptions about our prototypical utilities' operating and regulatory environments, we performed a series of sensitivity analyses (see Table 3, with further details provided in Appendix D). These alternate cases represent many of the most significant, though by no means all, potential sources of uncertainty and variation among utilities.[28] Moreover, even in regard to some of the sensitivities examined, some utilities may exhibit even more extreme divergence from our base-case assumptions. As such, our purpose here is not to bound the potential range of impacts, but rather to illustrate a number of key themes and considerations relevant to gauging the possible magnitude of those impacts.

Table 3. Sensitivity Cases

	Sensitivities	Description	SW Utility	NE Utility
Utility Operating Environment	Value of PV	Higher/lower PV capacity credit and ability of PV to offset non-generation capital expenditure (CapEx)	●	●
	Load Growth	Higher/lower load growth	●	●
	Fixed O&M Growth	Higher/lower growth rate of fixed O&M costs	●	●
	Non-Generating CapEx Growth	Higher/lower growth rate of non-generation CapEx	●	●
	Fuel Cost Growth	Higher/lower growth rate of fuel costs or wholesale energy market prices	●	●
	Coal Retirement	Early retirement of existing coal generation	●	
	Utility-Owned Generation Share	Higher share of utility-owned generation	●	
	Utility-Owned Generation Cost	Higher/lower cost of utility-owned generation	●	
	Forward Capacity Market Cost	Higher/lower market clearing price in the ISO-NE forward capacity market		●
Utility Regulatory Environment	Rate Design	Higher/lower fixed customer charges	●	●
	Rate Case Filing Period	Shorter/longer period between general rate cases	●	●
	Regulatory Lag	Shorter/longer period from the filing of a general rate case to implementation of new rates	●	●
	Test Year	Use of current or future test year during general rate cases, instead of historical test year	●	●
	PV Incentives	$0.5/Watt rebate provided by the utility to customers with PV	●	●

Three important structural features of the sensitivity analysis must be noted. First, for each sensitivity case, we characterize the impacts of customer-sited PV under the 10% PV penetration trajectory (i.e., where customer-sited PV ramps up to 10% of total retail sales over 10 years), ignoring the lower penetration levels considered within the base case analysis. We focus on this

[28] The set of sensitivities is partly constrained by the structure of the model. For example, as currently constructed, the model cannot explicitly represent time-differentiated or inclining block rates; the rate design sensitivities therefore consist only of varying combinations of flat volumetric, demand, and customer charges.

higher PV penetration in order to more clearly highlight and compare the relative degrees of sensitivity across the various cases examined, but acknowledge again that this is an arguably aggressive trajectory compared to current penetration levels and growth rates for most states and utilities. Were lower PV penetration levels assumed, the impacts of PV would be smaller and the ranges across sensitivity cases would be narrower, but the fundamental results would be qualitatively the same. Second, each sensitivity case varies a single assumption or small number of assumptions. In reality, however, a more complex set of interactions and interdependencies may exist among various modeling assumptions (e.g., between rate design and load growth). Third, variation in rate design and ratemaking assumptions are included in both the sensitivity analysis and the mitigation analysis in Section 6. The difference is that, for the sensitivity analysis, the alternate assumptions are applied both with and without customer-sited PV (to reflect the fact that such variations may exist independently of customer-sited PV), while in the mitigation analysis, the alternative assumptions are applied only in conjunction with PV and are defined somewhat differently. The significance of this distinction will be further discussed below.

We begin with an overview of the results across the full set of sensitivity cases, in order to illustrate in general terms how the magnitude of impacts from customer-sited PV depends on assumptions about the utility operating and regulatory environment. We then proceed by discussing specific sensitivity cases and explain why the shareholder and ratepayer impacts are larger or smaller than what is observed in the base case.

5.1 The *direction* of the impacts is generally consistent across the sensitivities considered, though the *magnitude* varies considerably

The shareholder and ratepayer impacts from customer-sited PV are directionally consistent across the sensitivity cases (see Figure 18 and Figure 19). Namely, with one exception, customer-sited PV results in a decrease in achieved shareholder earnings and ROE and an increase in all-in average retail rates, regardless of assumptions about the utility operating and regulatory environment.[29] The magnitude of those impacts, however, varies considerably across the cases, demonstrating that the financial impacts from customer-sited PV critically depend on the specific conditions of the utility. For the SW Utility, the reduction in achieved earnings from customer-sited PV ranges from roughly 5% to 13%, while the reduction in achieved ROE ranges from 1% to 9%, and the increase in average rates ranges from roughly 0% to 4%.[30] The impacts for the NE Utility are even more varied, ranging from a 6% to 41% reduction in earnings, a 5% to 38% reduction in ROE, and a 1% to 4% increase in average rates. The greater sensitivity in ROE and earnings impacts for the NE Utility are due to the fact that its ratebase and earnings are much smaller, relative to its total revenue requirements, and thus variations in the absolute level of those metrics lead to relatively large percentage changes.

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[29] The exception to the otherwise consistent directional trends occurs for the SW Utility in the high Value of PV case, where PV results in a very slight decrease in average rates.

[30] Throughout this section, we focus on the earnings and rate impacts over the full 20-year analysis period in order to capture any "end-effects" associated with reduced capital expenditures in the latter decade, but focus on ROE impacts over only the first 10 years, during which the impacts are most pronounced and interpretable. [30]

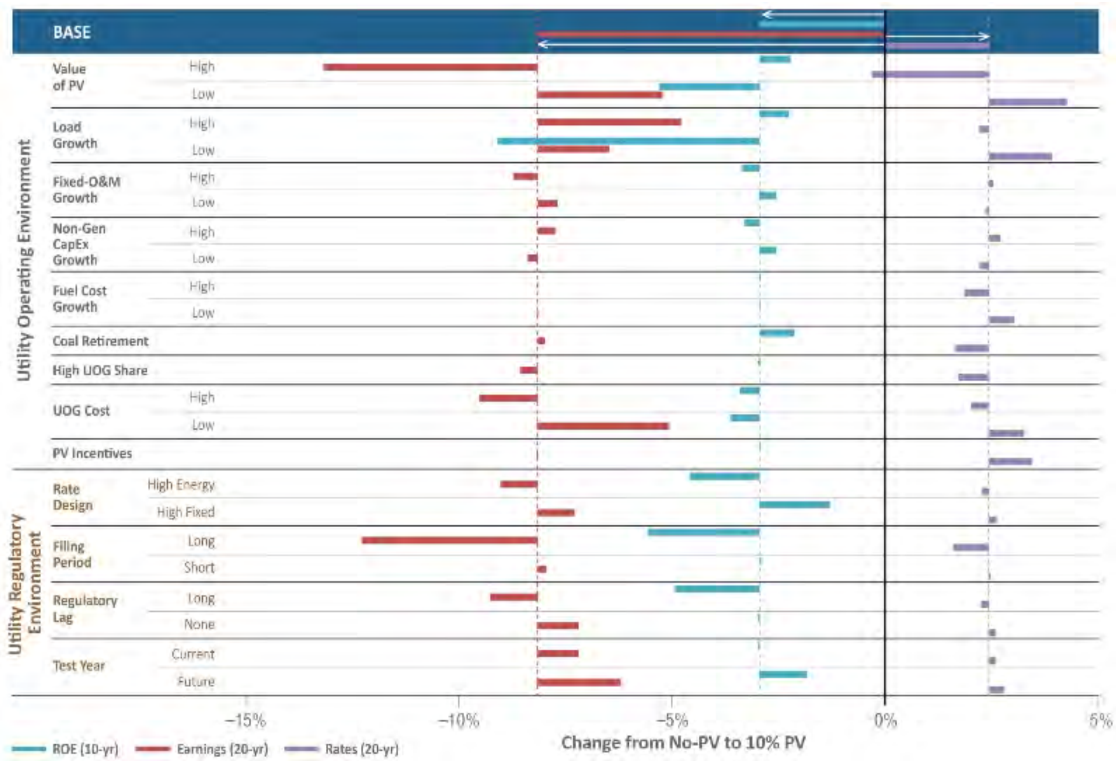


Figure 18. All Sensitivity Results for SW Utility

Figure 19. All Sensitivity Results for NE Utility

5.2 The financial impacts of customer-sited PV are particularly sensitive to the capacity value and avoided T&D costs of PV, with divergent implications for ratepayers vs. shareholders

As discussed throughout Section 4, the financial impacts of customer-sited PV on utility shareholders and ratepayers are driven, in part, by the associated impacts on utility costs (i.e., the avoided cost "value of PV"). Among the various sources of cost reductions, avoided generation capacity and T&D capacity costs are arguably the source of greatest uncertainty and disagreement (as evident when comparing the various studies summarized in Text Box 3). In the financial model used for the present analysis, the impacts of customer-sited PV on generation capacity and T&D capacity costs are driven by several parameters that define the "capacity credit" of customer-sited PV at the bulk power system level and on the distribution system. For the SW Utility, capacity credit assumptions affect the deferral of generation capacity investments as well as reductions in growth-related capital expenditures for T&D, while for the NE Utility, they affect the cost reductions associated with market purchases of generation and transmission capacity as well as reductions in growth-related capital expenditures for the distribution system.

We developed a set of alternate sensitivity cases to better understand the sensitivity of shareholder and ratepayer impacts from customer-sited PV to assumptions related to its capacity value and avoided T&D costs. These sensitivity cases involved modifying a number of parameters in the model (see Table 4), based on ranges for several of these parameters that exist in the literature (Hoff et al. 2008). With respect to the capacity credit at the bulk power level, in the High Value of PV scenario we slow the rate of decline of the capacity credit with increasing PV penetration, such that later vintages of PV installations contribute to a greater extent to reducing peak demand, while in the Low Value of PV scenario we assume a lower capacity credit for even early vintages of customer-sited PV. The scenarios also involve varying assumptions about the percentage of the capacity credit at the bulk power level that is then applied at the T&D level, where in the Low Value of PV case we assume 0% capacity credit for the purpose of T&D deferrals. Finally, in the Low Value of PV scenario, we also *increase* the growth rate for non-generation capital investments in conjunction with PV, to represent the possibility that integration costs for customer-sited PV could result in a net increase in distribution system expenditures.

Table 4. Value of PV Sensitivity Case Assumptions

	Case	Capacity credit at 0% penetration (for generation deferral)	Change in capacity credit per 1% increase in PV penetration	Portion of generation capacity credit applied at the T&D level	T&D cost escalation rate (2013-2022)
SW Utility	High Value of PV	78%	-1.0%	40%	1.9%/yr
	Base	78%	-5.7%	20%	1.9%/yr
	Low Value of PV	19%	-1.0%	0%	2.4%/yr
NE Utility	High Value of PV	68%	-1.0%	100%	3.7%/yr
	Base	68%	-4.6%	33%	3.7%/yr
	Low Value of PV	19%	-1.0%	0%	4.7%/yr

Given these alternate underlying assumptions, the resulting ranges in the value of PV are as shown in Table 5.[31] Roughly 60-75% of the difference in value of PV between the Low and High scenarios for each utility is associated with non-generation (i.e., T&D-related) capital expenditures, with the remainder associated primarily with some combination (depending on the utility) of generation capital expenditures and market purchases of generation and transmission capacity. As to be expected, the range of values in Table 5 span a narrower range than within the broader literature (Hansen et al. 2013) summarized in Text Box 3. Those latter estimates reflect variations across a much broader set of drivers for avoided costs (not just those associated with the capacity credit of customer-sited PV on the bulk power and T&D systems), as well as differences in the set of avoided cost categories included. Thus the value of PV sensitivity cases presented here should, by no means, be considered to represent the full possible range in the value of avoided costs to the utility or to society more broadly.

Table 5. Average Avoided Costs across Value of PV Sensitivity Cases (20-yr)

	Low	Base	High
SW Utility	$0.04/kWh	$0.09/kWh	$0.13/kWh
NE Utility	$0.08/kWh	$0.12/kWh	$0.17/kWh

Note: Values reported here are the avoided cost per unit of PV production (i.e. $/kWh-PV)

As shown in Figure 20, the impacts of customer-sited PV on shareholder earnings vary widely under these different assumptions related to the value of PV. Under the high value of PV scenarios, customer-sited PV results in greater reductions in capital expenditures than in the base case and thus, as a result, there are greater lost future earnings opportunities for the utility, exacerbating the earnings impacts. Under the low value of PV scenarios, the earnings impacts are correspondingly more moderate, as fewer capital expenditures are deferred.[32] The rate impacts from customer-sited PV are also quite sensitive to the value of PV, but move in the opposite direction: increasing under the low value of PV scenario (whereby customer-sited PV is less effective at reducing utility costs) and decreasing under the high value of PV scenario. Of some note, customer-sited PV leads to a slight reduction in average retail rates for the SW Utility under the high value of PV scenario. This occurs because the reduction in utility costs from PV exceeds the reduction in utility revenues.

The high degree of sensitivity of shareholder and ratepayer impacts to the value of PV – and the divergent implications of that sensitivity for shareholders versus ratepayers – has several implications. First, it reinforces the importance of efforts aimed at improving the data and methods for estimating the value of PV. Better understanding of the capacity value and avoided T&D costs of PV improves estimates of the impact of PV on shareholders and ratepayers. Second, it shows that, even within the somewhat limited range of assumptions about the value of PV considered here, it is conceivable that customer-sited PV could result in virtually no increase

[31] The value of PV is calculated as the difference in utility revenue requirements (on an NPV basis over 20 years) with and without PV, per unit of PV energy.

[32] In contrast to the earnings impacts, ROE impacts are relatively insensitive to alternate assumptions about the underlying value of PV. As previously discussed, ROE impacts from customer-sited PV are driven by its differential effect on utility costs vs. revenues. An increase (decrease) in the value of PV leads to a corresponding decrease (increase) in cost growth. However, that change in costs is a relatively small fraction of total utility costs, leading to the modest degree of sensitivity for the ROE impacts.

or perhaps even a slight decrease in average retail rates. And third, the results are suggestive of the potential to mitigate the ratepayer impacts of customer-sited PV through deployment strategies that seek to maximize its capacity deferral value (e.g., by placing PV in locations or with orientations that maximize its capacity credit). Policymakers must recognize, however, that such strategies may run counter to the financial interests of utility shareholders, whose earnings would be further eroded by greater reductions in capital expenditures.

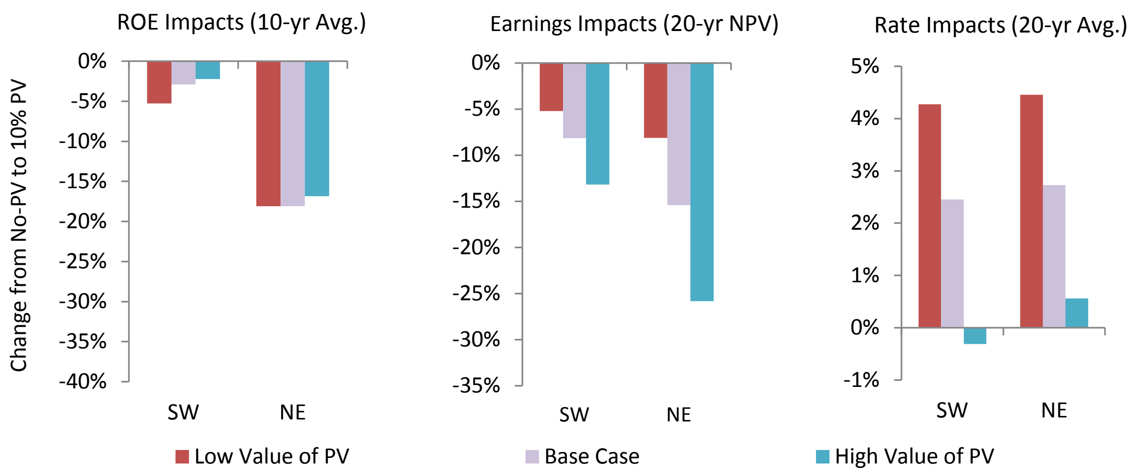
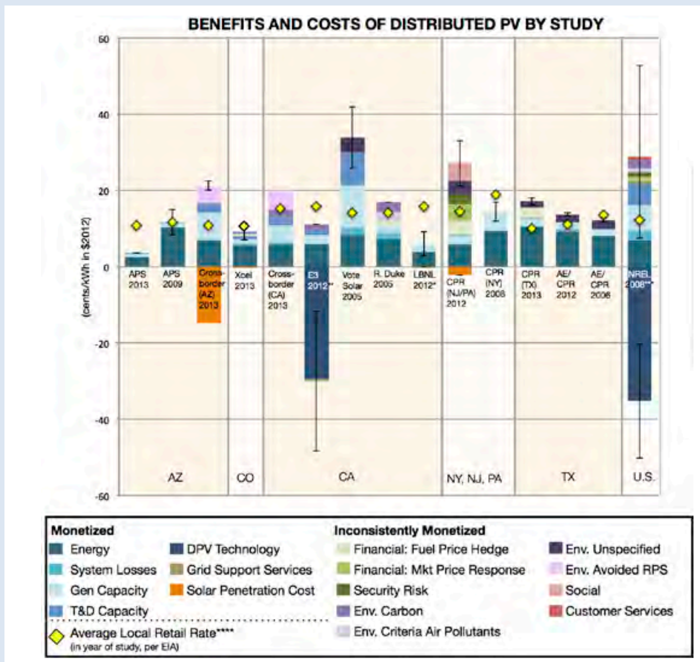


Figure 20. Sensitivity of PV Impacts to Value of Solar

Text Box 3. Estimates of the Value of Customer-Sited PV

The model used in this analysis is not specifically designed to estimate the value of PV; however, the estimates used within this study can be compared to those in the literature, which have often been developed using more-tailored tools. One recent meta-analysis (Hansen et al. 2013) compared estimates of the value of PV from studies conducted over the past decade, and found widely varying results, ranging from 3.6 cents/kWh to over 34 cents/kWh. The range in estimates is due in part to differences in assumptions about future costs, differences in methodologies, and differences in scope (e.g., value of PV from a societal perspective or a ratepayer perspective). Across studies, the range of the energy value of PV is 2.5 to 10.5 cents/kWh (driven in part by different fuel costs), the range of capacity value is 1 to 11 cents/kWh (driven by differences in the contribution of PV to reducing peak demand and the need for new capacity), the range in T&D value is 0 to 8.5 cents/kWh (depending on the ability of PV to defer investments), and the range in the environmental value is 0 to 4 cents/kWh (depending on which environmental impacts are quantified).

As described in Section 4, the value of PV in our Base Case declines from 10.3 to 8.5 cents/kWh for the SW Utility and from 15.8 to 12.3 cents/kWh for the NE Utility, when moving from the 2.5% to 10% penetration scenarios. The differences between the SW and NE Utilities are primarily due to differences in energy and capacity value. The value of PV estimated in our High and Low Value of PV sensitivities ranges from 4 to 17 cents/kWh across the utilities and scenarios at 10% PV penetration. These estimates of the value of PV all fall within the broad range reported in the literature. That said, a large portion of the change in value in our sensitivities is due to changes in non-generation capital expenditures.[33] The range of the value of PV in the broader literature, however, is driven in part by differences in estimates of avoided T&D costs, but other factors like differences in avoided energy, capacity, and environmental impacts contribute just as much to variations in the estimates of the value of PV.



Source: Hansen et al. (2013)

Figure 21. Comparison of the Estimated Value of PV across Recent Studies

[33] For example, the decrease in SW Utility non-generation capital expenditures from the High Value of PV case to the increase in the Low Value of PV case leads to a change in the value of PV of 7.3 cents/kWh. Similarly, the range due to differences in the non-generation capital expenditures in the High and Low Value of PV case for the NE Utility is 5.3 cents/kWh.

5.3 Low load growth exacerbates the impacts of customer-sited PV on rates and ROE

Load growth can vary substantially over time and among utilities, and is also subject to great uncertainty given the many underlying drivers at play (e.g., EE policies and programs, vehicle electrification, and macroeconomic trends). Within the context of the present analysis, load growth is important because of its relationship to the size and timing of utility capital expenditures (which also affects the timing of rate cases), the volume of retail sales over which fixed costs are spread, and the collection of utility revenues based on actual retail sales and peak demand levels. As discussed further below, however, these relationships are complex and, at times, somewhat idiosyncratic.

In order to characterize how the shareholder and ratepayer impacts of customer-sited PV depend on underlying load growth, we developed Low and High Load Growth sensitivities where the compound annual growth rates (CAGR) for both sales and peak demand were adjusted by +/- 2% relative to the Base Case (see Table 6).[34] The Low Load Growth cases thus entail roughly zero load growth for the SW Utility and slightly negative load growth for the NE Utility, while the High Load Growth cases entail growth rates on the order of roughly 3.5-4% per year. In conjunction with the load growth adjustments, we also adjusted the generation capacity expansion plan for the SW Utility and the amount of growth-related non-generation capital expenditure in order to maintain internal consistency across load growth scenarios.[35]

Table 6. Load Growth Assumptions in the Low and High Load Growth Sensitivities (CAGR)

		Low	Base	High
SW Utility	Sales	0.1%	2.1%	4.1%
	Peak Demand	0.1%	2.1%	4.1%
NE Utility	Sales	-0.6%	1.4%	3.4%
	Peak Demand	-0.5%	1.5%	3.5%

As shown in Figure 22, the impact of customer-sited PV on achieved ROE varies with load growth, though the degree of sensitivity depends on whether ROE impacts are measured in absolute or relative terms. For both utilities, ROE impacts are less severe with higher underlying load growth and, conversely, more severe with lower underlying load growth. This occurs because higher load growth is associated with greater growth-related capital expenditures, which in turn creates greater opportunities for cost savings from PV through deferral of those expenditures, thereby muting the impacts of PV on achieved ROE. In addition, the increased

[34] Load forecasts for several SW balancing authorities are presented in Appendix A. The EIA Annual Energy Outlook projects load growth of 0.3%/yr in New England, for the period 2012 to 2040, with a range in year-over-year growth of 0.1% to 0.6%/yr. For the Mountain region, EIA projects average growth of 1.3%/yr, with year-over-year growth ranging from 1.0% to 1.7%. EIA also reports that over the past thirty years the national average load growth (three-year moving average) ranged from -0.8% (in 2009) to 5.2% (in 1989).

[35] More specifically, we adjusted assumptions related to non-generation capital expenditures to ensure that the amount of non-generation capital expenditures that are not related to growth was the same across all three scenarios. We further increased growth related capital expenditures in the High Load Growth case and decreases the growth related capital expenditures in the Low Load Growth case for both utilities. For the NE Utility, none of the non-generation capital expenditures are related to load growth in the Low Load Growth case (due to the decrease in load from year to year), and thus PV does not result in any reduction to those costs.

pace of capital expenditures under high load growth triggers more frequent GRCs (for the SW Utility), which further moderates the impacts of customer-sited PV on ROE, as the utility is able to set new rates more frequently and thereby achieve closer alignment between its revenues and costs. When ROE impacts are measured in terms of a percentage change from the no-PV case, the sensitivity is somewhat more acute than when measured in terms of absolute, basis-point changes. This is because higher (lower) load growth leads to higher (lower) absolute levels of ROE in cases without PV, for the reasons noted above.[36] Thus, for basic arithmetic reasons, the basis-point changes caused by the introduction of customer-sited PV lead to larger swings when measured as a percentage of the ROE without PV.

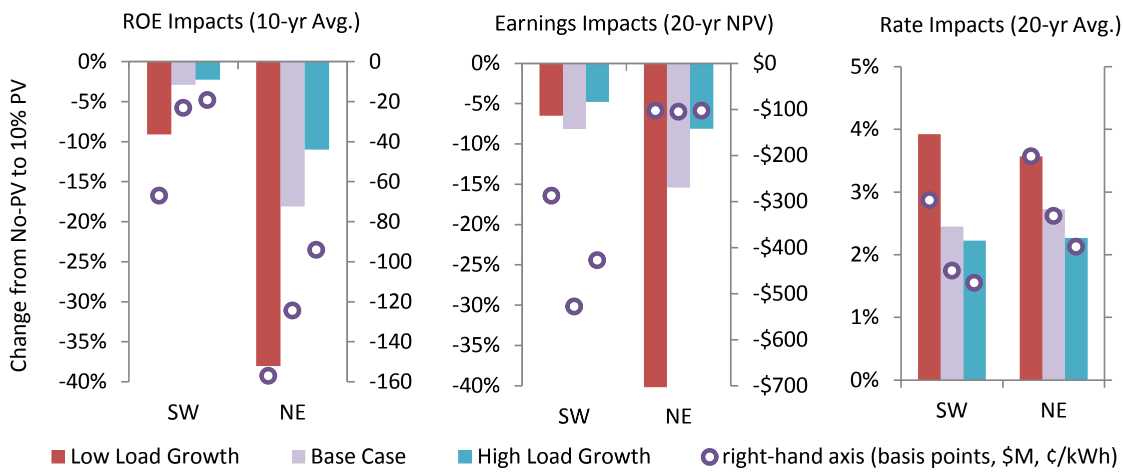


Figure 22. Sensitivity of PV Impacts to Load Growth

The sensitivity of the achieved earnings impacts from PV to load growth is somewhat more complex and involves several interrelated dynamics. The dependence of earnings impacts on underlying load growth partly are a function of the same dynamics described above in connection with ROE impacts (i.e., revenue growth between rate cases and frequency of rate cases). In addition, the underlying rate of load growth also affects the magnitude of capital expenditures, and thus the potential lost earnings opportunities associated with deferral of those expenditures. These various dynamics operate in opposing directions – for example, greater underlying load growth would tend to reduce earning erosion associated with lost revenues but increase earnings erosion associated with deferred capital expenditures – hence the irregular relationships exhibited in Figure 22. In the case of the NE Utility, these countervailing dynamics offset one another almost equally in both sensitivity cases, leading to effectively no change in absolute earnings impacts across cases. However, since the absolute earnings without PV are much smaller in the Low Load Growth case and much higher in the High Load Growth case, the earnings impacts on a percentage basis are highly sensitive to underlying load growth.

The retail rate impacts from PV are also sensitive to load growth, with larger increases in average rates occurring in the case of low load growth and smaller rate increases occurring with

[36] For the SW Utility, average ROE without PV was 7.4% in the Low Load Case and 8.6 % in the High Load Case, and for the NE Utility, it was 4.1% in the Low Load Case and 8.6% in the High Load Case.

higher load growth. This occurs due to the same dynamic discussed in connection with the ROE impacts: higher load growth requires greater capital expenditures in the case without PV, and thus greater opportunities for deferral of capital expenditures and cost savings from PV.

5.4 Shareholder impacts are more severe with retail rates that rely predominantly on volumetric energy charges and less severe when rates have larger fixed charges

Utility rate designs often follow similar general principles (e.g., stability in revenues, avoidance of undue discrimination, and fairness in allocation of costs among customer classes) but, in practice, allocation of revenue collection to energy, demand, and fixed customer charges can vary significantly across utilities. In order to examine how the impacts of PV may depend upon prevailing rate design, we developed sensitivity cases that assume varying degrees of reliance on energy charges and fixed customer charges.[37] Note that the sensitivity analysis here assumes these alternative rate designs both with and without PV, in recognition of the fact that a wide variety of rate designs are in use today for reasons unrelated to customer-sited PV. Within the mitigation analysis in Section 6, we instead explore the potential role of fixed customer charges and high demand charges as a strategy specifically for mitigating the financial impacts of customer-sited PV, in which case we consider a more extreme change in rate design that is implemented only in conjunction with the growth of PV.

Table 7 shows the composition of total utility revenues (or customer bills) for the base case and two sensitivity cases. For the High Energy Charges case, we assume that the costs allocated in the base case to fixed customer charges are instead allocated to volumetric energy charges (and leave the allocation to demand charges unchanged). For the High Customer Charges case, we assume a larger proportion of non-fuel costs are allocated to customer charges and correspondingly smaller proportion allocated to volumetric energy charges, compared to the base case (and leave fuel costs fully allocated to energy charges and the demand charges unchanged). The proportion of non-fuel costs allocated to customer charges was chosen such that the portion of total customer bills comprised of fixed customer charges doubles from the base case (e.g., fixed customer charges increase from 12% in the base case to 24% in the high customer charge case for the SW Utility).

Table 7. Rate Design Sensitivity Cases (Percent of Total Utility Revenues, without PV)

	High Energy Charges	Base Case	High Customer Charges
SW Utility			
Energy Charges	89%	77%	65%
Demand Charges	11%	11%	11%
Customer Charges	0%	12%	24%
NE Utility			
Energy Charges	92%	84%	76%
Demand Charges	8%	8%	8%
Customer Charges	0%	8%	16%

[37] Other important variations in utility rate designs may affect the impact of PV on utility shareholders and ratepayers, which we do not explore here but highlight as potential areas for follow-on analysis. These include tiered rates, time-of-use rates, and alternative PV compensation mechanisms such as value of solar tariffs.

As shown in Figure 23, the impacts of customer-sited PV on achieved ROE and earnings are more severe under the High Energy Charges case and less severe under the High Customer Charges case. In general, the greater the reliance on volumetric energy charges, the greater the impact customer-sited PV will have on a utility's collected revenue (given our assumption that the PV is net-metered and therefore offsets volumetric sales on a one-for-one basis) and the greater the resulting impact on shareholder ROE and earnings. Conversely, the greater the reliance on fixed customer charges or demand charges, the smaller the impact of PV on collected revenues and utility shareholder profitability.

The rate impacts of customer-sited PV are relatively insensitive to changes in rate design, with modestly smaller impacts under rate designs that rely heavily on volumetric energy charges and slightly larger impacts with rate designs relying more heavily on customer charges. These results may appear counter-intuitive on first glance and must be interpreted carefully, in light of how the average rate metric is calculated and what it means. As explained in Section 4, average all-in retail rates represent total collected revenue divided by total retail sales, across all customers, including both PV and non-PV customers. With higher fixed charges, the utility collects more revenues from customers with PV, which in turn translates to higher average retail rates and thus a greater change in average rates between cases with PV and without PV. By the same logic, the impact of PV on average rates is smaller when retail rates have larger volumetric energy charges. Importantly, however, we cannot infer from these results how the rate impacts for customers without PV vary with these alternate rate designs.

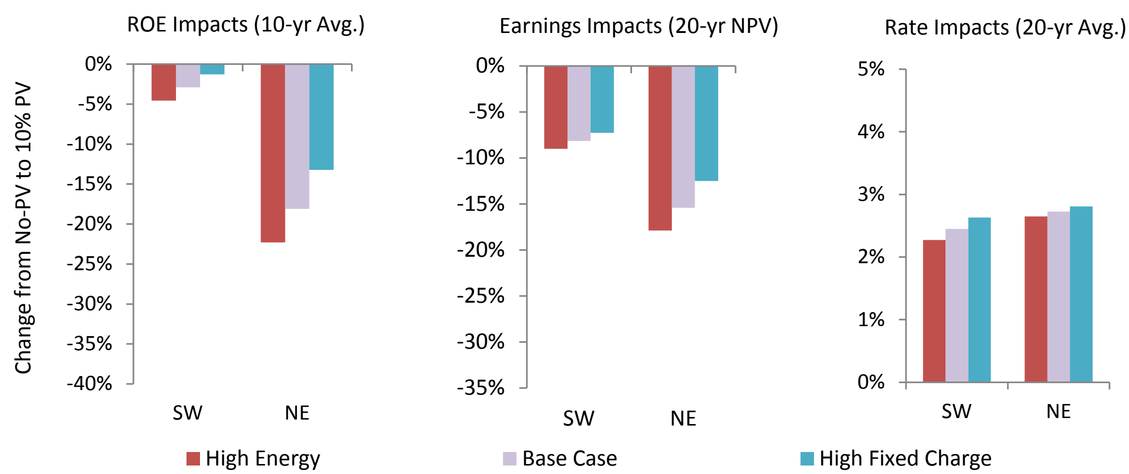


Figure 23. Sensitivity of PV Impacts to Rate Design

5.5 Greater lag between when a utility incurs costs and when those costs are reflected in new rates heightens the impacts of PV on utility shareholders, but mutes the impacts on ratepayers

Current ratemaking practices vary considerably across utilities and states, in terms of: rate case filing frequency, the period of time between the filing of a rate case and implementation of new rates (i.e., regulatory lag), and the type of test year. Accordingly, we developed a series of sensitivity cases to assess how the shareholder and ratepayer impacts of customer-sited PV may vary across differing ratesetting regimes. For the sensitivity cases, we consider longer (5-year) or shorter (2-year) periods between GRCs, longer (2-year) or shorter (0-year) periods of regulatory lag, and the use of current and future test years (i.e., where test year utility revenue requirement and billing determinants are based on the year of the GRC or on projections for the following year).[38]

This set of sensitivities is intended to reflect the range of practices used by utilities and regulators across the country. As in the case of the preceding rate design sensitivities, we apply the alternative-ratesetting-approaches to both the with-PV and without-PV cases, in order to assess how the shareholder and ratepayer impacts of PV may vary, given the range of ratesetting practices in place today. Later, in Section 6, we instead examine how these ratesetting practices might potentially serve as a strategy for mitigating the shareholder impacts of PV, if introduced in conjunction with the growth of customer-sited PV. For clarity the figures in this section present only the sensitivity cases where the impact of PV is the largest (longer periods between GRCs) or the smallest (future test years); the remaining results can be seen in Figure 18 and Figure 19 and Appendix D.

In general, the greater the lag between when a utility incurs costs and when those costs are reflected in new rates, the greater the impact of customer-sited PV on collected revenues and thus on shareholder profitability. As such, we observe larger impacts on achieved ROE and earnings in cases involving longer filing frequencies (i.e., less frequent rate cases), greater regulatory lag, or reliance on historic test years. Of these cases, the largest impact was observed with longer filing frequencies (see Figure 24). Conversely, the impacts are smaller with cases involving more frequent rate cases, less regulatory lag, or current or future test years. The shareholder impacts from PV are more sensitive to variations in these ratemaking conditions in the case of the NE Utility, given the more significant underlying misalignment between growth in non-fuel costs and retail sales.

The rate impacts exhibit the opposite set of relationships, though the degree of sensitivity is rather modest. The longer period of time between the setting of new rates results in a reduction in the impact of customer-sited PV on average retail rates. We therefore observe in Figure 24 that the increase in average all-in retail rates caused by PV is somewhat smaller in cases involving less frequent rate cases, greater regulatory lag, or reliance on historic test years (and is somewhat greater under the converse set of conditions).

[38] For the base case, we assume that the utilities file GRCs every three years and, in the case of the SW Utility, after any capital investment exceeding $900 million. We also assume that the utilities use an historical test year for establishing revenue requirements and that new rates go into effect one year after the GRC is filed.

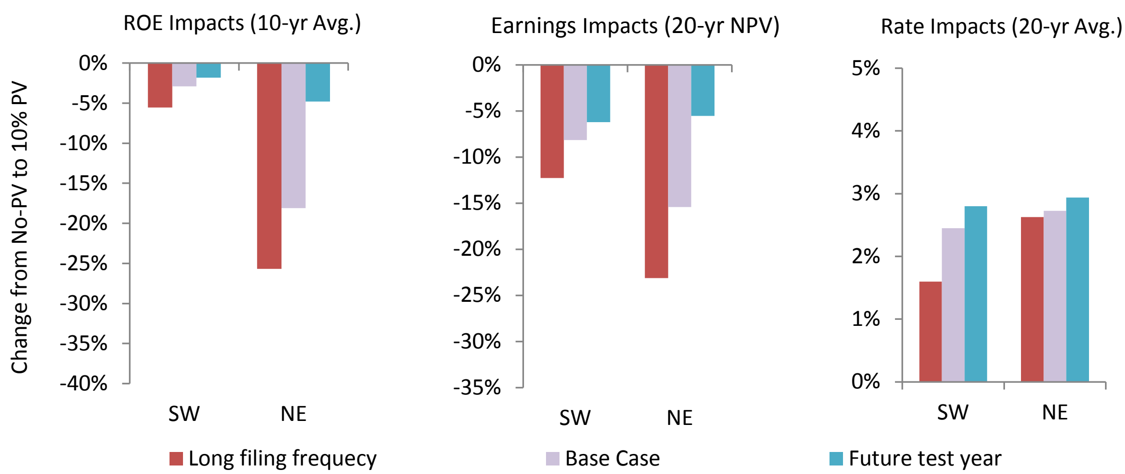


Figure 24. Sensitivity of PV Impacts to Long Rate Case Frequency and use of a Future Test Year

5.6 Shareholder and ratepayer impacts from PV vary modestly across the range of cost-related assumptions examined

We conducted a variety of other sensitivities that examine how shareholder and ratepayer impacts of PV depend on various cost-related elements of utility operating environments. These additional sensitivity cases included alternate assumptions about growth in fixed O&M costs, non-generation (i.e., T&D) capital expenditures, and fuel and purchased power costs; the capacity cost of utility-owned generation (SW Utility); ISO-NE FCM costs (NE Utility); the share of generation capacity consisting of utility-owned generation (SW Utility); early retirement of coal capacity with replacement by gas-fired generation (SW Utility); and ratepayer-funded rebates for customers to install PV.

As shown previously in Figure 18 and Figure 19, the shareholder and ratepayer impacts of PV vary to only a limited extent across most of these sensitivity cases, with two principal exceptions. The first is the set of sensitivities related to UOG costs for the SW utility, where higher costs lead to higher shareholder earnings erosion from PV, and lower costs lead to lower earnings erosion. Because shareholders generate earnings from capital investments in utility-owned generation, the higher the cost of that generation, the greater the earnings, and thus the greater erosion of earnings if those capital expenditures are deferred.

The other cost-related scenario exhibiting a significant degree of sensitivity is the case where the utility provides PV customers an up-front rebate (equal to $0.5/W), which results in a noticeable impact on average retail rates.[39] The rebate is an additional utility cost that is ultimately collected from all ratepayers, and thus the incremental increase in average retail rates, beyond that occurring in the base case, is due to the cost of the rebate program.[40] Although Figure 18

[39] Such financial incentives have been common practice in the United States, though in recent years they have been phased out and/or supplanted by other kinds of financial incentives.
[40] The model does not separate retail rate impacts of participants and non-participants, thus, we only represent rate impacts averaged across all customers.

and Figure 19 focus on the rate impacts over the full 20-year analysis period, it is more instructive in the case of this sensitivity to consider the impacts over just the first 10 years, during which the rebates are disbursed. Over that timeframe, the rate impacts from PV are roughly doubled relative to the base case with only net metering but no rebate program (a 3.6% increase in average all-in retail rates for the SW Utility, compared to 1.8% in the base case, and a 3.3% rate increase for the NE Utility, compared to 1.5% in the base case). Note, though, that we have not assumed in this sensitivity that ownership of RECs generated by the customer-sited PV are transferred to the utility in exchange for the rebate; if such a transfer were to occur, the utility would be able to apply those RECs directly towards its RPS obligations, which would offset some or all of the rate impacts associated with the rebate program costs. In Section 6, we explore the potential rate impacts associated with transferring ownership of these RECs to the utility.

Given these findings, the results for these cases illustrate several important relationships and themes. Of particular note, the sensitivity of shareholder impacts to underlying utility costs depends on the kind of cost and how it is recovered from ratepayers. Some costs are passed-through to customers through annual rate adjustments (e.g., fuel and purchased power costs).[41] Because those costs are fully recovered from ratepayers both with and without customer-sited PV, the growth of customer-sited PV does not impact recovery of those costs, and therefore the shareholder impacts of PV are independent of the magnitude of those costs or their rate of growth. Other costs, however, affect the utility's ratebase (e.g., non-generation capital expenditures and capacity costs for utility-owned generation). Utility shareholders earn a return on the equity of financing for those investments, and thus in general, the greater those underlying costs, the greater the impact of PV on shareholder earnings.

[41] The ability for utilities to pass particular costs to rates without a general rate case depends on the regulatory environment. We assume that the SW and NE Utility have fuel-adjustment clauses (FAC) that allow rates to be adjusted in response to changes in fuel and purchased power costs. Not all utilities will have these sorts of clauses and may instead rely on rate cases to adjust fuel and purchased power related rates.

6. Mitigation Results: To what extent can the impacts of PV be mitigated through regulatory and ratemaking measures?

This section examines the effectiveness of various measures that could be implemented by utilities and regulators to mitigate the financial impacts of PV on shareholders and/or ratepayers (see Table 8). Though by no means exhaustive, this set of measures includes many of the regulatory and ratemaking strategies implemented or discussed in connection with EE programs, or analogues that might apply to PV.[42] As suggested by Table 8, most of these measures specifically target the shareholder impacts from customer-sited PV (associated with either revenue erosion or lost earnings opportunities), and these measures may potentially exacerbate the ratepayer impacts from customer-sited PV, exemplifying one kind of tradeoff that can often arise.

Table 8. Mitigation Cases and Targeted Intent

Mitigation Measure	Description	Revenue Erosion	Lost Earnings Opportunities	Increased Rates
Revenue-per-Customer (RPC) Decoupling	Revenue decoupling is implemented by setting a revenue per-customer target in rate cases and adjusting rates annually between cases to collect revenues at the target level	●		○
Lost Revenue Adjustment Mechanism (LRAM)	Rates are adjusted annually to compensate the utility for the incremental loss of revenue occurring as a result of customer-sited PV	●		○
Shareholder Incentive	Utility shareholders receive additional earnings for the successful achievement of policy goals (in this case, related to customer-sited PV deployment)		●	○
Shorter Rate Case Filing Frequency	The period between GRC filing is reduced	●		○
No Regulatory Lag	The lag between the filing of GRCs and implementation of new rates is eliminated	●		○
Current & Future Test Years	Current or future test years are used to set utility revenue requirement during GRCs	●		○
Increased Demand Charge & Fixed Charge	An increased share of non-fuel costs is allocated to demand or fixed customer charges	●		○
Utility Ownership of Customer-Sited PV	The utility owns customer-sited PV systems, leases the systems back to the host customers or to intermediaries, and earns a return on the assets		●	○
Customer-Sited PV Counted toward RPS	All net-metered PV counts toward the utility's RPS compliance obligations			●

● Primary intended target of mitigation measure
○ May exacerbate impacts of customer-sited PV

[42] For example, we do not consider value of solar tariffs, non-fuel cost trackers, formula rates, multi-year rate plans, or various other options identified in the literature (Bird et al. 2013, Lowry et al. 2013, Linvill et al. 2013, Kihm and Kramer 2014).

We examine each of the mitigation options in Table 8 in isolation, but note that several could be coupled with each other (or with other mitigation measures) as part of a more comprehensive solution (e.g., combining RPC decoupling with shareholder incentives). Potential solutions to mitigate the impacts of PV may be more viable if they address concerns of both ratepayers and shareholders; such "comprehensive business models" as they relate to utility-sponsored EE programs are discussed in more detail in Satchwell et al. (2011).

As with the sensitivity analysis, the analysis of mitigation measures focuses on the 10% PV penetration scenario, in order to clearly reveal the effects of the mitigation measures considered. Were lower PV penetration levels assumed for this portion of the analysis, the results would be qualitatively similar but less discernible. Unlike the sensitivity analysis, however, the mitigation analysis involves changes from base case conditions that occur only in conjunction with PV. Thus we gauge the effectiveness of each mitigation measure in terms of the extent to which it restores shareholder earnings, shareholder ROE, and/or average rates to the levels that occur without PV under the base case utility conditions.

We highlight key themes within this section that emerge from the analysis of mitigation measures. In doing so, we group functionally similar mitigation measures together and focus on the particular metric(s) and timeframe (either the first 10 years of the analysis period or the entire 20-year period) that are most relevant to the mitigation measure in question. For example, many of the mitigation measures serve principally to address the revenue erosion impacts from customer-sited PV, in which case our discussion of shareholder impacts focuses on achieved ROE over the first 10 years, along with any associated changes in average rates. Other measures may instead serve primarily to address lost earnings opportunities associated with PV, in which case our discussion of shareholder impacts focuses on earnings over the full 20-year analysis period. The full set of results for each mitigation case, including all three metrics both the 10- and 20-year analysis periods, are included for reference in Appendix E.

As a final prefatory note, in the course of discussing the results of this analysis, we highlight how many of the mitigation measures considered may have divergent consequences for shareholders and ratepayers, or may entail tradeoffs with other policy or social objectives (e.g., increasing fixed customer charges may dampen the long-run price signal for energy conservation). Because of those issues and complexities, we stress that the following analysis represents neither an endorsement of any particular measure nor a complete examination of the broader set of implications associated with the measures considered.

6.1 Decoupling and LRAM can moderate the ROE impacts from PV, though their effectiveness depends critically on design and utility characteristics

The traditional electric utility business model in the United States provides a financial incentive for the utility to increase electricity sales between rate cases, commonly referred to as the "throughput incentive" (Eto et al., 1997, RAP 2011). A bias among utilities therefore exists against resources or policies, like EE or customer-sited PV, that decrease sales. Several regulatory tools have been used in the context of EE to mitigate this disincentive, including various forms of revenue decoupling as well as lost revenue adjustment mechanisms (LRAM), and we developed mitigation cases to explore their potential applicability for customer-sited PV.

Revenue decoupling is designed to address the misalignment of incentives towards EE and other demand-side resources by "decoupling" utility revenues from sales.[43] Revenue-per-customer (RPC) decoupling is one form of decoupling that allows revenues to grow based on growth in the number of customers between rate cases, rather than on growth in retail sales.[44] Another design element of decoupling is the application of a revenue growth factor, commonly called a "k-factor". The k-factor allows the revenue (or revenue-per-customer) established in a GRC to grow between rate cases to better match growth in fixed costs between rate cases. This is particularly important for a utility facing the effects of high cost inflation and high fixed cost (e.g., labor costs, pension costs) growth.

An LRAM, like decoupling, is also intended to address the "throughput incentive," though it does so by reimbursing the utility specifically for lost revenues directly attributable to EE programs. Thus, unlike revenue decoupling, which fully severs the tie between sales and revenues, an LRAM is more narrowly focused on only sales reductions associated with EE programs (or, in our analysis, customer-sited PV).[45] In practice, implementation of an LRAM can be contentious, as it requires estimation of the amount of energy saved as a result of the EE measure (Carter 2001). In this respect, LRAMs may be easier to implement for customer-sited PV than for EE, because PV production can be directly metered whereas the change in sales due to EE is more speculative.

In order to illustrate their potential applicability to customer-sited PV, we developed mitigation scenarios involving two variants of RPC decoupling – one with a k-factor and one without a k-factor – and one mitigation case with an LRAM. For the mitigation case involving RPC decoupling without a k-factor, growth in collected revenues is set equal to growth in the number of customers between rate cases. For the mitigation case involving RPC decoupling with a k-factor, the k-factor is set at the value necessary to restore ROE to the level achieved in the base case without PV. Under the LRAM mitigation case, the utility collects additional revenue on an annual basis between rate cases, equal to the product of the energy produced by PV and the non-fuel volumetric energy rate.

We assess the impact of these mitigation measures on achieved ROE and average retail rates by comparing the scenarios with 10% PV and the mitigation measure to scenarios with 10% PV and no mitigation measure (see Figure 25). As a point of reference, this figure and others throughout the remainder of this section also show the change in each metric between 0% and 10% PV under base-case conditions (i.e., with no mitigation measure), in order to illustrate the extent to which each mitigation measure either offsets or exacerbates the effect of PV. We focus our assessment of the effectiveness of RPC decoupling and LRAM on the change in achieved

[43] Critics of decoupling contend that it removes the utility's incentive to manage its costs between GRCs, among other things.
[44] As of July 2013, 14 states had approved revenue decoupling mechanisms for at least one utility (IEE 2013). See RAP (2011) for a description of the different forms of decoupling. We model RPC decoupling because it is the most common.
[45] As of July 2013, 18 states had approved lost-revenue adjustment mechanisms for at least one utility (IEE 2013).

average ROE, though the earnings impacts (which are included in Appendix E) are qualitatively similar.

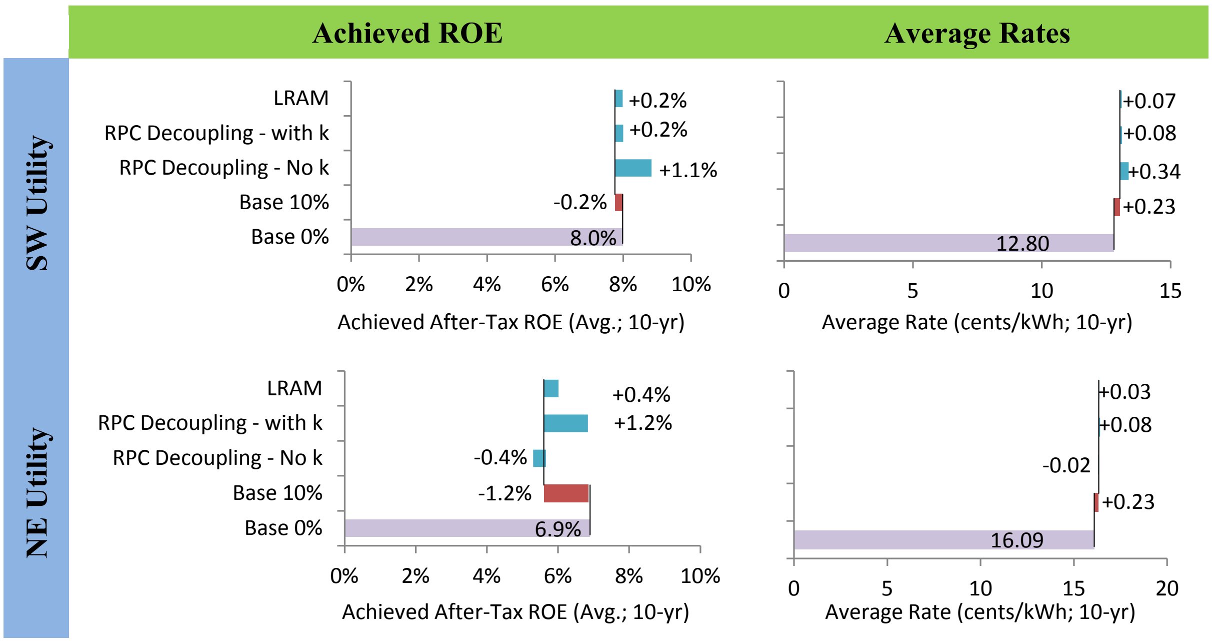


Figure 25. Mitigation of PV Impacts through Decoupling and LRAM

As shown in Figure 25, the various mitigation measures generally improve utility ROE, relative to cases with 10% PV and no mitigation measure, though to vastly varying degrees depending on the utility, the type of measure, and its design. With respect first to decoupling, implementing RPC decoupling *without* a k-factor leads to a 108 basis-point increase in achieved ROE for the SW Utility, resulting in an average ROE exceeding the level achieved without PV. This significant ROE improvement is due to the fact that growth in the number of customers is substantially higher than growth in non-fuel revenues in the base case with 10% PV,[46] and thus the utility collects substantially greater revenues when those revenues are tied more closely to growth in the number of customers, as occurs with RPC decoupling. Conversely, customer growth is low for the NE Utility relative to growth in non-fuel revenues, thus RPC decoupling without a k-factor actually exacerbates ROE erosion. For both utilities, RPC decoupling with a k-factor restores ROE back to the level achieved without PV, under base case conditions. This outcome is by design, based on choice of the k-factor (which, in the case of our analysis, requires a negative k-factor for the SW Utility and a positive k-factor for the NE Utility).

We see an improvement in achieved average ROE when we implement a LRAM in the case with 10% PV. A LRAM is designed to mitigate only the revenues lost due to the customer-sited PV savings (as opposed to the RPC decoupling mechanism that is designed to mitigate *all* lost revenues). To calculate the additional revenues to the utility from the LRAM, we multiplied the

[46] Non-fuel revenues are the point of comparison because we assume the utility collects fuel revenues on an annual basis through an FAC, which perfectly matches fuel revenues with fuel and purchased power costs. Growth in non-fuel revenues is a function of growth in billing determinants (retail sales, peak demand, and number of customers).

energy savings from customer-sited PV by the non-fuel volumetric energy rate. In the SW Utility the LRAM virtually achieves ROE comparability, but in the NE Utility an LRAM is not enough to achieve ROE comparability. This is due primarily to the fact that the LRAM, as implemented in our analysis, only compensates the utility for lost non-fuel *energy* revenues and does not include utility revenues collected via a *demand* charge, which are also reduced by customer-sited PV. The NE Utility collects a larger proportion of non-fuel revenues from a demand charge than the SW Utility, and the LRAM, therefore, only compensates the NE Utility for a small proportion of lost revenues.

To the extent that decoupling and LRAM mitigate the ROE impacts from customer-sited PV, they do so by increasing revenues, which necessarily increases average retail rates (given that average rates are simply total revenues divided by total retail sales).[47] Thus, while these measures may mitigate the impact of PV on shareholders, tradeoffs exist in the form of increases in average retail rates (albeit fairly modest ones for the particular scenarios examined here), above and beyond any rate increases that occur as a result of customer-sited PV. In particular, excluding the case of RPC decoupling without a k-factor, the decoupling and LRAM cases result in additional rate increases of 0.07 to 0.08 cents/kWh (0.5 to 0.6%) for the SW Utility and 0.03 to 0.08 cents/kWh (0.2 to 0.5%) for the NE Utility. The fact that increase in rates needed to achieve ROE comparability is similar between the two utilities, even though ROE must increase to a greater degree for the NE Utility, reflects the relatively small ratebase of the NE Utility compared to the SW Utility.

6.2 Shareholder incentive mechanisms may be used to create utility earnings opportunities from customer-sited PV

While decoupling and LRAM mechanisms may mitigate the revenue erosion from demand-side resources such as PV and EE, they do not address the other fundamental disincentive that the traditional electric utility business model creates towards those resources. Namely, those resources, to the extent that they defer capital expenditures by the utility, also erode its opportunity to generate earnings from those capital investments. One solution to correcting that incentive misalignment is to allow the utility to collect additional revenues for successful implementation of EE programs or achievement of energy savings goals, thereby creating positive earnings opportunities from EE investments by the utility.

Such so-called "shareholder incentive mechanisms" for EE have been used in many forms over the past two decades. Most commonly, shareholder incentives are based on a share of EE program costs or are calculated as a portion of the net benefits resulting from EE program implementation.[48] Depending on their specific design, shareholder incentive mechanisms may

[47] It may not always be the case that a decoupling mechanism results in increased customer bills. In particular, if a utility without decoupling collects more than its revenue requirement, the implementation of decoupling would result in a refund to customers. In addition, some jurisdictions (e.g., Colorado) have authorized "dead-bands" in conjunction with decoupling, in order to ensure that customer bills do not increase or decrease beyond a certain amount (e.g., 2%).
[48] As of July 2013, 28 states had approved a shareholder incentive mechanism for at least one utility, broken out as: 8 states with incentives based on a percentage of EE program costs, 13 states with incentives based on shared net

encourage utilities to meet or exceed energy savings targets (e.g. performance targets or cost bonus mechanisms), to invest shareholder funds in EE programs (e.g. cost capitalization programs), or to pursue efficiency options that produce the greatest net benefit (e.g., shared net benefits) (Cappers and Goldman 2009).

Because shareholder incentives for EE have generally been implemented in conjunction with utility-administered EE programs, we developed a mitigation case involving a shareholder incentive mechanism for customer-sited PV implemented in conjunction with a utility-administered PV rebate program.[49] For the purpose of isolating the impact of the shareholder incentive, we also include this rebate program in the comparison case without the shareholder incentive. Specifically, we assume that the utility offers a $0.5/W rebate for customer-sited PV (i.e., the same program explored earlier within the sensitivity analysis), and that the shareholder incentive is equal to 10% of the rebate cost (i.e., $0.05/W of customer-sited PV capacity installed in each year), where these additional revenues go directly to utility earnings. This is similar to a "cost capitalization" shareholder incentive mechanism, as has been used for utility-administered EE programs.

As shown in Figure 26, implementation of the modeled shareholder incentive mechanism increases both utilities' average achieved earnings, relative to what occurs with 10% PV and no shareholder incentive.[50] Under the specific shareholder incentive mechanism modeled here, earnings are not fully restored to the level achieved with no PV; naturally, the extent of earnings gains is a function of the design of the modeled shareholder incentive mechanism, where greater or lesser earnings gains could be achieved simply by increasing or decreasing the specified $0.05/W shareholder incentive. Important to note though is that shareholder incentives are generally not intended to achieve complete earnings comparability, but instead to compensate the utility only for the portion of earnings erosion associated with deferred/avoided capital expenditures (i.e., the lost earnings opportunity effect).

As in the case of decoupling and LRAM, any increase in achieved earnings associated with a shareholder incentive mechanism is the direct result of increased utility revenues, which by definition implies an increase in average retail rates and thus a tradeoff between the impacts on shareholders and ratepayers. In the case of the specific shareholder incentive mechanism modeled here, the shareholder incentives increase average retail rates by 0.04 cents/kWh for the SW Utility and 0.05 cents/kWh for the NE Utility (in addition to the increases that occur as a result of customer-sited PV under base-case assumptions).

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benefits, 4 states with incentives based on a percentage of avoided costs, and 3 states with incentive mechanisms approved but specifics yet to be determined (IEE 2013).

[49] Even in cases where such programs are not offered, utilities may still be in a position to help or hinder the development of customer-sited PV through administrative practices related to net-metering and interconnection. A shareholder incentive may thus still be applicable in those cases by rewarding utilities for helping to reach policy goals related to the deployment of customer-sited PV.

[50] We focus here on achieved earnings over the first 10 years, as that is the period over which shareholder incentives are provided (given that they are tied to administration of the PV rebate program, which is offered only over the initial 10 years). As discussed earlier (see Figure 15), additional earnings erosion from customer-sited PV occurs in the second 10-year period, due to deferral of capital expenditures in those years.

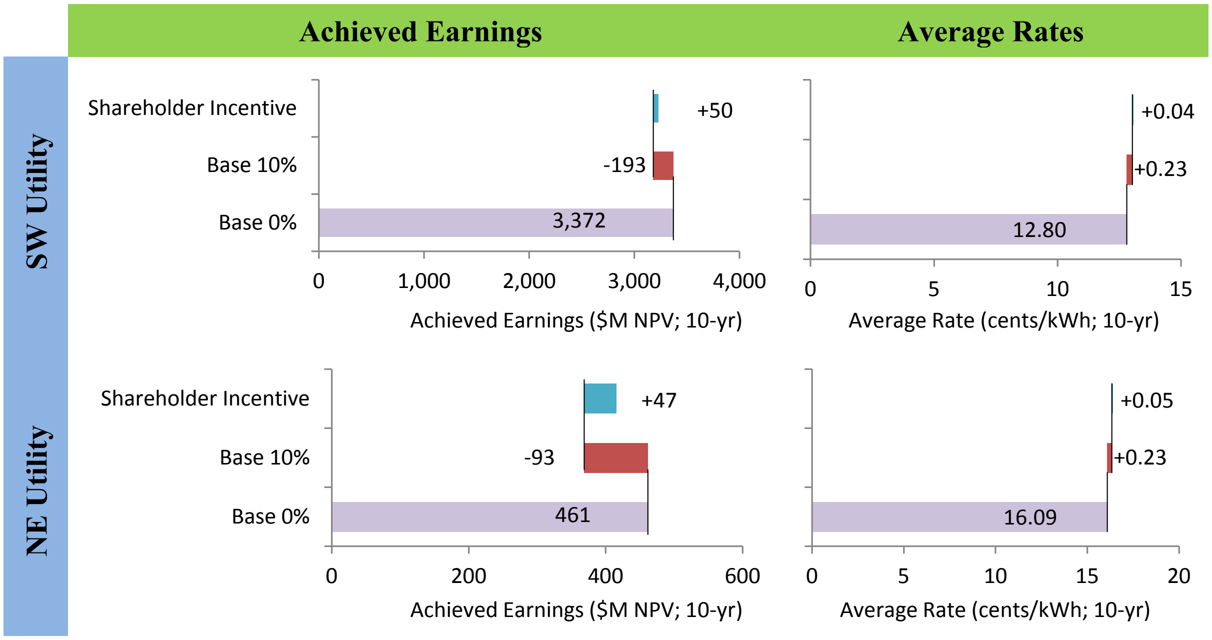

Figure 26. Mitigation of PV Impacts through Shareholder Incentives

6.3 Alternative ratesetting approaches may also significantly mitigate ROE impacts from customer-sited PV

Similar to decoupling and LRAM, the mitigation measures in this section may also serve to mitigate the revenue erosion from customer-sited PV and the associated impacts on shareholder ROE. However, while decoupling and LRAM achieve that outcome by potentially increasing revenue collection through rate adjustments in between rate cases, the mitigation measures considered in this section do so by reducing the amount of time between when utilities incur costs and when those costs are reflected in rates. These options, herein referred to as "alternative ratesetting approaches", include: more-frequent filing of rate cases, use of current or future test years in rate cases, and reduced regulatory lag between filing of rate cases and implementation of new rates. These measures boost utility revenues and shareholder ROE specifically in situations where utility costs are growing faster than its billing determinants, as is the case for both of the prototypical utilities under base-case conditions with 10% PV.

Alternative ratesetting approaches such as these have been discussed in the literature as a mitigation measure to address the disincentive for utilities to pursue EE, and might similarly be considered in the context of customer-sited PV (e.g., Carter 2001, Lowry et al. 2013). In Section 5, we found that utilities with more contemporaneous ratesetting approaches are less sensitive to the addition of customer-sited PV, while here we consider the adoption of alternative ratesetting approaches specifically as means to mitigating the financial impacts of PV on utility shareholders (i.e., where these ratesetting approaches are adopted in conjunction with PV).

To be sure, these ratesetting approaches entail a variety of important tradeoffs. More frequent filing of rate cases can reduce the incentives for utilities to minimize costs between rate cases and could potentially lead to perpetual rate cases (Carter 2001), which are costly and time consuming for regulatory staff and intervenors. Future test years require the use of sophisticated cost forecasts for establishing revenue requirements and billing determinants, which can be contentious (Costello 2013). And administrative process requirements can limit the potential for reducing regulatory lag between when new rates are adopted and when they go into effect.

Notwithstanding these important tradeoffs and limits, our analysis shows that these alternative ratesetting approaches may mitigate the impact of PV on achieved ROE. In fact, for the particular utilities and mitigation cases examined here, in most cases these measures more-than-offset the erosion in shareholder ROE caused by PV under base-case utility conditions, in which case they may be deemed as going "too far" in attempting to mitigate the effects of PV. As shown in Figure 27, the increase in ROE is most pronounced when switching from an historical test year to a future test year, resulting in an average ROE for both utilities that substantially exceeds the levels achieved under base case conditions without PV. Switching from an historical test year to a current test year or reducing regulatory lag by one year (which are functionally equivalent within the financial model used for this analysis) also increase achieved ROE to levels above the base-case ROE with no PV. Shortening the rate case filing frequency from three years to two years also mitigates the ROE impacts, though to a lesser extent than the other measures, and in the case of the NE Utility, only partially restoring achieved ROE back to the level achieved in the base case without PV.

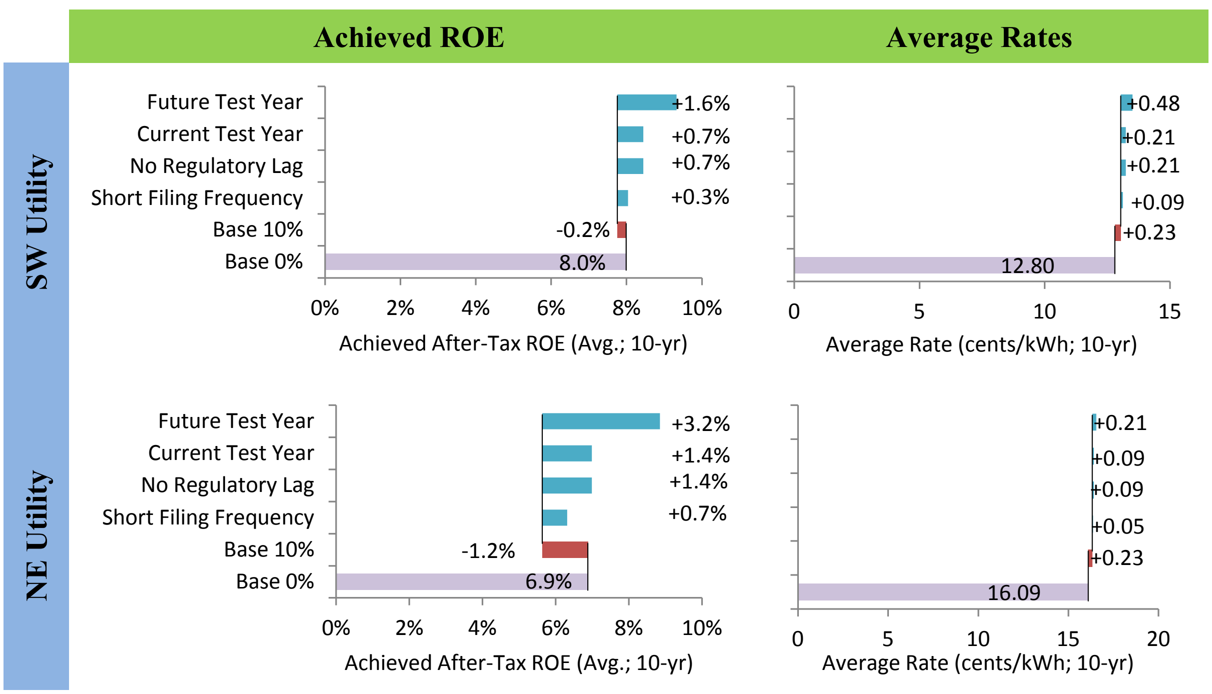

Figure 27. Mitigation of PV Impacts through Alternative Ratesetting Approaches

As with decoupling and LRAM, improved shareholder ROE under the mitigation measures considered here occurs as a result of increased revenue collection, which by definition entails an increase in average retail rates (beyond that which occurs in the base case with no PV). As noted above, however, in the case of these alternative ratesetting approaches, the increased revenues and thus the associated increase in average retail rates occurs specifically in cases where the utility's costs are increasing faster than its billing determinants. Under these particular conditions, more-contemporaneous ratesetting approaches improve the ability of the utility to reflect those cost increases in its retail rates, thereby potentially mitigating the impacts of customer-sited PV on shareholder ROE while exacerbating its impacts on average rates.

6.4 Increased fixed customer charges and demand charges can moderate the impact of PV on shareholder ROE, but in some cases may exacerbate those impacts

We assess the effectiveness of changes in rate design as a mitigation measure where the utility increases the share of revenue collected through demand or fixed customer charges in response to increased deployment of customer-sited PV. Because a large proportion of the utility's total costs are fixed in the short run (i.e., do not vary between rate cases with changes in consumption), collection of revenue based on a fixed charge may better match revenues to costs between rate cases, especially in an environment with low load growth. Similarly, an increase in revenue collected from demand charges may reduce the impact to utility collected revenues from declines in retail energy sales, because EE and PV do not reduce demand by as much as they reduce energy sales. Such changes to rate designs have often been proposed on occasion in order to mitigate the revenue erosion impacts of EE, and have been discussed more broadly as a strategy for better aligning utility revenues and costs (RAP 2011, EEI 2013, Hledik 2014).[51]

Important policy tradeoffs, however, arise in connection to increased fixed customer charges or demand charges, and corresponding decreases in volumetric energy charges. The first is that higher fixed charges reduce the incentive for customers to conserve energy and to invest in PV. Alternatively, high fixed charges might motivate customers to invest in onsite generation with storage, and to bypass the utility altogether – which would further exacerbate the problems that the change in rate design was intended to address in the first place. These potential dynamics highlight one important difference between high fixed customer charges and RPC decoupling: although both measures similarly tie utility revenues more closely to the number of customers (and growth therein), RPC decoupling does so in a manner that maintains the same volumetric charges for customers, and thus does not diminish customers' incentive for EE and distributed generation (or provide an increased incentive for grid defection). A separate but related policy tradeoff is that, in general, increased fixed customer charges limit customers' ability to manage their total utility bill, which may raise concerns related specifically with respect to low- and fixed- income customers. Increased demand charges may entail less severe tradeoffs than occur with high fixed customer charges, but many utilities do not have the meter capabilities to record and bill demand for residential customers, and thus a greater reliance upon demand charges for residential customers would require deployment of the necessary metering and billing systems.

[51] In particular, a form of rate design called straight-fixed variable (SFV) , where by fixed utility costs are recovered primarily through fixed customer charges, has been implemented in three states for electric utilities and 9 states for gas utilities (EEI 2013). Similarly some utilities are implementing fixed charges that are applied only to customers with PV (e.g., APS in Arizona, Dominion Virginia Power in Virginia). The motivation for targeted fixed charges is to ensure that customers with PV still contribute to covering a portion of the fixed costs of the utility system needed to serve customers with PV. Challenges in making these decisions include: determining what portion of costs are truly fixed in the long-run, determining how much of a cross-subsidy between participants and non-participants is acceptable, and balancing market transformation goals with considerations of equity, among others. We do not model targeted fixed customer charges, but note the importance of this issue for future analyses.

Although we do not examine these various policy tradeoffs within the context of the present analysis, we highlight their potential importance for decision-makers and for future studies.

For the purpose of our mitigation analysis, we specified two scenarios involving alternative rate designs – a high demand charge case and a high fixed customer charge case – applied to all customers. Both entail shifting all non-fuel costs that were recovered through volumetric charges in the base case to either demand charges (in the high demand charge case) or fixed customer charges (in the high fixed customer charge case). The resulting share of revenue collected through volumetric, demand, and fixed charges is shown in Table 9. Note that the high fixed customer charge case in this mitigation analysis is more heavily weighted towards customer charges than the high fixed customer charge case in the sensitivity analysis in Section 5. Note also that the shift in revenue allocation, from one scenario to another, is more severe for the SW Utility than for the NE Utility, because the NE Utility relies on energy market purchases to meet its entire retail sales obligation, and those costs are collected through volumetric energy charges in all cases. Finally, it is important to reiterate that these rates are applied to all customers (i.e., both those with PV and without PV) and to all rate classes, though we acknowledge that many of the rate design discussions surrounding PV involve changes to rate design just for customers with PV.[52]

Table 9. Rate Design Mitigation Cases (Percent of Total Utility Revenues)

	Base Case	High Demand Charges	High Customer Charges
SW Utility			
Volumetric Charges	77%	24%	24%
Demand Charges	11%	63%	11%
Customer Charges	12%	12%	65%
NE Utility			
Volumetric Charges	84%	64%	64%
Demand Charges	8%	28%	8%
Customer Charges	8%	8%	28%

In general, the results of these mitigation scenarios show that shifting revenue collection from volumetric energy charges to demand charges or fixed customers charges can mitigate shareholder impacts from customer-sited PV, though the degree of mitigation – and, indeed whether or not the shareholder impacts from PV are mitigated or *exacerbated* – depends critically on the specific circumstances of the utility. In describing the shareholder impacts of these mitigation measures, we focus here on the impacts to ROE, as rate design measures principally serve principally to address issues associated with revenue erosion, rather than lost earnings opportunities; however the impacts of each mitigation measure on achieved earnings are included for reference in Appendix D.

As shown in Figure 28, moving to a rate design with high fixed customer charges has dramatically different impacts on the SW Utility and NE Utility. In particular, the SW Utility sees a significant improvement in achieved average ROE with a high fixed customer charge,

[52] The financial model used for this analysis does not distinguish between participants and non-participants, or among customer classes, but future editions of the model and future research will explore differential rate designs for customers with and without PV, and for different rate classes.

with the increase in ROE more than offsetting the erosion in ROE that occurs under the 10% PV scenario with base case rate design assumptions. In contrast, the NE Utility sees a further erosion of shareholder ROE under the high fixed customer charge case.

The differing results for the two utilities reflect underlying differences in the relative growth rate for the number of customers compared to growth rate for retail sales. The SW Utility has customer growth of 2.7% per year compared to 1.7% annual growth in retail sales with 10% PV, while the NE Utility has customer growth of 0.3% per year compared to 1.0% annual growth in retail sales with 10% PV (from 2013 to 2032). As a result, tying growth in revenues more closely to growth in the number of customers increases revenue collection by the SW Utility, better aligning revenues and costs between rate cases, while the opposite occurs for the NE Utility. These divergent results for the two utilities mirror those that occur under the mitigation scenario involving RPC decoupling without a k-factor, for the same underlying reasons.

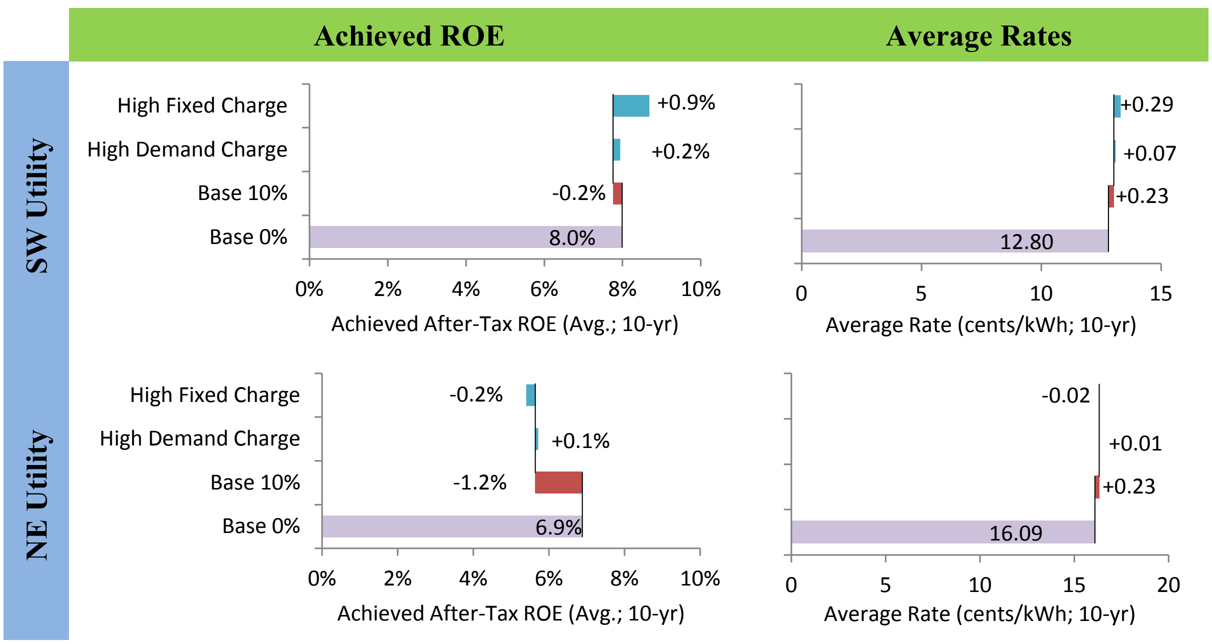

Figure 28. Mitigation of PV Impacts through Increased Customer Charges or Demand Charges

Moving to a rate design with high demand charges has a much more modest impact, compared to the high fixed charge scenario, resulting in a small increase in achieved ROE (relative to the base case at 10% PV penetration) for both utilities. These increases in achieved ROE reflect the fact that, for both prototypical utilities, growth in peak demand is greater than growth in retail sales with 10% PV. Tying non-fuel revenues to peak demand therefore allows the utility to collect greater revenues between rate cases than under the base case rate design.

Any increase in achieved ROE due to a shift towards higher fixed customer charges or demand charge is the direct result of an increase in total utility revenue collection. As with all of the other mitigation measures discussed thus far that also serve to increase revenues, some increase in average retail rates also occurs (beyond the increase that occurs in the base case with PV). As such, Figure 28 shows that average rates increase under the high fixed charge scenario for the

SW Utility and under the high demand charge scenario for both utilities. Important to note, however, is that such an increase in rates represents the average increase across all customers, and the impacts may differ substantially between customers with and without PV. Therefore one cannot conclude from this analysis how a move towards these particular rate design scenarios would impact customers without PV, and whether or not it would mitigate any increase in those customers' rates that otherwise occur as a result of customer-sited PV.[53]

6.5 Utility ownership of customer-sited PV may offer sizable earnings opportunities, potentially offsetting much of the earnings impacts from PV that otherwise occur

As with EE, customer-sited PV can erode shareholder earnings as a result of deferred or avoided capital expenditures, in addition to the earnings erosion associated with any mismatch in its effect on utility costs and revenues. In order to mitigate the shareholder impacts of lost earnings opportunities resulting from EE, utilities in some jurisdictions have been allowed to finance customer EE measures and earn an authorized return on those investments. Similarly, the lost earnings opportunities resulting from customer-sited PV could be mitigated by allowing customer-sited PV to become a regulated investment opportunity for utilities (SEPA 2008, SEPA 2009). This might involve full utility ownership of customer-sited PV assets, as proposed by APS and Tucson Electric Power (TEP), or may consist of utility financing of customer investments, similar to Public Service Electric and Gas (PSE&G)'s Solar Loan Program.[54]

To be sure, utility ownership or financing of customer-sited PV may raise a variety of significant policy and regulatory questions, not the least of which being whether a regulated utility should be allowed to provide a service similar to that provided by unregulated, competitive companies (including, in some cases, unregulated affiliates of the utility). In the case of a regulated utility, ratepayers would generally bear some portion of the risk of such investments. Furthermore, some states no longer allow regulated utilities to own generation (as in our NE Utility), in which case utility ownership of customer-sited generation may be prohibited or would require special authorization.[55]

Putting aside those important policy questions, we assume for the purpose of our analysis that the regulated utility is allowed to own customer-sited PV[56] and earn its authorized rate of return on those assets. We consider two scenarios: one bookend scenario in which the utilities own 100%

[53] As noted elsewhere in this report, LBNL expects to conduct follow-up analyses to examine the differential impacts of changes in rate design on customers with and without PV.

[54] The APS and TEP proposals differ in important ways, but both would involve utility ownership of PV systems installed on customer rooftops. Under the PSE&G Solar Loan program, the regulated utility provides loans to residential and commercial customers to purchase PV systems (which are net-metered), and the utility is allowed to add the cost of the program to its ratebase.

[55] See Wiser et al. (2010) for examples of utility ownership of customer-sited PV, including the Massachusetts Green Communities Act of 2008, which allows the state's regulated electric distribution companies to construct, own, and operate up to 50 MW of solar generation each.

[56] We assume that customer-sited PV costs $5.5/W_{dc}$ in 2010 and declines linearly to $2.1/W_{dc}$ in 2020, which corresponds to the mid-point cost reduction case from DOE's SunShot Vision Study (DOE 2012). We also assume that the utility is able to take advantage of the 30% investment tax credit (ITC) for installations prior to the end of 2016 and a 10% ITC for installations after 2016 (as would be the case for systems owned by any commercial entity, including a regulated utility).

of customer-sited PV capacity in their service territories, and another in which they own 10% of PV capacity. As in all other scenarios, PV systems are assumed to be installed behind the customer-meter and interconnected via a standard net metering arrangement; thus the impacts on utility billing determinants under this mitigation scenario are the same as in the base case. However, the utility is assumed to receive additional revenues from customers with PV systems that are owned or financed by the utility, and those revenues are assumed to be sufficient to provide the utility both a return *of* and *on* its investment. For the purpose of modeling this mitigation measure, we assume that these additional revenues can be approximated by adding the up-front cost of the customer-sited PV systems to the utility's ratebase, in the year in which the systems are installed.[57] With this approach, the SW and NE Utility capital costs increased by $2.8 billion and $2.6 billion, respectively, under the scenario where 100% of customer-sited PV is owned by the utility, and by proportionally smaller amounts under the scenario with utility ownership of 10% of all customer-sited PV.

For the purpose of examining this set of mitigation strategies, we focus on the impacts to shareholder ROE and earnings over the full 20-year analysis period, given that the lost earnings opportunities associated with customer-sited PV occur over that entire span (Figure 29). We do present impacts on rate impacts, as the incremental changes to average rate impacts for these mitigation cases are assumed to fall solely on PV customers, and thus changes to average rates for all customers (which is what the financial model estimates) are not a meaningful measure.

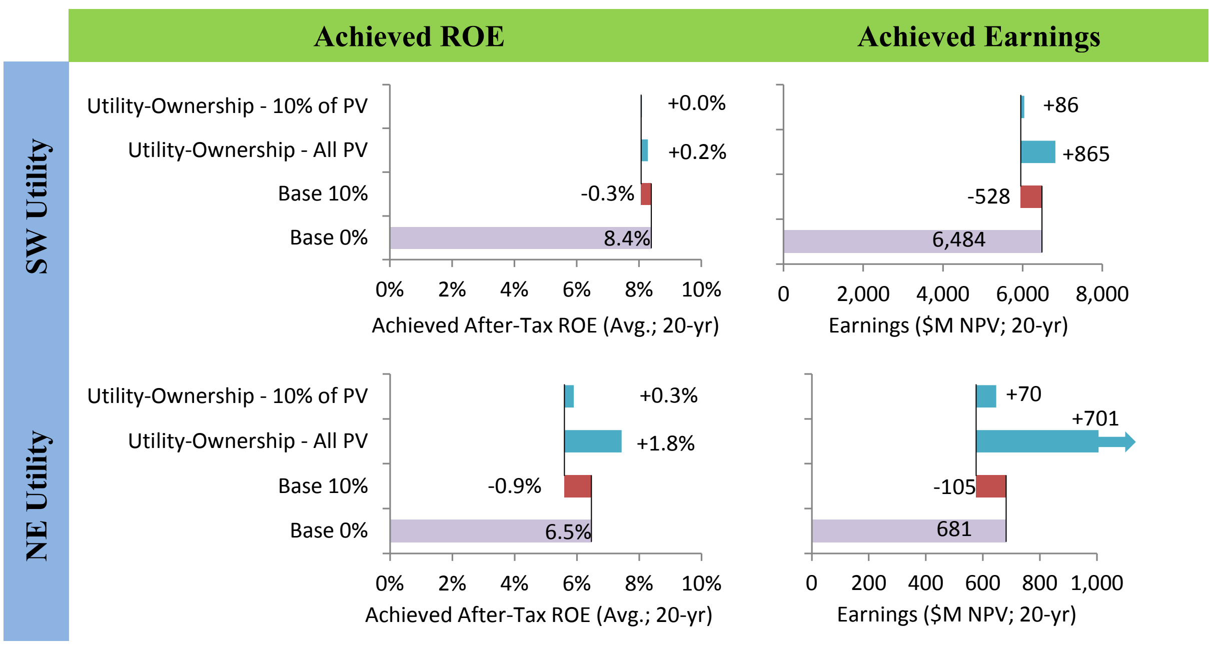

Figure 29. Mitigation of PV Impacts through Utility Ownership of Customer-Sited PV

[57] This modeling approach is thus akin to a cost capitalization shareholder incentive for EE programs, where EE program costs are added to the utility ratebase and recovered from all ratepayers. In the case of utility-owned, net-metered PV, revenues required to recover the cost of utility-owned PV would, in all likelihood, be recovered only from participating customers (e.g., via on-bill financing or some other mechanism), but for simplicity, we model revenue impacts as though they were recovered through base rates.

Under the scenarios in which the utilities own all customer-sited PV, achieved earnings and ROE rise significantly. In fact, for the NE Utility, where the only other utility investments are in the distribution system, allowing all PV to be owned by the utility leads to a doubling of achieved earnings over the 20-year analysis period. The SW Utility has a much larger ratebase prior to the addition of customer-sited PV, so the impact of utility ownership of PV is less dramatic, though the increase in earnings nevertheless more-than-offsets the decline in earnings that occurs under the base case with 10% PV. Under the arguably more realistic scenario in which the utilities own 10% of customer-sited PV, the increase in achieved earnings is only 10% of what occurs when the utilities own 100%. Thus, although achieved earnings and ROE increase for both utilities, those increases do not restore profitability back to the levels that occur under the base case without PV.

6.6 Automatically counting customer-sited PV towards RPS compliance can substantially mitigate the rate impacts from PV

The preceding mitigation measures all focused on addressing impacts of customer-sited PV on utility shareholders, and in most cases involved some corresponding increase in average rates. In contrast, one option for potentially mitigating the impacts on utility ratepayers is to automatically count all customer-sited PV directly toward the utility's RPS compliance obligation (without requiring any explicit payment by the utility).[58] This differs from the base case, where customer-sited PV indirectly reduces RPS compliance obligations by virtue of reducing retail sales, but RECs generated by customer-sited PV systems are assumed to remain the property of the system owner and are not automatically applied towards RPS compliance. In effect, this mitigation approach entails transferring ownership of RECs as a condition of receiving service under net-metering, thereby reducing the number of RECs that the utility would otherwise be required to procure in order to meet its RPS obligations.[59]

As do all other mitigation options, this one also involves a variety of tradeoffs. First is that it tantamount to reducing existing RPS requirements, as it reduces the amount of renewables that the utility would otherwise procure (without leading to any increase in customer-sited PV). Second, to the degree that customers' decisions to add PV is driven by their desire to retain or sell RECs from their PV system, automatically transferring REC ownership to the utility may degrade the value of PV to the customer and reduce deployment (as well as raise concerns about unlawful taking of private property). For these reasons and others, such transfers of REC ownership have often been controversial (Holt et al. 2007).

[58] Although not considered here, multipliers that are applied to RECs from customer-sited PV for purposes of RPS compliance would similarly serve to mitigate the rate impacts from customer-sited PV by reducing RPS compliance costs.

[59] In general, customer-sited PV is allowed by regulators to be counted towards utility RPS compliance; however, in most cases, ownership of the associated RECs remains with the owner of the system, unless the utility provides some kind of direct payment or explicit financial incentive. Recently, however, APS proposed an approach, termed "track and record", whereby all distributed solar in its service territory would be applied towards its RPS requirements, regardless of whether or not the systems received any direct financial incentive from the utility.

As shown in Figure 30, applying RECs generated by customer-sited PV toward the utilities' RPS compliance obligations without requiring any explicit utility payment offsets a substantial portion of the increases in average retail rates that otherwise occur in conjunction with customer-sited PV. In the case of the SW Utility, the rate impacts are reduced by roughly half, relative to the base case with 10% PV, while for the NE Utility, the rate impacts are offset almost in entirety. The degree of mitigation depends, among other factors, on the cost of avoided RECs, which in turn reflects the cost of renewable energy relative to non-renewable generation: when RECs are expensive, allowing customer-sited PV to count toward the RPS leads to a greater reduction in utility costs and thus a greater reduction in average rates. Thus, the mitigation is larger for the NE Utility, where assumed REC prices are higher ($35/MWh) than for the SW Utility (with an "effective" price of RECs of $23/MWh).[60] By the same logic, the results shown in Figure 30 would differ if other assumptions were made about the underlying cost of RECs (or, more generally, about the cost of renewable energy relative to the cost of non-renewable energy that RPS procurement displaces). Applying customer-sited PV toward utility RPS obligations does not impact utility ROE or earnings, as we assume that the avoided RPS compliance costs are an annual pass-through to customers.[61]

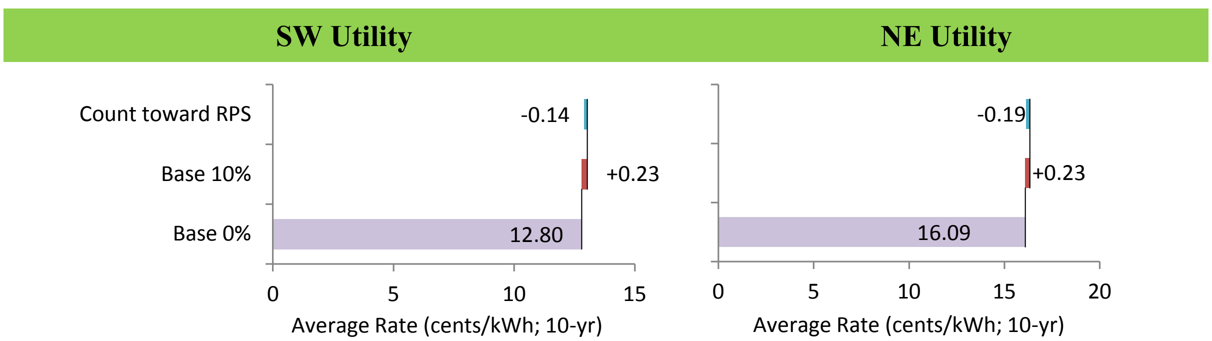

Figure 30. Mitigation of PV Impacts by Applying RECs from Customer-Sited PV towards RPS Obligations

[60] For simplicity of modeling, we apply this REC price for all RPS obligations of the NE Utility; had we assumed higher REC prices, such as those typical of solar set-aside markets, the mitigation of rate impacts would be even greater. The SW Utility is assumed to purchase RECs and energy as a bundled product, and thus the effective REC price is simply the difference between the cost of power purchase agreements (PPAs) for renewables and for conventional generation.

[61] We assume that the SW Utility meets its RPS obligation through a combination of utility-owned renewable generation and PPAs, but that PPAs are the marginal resource and are treated as pass-through costs.

7. Conclusion

This analysis relied upon a *pro-forma* financial model to quantify the potential impacts of customer-sited PV on two prototypical investor-owned utilities: a vertically integrated utility located in the southwest and wires-only utility located in the northeast. For each utility, we modeled the impacts of customer-sited PV over a 20-year period, estimating changes in utility costs, revenues, average rates, and utility shareholder earnings and return-on-equity. These impacts were evaluated under a base-case set of assumptions for each utility, as well as under a wide range of sensitivity cases that considered alternate assumptions about the utilities' operating and regulatory environments. Finally, we analyze a number of possible options for mitigating the impacts of customer-sited PV on utility shareholders and ratepayers.

7.1 Policy Implications

The findings from this analysis suggest several policy implications. First, even at penetration levels substantially higher than exist today, the impact of customer-sited PV on average retail rates *may* be relatively modest. We consider customer-sited PV penetration levels that ramp up to 10% of retail sales in 2022, compared to current rates of 1-2% in high-penetration states and a U.S. average of 0.2%. For the two prototypical utilities considered within our analysis, this PV deployment trajectory leads to roughly a 3% increase in average, all-in retail rates under our base-case set of assumptions, and to a 0% to 4% rate increase across the various sensitivity cases tested. These results should, of course, be considered in light of the nature and scope of our analysis – for example, that they are modeled results based on certain assumptions about the prototypical utilities and about how distributed PV impacts costs and revenues, and that the analysis considers the impact of distributed PV in isolation from other factors that may simultaneously place downward pressure on sales and/or upward pressure on rates. Nevertheless, our analysis suggests that distributed PV is unlikely, on its own, to lead to rate impacts of such a magnitude as to dramatically alter the customer-economics of PV, and to thereby result in a "death spiral" of departing load and concomitant rate increases. To the extent that efforts to mitigate the rate impacts of customer-sited PV are still warranted, utilities, policymakers, and solar stakeholders likely have sufficient time to address these concerns in a measured and deliberate manner.

Compared to the impacts on ratepayers, the impacts of customer-sited PV on utility shareholders are potentially much more pronounced. In the case of the two prototypical utilities in our analysis, for example, shareholder earnings fell by 8% for the SW utility and by 15% for the NE utility under the base-case assumptions and at 10% PV penetration, but fell by as much as 13% and 41% (for the SW utility and NE utility, respectively) under certain other conditions. The potential magnitude of these impacts – especially among wires-only utilities or other utilities with a relatively small ratebase – may create more immediate pressure on utilities to address shareholders concerns about the erosion of profits caused by customer-sited PV. However, as shown in the analysis, these impacts are highly dependent upon the specifics of the utility operating and regulatory environment, and it will therefore be important for policymakers and others to consider the particular conditions of any individual utility when assessing the possible impacts of customer-sited PV on the utility's shareholders.

Finally, our analysis shows that a variety of measures that constitute arguably "incremental" changes to utility business or regulatory models (as opposed to wholesale paradigm shifts) could be deployed to mitigate the impacts of customer-sited PV on utility ratepayers and shareholders. As shown, however, the potential efficacy of these measures may vary considerably depending upon both their design and upon the specific utility circumstances. For example, within our analysis, when revenue-per-customer (RPC) decoupling is implemented in conjunction with customer-sited PV, the result can range from a worsening of utility profitability to a dramatic improvement in profitability beyond the level achieved without PV, depending on the utility and the choice of design elements (e.g., a "k-factor"). Moreover, many potential mitigation strategies entail substantive tradeoffs. These tradeoffs may exist between ratepayers and shareholders; for example, decoupling and other mitigation measures that involve changes to the way the utility collects revenue may lead to increases in average retail rates. Important tradeoffs may also exist among competing policy and regulatory objectives – for example, among the various principles of ratemaking, or between policy objectives associated with ratepayer equity and environmental goals. Given the complex set of issues involved in implementing many of the possible mitigation measures, regulators may wish to address concerns about the ratepayer and shareholder impacts of customer-sited PV within the context of broader policy- and rate-making processes.

7.2 Future Research

As a scoping study, one key objective of the present research is to help identify additional questions and issues worthy of further analysis. Although by no means an exhaustive list, these areas for future research include the following, many of which will be addressed through follow-on work to the present study and refinements to LBNL's utility financial model:

- ***Benchmark the impacts of customer-sited PV against other factors affecting utility profitability and customer rates.*** Utility shareholder returns and earnings, as well as retail electricity rates, are impacted by many factors, and various forms of cross-subsidy exist within utility ratemaking. Understanding how the impacts of PV measure up against these other issues may help utilities and policymakers gauge the severity and importance of the impacts associated with customer-sited PV, and budget their resources accordingly.

- ***Examine the combined impacts from customer-sited PV, aggressive energy efficiency, and other demand-side measures.*** This report examined the impacts of customer-sited PV in isolation. In reality, however, the growth of customer-sited PV is often occurring in tandem with aggressive energy efficiency programs and other changes to electricity consumption patterns and end-uses, and adoption of distributed storage technologies could potentially expand greatly in the future. Understanding how the impacts from these trends may compound and interact will enable more informed judgments about the severity of, and options for holistically addressing, any possible impacts on utility shareholders and ratepayers.

- ***Examine differential impacts among customer groups.*** The present analysis considered the impacts on utility ratepayers as a whole, but did not differentiate between the impacts among separate customer classes (e.g., residential vs. commercial) or between customers with and without PV. These distinctions are important both because of differences in underlying rate design among customer classes, and because certain mitigation measures are aimed at increasing revenue collection from solar customers, specifically.

- ***Examine a broader range of mitigation options and combinations thereof.*** For reasons of tractability, the present study considered only a subset of possible measures for mitigating the utility and ratepayer impacts from PV, and considered only individual mitigation options in isolation. A wide variety of other measures have also been suggested and are worthy of further analysis, including (among others): stand-by rates, time-based pricing, two-way rates such as value-of-solar tariffs or feed-in tariffs, bi-directional distribution rates, non-fuel cost trackers, formula rates, multi-year rate plans, separate customer classes for PV customers, unbundled pricing of utility services, and performance-based ratemaking (e.g., see Bird et al. 2013, Lowry et al. 2013, Linvill et al. 2013, Kihm and Kramer 2014). Analyzing varying combinations of such measures may allow for identification of comprehensive utility business and regulatory models to address issues related to customer-sited PV.

- ***Continue improving methods for estimating the avoided costs from customer-sited PV.*** As our analysis has shown, the impacts of customer-sited PV on utility shareholders and ratepayers are highly sensitive to the value of avoided costs. However, those avoided costs are complex and are often highly specific to the particular utility (or even to a localized region within the utility's service territory). Continued refinements to the methods and data used to estimate avoided costs – especially those related to avoided generation, transmission, and distribution capacity costs – will be critical to enabling reliable and utility-specific analyses of the shareholder and ratepayer impacts of customer-sited PV.

- ***Identify strategies for maximizing the avoided costs of customer-sited PV.*** In addition to the kinds of ratemaking and regulatory measures mentioned above, utilities and regulators may also be able to mitigate the rate impacts of customer-sited PV by directing or incentivizing its deployment in such a manner to maximize the avoided costs (e.g., through integrated distribution system planning, geographically targeted incentive structures, etc.).

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Appendix A: Utility Characterization Key Inputs

The impact of PV on utility shareholders and ratepayers depends on the underlying characteristics of the utility. Further details on key aspects of the two prototypical utilities are provided below.

Southwest Regional Load Forecasts

For the SW Utility energy and peak demand growth, we adjusted the load forecasts in the APS 2012 IRP to values that were representative of the southwest (i.e., 2.1% annual growth in energy and peak demand). We used load growth values from the Western Interconnection's most recent transmission expansion study.

Balancing Authority	Load Growth (CAGR, 2010-2021)	
	Annual Energy	Peak Demand
APS	2.7%	2.7%
CFE	2.9%	4.0%
EPE	2.6%	2.8%
NEVP	0.8%	0.9%
PACE	1.6%	3.0%
PNM	1.1%	0.9%
PSCO	1.0%	0.3%
SPP	1.0%	0.8%
SRP	1.3%	1.1%
TEP	0.3%	0.0%
WACM	2.2%	2.2%
WALC	1.0%	1.0%

Source: WECC ten-year plan

Southwest Utility Line-Item Capital Investments

Since the SW Utility is vertically integrated, we model periodic investments in new utility-owned generation. The generators include natural gas-fired peaker plants (combustion turbines), natural-gas fired mid-merit plants (combined cycle gas turbines), and utility-scale PV plants. The utility-scale PV plants contribute to meeting the utility's RPS obligation.

Year	Investment Type	Nameplate Capacity (MW)	Capital Cost ($M)	Annual O&M Cost ($M)
2013	Utility-scale PV	100	200.0	2.50
2014	Utility-scale PV	100	200.0	2.50
2017	Utility-scale PV	100	200.0	2.50
2019	Utility-scale PV	200	400.0	5.00
2019	Natural gas peaker	103	123.8	0.63
2020	Natural gas peaker	103	126.9	0.65
2020	Natural gas mid-merit	672	719.6	4.05
2021	Utility-scale PV	100	200.0	2.50
2021	Natural gas peaker	616	780.1	3.96
2023	Utility-scale PV	100	200.0	2.50
2023	Natural gas peaker	615	806.3	4.14

2024	Natural gas peaker	308	420.1	2.12
2025	Utility-scale PV	200	400.0	5.00
2025	Natural gas mid-merit	672	841.1	4.55
2027	Utility-scale PV	100	200.0	2.50
2027	Natural gas peaker	205	301.6	1.52
2029	Natural gas peaker	615	904.8	4.77
2031	Natural gas peaker	615	904.8	5.00

Validation of Range of Fixed Customer Charges

In the sensitivity analysis (Section 5) we consider a range of potential fixed customer charges and volumetric charges. For the High Customer Charges case, we assume a larger proportion of non-fuel costs that were allocated to volumetric charges in the Base Case are instead allocated to customer charges (and leave the fuel costs fully allocated to volumetric charges and the demand charges unchanged). The specific proportion of non-fuel costs allocated to customer charges was chosen such that the fixed customer charge portion of customer bills doubles from the base case.

We verified the reasonableness of this range by estimating the fraction of a typical residential customer bill that is based on fixed customer charges at a sample of utilities in the Southwest and Northeast (see Figure 31). In the Southwest, 1% to 19% of typical residential bills are made up of fixed customer charges (with actual charges ranging from \$1.6 to \$18.5/month). In the Northeast, 4% to 14% of typical residential bills are made up of fixed customer charges (with actual charges ranging from \$4 to \$16.4/month).

In each case we estimated typical bills based on the average residential customer consumption for the state (based on EIA Form 861 for 2012), the volumetric rate for residential customers, and the fixed customer charges for residential customers at each of the utilities.

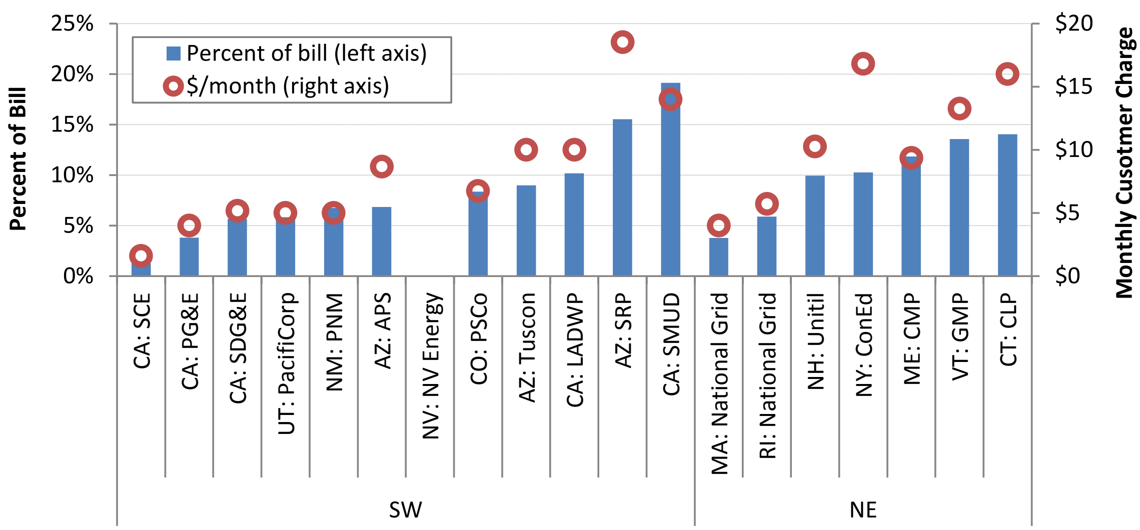


Figure 31. Proportion of a Typical Residential Bill Derived from Fixed Customer Charges for Utilities in the Southwest and Northeast

Appendix B. PV Characterization

Modeling the impact of PV on retail sales and peak demand

We assume that all customer-sited PV is on a net-metering rate that is otherwise the same as the rates for all other customers. PV generation therefore reduces sales on a one for one basis: one kWh of PV energy reduces the customer's sales billing determinant by one kWh. On the other hand, PV generation does not reduce the demand billing determinant on a one for one basis: one kW of PV reduces customer demand by less than one kW.

For the purpose of calculating the impacts of customer-sited PV on demand charge revenues, we use estimates of the capacity credit of PV (Hoff et al 2008) to estimate the reduction in peak demand from PV. At low penetration of PV, the contribution of PV to reducing peak demand is relatively high due to the correlation of PV production and peak demand. We also account for the decline in the capacity contribution of PV as PV penetration increases and peak net-load shifts into the early evening. For the SW utility, we use a relationship between the capacity credit of PV and PV penetration derived from NV Energy. For the NE Utility we use a relationship from Rochester Gas and Electric. We base the capacity credit of each increment of PV on the overall system level penetration of PV, which includes the assumed level of deployment of utility-scale PV.

Modeling of impact of PV on costs

The capacity credit of PV also dictates the ability of customer-sited PV to defer generation investments for the SW Utility and the ability of PV to reduce capacity purchases from the FCM for the NE Utility. We further assume that only a fraction of the capacity credit at the system level applies to reducing utility investments in non-generation capital expenditures at the local level. In the High Value of PV scenario we slow the rate of decline of the capacity credit with increasing PV penetration, such that later vintages of PV installations still contribute to reducing peak demand.[62] We also assume that a greater fraction of the capacity credit at the system level can reduce non-generation capital investments. In the Low Value of PV sensitivity we assume a lower capacity credit for even early vintages of customer-sited PV[63] and we further assume that non-generation capital investments need to increase during the period when PV is being added.

Solar PV at low penetration levels tends to displace more expensive fuels due to its correlation with times of high demand. We define the time-of-delivery (TOD) energy factor as the ratio of the average fuel cost displaced by PV to the time-average marginal fuel cost over a year. The TOD energy factor of PV is greater than 100% at low penetration levels (indicating fuels displaced by PV are more expensive than the average marginal fuel). We also account for the decline in the TOD energy factor with increasing penetration of PV as PV begins to displace lower and lower cost fuels. We base the relationship of the TOD energy factor with penetration

[62] In particular we use the low rate of decline of the capacity credit of PV estimated for Portland General Electric in Hoff et al., 2008, but we still start with a high capacity credit at low penetration for our prototypical utilities.
[63] We use the low capacity credit and corresponding rate of decline of PV estimated for Portland General Electric in Hoff et al., 2008.

on merit-order dispatch analysis of generators in Arizona and ISO-NE for the SW and NE Utility, respectively. The TOD energy factor and marginal capacity credit of PV as PV penetration increases between 2013 and 2022 are shown for the SW Utility in Figure 32 and NE Utility in Figure 33.

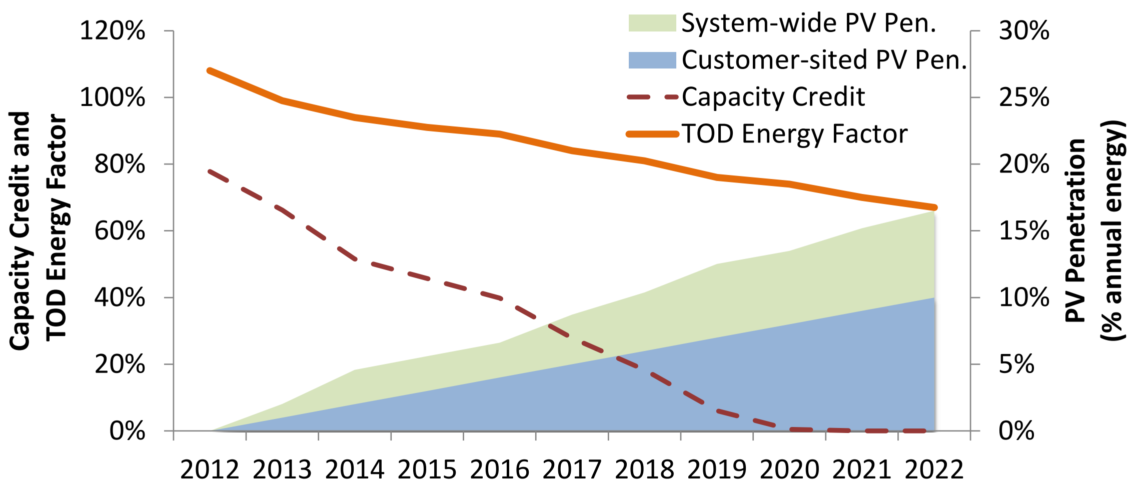


Figure 32. Capacity Credit and TOD Energy Factor of PV for the SW Utility

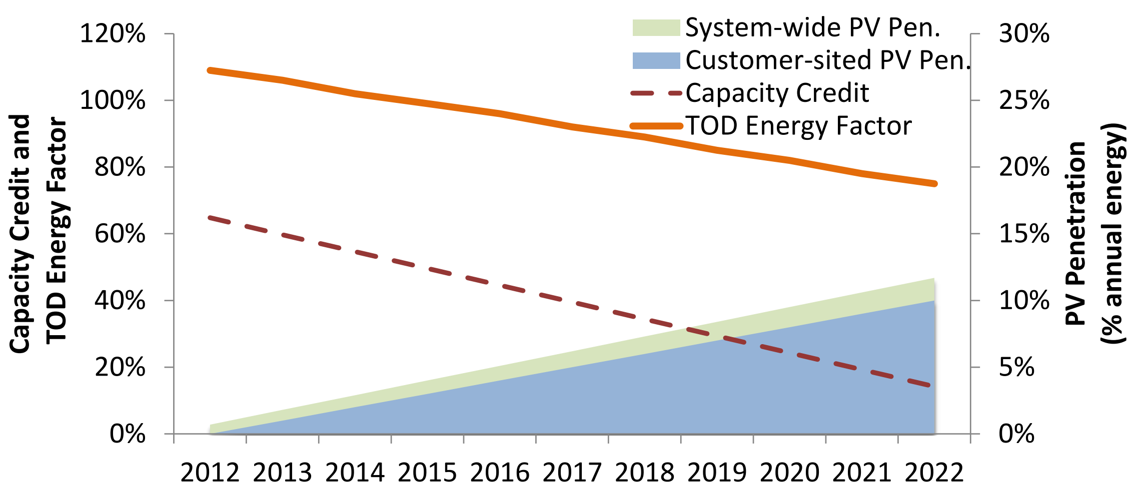


Figure 33. Capacity Credit and TOD Energy Factor of PV for the NE Utility

Key Input	Southwest Utility	Northeast Utility
PV capacity credit at 0% PV penetration	78%	68%
Decline in incremental capacity credit per 1% increase in PV penetration	-5.7%	-4.6%
TOD Energy Factor at 0% PV penetration	108%	111%
Decline in TOD Energy Factor per 1% increase in PV penetration	-2.3%	-3.1%

Methods to approximate breakdown of value of PV

The model used to estimate the revenue requirement of the SW and NE Utility with and without PV involves many complex calculations. We benchmarked the avoided cost estimated by the model (see Figure 11) against a set of "back-of-the-envelope" calculations for the different value components of PV. We used values from 2018 as this year was the last year before PV began to defer lumpy conventional generation units in the SW Utility, which greatly complicates estimates of the change in the revenue requirement. The table below includes the method used to estimate each value component of PV, followed by the numerical parameters used in the model for the year 2018 for each of the utilities, and the resulting calculated value (as shown in Figure 11). In some cases, where a simple back-of-the envelope estimate was not available, we simply used a stipulated value for that component.

PV Value Component	Method to Estimate Value	Southwest Utility	Northeast Utility
Avoided Energy	Average energy cost * TOD Energy Factor	$33/MWh * 98% = $32.4/MWh	$72/MWh * 89% = $63.8/MWh
Avoided Losses – Energy	Avoided Energy * Energy losses	$32.4/MWh * 7% = $2.3/MWh	$63.8/MWh * 4.1% = $2.6/MWh
Avoided Capacity	Capacity market price * Nameplate capacity of PV * PV capacity credit / Energy from PV	$88.6/kW-yr * 1008 MW * 41%/ 2030 GWh/yr = $17.9/MWh	$88.5/kW-yr * 945 MW * 47%/ 1408 GWh/yr = $27.9/MWh
Avoided Losses-Capacity	Avoided Capacity * Capacity Losses	$17.9/MWh * 15% = $2.7/MWh	$27.9/MWh * 8% = $2.2/MWh
Avoided Reserves	(Avoided Capacity + Avoided Losses-Capacity) * Reserve Margin	($17.9/MWh + $2.7/MWh) * 14% = $2.9/MWh	($27.9/MWh + $2.2/MWh) * 17.2% = $5.2/MWh
Avoided RPS	REC price * RPS Requirement	$23/MWh * 14% = $3.2/MWh	$35/MWh * 20% = $7/MWh
Avoided Transmission	SW: Assumption NE: Transmission access charge * Percent of PV capacity credit that offsets transmission * Nameplate of PV * PV capacity credit / Energy from PV	Assumption = $5/MWh	$76.8/kW-yr * 20% * 945 MW * 47% / 1408 GWh/yr = $4.8/MWh
Avoided Distribution	Assumption	Assumption = $10/MWh	Assumption = $10/MWh

Appendix C. Base Case Results

We report the Base Case achieved earnings, return on equity, and all-in average retail rates with and without PV for the Southwest and Northeast Utility. In cases with PV we also report the percent change in the metric relative to the Base Case without PV.

Southwest Utility

	Achieved After-Tax Earnings (% change from 0% PV Penetration)				
PV Penetration	**0%**	**2.5%**	**5%**	**7.5%**	**10%**
2013-2022 (10-year NPV @ WACC)	$3.37B	$3.32B (-1.4%)	$3.27B (-2.9%)	$3.23B (-4.2%)	$3.18B (-5.7%)
2013-2032 (20-year NPV @ WACC)	$6.48B	$6.23B (-3.9%)	$6.25B (-3.6%)	$5.97B (-7.9%)	$5.96B (-8.1%)

	Achieved After-Tax ROE (% change from 0% PV Penetration)				
PV Penetration	**0%**	**2.5%**	**5%**	**7.5%**	**10%**
2013-2022 (10-year Avg. @ WACC)	7.99%	7.97% (-0.3%)	7.90% (-1.1%)	7.84% (-1.8%)	7.76% (-2.9%)
2013-2032 (20-year Avg. @ WACC)	8.40%	8.22% (-2.1%)	8.30% (-1.1%)	8.07% (-3.9%)	8.07% (-3.9%)

	Average All-in Retail Rate (% change from 0% PV Penetration)				
PV Penetration	**0%**	**2.5%**	**5%**	**7.5%**	**10%**
2013-2022 (10-year Avg. @ 5%)	12.8 ¢/kWh	12.8 ¢/kWh (0.3%)	12.9 ¢/kWh (0.7%)	13.0 ¢/kWh (1.2%)	13.0 ¢/kWh (1.8%)
2013-2032 (20-year Avg. @ 5%)	14.2 ¢/kWh	14.2 ¢/kWh (0.0%)	14.4 ¢/kWh (1.0%)	14.4 ¢/kWh (1.3%)	14.6 ¢/kWh (2.5%)

Northeast Utility

	Achieved After-Tax Earnings (% change from 0% PV Penetration)				
PV Penetration	**0%**	**2.5%**	**5%**	**7.5%**	**10%**
2013-2022 (10-year NPV @ WACC)	$461M	$436M (-5.5%)	$412M (-10.7%)	$390M (-15.5%)	$368M (-20.2%)
2013-2032 (20-year NPV @ WACC)	$681M	$651M (-4.5%)	$623M (-8.6%)	$598M (-12.2%)	$576M (-15.4%)

	Achieved After-Tax ROE (% change from 0% PV Penetration)				
PV Penetration	**0%**	**2.5%**	**5%**	**7.5%**	**10%**
2013-2022 (10-year Avg. @ WACC)	6.88%	6.56% (-4.7%)	6.24% (-9.3%)	5.94% (-13.7%)	5.64% (-18.1%)
2013-2032 (20-year Avg. @ WACC)	6.47%	6.24% (-3.6%)	6.01% (-7.1%)	5.80% (-10.4%)	5.60% (-13.5%)

	Average All-in Retail Rate (% change from 0% PV Penetration)				
PV Penetration	**0%**	**2.5%**	**5%**	**7.5%**	**10%**
2013-2022 (10-year Avg. @ 5%)	16.1 ¢/kWh	16.1 ¢/kWh (0.1%)	16.2 ¢/kWh (0.4%)	16.2 ¢/kWh (0.8%)	16.3 ¢/kWh (1.5%)
2013-2032 (20-year Avg. @ 5%)	19.2 ¢/kWh	19.2 ¢/kWh (0.2%)	19.3 ¢/kWh (0.7%)	19.5 ¢/kWh (1.5%)	19.7 ¢/kWh (2.7%)

Appendix D: Sensitivity Analysis Results

We examine the sensitivity of the impact of PV to differences in the utility operating environment and regulatory environment from that modeled in the Base Case. This appendix includes a detailed description of the assumptions used in the sensitivity cases followed by tables with detailed results of the sensitivity cases for both the initial 10-year period (2013-2022) and the full 20-year analysis period (2013-2032). The sensitivity results show the earnings, ROE, and retail rates with and without PV, the difference in the metric, and the percent change in the metric with PV.

Sensitivity Case Definitions

	Sensitivity Case	Definition
Utility Operating Environment	High Value of PV	Incremental capacity credit of PV decreases at much slower rate with penetration. Increase offset of growth-related CapEx to 100% of PV capacity credit.
	Low Value of PV	Incremental capacity credit of PV at low penetration is only about 20%, and decreases at a slow rate with penetration. Decrease offset of Growth-related CapEx to 0% of PV capacity credit and increase capital expenditure growth rate by +1%/yr in years with new customer PV.
	High Load Growth	Load growth rate increased by +2%/yr and line item CapEx plan is shifted into earlier years (for SW Utility)
	Low Load Growth	Load growth rate decreased by -2%/yr and line item CapEx plan is shifted into later years (for SW Utility)
	High Fixed O&M Cost Growth	Fixed O&M cost growth rate increased by +2%/yr
	Low Fixed O&M Cost Growth	Fixed O&M cost growth rate decreased by -2%/yr
	High Non-Generating CapEx Growth	CapEx cost growth rate is increased by +1%/yr
	Low Non-Generating CapEx Growth	CapEx cost growth rate is decreased by -1%/yr
	High Fuel/Purchased Power Cost Growth	Fuel/purchased power cost growth rate is increased by +2%/yr
	Low Fuel/Purchased Power Cost Growth	Fuel/purchased power cost growth rate is decreased by -2%/yr
	Coal Retirement	1200 MW of existing coal capacity is retired in 2018 and replaced with new natural gas-fired combined cycle plants (CCGT)
	High Utility-Owned Generation Share	Additional CCGT capacity (600 MW) is built in 2015 and 2018 to decrease the amount of short-term capacity purchased by the SW utility
	High Utility-Owned Generation Cost	Cost of building new utility-owned generation (UOG) is increased by +20%
	Low Utility-Owned Generation Cost	Cost of building new utility-owned generation (UOG) is decreased by -20%
	High FCM Cost Growth	Cost of purchasing capacity in the forward capacity market (FCM) is increased by +20%
	Low FCM Cost Growth	Cost of purchasing capacity in the FCM is decreased by -20%
Utility Regulatory Environment	Rate Design: High Fixed Customer Charge	Share of costs recovered through fixed customer charges is doubled and non-fuel costs recovered through volumetric energy charges is reduced
	Rate Design: High Volumetric Rates	Share of non-fuel costs recovered through volumetric energy rates is increased and fixed customer charges are eliminated
	Long Rate Case Filing Period	Filing period of general rate cases (GRCs) is increased by two years
	Short Rate Case Filing Period	Filing period of GRCs is decreased by one year
	Long Period of Regulatory Lag	Regulatory lag is increased by one year
	Short Period of Regulatory Lag	Regulatory lag is decreased by one year
	Current Test Year	Test year is changed from historic to current
	Future Test Year	Test year is changed from historic to future
	PV Incentives	Provide a $0.5/Watt incentive from the utility to customers with PV

Southwest Utility – 10-year Sensitivity Results (2013 to 2022)

Sensitivity Case		After-Tax Achieved Earnings ($M NPV@WACC)	After-Tax Achieved ROE (% Avg.@WACC)	All-in Average Retail Rates (cents/kWh Avg.@WACC)
Base	0% PV	3,372	7.99%	12.80
	10% PV	3,179	7.76%	13.03
	Difference	-193	-0.23%	0.23
	% Change	**-5.7%**	**-2.9%**	**1.8%**
High Value of PV	0% PV	3,372	7.99%	12.80
	10% PV	3,127	7.81%	12.82
	Difference	-245	-0.18%	0.02
	% Change	**-7.3%**	**-2.2%**	**0.1%**
Low Value of PV	0% PV	3,372	7.99%	12.80
	10% PV	3,192	7.57%	13.17
	Difference	-180	-0.42%	0.37
	% Change	**-5.3%**	**-5.3%**	**2.9%**
High Load Growth	0% PV	4,276	8.55%	12.65
	10% PV	4,012	8.36%	12.81
	Difference	-263	-0.19%	0.16
	% Change	**-6.2%**	**-2.3%**	**1.3%**
Low Load Growth	0% PV	2,662	7.37%	13.04
	10% PV	2,406	6.70%	13.25
	Difference	-256	-0.67%	0.21
	% Change	**-9.6%**	**-9.1%**	**1.6%**
High Fixed O&M Growth	0% PV	3,219	7.62%	12.98
	10% PV	3,021	7.37%	13.22
	Difference	-198	-0.26%	0.24
	% Change	**-6.2%**	**-3.3%**	**1.8%**
Low Fixed O&M Growth	0% PV	3,509	8.32%	12.63
	10% PV	3,321	8.10%	12.85
	Difference	-188	-0.21%	0.22
	% Change	**-5.4%**	**-2.5%**	**1.7%**
High Non-Generating CapEx Growth	0% PV	3,412	7.61%	12.97
	10% PV	3,213	7.36%	13.20
	Difference	-199	-0.25%	0.24
	% Change	**-5.8%**	**-3.3%**	**1.8%**
Low Non-Generating CapEx Growth	0% PV	3,332	8.35%	12.65
	10% PV	3,145	8.13%	12.87
	Difference	-187	-0.21%	0.22
	% Change	**-5.6%**	**-2.5%**	**1.8%**
High Fuel Cost Growth	0% PV	3,372	7.99%	13.32

	10% PV	3,179	7.76%	13.50
	Difference	-193	-0.23%	0.19
	% Change	**-5.7%**	**-2.9%**	**1.4%**
Low Fuel Cost Growth	0% PV	3,372	7.99%	12.35
	10% PV	3,179	7.76%	12.62
	Difference	-193	-0.23%	0.27
	% Change	**-5.7%**	**-2.9%**	**2.2%**
Coal Retirement	0% PV	3,389	7.72%	13.01
	10% PV	3,168	7.56%	13.01
	Difference	-221	-0.17%	0.01
	% Change	**-6.5%**	**-2.1%**	**0.0%**
High Utility-Owned Generation Share	0% PV	3,407	7.63%	12.85
	10% PV	3,180	7.40%	13.03
	Difference	-228	-0.23%	0.18
	% Change	**-6.7%**	**-3.0%**	**1.4%**
High Utility-Owned Generation Cost	0% PV	3,421	7.96%	12.87
	10% PV	3,187	7.69%	13.06
	Difference	-233	-0.27%	0.19
	% Change	**-6.8%**	**-3.4%**	**1.5%**
Low Utility-Owned Generation Cost	0% PV	3,377	8.11%	12.77
	10% PV	3,171	7.82%	13.00
	Difference	-206	-0.29%	0.23
	% Change	**-6.1%**	**-3.6%**	**1.8%**
High Fixed Customer Charge	0% PV	3,408	8.07%	12.83
	10% PV	3,268	7.97%	13.10
	Difference	-140	-0.10%	0.27
	% Change	**-4.1%**	**-1.3%**	**2.1%**
High Volumetric Rates	0% PV	3,336	7.90%	12.77
	10% PV	3,091	7.54%	12.96
	Difference	-246	-0.36%	0.19
	% Change	**-7.4%**	**-4.6%**	**1.5%**
Long Rate Case Filing Period	0% PV	3,177	7.51%	12.66
	10% PV	2,905	7.10%	12.82
	Difference	-271	-0.42%	0.16
	% Change	**-8.5%**	**-5.5%**	**1.3%**
Short Rate Case Filing Period	0% PV	3,495	8.28%	12.89
	10% PV	3,293	8.04%	13.11
	Difference	-203	-0.24%	0.23
	% Change	**-5.8%**	**-2.9%**	**1.8%**
Long Regulatory Lag	0% PV	3,157	7.49%	12.65
	10% PV	2,914	7.12%	12.83
	Difference	-243	-0.37%	0.18
	% Change	**-7.7%**	**-4.9%**	**1.4%**
Short Regulatory Lag	0% PV	3,694	8.71%	13.03

	10% PV	3,460	8.45%	13.24
	Difference	-234	-0.26%	0.21
	% Change	**-6.3%**	**-3.0%**	**1.6%**
Current Test Year	0% PV	3,694	8.71%	13.03
	10% PV	3,460	8.45%	13.24
	Difference	-234	-0.26%	0.21
	% Change	**-6.3%**	**-3.0%**	**1.6%**
Future Test Year	0% PV	4,031	9.50%	13.27
	10% PV	3,813	9.33%	13.51
	Difference	-218	-0.17%	0.23
	% Change	**-5.4%**	**-1.8%**	**1.8%**
PV Incentives	0% PV	3,372	7.99%	12.80
	10% PV	3,179	7.76%	13.26
	Difference	-193	-0.23%	0.46
	% Change	**-5.7%**	**-2.9%**	**3.6%**

Southwest Utility – 20-year Sensitivity Results (2013 to 2032)

Sensitivity Case		After-Tax Achieved Earnings ($M NPV@WACC)	After-Tax Achieved ROE (% Avg.@WACC)	All-in Average Retail Rates (cents/kWh Avg.@WACC)
Base	0% PV	6,484	8.40%	14.24
	10% PV	5,956	8.07%	14.59
	Difference	-528	-0.33%	0.35
	% Change	**-8.1%**	**-3.9%**	**2.5%**
High Value of PV	0% PV	6,484	8.40%	14.24
	10% PV	5,630	8.12%	14.20
	Difference	-854	-0.27%	-0.04
	% Change	**-13.2%**	**-3.2%**	**-0.3%**
Low Value of PV	0% PV	6,484	8.40%	14.24
	10% PV	6,145	7.92%	14.85
	Difference	-339	-0.48%	0.61
	% Change	**-5.2%**	**-5.7%**	**4.3%**
High Load Growth	0% PV	8,929	8.99%	13.93
	10% PV	8,502	8.81%	14.24
	Difference	-427	-0.18%	0.31
	% Change	**-4.8%**	**-2.0%**	**2.2%**
Low Load Growth	0% PV	4,434	7.62%	14.61
	10% PV	4,147	7.13%	15.18
	Difference	-288	-0.49%	0.57
	% Change	**-6.5%**	**-6.4%**	**3.9%**
High Fixed O&M Growth	0% PV	6,235	8.06%	14.57
	10% PV	5,691	7.70%	14.94
	Difference	-544	-0.36%	0.37
	% Change	**-8.7%**	**-4.5%**	**2.5%**
Low Fixed O&M Growth	0% PV	6,691	8.69%	13.94
	10% PV	6,176	8.39%	14.27
	Difference	-516	-0.30%	0.33
	% Change	**-7.7%**	**-3.4%**	**2.4%**
High Non-Generating CapEx Growth	0% PV	6,908	7.96%	14.73
	10% PV	6,372	7.61%	15.13
	Difference	-535	-0.35%	0.40
	% Change	**-7.7%**	**-4.4%**	**2.7%**
Low Non-Generating CapEx Growth	0% PV	6,131	8.81%	13.84
	10% PV	5,616	8.52%	14.15
	Difference	-515	-0.28%	0.31
	% Change	**-8.4%**	**-3.2%**	**2.2%**
High Fuel Cost Growth	0% PV	6,484	8.40%	15.25
	10% PV	5,956	8.07%	15.53

	Difference	-528	-0.33%	0.29
	% Change	**-8.1%**	**-3.9%**	**1.9%**
Low Fuel Cost Growth	0% PV	6,484	8.40%	13.47
	10% PV	5,956	8.07%	13.88
	Difference	-528	-0.33%	0.41
	% Change	**-8.1%**	**-3.9%**	**3.0%**
Coal Retirement	0% PV	6,713	8.28%	14.63
	10% PV	6,178	8.01%	14.87
	Difference	-535	-0.27%	0.25
	% Change	**-8.0%**	**-3.2%**	**1.7%**
High Utility-Owned Generation Share	0% PV	6,708	8.21%	14.44
	10% PV	6,133	7.87%	14.70
	Difference	-575	-0.34%	0.25
	% Change	**-8.6%**	**-4.1%**	**1.7%**
High Utility-Owned Generation Cost	0% PV	6,678	8.36%	14.41
	10% PV	6,042	7.98%	14.70
	Difference	-637	-0.38%	0.29
	% Change	**-9.5%**	**-4.5%**	**2.0%**
Low Utility-Owned Generation Cost	0% PV	6,176	8.32%	14.02
	10% PV	5,864	8.16%	14.48
	Difference	-312	-0.16%	0.46
	% Change	**-5.1%**	**-1.9%**	**3.3%**
High Fixed Customer Charge	0% PV	6,544	8.48%	14.27
	10% PV	6,067	8.24%	14.64
	Difference	-477	-0.24%	0.38
	% Change	**-7.3%**	**-2.8%**	**2.6%**
High Volumetric Rates	0% PV	6,424	8.32%	14.21
	10% PV	5,844	7.90%	14.54
	Difference	-580	-0.41%	0.32
	% Change	**-9.0%**	**-5.0%**	**2.3%**
Long Rate Case Filing Period	0% PV	6,289	8.08%	14.15
	10% PV	5,517	7.46%	14.38
	Difference	-772	-0.62%	0.23
	% Change	**-12.3%**	**-7.6%**	**1.6%**
Short Rate Case Filing Period	0% PV	6,618	8.60%	14.30
	10% PV	6,091	8.29%	14.65
	Difference	-527	-0.31%	0.35
	% Change	**-8.0%**	**-3.7%**	**2.5%**
Long Regulatory Lag	0% PV	6,068	7.86%	14.06
	10% PV	5,506	7.45%	14.37
	Difference	-562	-0.40%	0.32
	% Change	**-9.3%**	**-5.1%**	**2.3%**
Short Regulatory Lag	0% PV	6,929	9.00%	14.44
	10% PV	6,430	8.75%	14.81

	Difference	-499	-0.25%	0.38
	% Change	**-7.2%**	**-2.8%**	**2.6%**
Current Test Year	0% PV	6,929	9.00%	14.44
	10% PV	6,430	8.75%	14.81
	Difference	-499	-0.25%	0.38
	% Change	**-7.2%**	**-2.8%**	**2.6%**
Future Test Year	0% PV	7,397	9.67%	14.64
	10% PV	6,937	9.50%	15.06
	Difference	-459	-0.16%	0.41
	% Change	**-6.2%**	**-1.7%**	**2.8%**
PV Incentives	0% PV	6,484	8.40%	14.24
	10% PV	5,956	8.07%	14.73
	Difference	-528	-0.33%	0.49
	% Change	**-8.1%**	**-3.9%**	**3.4%**

Northeast Utility – 10-year Sensitivity Results (2013 to 2022)

Sensitivity Case		After-Tax Achieved Earnings ($M NPV@WACC)	After-Tax Achieved ROE (% Avg.@WACC)	All-in Average Retail Rates (cents/kWh Avg.@WACC)
Base	0% PV	461	6.88%	16.09
	10% PV	368	5.64%	16.33
	Difference	-93	-1.25%	0.23
	% Change	**-20.2%**	**-18.1%**	**1.5%**
High Value of PV	0% PV	461	6.88%	16.09
	10% PV	349	5.72%	16.10
	Difference	-112	-1.16%	0.01
	% Change	**-24.3%**	**-16.8%**	**0.1%**
Low Value of PV	0% PV	461	6.88%	16.09
	10% PV	386	5.64%	16.54
	Difference	-75	-1.24%	0.44
	% Change	**-16.3%**	**-18.1%**	**2.8%**
High Load Growth	0% PV	731	8.55%	15.83
	10% PV	633	7.61%	16.05
	Difference	-98	-0.94%	0.21
	% Change	**-13.4%**	**-11.0%**	**1.3%**
Low Load Growth	0% PV	241	4.13%	16.51
	10% PV	150	2.56%	16.79
	Difference	-91	-1.57%	0.29
	% Change	**-37.6%**	**-38.0%**	**1.7%**
High Fixed O&M Growth	0% PV	358	5.34%	16.24
	10% PV	262	4.01%	16.48
	Difference	-96	-1.33%	0.24
	% Change	**-26.9%**	**-25.0%**	**1.5%**
Low Fixed O&M Growth	0% PV	554	8.26%	15.96
	10% PV	464	7.10%	16.19
	Difference	-90	-1.16%	0.23
	% Change	**-16.2%**	**-14.1%**	**1.4%**
High Non-Generating CapEx Growth	0% PV	460	6.53%	16.13
	10% PV	366	5.35%	16.36
	Difference	-94	-1.18%	0.23
	% Change	**-20.4%**	**-18.0%**	**1.5%**
Low Non-Generating CapEx Growth	0% PV	462	7.22%	16.06
	10% PV	370	5.90%	16.30
	Difference	-92	-1.31%	0.23
	% Change	**-20.0%**	**-18.2%**	**1.5%**
High Fuel Cost Growth	0% PV	461	6.88%	17.16

	10% PV	368	5.64%	17.41
	Difference	-93	-1.25%	0.26
	% Change	**-20.2%**	**-18.1%**	**1.5%**
Low Fuel Cost Growth	0% PV	461	6.88%	15.19
	10% PV	368	5.64%	15.41
	Difference	-93	-1.25%	0.22
	% Change	**-20.2%**	**-18.1%**	**1.4%**
High Forward Capacity Market Cost	0% PV	461	6.88%	16.60
	10% PV	368	5.64%	16.83
	Difference	-93	-1.25%	0.23
	% Change	**-20.2%**	**-18.1%**	**1.4%**
Low Forward Capacity Market Cost	0% PV	461	6.88%	15.59
	10% PV	368	5.64%	15.83
	Difference	-93	-1.25%	0.24
	% Change	**-20.2%**	**-18.1%**	**1.5%**
High Fixed Customer Charge	0% PV	428	6.38%	16.06
	10% PV	362	5.54%	16.32
	Difference	-66	-0.84%	0.26
	% Change	**-15.4%**	**-13.2%**	**1.6%**
High Volumetric Rates	0% PV	495	7.38%	16.13
	10% PV	375	5.73%	16.34
	Difference	-120	-1.65%	0.21
	% Change	**-24.3%**	**-22.3%**	**1.3%**
Long Rate Case Filing Period	0% PV	390	5.82%	16.03
	10% PV	282	4.32%	16.24
	Difference	-107	-1.49%	0.22
	% Change	**-27.6%**	**-25.7%**	**1.3%**
Short Rate Case Filing Period	0% PV	499	7.44%	16.13
	10% PV	413	6.32%	16.37
	Difference	-86	-1.12%	0.24
	% Change	**-17.2%**	**-15.0%**	**1.5%**
Long Regulatory Lag	0% PV	396	5.91%	16.03
	10% PV	285	4.37%	16.24
	Difference	-111	-1.55%	0.21
	% Change	**-28.1%**	**-26.2%**	**1.3%**
Short Regulatory Lag	0% PV	530	7.91%	16.16
	10% PV	457	6.99%	16.42
	Difference	-73	-0.92%	0.26
	% Change	**-13.8%**	**-11.6%**	**1.6%**
Current Test Year	0% PV	530	7.91%	16.16
	10% PV	457	6.99%	16.42
	Difference	-73	-0.92%	0.26
	% Change	**-13.8%**	**-11.6%**	**1.6%**
Future Test Year	0% PV	624	9.30%	16.25

	10% PV	579	8.85%	16.54
	Difference	-45	-0.45%	0.29
	% Change	**-7.1%**	**-4.8%**	**1.8%**
PV Incentives	0% PV	461	6.88%	16.09
	10% PV	368	5.64%	16.63
	Difference	-93	-1.25%	0.54
	% Change	**-20.2%**	**-18.1%**	**3.3%**

Northeast Utility – 20-year Sensitivity Results (2013 to 2032)

Sensitivity Case		After-Tax Achieved Earnings ($M NPV@WACC)	After-Tax Achieved ROE (% Avg.@WACC)	All-in Average Retail Rates (cents/kWh Avg.@WACC)
Base	0% PV	681	6.47%	19.19
	10% PV	576	5.60%	19.71
	Difference	-105	-0.87%	0.52
	% Change	**-15.4%**	**-13.5%**	**2.7%**
High Value of PV	0% PV	681	6.47%	19.19
	10% PV	505	5.36%	19.30
	Difference	-176	-1.11%	0.11
	% Change	**-25.8%**	**-17.1%**	**0.6%**
Low Value of PV	0% PV	681	6.47%	19.19
	10% PV	626	5.63%	20.05
	Difference	-55	-0.84%	0.86
	% Change	**-8.1%**	**-12.9%**	**4.5%**
High Load Growth	0% PV	1,272	8.68%	18.71
	10% PV	1,169	8.10%	19.13
	Difference	-103	-0.58%	0.42
	% Change	**-8.1%**	**-6.7%**	**2.3%**
Low Load Growth	0% PV	250	2.81%	19.99
	10% PV	148	1.63%	20.70
	Difference	-103	-1.18%	0.71
	% Change	**-41.0%**	**-41.9%**	**3.6%**
High Fixed O&M Growth	0% PV	476	4.56%	19.48
	10% PV	369	3.61%	20.03
	Difference	-108	-0.95%	0.55
	% Change	**-22.6%**	**-20.8%**	**2.8%**
Low Fixed O&M Growth	0% PV	851	8.06%	18.93
	10% PV	749	7.26%	19.44
	Difference	-103	-0.80%	0.50
	% Change	**-12.0%**	**-10.0%**	**2.6%**
High Non-Generating CapEx Growth	0% PV	713	6.09%	19.30
	10% PV	605	5.26%	19.83
	Difference	-108	-0.83%	0.53
	% Change	**-15.1%**	**-13.7%**	**2.7%**
Low Non-Generating CapEx Growth	0% PV	652	6.81%	19.10
	10% PV	549	5.90%	19.62
	Difference	-103	-0.91%	0.52
	% Change	**-15.8%**	**-13.3%**	**2.7%**
High Fuel Cost Growth	0% PV	681	6.47%	21.35
	10% PV	576	5.60%	21.95

	Difference	-105	-0.87%	0.60
	% Change	**-15.4%**	**-13.5%**	**2.8%**
Low Fuel Cost Growth	0% PV	681	6.47%	17.56
	10% PV	576	5.60%	18.03
	Difference	-105	-0.87%	0.47
	% Change	**-15.4%**	**-13.5%**	**2.7%**
High Forward Capacity Market Cost	0% PV	681	6.47%	19.89
	10% PV	576	5.60%	20.41
	Difference	-105	-0.87%	0.52
	% Change	**-15.4%**	**-13.5%**	**2.6%**
Low Forward Capacity Market Cost	0% PV	681	6.47%	18.49
	10% PV	576	5.60%	19.02
	Difference	-105	-0.87%	0.53
	% Change	**-15.4%**	**-13.5%**	**2.8%**
High Fixed Customer Charge	0% PV	624	5.93%	19.16
	10% PV	546	5.31%	19.69
	Difference	-78	-0.61%	0.54
	% Change	**-12.5%**	**-10.4%**	**2.8%**
High Volumetric Rates	0% PV	739	7.01%	19.23
	10% PV	607	5.88%	19.73
	Difference	-132	-1.13%	0.51
	% Change	**-17.9%**	**-16.1%**	**2.6%**
Long Rate Case Filing Period	0% PV	560	5.33%	19.12
	10% PV	431	4.19%	19.62
	Difference	-130	-1.14%	0.50
	% Change	**-23.1%**	**-21.4%**	**2.6%**
Short Rate Case Filing Period	0% PV	752	7.13%	19.23
	10% PV	655	6.36%	19.77
	Difference	-96	-0.77%	0.53
	% Change	**-12.8%**	**-10.8%**	**2.8%**
Long Regulatory Lag	0% PV	565	5.38%	19.12
	10% PV	436	4.24%	19.62
	Difference	-129	-1.14%	0.50
	% Change	**-22.8%**	**-21.1%**	**2.6%**
Short Regulatory Lag	0% PV	819	7.76%	19.27
	10% PV	739	7.17%	19.82
	Difference	-80	-0.59%	0.55
	% Change	**-9.8%**	**-7.6%**	**2.8%**
Current Test Year	0% PV	819	7.76%	19.27
	10% PV	739	7.17%	19.82
	Difference	-80	-0.59%	0.55
	% Change	**-9.8%**	**-7.6%**	**2.8%**
Future Test Year	0% PV	964	9.13%	19.36
	10% PV	911	8.84%	19.93

	Difference	-53	-0.29%	0.57
	% Change	**-5.5%**	**-3.1%**	**2.9%**
PV Incentives	0% PV	681	6.47%	19.19
	10% PV	576	5.60%	19.90
	Difference	-105	-0.87%	0.71
	% Change	**-15.4%**	**-13.5%**	**3.7%**

Appendix E: Mitigation Analysis Results

We examine the effectiveness of different mitigation measures to lessen the impacts of PV modeled in the Base Case. This appendix includes detailed results of the mitigation cases for both the initial 10-year period (2013-2022) and the full 20-year analysis period (2013-2032). The mitigation results show the earnings, ROE, and retail rates at 10% PV compared to the Base Case at 10% PV without the mitigation measure.

Southwest Utility – 10-year Mitigation Results (2013 to 2022)

Mitigation Case		After-Tax Achieved Earnings ($M NPV@WACC)	After-Tax Achieved ROE (% Avg.@WACC)	All-in Average Retail Rates (cents/kWh Avg.@WACC)
Base	0% PV	3,372	7.99%	12.80
	10% PV	3,179	7.76%	13.03
	Difference	-193	-0.23%	0.23
RPC Decoupling: No k-factor	10% PV	3,625	8.84%	13.37
	Difference from Base 10%	446	1.08%	0.34
RPC Decoupling: with k-factor	10% PV	3,283	8.00%	13.11
	Difference from Base 10%	104	0.24%	0.08
Lost Revenue Adjustment Mechanism	10% PV	3,277	7.99%	13.10
	Difference from Base 10%	98	0.23%	0.07
Shareholder Incentive	10% PV	3,229	7.88%	13.30
	Difference from Base 10%	50	0.12%	0.27
High Demand Charge	10% PV	3,269	7.94%	13.10
	Difference from Base 10%	90	0.19%	0.07
High Fixed Customer Charge	10% PV	3,566	8.69%	13.32
	Difference from Base 10%	387	0.93%	0.29
Short Rate Case Filing Frequency	10% PV	3,293	8.04%	13.11
	Difference from Base 10%	113	0.28%	0.09
No Regulatory Lag	10% PV	3,460	8.45%	13.24
	Difference from Base 10%	280	0.69%	0.21
Current Test Year	10% PV	3,460	8.45%	13.24
	Difference from Base 10%	280	0.69%	0.21
Future Test Year	10% PV	3,813	9.33%	13.51
	Difference from Base 10%	634	1.57%	0.48
Utility Ownership of PV - All PV	10% PV	3,751	8.01%	N/A
	Difference from Base 10%	571	0.25%	N/A
Utility Ownership of PV - 10% of PV	10% PV	3,236	7.78%	N/A
	Difference from Base 10%	57	0.03%	N/A
Customer-Sited PV Counted toward RPS	10% PV	3,179	7.76%	12.89
	Difference from Base 10%	0	0.00%	-0.14

Southwest Utility – 20-year Mitigation Results (2013 to 2032)

Mitigation Case		After-Tax Achieved Earnings ($M NPV@WACC)	After-Tax Achieved ROE (% Avg.@WACC)	All-in Average Retail Rates (cents/kWh Avg.@WACC)
Base	0% PV	6,484	8.40%	14.24
	10% PV	5,956	8.07%	14.59
	Difference	-528	-0.33%	0.35
RPC Decoupling: No k-factor	10% PV	6,520	8.92%	14.86
	Difference from Base 10%	564	0.85%	0.27
RPC Decoupling: with k-factor	10% PV	5,947	8.13%	14.58
	Difference from Base 10%	-8	0.06%	-0.01
Lost Revenue Adjustment Mechanism	10% PV	6,053	8.23%	14.64
	Difference from Base 10%	98	0.15%	0.05
Shareholder Incentive	10% PV	6,006	8.15%	14.75
	Difference from Base 10%	50	0.08%	0.17
High Demand Charge	10% PV	6,059	8.22%	14.64
	Difference from Base 10%	103	0.15%	0.05
High Fixed Customer Charge	10% PV	6,443	8.81%	14.82
	Difference from Base 10%	487	0.74%	0.23
Short Rate Case Filing Frequency	10% PV	6,091	8.29%	14.65
	Difference from Base 10%	136	0.22%	0.06
No Regulatory Lag	10% PV	6,430	8.75%	14.81
	Difference from Base 10%	474	0.68%	0.23
Current Test Year	10% PV	6,430	8.75%	14.81
	Difference from Base 10%	474	0.68%	0.23
Future Test Year	10% PV	6,937	9.50%	15.06
	Difference from Base 10%	982	1.43%	0.47
Utility Ownership of PV - All PV	10% PV	6,821	8.29%	N/A
	Difference from Base 10%	865	0.21%	N/A
Utility Ownership of PV - 10% of PV	10% PV	6,042	8.09%	N/A
	Difference from Base 10%	86	0.02%	N/A
Customer-Sited PV Counted toward RPS	10% PV	5,956	8.07%	14.45
	Difference from Base 10%	0	0.00%	-0.14

Northeast Utility – 10-year Mitigation Results (2013 to 2022)

Mitigation Case		After-Tax Achieved Earnings ($M NPV@WACC)	After-Tax Achieved ROE (% Avg.@WACC)	All-in Average Retail Rates (cents/kWh Avg.@WACC)
Base	0% PV	461	6.88%	16.09
	10% PV	368	5.64%	16.33
	Difference	-93	-1.25%	0.23
RPC Decoupling: No k-factor	10% PV	345	5.28%	16.31
	Difference from Base 10%	-23	-0.36%	-0.02
RPC Decoupling: with k-factor	10% PV	450	6.88%	16.41
	Difference from Base 10%	81	1.24%	0.08
Lost Revenue Adjustment Mechanism	10% PV	395	6.05%	16.36
	Difference from Base 10%	27	0.41%	0.03
Shareholder Incentive	10% PV	416	6.36%	16.68
	Difference from Base 10%	47	0.72%	0.35
High Demand Charge	10% PV	374	5.72%	16.34
	Difference from Base 10%	6	0.08%	0.01
High Fixed Customer Charge	10% PV	353	5.40%	16.31
	Difference from Base 10%	-15	-0.24%	-0.01
Short Rate Case Filing Frequency	10% PV	413	6.32%	16.37
	Difference from Base 10%	45	0.68%	0.05
No Regulatory Lag	10% PV	457	6.99%	16.42
	Difference from Base 10%	89	1.36%	0.09
Current Test Year	10% PV	457	6.99%	16.42
	Difference from Base 10%	89	1.36%	0.09
Future Test Year	10% PV	579	8.85%	16.54
	Difference from Base 10%	211	3.22%	0.21
Utility Ownership of PV - All PV	10% PV	829	7.50%	N/A
	Difference from Base 10%	461	1.87%	N/A
Utility Ownership of PV - 10% of PV	10% PV	415	5.95%	N/A
	Difference from Base 10%	46	0.31%	N/A
Customer-Sited PV Counted toward RPS	10% PV	368	5.64%	16.14
	Difference from Base 10%	0	0.00%	-0.19

Northeast Utility – 20-year Mitigation Results (2013 to 2032)

Mitigation Case		After-Tax Achieved Earnings ($M NPV@WACC)	After-Tax Achieved ROE (% Avg.@WACC)	All-in Average Retail Rates (cents/kWh Avg.@WACC)
Base	0% PV	681	6.47%	19.19
	10% PV	576	5.60%	19.71
	Difference	-105	-0.87%	0.52
RPC Decoupling: No k-factor	10% PV	469	4.60%	19.64
	Difference from Base 10%	-108	-1.00%	-0.07
RPC Decoupling: with k-factor	10% PV	642	6.27%	19.76
	Difference from Base 10%	66	0.67%	0.04
Lost Revenue Adjustment Mechanism	10% PV	603	5.87%	19.73
	Difference from Base 10%	27	0.27%	0.02
Shareholder Incentive	10% PV	624	6.07%	19.93
	Difference from Base 10%	47	0.47%	0.22
High Demand Charge	10% PV	591	5.73%	19.72
	Difference from Base 10%	15	0.14%	0.01
High Fixed Customer Charge	10% PV	502	4.91%	19.67
	Difference from Base 10%	-74	-0.69%	-0.05
Short Rate Case Filing Frequency	10% PV	655	6.36%	19.77
	Difference from Base 10%	79	0.76%	0.05
No Regulatory Lag	10% PV	739	7.17%	19.82
	Difference from Base 10%	163	1.57%	0.10
Current Test Year	10% PV	739	7.17%	19.82
	Difference from Base 10%	163	1.57%	0.10
Future Test Year	10% PV	911	8.84%	19.93
	Difference from Base 10%	335	3.24%	0.21
Utility Ownership of PV - All PV	10% PV	1,277	7.43%	N/A
	Difference from Base 10%	701	1.84%	N/A
Utility Ownership of PV - 10% of PV	10% PV	646	5.90%	N/A
	Difference from Base 10%	70	0.30%	N/A
Customer-Sited PV Counted toward RPS	10% PV	576	5.60%	19.59
	Difference from Base 10%	0	0.00%	-0.13

BEYOND SHARING:

HOW COMMUNITIES CAN TAKE OWNERSHIP OF RENEWABLE POWER

John Farrell

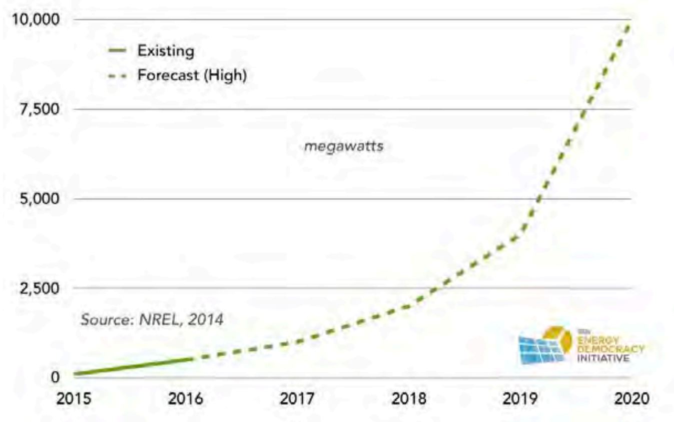
April 2016

ILSR INSTITUTE FOR Local Self-Reliance

EXECUTIVE SUMMARY

In the past five years, the opportunity for community renewable energy has coalesced around "shared solar," where participants share the electricity output from a nearby solar array in the form of credits on their electricity bill. Some forecasts suggest that shared solar could supply 5-10 gigawatts of new power capacity in the next 5 years.

FIGURE A. FORECAST GROWTH IN SHARED SOLAR



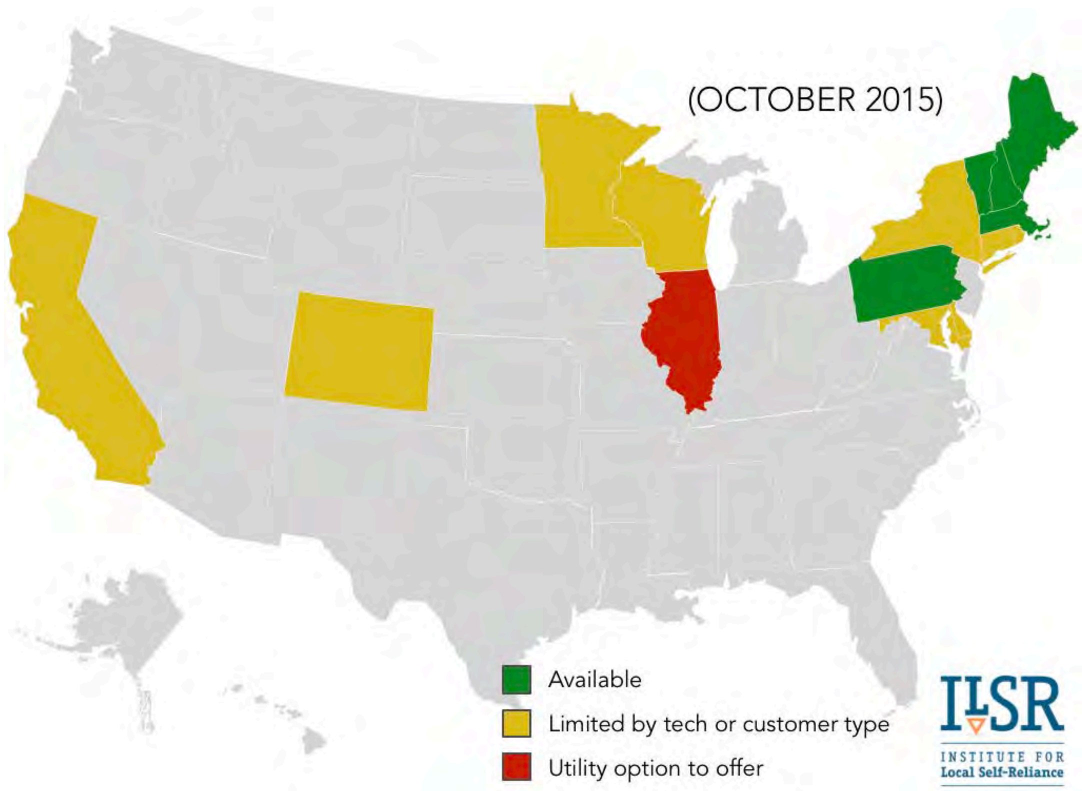
But shared solar is just a small slice of the community renewable energy opportunity, which could include many other renewable technologies such as wind or geothermal, but also community-owned projects that would allow greater local capture of economic benefits. While shared solar is a model shown to avoid several of the pitfalls typical for community renewable energy, these pitfalls could be bridged to much more broadly expand the economic opportunity.

U.S. Barriers to Community Renewable Energy

Three major barriers still inhibit widespread expansion of community renewable energy, much as they did when ILSR published its community solar report in 2010.

1. **Federal and state securities laws**, meant to shield ordinary people from Ponzi schemes and bad investments, are often too onerous for community-scale renewable energy projects.
2. **Federal tax incentives** require specific and sufficient tax liability, in ways that often precludes ordinary community investors.
3. Finally, **legal limitations to sharing electricity output** from community-based renewable energy projects mean only states with explicit exemptions are likely to see substantial growth in community renewables.

FIGURE B. ONLY 16 STATES SUPPORT SOME FORM OF VIRTUAL NET METERING OR COMMUNITY ENERGY



Busting the Barriers?

Within limits, policy makers have found ways to work around or reduce the barriers to community renewable energy, but their solutions haven't yet proven widely scalable without significant compromise.

- **State and federal crowd funding laws** have carved out exemptions from securities limitations, although the laws remain substantially complex and compliance is expensive.
- Successful community renewable energy projects have found **third party "tax equity" partners** to provide access to a fraction of the tax incentives, but far less than if they could have captured the incentives themselves. The **long-term phase out of federal renewable energy incentives (and potential substitution of low-cost capital)** may finally

address the incentive inequity between community-based and single-party, for-profit projects.

- **Shared solar** typically has third party or utility owners of community-based projects with participation limited to compensation via electric bill credits. In this manner, the third party or utility allows shared solar to overcome the securities and tax incentive barriers. Although proven to be the most replicable, shared solar usually requires a sacrifice of community ownership and control. Additionally, some utility-run programs may offer poor payback or be designed to divert customers from individual solar ownership.
- **Cooperatives**, very popular in the grocery and agriculture industry, solve the securities barrier by allowing unlimited fundraising from members and retain economic benefits for member-owners. A promising solution, cooperatives may face the same challenges (i.e. access to federal tax incentives) as other community-based institutions.

Exceptional Community Renewable Energy Projects

Despite the barriers, a number of clever entrepreneurs have pulled together community renewable energy projects that combine local, community-scale renewable energy and local ownership. Selected examples from the report include:

- A 35-member LLC in University Park Maryland installed a community solar array on a local church
- Nearly 200 Iowa rural residents financed 6 community-owned turbines
- Over 600 South Dakota residents are owners in a 7-turbine wind power project hosted by Basin Electric Cooperative

Cities as "Community"

More than 2,000 cities have municipal electric utilities. Cities with municipal utilities like Georgetown or Denton, Texas, have already signed contracts for 70 to 100% renewable electricity. Many more cities have pooled their resources to procure renewable energy in joint ventures. In a few states, municipalities are able to make clean energy procurement a priority via "local energy aggregation," and two California aggregations, Marin Clean Energy and Sonoma Clean Power, already offer electricity at competitive prices with a higher portion of renewable energy than incumbent utilities.

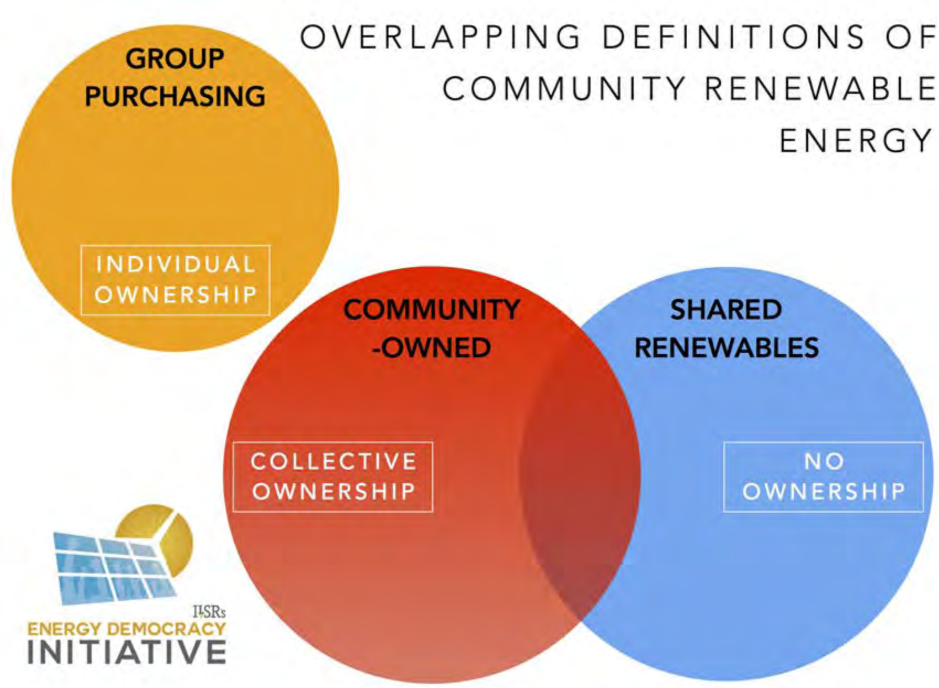
A Community Renewable Energy Gold Standard

There are four key principles to successful and meaningful community renewable energy:

1. Tangible benefits for participants
2. Flexibility of ownership structure
3. Additive to other renewable energy policies
4. Access for all

While these principles apply to all community renewable energy, ILSR prioritizes community-owned renewable energy, in particular, for its greater economic benefits and local control. As is shown below, community-ownership may be distinct from shared solar, or from collective action that supports individual ownership, such as group purchasing. Some examples of the three categories are shown in the full report.

FIGURE C. OVERLAPPING DEFINITIONS OF COMMUNITY RENEWABLE ENERGY



Shared renewables have led the development of community renewable energy and the forecasts for growth because it bypasses two of the most significant barriers, securities regulation and access to tax incentives. But proponents of community renewable energy should look beyond sharing. Ownership allows local decision making about location, hiring, and participation that shared solar may not, and it will require all forms of community renewable energy to make it as ubiquitous in the 21st century as utility ownership was in the 20th.

ACKNOWLEDGEMENTS

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Related ILSR Publications

Is Bigger Best in Renewable Energy?
By John Farrell, September 2016

Public Rooftop Revolution
By John Farrell, June 2015

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Since 1974, the Institute for Local Self-Reliance (ILSR) has worked with citizen groups, governments and private businesses to extract the maximum value from local resources.

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INTRODUCTION

By the end of 2015, U.S. renewable energy capacity from wind and solar power eclipsed 100,000 megawatts, with another year of historic growth. Despite its many advantages, however, community renewable energy has been a small fraction of this impressive figure.

Definition of Community-Owned Renewable Energy

+ Community-scale or distributed power generation
+ Collective action to own, develop, or share output

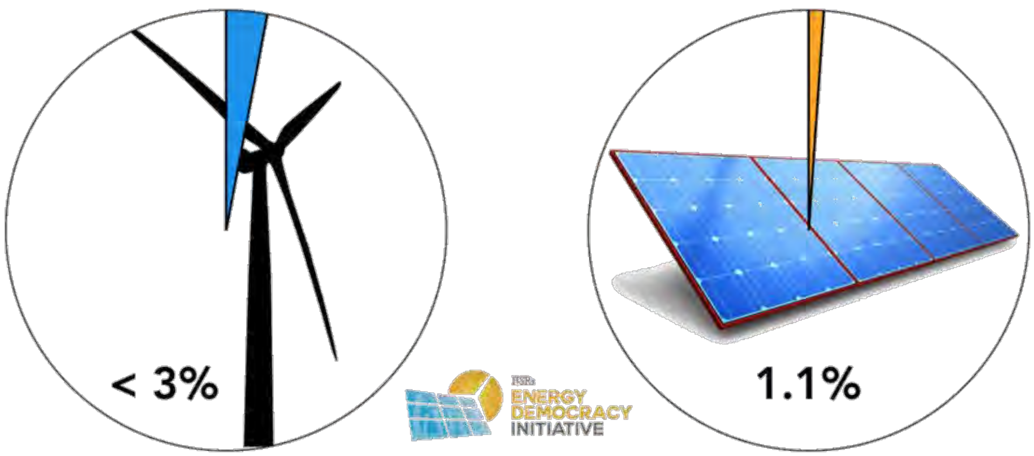
In this report, we talked about several forms of community renewable energy. Community-owned renewables are owned locally, by members of the community. Shared renewables may or may not be locally owned, but the community can share the output. Group purchasing involves collective action to purchase renewable energy, such as rooftop solar arrays, but the benefits accrue to the individuals who host the solar on their rooftops.

Unlike traditional electricity generation, wind and solar are very compatible with the first criteria—community scale—because both wind and solar power plants are made up of several to several hundred modular power sources (turbines or panels). Distributing power generation from these sources is relatively easy and economical under the current rules for the electricity system, especially in comparison to the severe limitations on collective ownership.

For wind power, the scale of most wind farms makes them expensive, and their remote location makes sharing electricity output with the typical policies nearly impossible. The result is that less than 5% of total installed wind power capacity was part of a community renewable energy project through 2010. Less than 3% of wind power capacity added since then has been community-owned (and none have shared output).[1]

[1] *See Appendix for more detail on Figure 1.*

FIGURE 1. PERCENT COMMUNITY-BASED WIND AND SOLAR IN THE U.S.



For wind power, the lack of collective ownership in the U.S. may not come as a surprise, but it should. In Denmark, for example, wind turbines were legally required to be owned by electricity consumers. Danish wind projects are typically owned by several to several hundred landowners and farmers in "wind partnerships." The result is that **20% of Denmark's power comes from wind, and 85% of that is owned by the residents of Danish communities.**[2]

For U.S. solar energy, there has been massive growth in distributed generation, but limited opportunity for collective ownership. Half of the 25,000 MW of solar serves single residential or commercial property owners, with a scant 70 MW of community solar projects through the end of 2015.[3] On the one hand, this is an impressive figure, mimicking the 50% of renewable energy capacity in Germany owned by citizens and cooperatives (below).[4] On the other hand, with nearly half of U.S. households and businesses unable to host their own solar panel, continuing growth in citizen ownership will require options for collective ownership or shared benefits.

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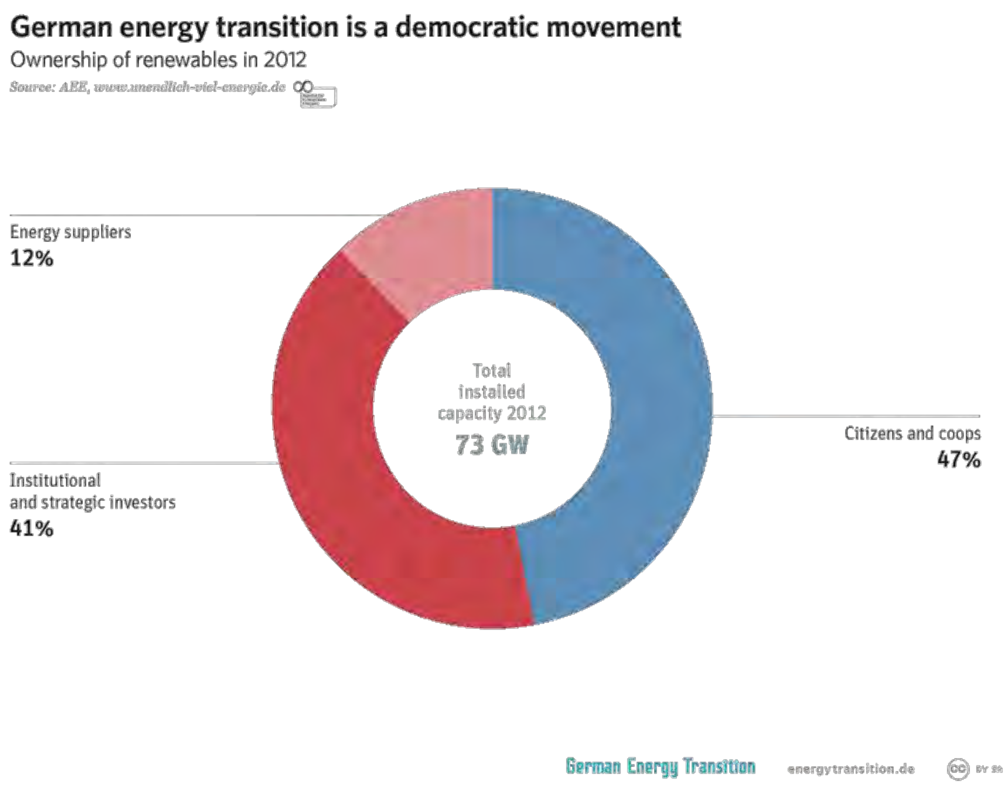
[2] Commission for Environmental Cooperation. "Guide to Developing a Community Renewable Energy Project in North America." March 2010. Accessed April 8, 2016. http://bit.ly/1Lm5IBJ.

[3] Barth, Bianca and Taylor Mike. "Technical Brief Community Solar." Solar Electric Power Association. February 2012. Accessed April 8, 2016. http://bit.ly/1Wi77BG.

[4] Farrell, John. "Citizen Ownership Remains Foundation of German Renewable Energy Explosion." The Institute for Local Self-Reliance. June 2, 2014. Accessed April 8. 2016. http://bit.ly/22ibVqg.

FIGURE 2. PERCENT COMMUNITY-BASED RENEWABLE ENERGY IN GERMANY



The relative dearth of U.S. community renewable energy stands in stark contrast to the opportunity for distributed power generation and the need for collective ownership options. The following map shows that nearly every U.S. state could get 25% or more of its electricity from rooftop solar alone, and two-thirds of states could get 33% or more.

FIGURE 3. U.S. ROOFTOP SOLAR POTENTIAL (2016)

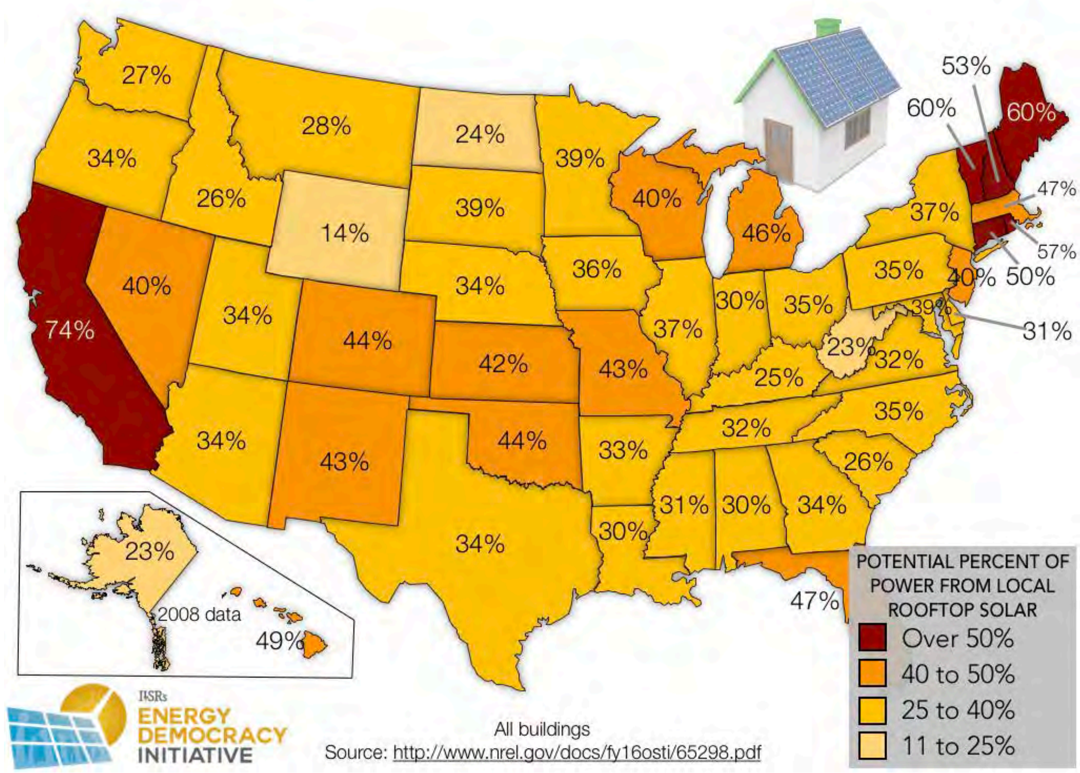


FIGURE 4. PERCENT OF U.S. HOUSEHOLDS THAT CAN HOST SOLAR ENERGY

But millions of homes and businesses can't host solar arrays or wind turbines but have an interest in reducing their reliance on fossil fuels and on distant utilities. For example, the following graphic shows that half of U.S. households don't have access to a sunny rooftop with sufficient space for a solar array. Similarly, about [half of businesses] lack control of sufficient roof space to meet significant portion of demand.[5]

Additionally, many homes and businesses with or without the physical property to support solar or wind lack the financial wherewithal to make the upfront investment in renewable energy, despite its long-term economic benefits.

Community renewable energy can extend the benefits of the electricity system's transformation to everyone and building political support for its acceleration. It's a timely opportunity, with an electricity system in the throes of a major transformation on the very issues of scale and ownership.

Power generation is being distributed and decentralized, and with it the power over the grid itself. After a century of utility energy monopolies in electricity generation, the 21st century is bringing a transition to energy democracy. This report explores the opportunity of energy democracy and community renewable energy by illustrating:

1. The benefits of community renewable energy.
2. The major barriers to community renewable energy.
3. The barrier-busting policies and strategies to unlock its full potential.
4. The remarkable examples of community projects that have already overcome the barriers.
5. How cities and electric cooperatives represent existing "communities" than can go renewable.

[5] *Note: Accounts for roof orientation, space, solar radiation, but not roof age, condition, or building material.* Brockway, Anna M.; Feldman, David; Margolis, Robert & Ulrich, Elaine. "Shared Solar: Current Landscape, Market Potential, and the Impact of Federal Securities Regulation." National Renewable Energy Laboratory. April 2015. Accessed April 8, 2016. http://1.usa.gov/1HL2AfW.

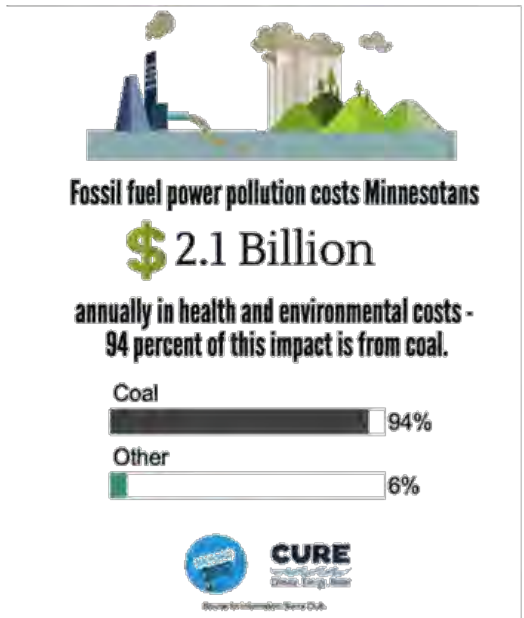
BENEFITS OF COMMUNITY RENEWABLE ENERGY

The benefits of community renewable energy fall into four categories: benefits from renewable energy, benefits of distributed power generation (scale), benefits of community scale and offsite generation, and benefits of local ownership. The benefits are cumulative from top to bottom.

The benefits of renewable energy include:

- **Price certainty**, because of zero fuel costs for wind and sun. In Minnesota regulators value the zero fuel cost of solar at 3.2¢ per kilowatt-hour of natural gas electricity avoided, a total of $13 million if all natural gas power generation in the state were supplanted by solar energy.[67]
- **Health benefits** due to zero environmental externalities from power generation, estimated at 2-5% of Gross Domestic Product, or between $360 to nearly $900 billion.[8]

FIGURE 5. COST OF FOSSIL FUEL POLLUTION



[6] Liberkowski, Amy A. “VOS Calculation Community Solar Gardens Program Docket No. E002/M-13-867.” Rates and Regulatory Affairs. March 2, 2015. Accessed April 8. 2016. http://cl.ly/0X04302I301S.

[7] U.S. Energy Information Administration. “Minnesota State Profile and Energy Estimates.” March 17, 2016. Accessed April 8, 2016. http://cl.ly/0X04302I301S.

[8] Union of Concerned Scientists. “Benefits of Renewable Energy Use.” 2013. Accessed April 8, 2016. http://bit.ly/1lxOWE4.

The benefits from distributed generation include:

- **Reducing variability** of renewable energy production.[9]
- **Minimizing losses** of electricity through long-distance transmission.[10]
- **Use of brownfields** or already-developed property for energy generation.
- Ability, in the aggregate, to **reduce maintenance and capital expenses** for distribution grid infrastructure. For example, the Long Island Community Microgrid will use 25 megawatts of distributed solar and battery storage to avoid a $300 million grid upgrade.[11]
- **Resiliency**, by providing power generation locally to power important community buildings, e.g. powering hospitals when the larger grid fails.

The benefits of community renewable energy include:

- **Greater participation**:
  - An opportunity to go solar for the 50% of American homes and businesses that can't host solar
  - With an average of 213 participants per megawatt, the first 40 MW of community solar projects helped over 8,500 people go solar.[12]
- **Economies of scale**, because community-scale institutions are less costly per Watt of capacity than individual solar arrays.

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[9] Farrell, John. "Solving Solar's Variability with More Solar." The Institute for Local Self-Reliance. February 17, 2011. Accessed April 8, 2016. http://bit.ly/1Yjo39k.

[10] Wirfs-Brock, Jordan. "Lost in Transmission: How Much Electricity Disappears Between a Power Plant and Your Plug." Inside Energy. November 6, 2015. Accessed April 8, 2016. http://bit.ly/1RIBkVT.

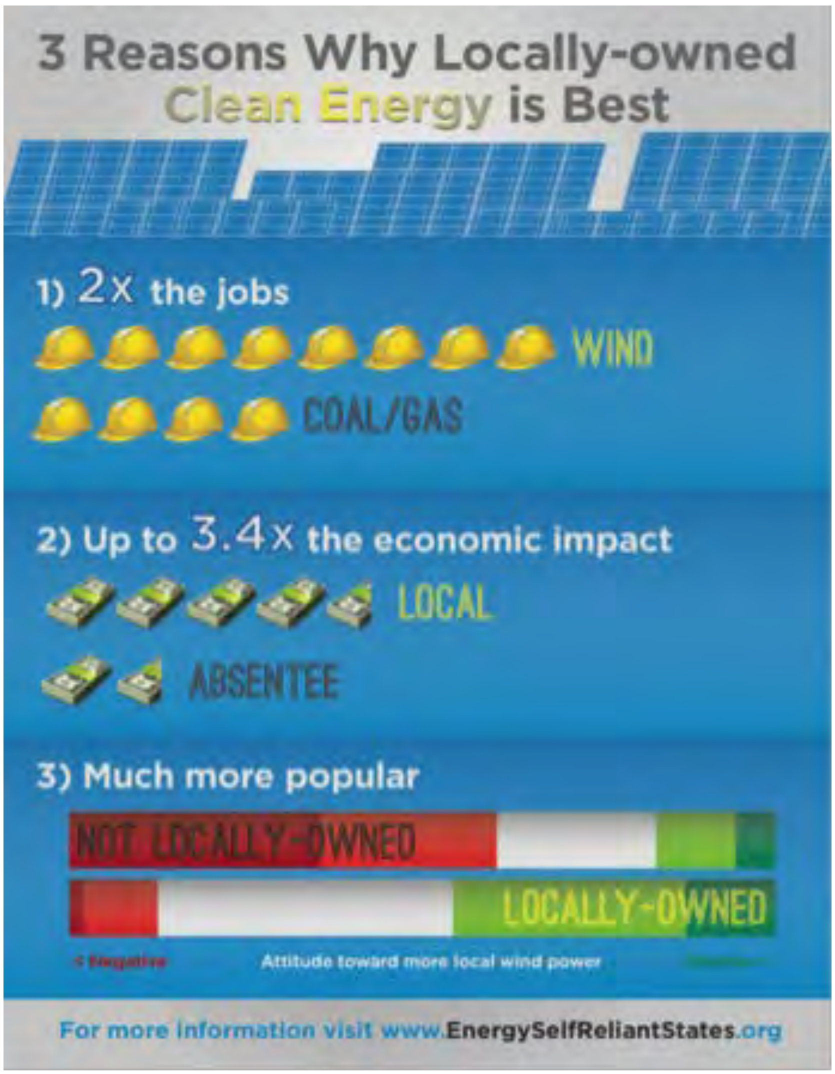
[11] Farrell, John and Grimley, Matt. "Report: Mighty Microgrids." The Institute for Local Self-Reliance. March 3, 2016. Accessed April 8, 2016. http://bit.ly/1YjpK6P.

[12] Community Solar Hub. "Statistics." Accessed June 11, 2015. http://bit.ly/1QPiJWx.

The benefits from community-owned renewable energy include:

- Substantially greater economic benefits and job creation in the host community.[13]
- **Reducing concentration of political and economic power** in the electricity business.

FIGURE 6. BENEFITS OF LOCALLY OWNED ENERGY



[13] Farrell, John. "Report: Advantage Local – Why Local Energy Ownership Matters." The Institute for Local Self-Reliance. September 24, 2014. Accessed April 8, 2016. http://bit.ly/1qANZTv.

U.S. BARRIERS TO COMMUNITY RENEWABLE ENERGY

Despite the enormous benefits, U.S. rules for renewable energy development have yet to catch up to the 21st century opportunity for community renewable energy. Federal securities laws make raising capital for community renewable energy relatively onerous. Federal incentives largely favor individual or corporate ownership and hinder ownership by community-benefit entities, such as public or nonprofit organizations. State rules allow monopoly utilities to wield enormous influence over potential competition on the distributed grid and generally prohibit sharing electricity from a solar or wind project owned in common.

The following sections provide more detail on these barriers.

Costly Securities Regulation

The first question in developing any energy project is "where's the money coming from?" Community renewable energy, especially community-owned energy, faces a unique challenge in raising capital because the owners of the wind or solar project are often distinct from the property owner, and spread over a wide geographic region.

The simplest way to raise capital is through an existing entity, such as a community institution, local government, place of worship, or nonprofit organization. But as discussed in the next section, these entities can raise money for community projects, but not access tax incentives to fund and finance them.

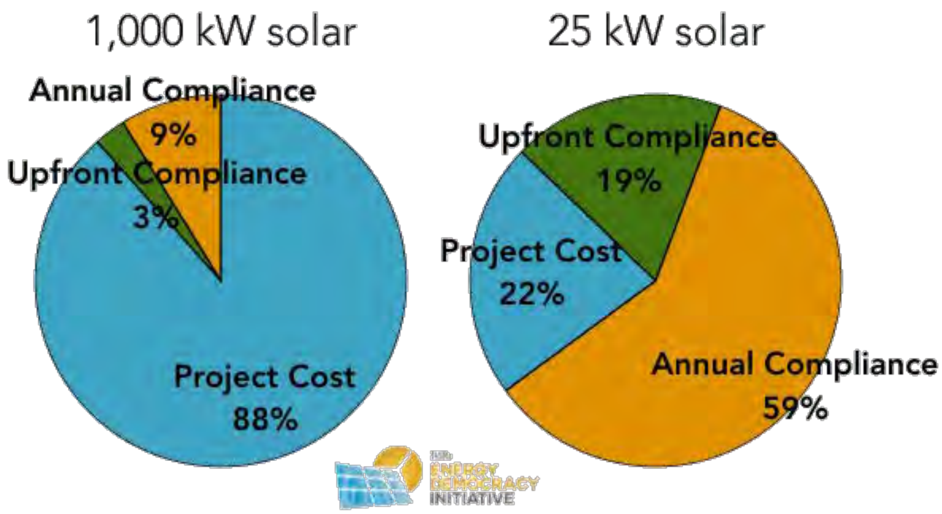
Alternatively, a community-owned energy project can be financed through a new organization and raise capital from the community directly.

Enter securities law.

To raise money from potential investors, large and small, a community renewable energy project must file with the relevant federal (Securities and Exchange Commission) or state securities agency (e.g. Department of Commerce) to explain their offering, their pitch to investors, and to have their financials reviewed.

Federal and state statutes designed to protect investors from fraud represent high-dollar compliance costs for many relatively small-dollar community renewable energy projects. Federal compliance is particularly costly, with upfront and annual compliance costs in the hundreds of thousands of dollars.[14] For a 1 megawatt solar project on an IKEA store, the upfront costs and first year compliance costs are more than a tenth the total project cost. For a small, 25 kilowatt solar array like the University Park community-owned solar project, compliance costs exceed 75% of the project's installed cost.

FIGURE 7. FEDERAL SECURITIES COMPLIANCE COSTS



Fortunately, states offer exemptions to securities registration with the federal government for smaller projects, but the exemptions have limitations on the number of "non-accredited" investors (a.k.a. non-wealthy folks) and on advertising. Compliance costs are lower than for federal registration, but still run in the tens of thousands of dollars annually. The result is relatively few successful community renewable energy offerings. The following table illustrates the exemptions to federal securities registration and their limitations. Additional state-level rules may apply.

[14] Bolinger, Mark and Wiser, Ryan. "A Comparative Analysis of Business Structures Suitable for Farmer-Owned Wind Power Projects in the United States." *Ernest Orlando Lawrence Berkeley National Laboratory*. November 2004. Accessed April 8, 2016. http://1.usa.gov/1RJjR2f.

FIGURE 8. STATE SECURITIES EXEMPTIONS AND RESTRICTIONS

Exemption	Restrictions
Regulation D, rule 506(b)	Allows up to 35 non-accredited investors, “so long as they have a certain amount of financial sophistication and are provided a certain disclosure document.” No advertising
Regulation D, rule 506(c)	Accredited investors only.
Regulation D, rule 504	Limit of $1 million. General solicitation/advertising typically not allowed.
Intrastate, rule 147	Must get 80% of its proceeds from within the state, have 80% of its assets, and 100% of purchasers from within state. May only advertise within the state.
Regulation A	Up to $5 million.
Private placement	Must have prior relationship with investors. No advertising.

Sources: Multiple

Inaccessible Tax Incentives

The federal tax incentives for renewable energy (the 30% tax credit for solar and the 2.2¢-per-kilowatt-hour production tax credit for wind) have long made community renewable energy more complex. Many of the logical entities to invest in community-based projects – local governments, most cooperatives, places of worship, or other nonprofit organizations – don’t pay federal income tax and can’t use tax credits.

Even when community-owned projects are organized as for-profit partnerships or limited liability companies, the participants often lack sufficient tax liability to use the federal incentive. For example, a typical 2 megawatt wind turbine generates more than $130,000 in tax credits each year, which would require 18 owners with average tax liability of $7,500.[15] But it gets more complex.

Even with many owners splitting the tax credit, unless they are involved in the day-to-day operation of the wind or solar project – behavior the IRS called "material participation" – their investor status allows them to only use the tax credit to offset "passive income."[16]

Definition of Passive Income

Passive income is income earned from rental property and other investments where the owner does not "materially participate." The vast majority of households have little or no passive income.

For many individuals, the only tax liability they can offset with the tax credits may be the income from the renewable energy project itself (unless they invest in other ventures in a similar fashion, or have rental property). Although the federal tax credit can be carried forward to next year's tax filing, it's unclear for how long.[17]

These limitations drive community developers into partnerships with large companies or Wall Street banks who can use tax credits and provide capital, but who take a substantial cut of the project revenue in exchange. The "flip" arrangement was commonly used in community wind, where a big investor retains nearly-full ownership of a community wind or solar project for years to absorb the tax incentives (usually 10 or more years for wind and 6-7 years for solar), and then ownership of the project flips back to the local owners.[18]

These arrangements increase the cost and complexity of developing community renewable energy projects relative to private or corporate ownership, but can still benefit of participants. In our 2010 report on community solar, for

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[15] Agresti, James D. and Bohn, Christopher Edward. "Tax Facts." Just Facts. July 7, 2015. Accessed April 8, 2016. http://www.justfacts.com/taxes.asp.

[16] Farrell, John. "Broadening Wind Energy Ownership by Changing Federal Incentives." The Institute for Local Self-Reliance. April 2008. Accessed April 8, 2016. http://bit.ly/1SkPYkB.

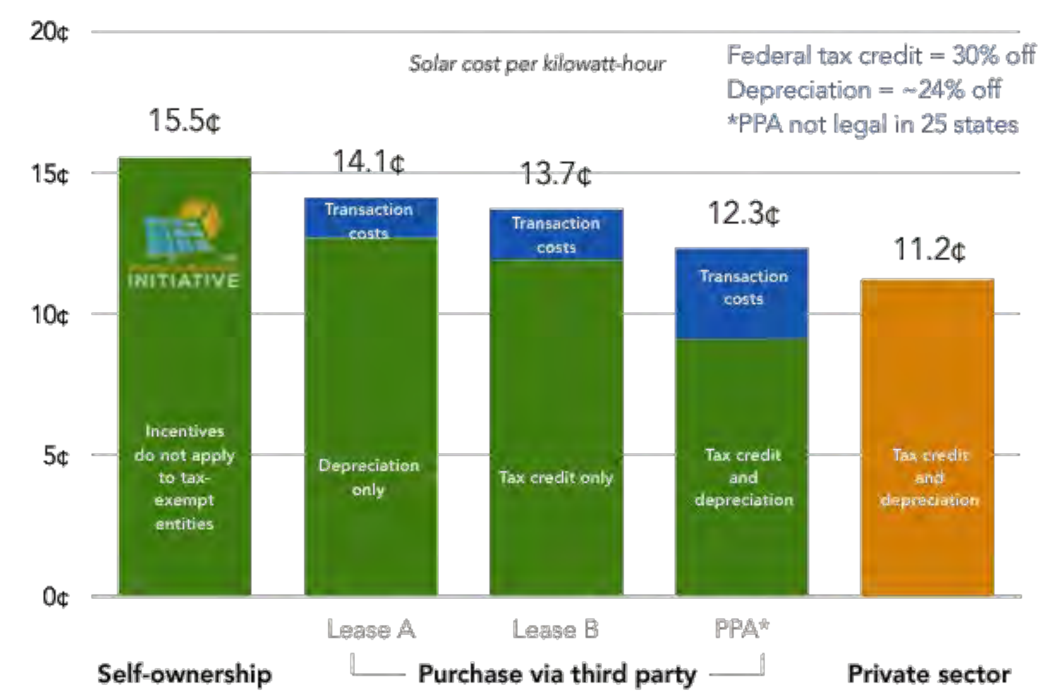
[17] TaxAct. "Form 5695 – Residential Energy Credit Carry Over." Accessed April 8, 2016. http://bit.ly/1qyY3fv.

[18] Farrell, John. "More Than a 'Flip' – Community Wind Projects Still Require Financing Acrobatics." *The Institute for Local Self-Reliance*. January 26, 2011. Accessed April 8, 2016. http://bit.ly/1MldK3U.

example, only one-third of successful projects were able to use the federal tax credit, but they were generally the most financially worthwhile "investments."[19]

The chart below illustrates this issue of tax credit access by comparing the cost of solar electricity for projects owned by a non-taxable entity. On the left is a solar project priced without any federal tax incentives. In the middle are three common options for third-party ownership where the city or nonprofit retains some of the economic value of federal tax incentives. The bar on the right shows that none of a non-taxable entity's strategies to own solar can compete with a private, for-profit entity that has straightforward access to the federal incentives.

FIGURE 9. SOLAR ENERGY COSTS MORE FOR NON-TAXABLE ORGANIZATIONS



There was one significant exception to the inaccessibility of federal tax credits. After the financial crisis in 2008, legislation included in the federal Recovery Act allowed conversation of the tax credit into a cash grant for projects begun between 2009 and 2011. The law addressed a severe shortage of tax liability to absorb the renewable energy tax credits due to the collapse of the economy,

[19] Farrell, John. "Community Solar Power: Obstacles and Opportunities." *The Institute for Local Self-Reliance*. September 8, 2010. Accessed April 8, 2016. http://bit.ly/23qerx3.

but by removing the tax liability barrier it also opened the door to several of the exceptional community renewable energy projects highlighted later. It was also much more efficient, delivery more of the dollars directly to projects, rather than to Wall Street tax equity partners.[20] Unfortunately, the cash grant program was allowed to expire at the end of 2011.

Limitations to Sharing Power

For community renewable energy projects that overcome the first two challenges, the issue of electricity production awaits.

A fundamental concept in a community renewable energy project (beyond ownership) is sharing the electricity produced. But while individuals can use on-site solar or other renewable generation to offset their electric bill in 44 states (called "net metering"), the rules for sharing electricity from non-utility projects are much more limited. In many cases, utilities have been fighting to weaken traditional net metering laws and so far, only 16 states have a policy that allows electricity sharing (see map on the next page).[21]

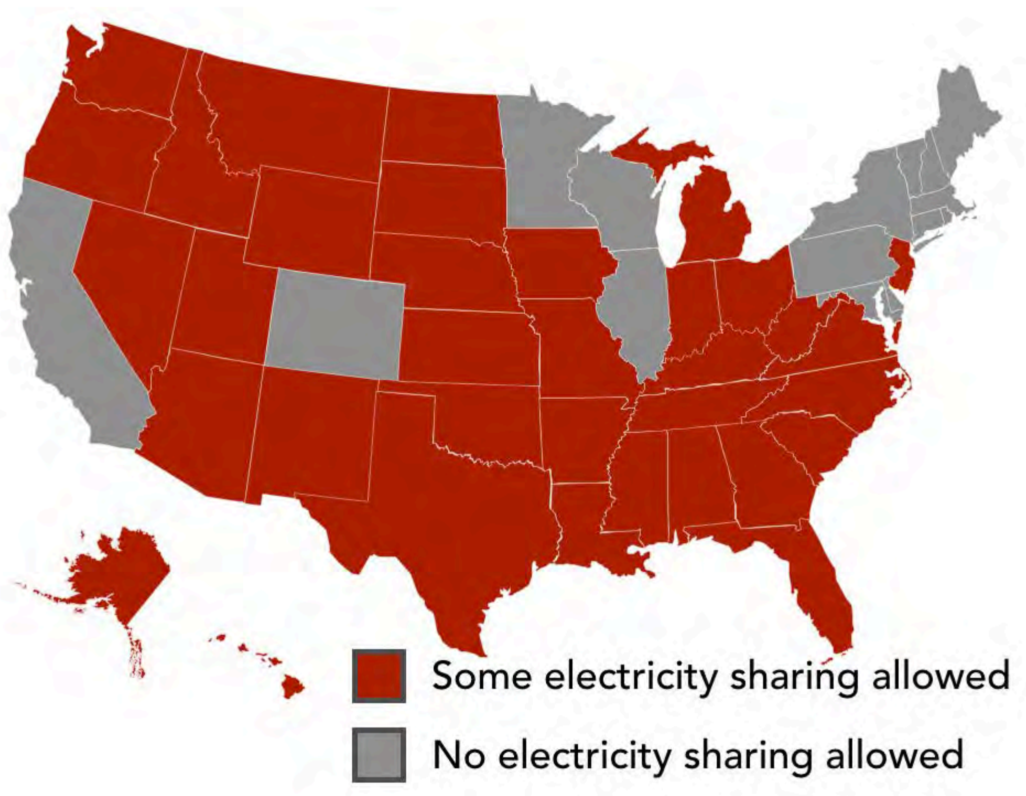
In most states, no one but the utility can sell electricity to customers within a given geographic area. These are called monopoly or franchise rights. There are three common exceptions, all of limited value to community renewable energy. Self-generation, usually supported by net metering, allows a single property owner to offset power use with on-site power generation, but not to share those electricity credits with others. Selling power to the utility directly means competing with large-scale power plants on price, even though distributed generation has higher value. Selling to third party owners is allowed in about two dozen states, but requires identifying a property owner who is willing and able to host a community renewable energy facility.

In other words, there's no widespread policy that allows for easy sharing of electricity generation from community renewable energy projects. The only resolution is changing the rules.

[20] Farrell, John. "Federal Tax Credits Handcuff Clean Energy Development." The Institute for Local Self-Reliance. December 5, 2011. Accessed April 8, 2016. http://bit.ly/1WiTodW.

[21] Farrell, John. "Update: Distributed Renewable Energy Under Fire." The Institute for Local Self-Reliance. October 21, 2015. Accessed April 8, 2016. http://bit.ly/1oK2LFC.

FIGURE 10. THIRTY-FOUR STATES DON'T ALLOW ELECTRICITY SHARING FOR COMMUNITY RENEWABLE ENERGY PROJECTS



BARRIER BUSTING

There are three big tools for breaking down the barriers to community renewable energy: using non-tax-based incentives for renewable energy, simplifying the process of raising capital, and adopting formal "community energy" laws that enable power sharing. The impact of adoption could be enormous. In the community solar market alone, the National Renewable Energy Laboratory estimates that residential and commercial customers who can't have their own rooftop solar array could be participants in 5,500 to 11,000 megawatts of solar (a 22 to 44% increase over the total installed base) by 2020 with the right rules in place.[22]

Tax Structure

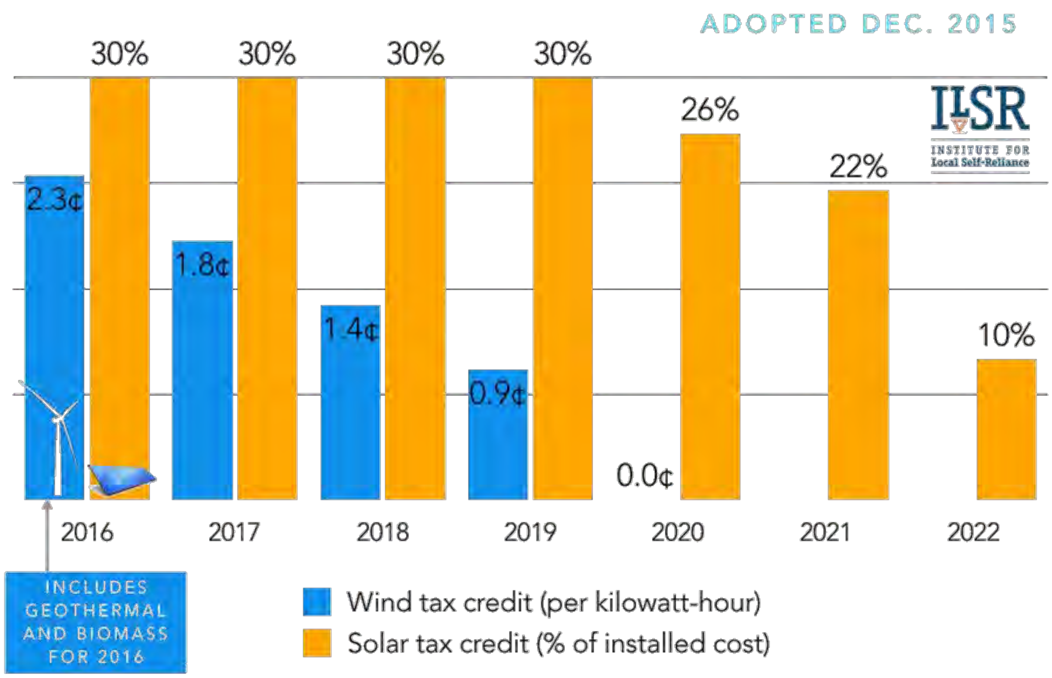
There are two solutions to the federal tax incentive problem for community renewable energy projects. One is to change federal incentives so they do not favor taxable over nontaxable entities. For example, Congress could opt to offer the incentive as a cash grant, as it did during the financial crisis (2009-2011). Later, we feature two examples of community wind projects enabled by this time-limited opportunity.

Although the tax credit for both wind and solar remarkably won extension in late 2015, its design wasn't improved relative to non-taxable entities. This is in part because the rules of legislating typically require a single Congressional approval for tax credits, but at least two votes for cash payments: authorization and appropriation. Political simplicity means greater financial complexity for community ownership.

The second solution to the unequal incentive problem is to move to low cost financing rather than relying on tax incentives. The 2015 federal tax credit extension already includes a scheduled phase out (shown below), by 2020 for wind, geothermal, and biomass projects and by 2023 for solar.

[22] Brockway, Anna M.; Feldman, David; Margolis, Robert & Ulrich, Elaine. "Shared Solar: Current Landscape, Market Potential, and the Impact of Federal Securities Regulation." National Renewable Energy Laboratory. April 2015. Accessed April 8, 2016. http://1.usa.gov/1HL2AfW.

FIGURE 11. THE FEDERAL RENEWABLE ENERGY TAX CREDIT PHASE-OUT



This eventual expiration may reduce the disincentive toward public and community ownership structures because developers (community or otherwise) will no longer have to seek Wall Street "tax equity" partners to absorb the tax incentives. Such partnerships have been expensive, but necessary.[23]

[Updated April 2019 during PDF re-release to correct inaccuracy regarding the loss of the federal tax credit] The following chart shows that losing the federal tax credit will make developing renewable energy projects more expensive. Compared to having no tax benefit at all, a solar energy project produces energy at a 25 percent discount--9 cents versus 12.1 cents--by partnering with an entity that can capture the tax credit. While difficult to do, a community-based project could lower costs by 10 percent--from 9 cents to 8.1 cents--if its members could fully capture the federal tax incentives without relying on a tax equity partner.[24]

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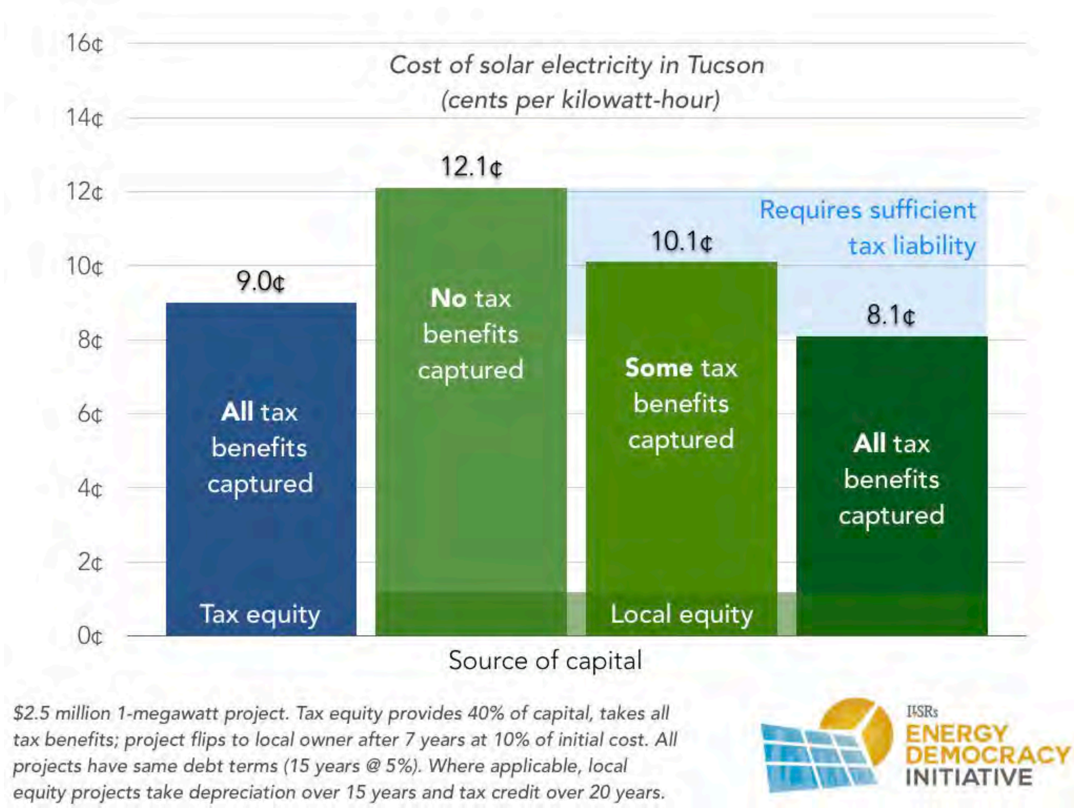
[23] Farrell, John. "Why tax credits make lousy renewable energy policy." The Institute for Local Self-Reliance. November 17, 2010. Accessed April 8, 2016. http://bit.ly/1RWpjLT.

[24] Farrell, John. "Further Thoughts on the Economics of Losing the Federal Solar Tax Credit." (ILSR, 10/12/16). Accessed 4/9/19 at http://bit.ly/2OYDff2.

FIGURE 12. THE COST OF LOSING THE FEDERAL TAX CREDIT VARIES



(The Promise of) Financing in the Crowd

In 2012, a California-based organization called Solar Mosaic garnered significant attention with its launch of crowd financing for community-based solar projects.[25] Mosaic's platform allowed ordinary folks in California and New York, and accredited investors everywhere, to make a modest (4 to 6%) investment return on community-based solar installations in their state, with the company expected to expand to other states. By 2014, Mosaic had expanded to two dozen projects and over 3,000 investors, supporting a variety of projects on private and community buildings, such as a youth employment center in Oakland, CA, and a convention center in Wildwood, NJ.[26] It had yet to

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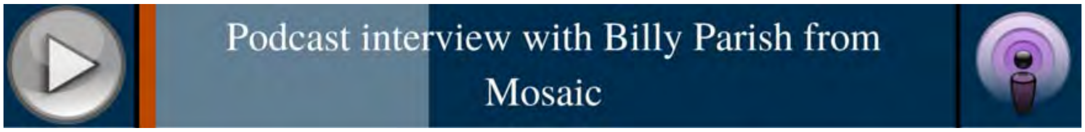
25 Farrell, John. "Millions of People Investing in Solar – Episode 16 of Local Energy Rules." *The Institute for Local Self-Reliance*. February 20, 2014. Accessed April 8, 2016. http://bit.ly/1VeiQ4E.

26 Farrell, John. "New Community Solar Crowdfunding Opportunity Sells Out in 24 Hours." *The Institute for Local Self-Reliance*. January 10, 2013. Accessed April 11, 2016. http://bit.ly/1qjGSy0.

use crowd-sourced dollars to support community-owned solar, but Mosaic president Billy Parish expressed interest in the idea in this 2014 podcast with ILSR's John Farrell.[27]



Concurrent with Mosaic's rise in prominence, the federal government passed the JOBS Act, promising a new way for small groups of ordinary people to pool their money to invest in renewable energy (and many other kinds of) projects.[28]

The excitement of crowd finance in those years makes the ensuing silence much more profound.

Sometime in 2015, Mosaic changed strategy to finance individual residential, rather than community-based, installations. Investors could still make a return, but by providing low-interest loans (5% over 20 years) to individuals for solar on their own property, to promote ownership rather than leasing.[29] And the federal rules? Draft rules were released for comment in October 2013, but not finally adopted until October 2015, with an additional 6-month delay until implementation.[30]

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27 "Millions of People Investing in Solar – Episode 16 of Local Energy Rules."

28 Farrell, John. "Crowdfunding for Community Power?" *The Institute for Local Self-Reliance*. June 19, 2012. Accessed April 8, 2016. http://bit.ly/1Nfg1IR.

29 Woody, Todd. "Why Your Neighbors Will Finance Solar Panels for Your Roof." *The Atlantic*. April 16, 2014. Accessed April 11, 2016. http://theatln.tc/1Okgwnc.

30 U.S. Securities and Exchange Commission. "SEC Adopts Rules to Permit Crowdfunding." October 30, 2015. Accessed April 8, 2016. http://1.usa.gov/1Qf3AzL.

FIGURE 13. FEDERAL CROWDFUNDING RULES

The adopted rules promise to less onerous compliance rules for small dollar projects, and an avenue for ordinary investors to participate (more detail in the Appendix).

It remains to be seen whether the new federal rules will prove a boon or not, because they may not be significantly less onerous than other securities requirements. Business lawyers at national law firm Dorsey and Whitney aren't very optimistic:

"Compared to a traditional private placement under Regulation D, **the costs of compliance** – particularly the preparation of the offering statement, necessary financial statements, as well as the ongoing reporting requirements – in relation to the maximum offering size, **may impede widespread reliance on the new crowdfunding rules**."[31]

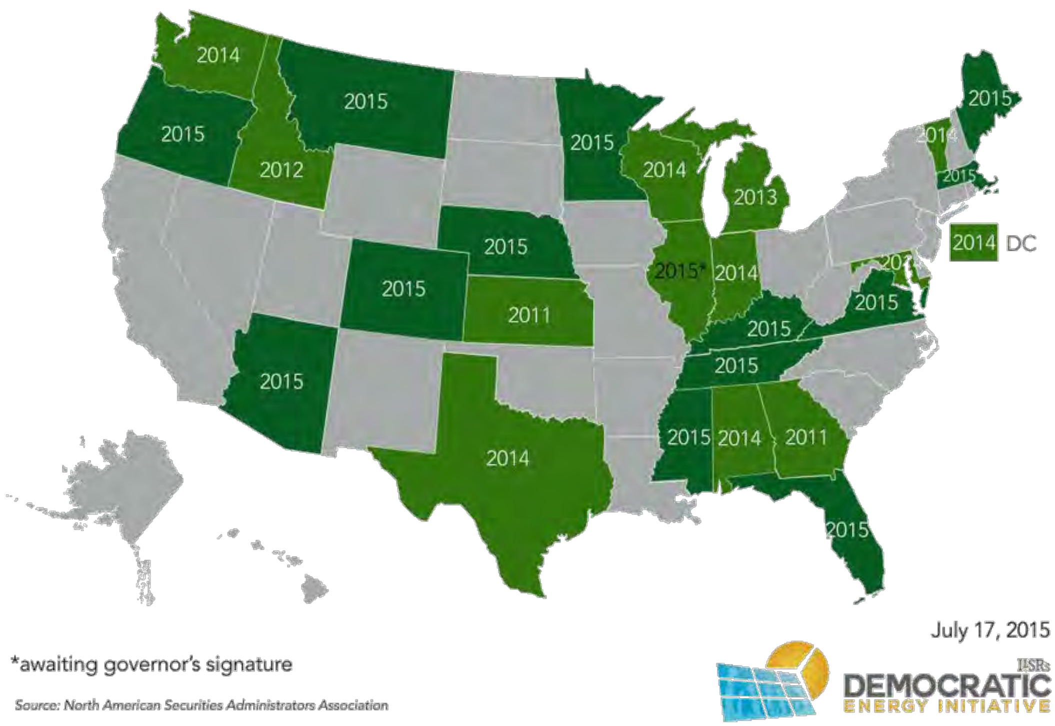
On the whole, the rules may not provide much advantage over existing exemptions from federal crowdfunding rules, other than allowing interstate investment. And the state rules have been in place, sometimes for several years, while the federal government was evaluating its rules.

[31] Dorsey and Whitney Law Firm. "Crowdfunding Part 2 – Initial and Ongoing Disclosure Requirements." November 19, 2015. Accessed April 8, 2016. http://bit.ly/1S2dB4A.

State Crowdfunding Laws

Many state level crowdfunding laws, based on existing exemptions from federal oversight, were implemented while the federal rules were bogged down. Through 2015, 25 states plus the District of Columbia adopted rules to simplify financing for small projects (see map below).

FIGURE 14. STATE CROWDFUNDING LAWS



The adopted state laws (more detail in the Appendix) have very similar terms to the recently adopted federal crowdfunding rules.

FIGURE 15. TYPICAL STATE CROWDFUNDING RULES

Despite the more rapid adoption of policies, the state crowdfunding programs haven't scaled up quickly. According to the New York Times, through June 2015 just 95 companies successfully raised capital using state-based crowdfunding laws despite being available in half of U.S. states.[32]

The lone exception to the general malaise of crowd financing community renewable energy is the donation model. Oakland-based RE-VOLV has a unique offer: a "pay-it-forward" contribution.[33] So far, 765 donors have made over $120,000 in tax-deductible contributions to fund solar installations on a food cooperative, place of worship, and dance studio. The solar recipients pay nothing upfront, but lease the system from RE-VOLV (paid for by their energy savings). RE-VOLV, in turn, uses the lease revenue as seed money to fund the next community solar project. It's the "people funded sun pay-it-forward" model, with a promise of accelerating growth as the existing projects continue to help fund future ones.

Although crowdfunding has enjoyed significant success when "investors" are making donations, as with Kickstarter (for a variety or products) or RE-VOLV (for solar), there remains significant tension between securities laws to protect investors and the relatively unsophisticated market of community renewable energy projects.

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32 Cowley, Stacy. "Tired of Waiting for U.S. to Act, States Pass Crowdfunding Laws and Rules." The New York Times. June 3, 2015. Accessed April 8, 2016. http://nyti.ms/1JlVpR6.

33 RE-VOLV. "Home page." Accessed April 11, 2016. https://re-volv.org/.

Community Shared Solar

The most promising policy for breaking the community renewable energy barrier has been commonly called "shared solar." In most cases, these projects are owned by the electric utility or third parties, with participants purchasing a "subscription" for a share of the electricity output for a limited time (e.g. 15-20 years).

The upside is that a subscription (rather than ownership) limits exposure to risk and simplifies raising capital. Subscribers don't have to process or manage filing for tax incentives, and shares can be purchased for as little as $250. Furthermore, the subscriber model insulates projects from securities law limitations because instead of being investors, subscribers are essentially pre-paying for electricity that will be credited to their bill.[34]

FIGURE 16. HOW SHARED SOLAR BUSTED THE BARRIERS

This upside is also the downside: shared solar projects are not collective ownership.

The following graphic from the Department of Energy's SunShot initiative illustrates the difference between the community-driven financial models (where investors pool money to sell electricity to a community) or group purchasing

[34] *In general, participation in shared solar is not a security if the participant's primary motivation is personal consumption (i.e. reducing their bill) not the expectation of profit. CommunitySun received a "no-action" letter from the SEC regarding their model of purchasing shares and getting bill credits.From Feldman, et al: "The central questions in determining whether an interest in a shared solar project is considered an investment contract and therefore a security appear to be the motivation of the participant and the perception of the financial instrument."*

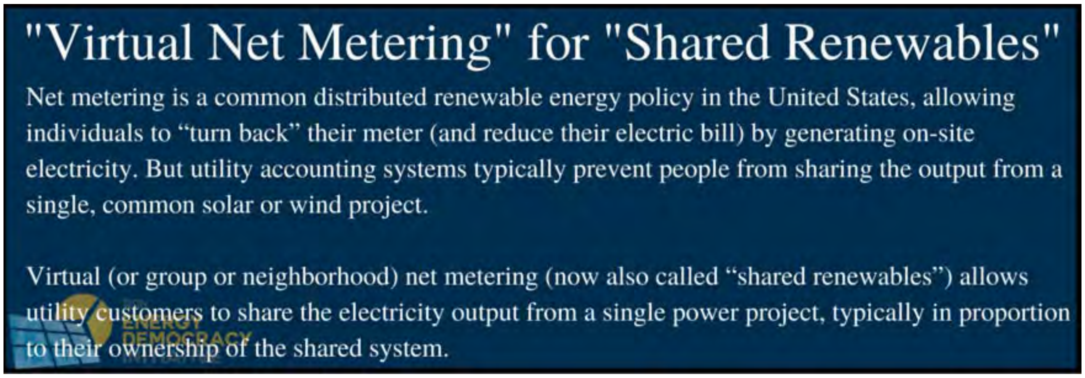
(where individuals bid together for solar arrays for their individual use) and the offsite or onsite "shared solar" concept.[35]

FIGURE 17. FORMS OF COMMUNITY ENERGY PROJECTS (CREDIT: SUNSHOT)

Source: SunShot

[35] Brockway, Anna. "No Roof, No Problem: Shared Solar Programs Make Solar Possible For You." Department of Energy: SunShot Program. January 29, 2015. Accessed April 10, 2016. http://1.usa.gov/1COZgl2.

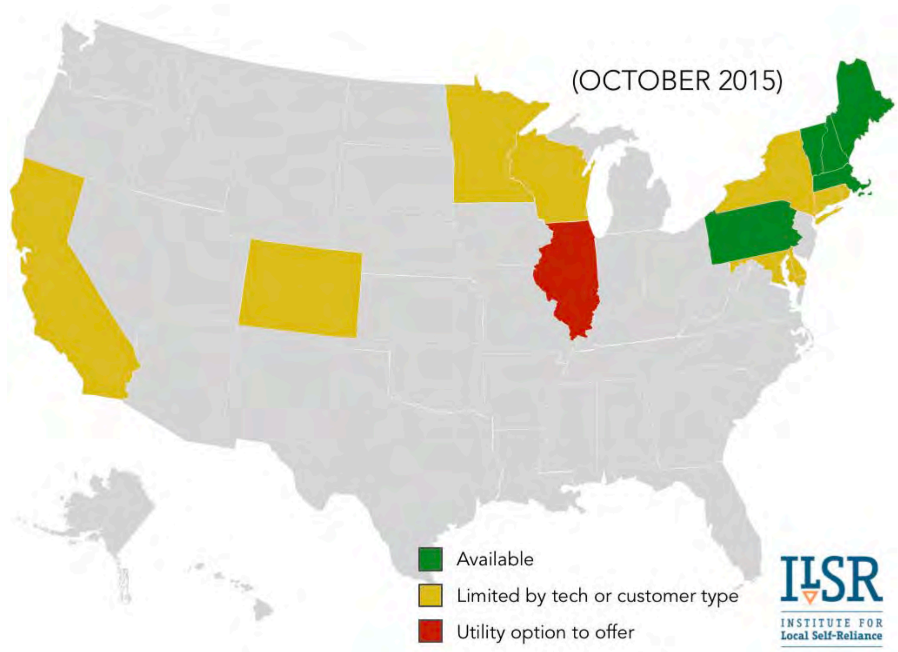
The key policy to enable on- or off-site shared solar is often called "virtual net metering."[36]



Unless a utility offers a program voluntarily (typically one in which they own the solar array), shared solar is enabled by virtual net metering or explicit community solar laws. Most of the 16 states with such laws restrict availability to solar energy and many limit availability to municipal governments or select electric customers. The following map illustrates.

[36] Farrell, John. "Virtual Net Metering." The institute for Local Self-Reliance. November 4, 2015. Accessed April 10, 2016. http://bit.ly/1SIwQO5.

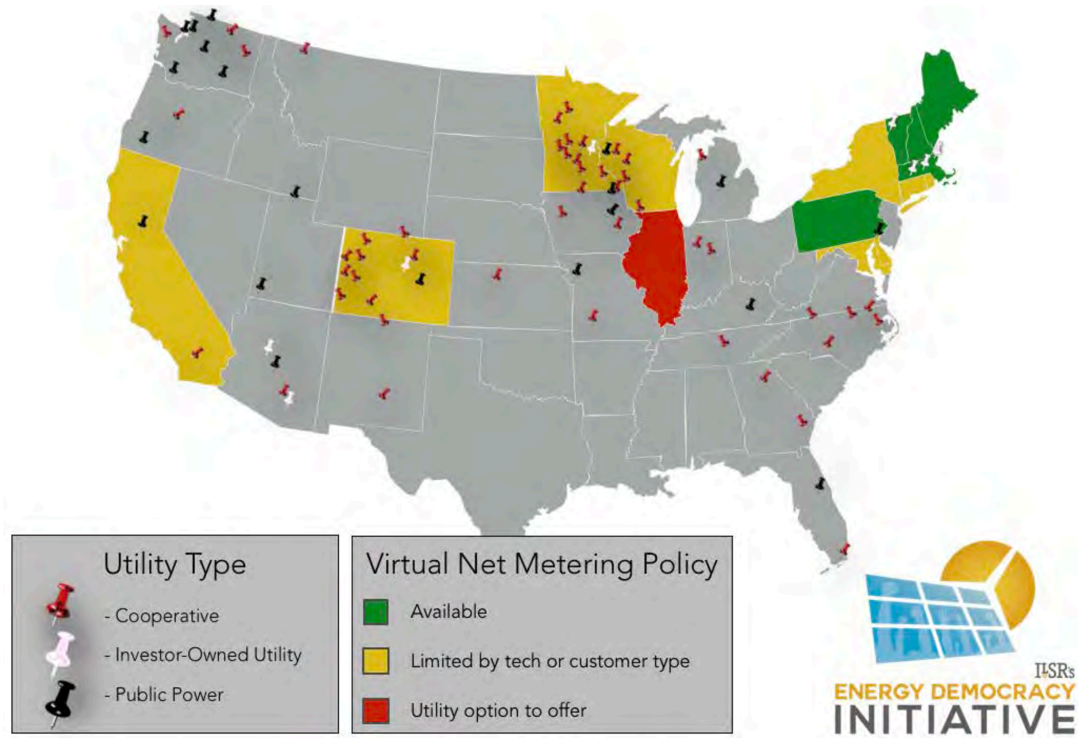
FIGURE 18. ONLY 16 STATES SUPPORT SOME FORM OF VIRTUAL NET METERING OR COMMUNITY ENERGY



The map below shows the success of implementing good state policy.[37] Most existing community solar programs overlap with favorable state policy regimes. Washington is an interesting exception, where the state lacks a virtual net metering policy, but has a history of a very generous state tax incentive for community-owned solar that spawned a number of projects.

[37] Stumo-Langer, Nick. "Are Rural Electric Cooperatives Driving or Just Dabbling in Community Solar?" The Institute for Local Self-Reliance. March 11, 2016. Accessed April 10, 2016. http://bit.ly/1qCAUsl.

FIGURE 19. COMMUNITY SOLAR PROJECTS AND AVAILABILITY OF SUPPORTIVE POLICY



Although much more likely there, community shared solar projects aren't limited to states with adopted policies. A number of utilities—particularly rural electric cooperatives—have offered community solar projects to their customers in other states including Georgia, Iowa, Michigan, and North Carolina.[38] New policies are also under active consideration in New Mexico and Virginia.[39] Hawaii enacted a law in 2015, and its program launch is awaiting a "value of solar" determination after an initial (poorly designed) utility program was shut down by the state's Commission.[40]

Colorado company Clean Energy Collective has pioneered the development of a shared solar model that has been successful across eight states and even more utilities. The company sells 50-year ownership shares in community solar

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38 Ibid.

39 Shared Renewables HQ. "U.S. Shared Energy Map." Accessed April 10, 2016. http://bit.ly/1QPig6I.

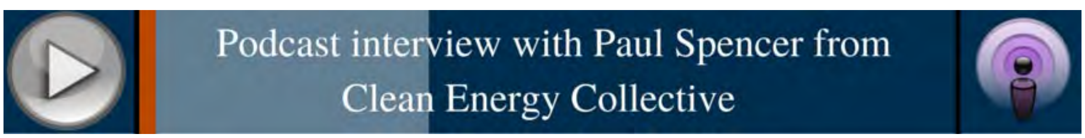
40 Shimogawa, Duane. "State regulators nix Hawaiian Electric's community solar pilot project." Pacific Business Journal. September 15, 2015. Accessed April 10, 2016. http://bit.ly/1JTsD5t.

projects arranged in partnership with the hosting electric utility. The for-profit company is able to capture and pass through the federal tax credit, thereby lowering the cost of purchasing or financing a share of ownership. Perhaps its biggest contribution is solving the issue of sharing electricity output by negotiating arrangements with utilities that are not compelled by law.

The company is also striving to solve the upfront cost barrier (at least for credit-worthy Massachusetts customers) by offering a "pay as you go" option. With the "SolarPerks" program, customers pay nothing upfront and simply substitute power from Clean Energy Collective for power from their utility, at a price that is "below the prevailing retail rate."[41]

Their community solar offerings may also offer a discount relative to individual ownership, for those who have the option. In a recent project developed for the Wright-Hennepin electric cooperative in Minnesota, for example, the Collective's community solar project offered a 12-year reduction in payback for a solar investment, from an abysmal 32 years to a still-long 20 years.[42]

For more on Clean Energy Collective's model and business, listen to this 2013 podcast with CEO Paul Spencer.



The **"Simple Solar"** offering by the Cedar Falls, IA, municipal utility is another good illustration. Customers will receive a credit to their electric bill for their share of electricity production, but (unlike with net metering), the energy credit will be based on the "market energy supply costs for the billing period."[43] Originally much smaller, high demand led the utility to increase the size of the solar project to 1.5 megawatts, and it now has over 1,200 residential and business subscribers. The increased size also drove down the price to $270 per 170 Watt panel ($1.59 per Watt), far less than a comparable individually-owned system (typical installed costs are around $3.00 per Watt).

A relatively recent community renewable energy model piloted by a Vermont law clinic may take advantage of electricity sharing laws and avoid securities

41 Trabish, Herman K. "How the utility role in community solar is evolving as the sector matures." *Utility Dive*. January 7, 2016. Accessed April 11, 2016. http://bit.ly/23HJBBd.

42 Farrell, John. "Minnesota's First Community Solar Project is Minnesota-Made." The Institute for Local Self-Reliance. September 7, 2012. Accessed April 11, 2016. http://bit.ly/1NkXNpp.

43 CFU Simple Solar. "FAQs." Accessed April 11, 2016. http://bit.ly/1SJV7TV.

regulation issues. The model has participants purchase their shares directly from the solar installer, rather than via the community solar organization.[44] Instead of acting as an aggregator of capital, the community solar organization (usually a limited liability company) has a more limited role, and "jointly maintains the array, sharing expenses for insurance, taxes, cutting the grass."[45] The direct purchase means each individual is shopping separately, not investing collectively, and thus there is no security to advertise. However, the model hinges on the Vermont's virtual net metering law, allowing each individual to net the production from their share of the community solar array against their home energy use.

Aided by new policy, community shared solar is expected to expand rapidly in the next five years. In a report published by the National Renewable Energy Laboratory in April 2015, researchers estimated that shared solar could account for 5 to 11 gigawatts of solar capacity, for residential and non-residential participants, by 2020.[46] With relatively high participation rates (213 participants per megawatt) in early community solar projects, these figures suggest that over a million Americans could participate in shared solar in the next 4 years.[47]

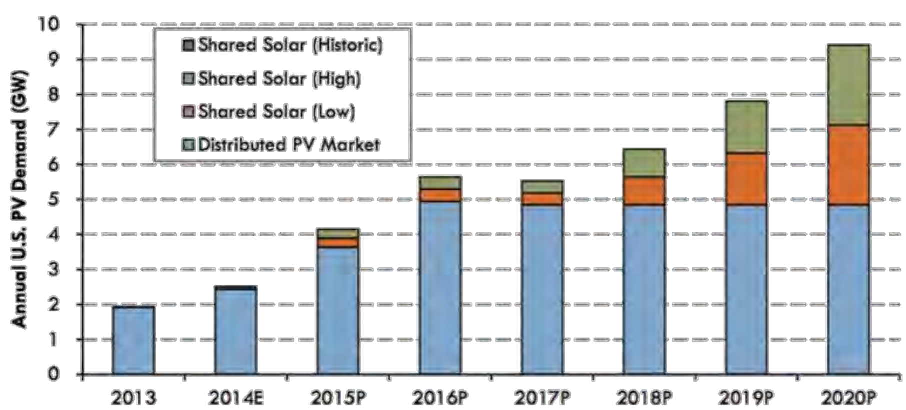


Figure ES-1. Estimated PV market potential of onsite and shared solar distributed PV capacity

Source: Community Solar Hub

[44] Email with Kevin Jones, Vermont Law School, 10/27/15.

[45] Ibid.

[46] Brockway, Anna. "No Roof, No Problem: Shared Solar Programs Make Solar Possible For You." Department of Energy: SunShot Program. January 29, 2015. Accessed April 10, 2016. http://1.usa.gov/1COZgl2.

[47] Community Solar Hub. "Statistics." Accessed June 11, 2015. http://bit.ly/1QPiJWx.

FIGURE 20. ESTIMATED DISTRIBUTED AND COMMUNITY SOLAR PV MARKET POTENTIAL (NREL, 2014)

The big questions for the subscriber model, aside from falling short of collective ownership, is whether it can meet the other principles for community renewable energy, including tangible benefits, be additive to other renewable energy policies, and ensure access to all.

Limitations of Shared Solar

The biggest limitation on shared solar is policy. Community shared solar may be simpler than the ownership model, but to be developed by anyone other than the utility company, it requires utility cooperation (e.g. such as Clean Energy Collective) or enabling state legislation.

Be even where implemented, shared solar has room for improvement.

For one, shared solar programs should always offer ownership options beyond utility ownership, and program rules should facilitate collective ownership where possible. In most cases, ownership is retained by the utility or a third party, giving the participants little say in the decisions of the community solar project, from hiring to contracts with other local businesses, to the project location. The tradeoff seems relatively inexpensive when tax law limits how much of the tax benefits can be captured locally, but as the incentives fade in prominence, the loss of control may be more than it is worth.

Another potential improvement is expanding beyond solar. Community wind projects have proven popular with community ownership, but face many of the same barriers as community-owned solar. Shared renewables policies should be broadened to include non-solar technologies, from wind to geothermal (as district heating, for example) to anaerobic digesters, to provide a workaround for securities limitations.

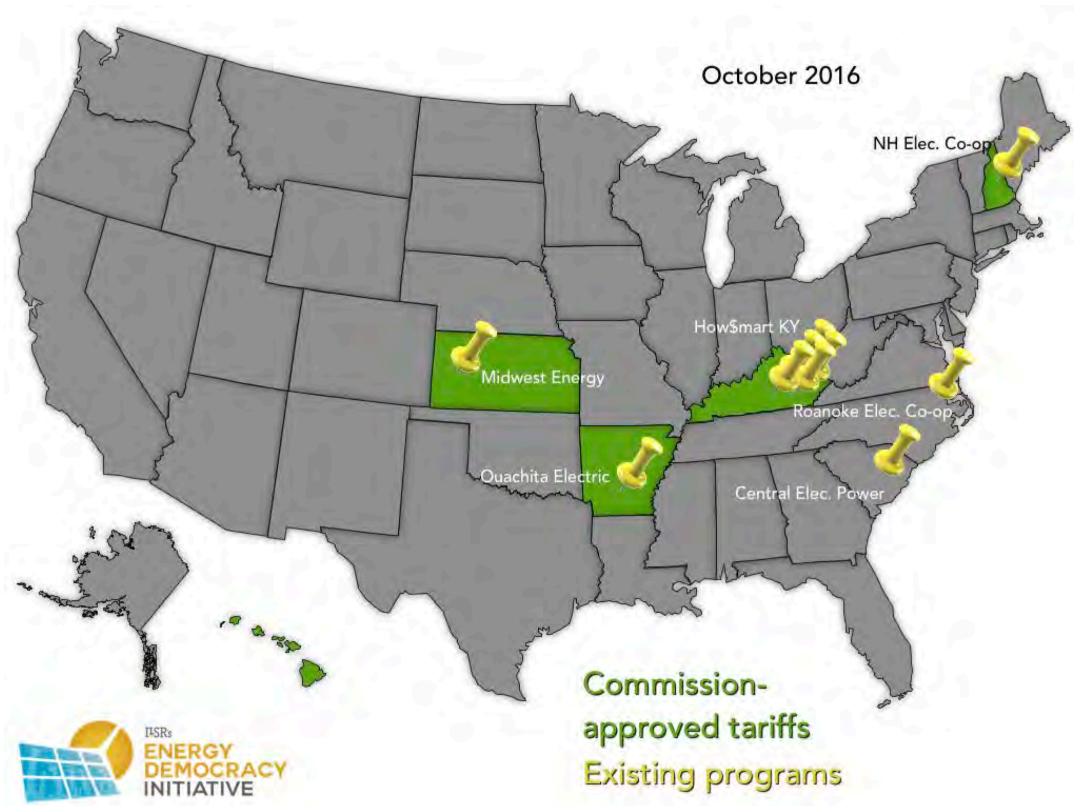
4 Ways to Improve Shared Renewables

1. Facilitate collective ownership
2. Expand beyond solar
3. Enable low-income access
4. Increase transparency of benefits

A third place for improvement (in all forms of community renewables, not limited to shared solar) is financing. Especially with early shared solar programs, participants had to pay an upfront cost from several hundred to several thousand dollars to buy a share. Even as the programs have expanded to include financing, only participants with high credit scores are able to access financing. Full deployment of community solar will require financing options that can be accessed by low- and moderate-income households. Some promising options include on-bill repayment of subscription costs via the utility bill, which have much lower default rates than consumer loans, or institutional anchor tenants for community solar projects that are committed to claiming subscriptions of participants who fall short on payments.

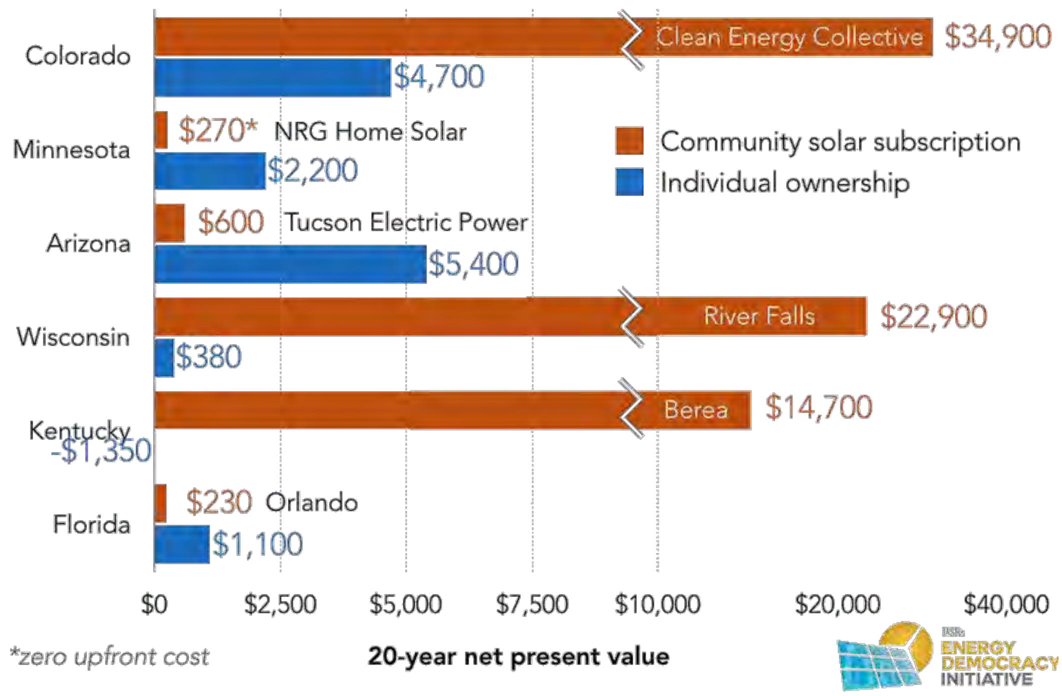
Despite having a heavy reliance on large-scale fossil fuel generation, rural electric cooperatives have been much more likely to experiment with community solar and tools like on-bill financing to allow member participation. The following map shows active on-bill financing programs, almost entirely provided by rural electric cooperatives.

FIGURE 21. EXISTING ON-BILL REPAYMENT PROGRAMS



A final issue for shared solar is transparency of participant costs and benefits. Early program and project designs vary widely, leading to wide variance in financial benefits. The following chart compares the 20-year benefits of a 5-kilowatt community solar subscription (top bar of each set, in orange) to a comparable 5-kilowatt customer-owned solar array on their property (bottom bar, in blue).

FIGURE 22. COMPARING COMMUNITY SOLAR VALUE



Utility sponsored programs in Arizona (Tucson Electric Power) and Florida (Orlando Public Utilities Commission) create very modest savings, and are less lucrative than an individual having solar on their own roof. In the case of Tucson, the financial benefit is basically a roof rental fee from the utility, far less than the value of reducing energy purchases with a rooftop solar array. In Orlando, the bill credit starts out several cents lower per kilowatt-hour than the retail electricity price, costing the customer more out of pocket until the credit rises above the retail rate in approximately year 10.

In contrast, utility-offered programs by municipal utilities in Kentucky and Wisconsin both offer significant benefits over the long term. In both cases, relatively low upfront costs are offset quickly by energy savings, even though the savings rates in both cases are less than 8¢ per kilowatt-hour.

In Colorado, where third parties provide community solar, the community solar savings (from Clean Energy Collective, in this case) far outstrip individual panel ownership, because the full retail credit quickly offsets the high upfront cost. In Minnesota, a similar program structure is a strength, with bill credits actually higher than the retail rate due to the inclusion of solar renewable energy credits of 2-3¢ per kilowatt-hour. The savings from the NRG Home Solar program are smaller than for ownership over 20 years because the subscription cost escalates, potentially faster than the bill credit. But with zero upfront cost for credit-worthy customers, it may be more attractive than the modestly higher returns from having a solar-adorned roof.[48]

California provides an example of where "shared solar" becomes a lot like "green pricing," where customers pay a premium for power from community solar. Part of the program is literally that, where customers will be able to green up their electricity supply from utility-owned solar arrays, but will have to pay 15 to 35% more per kilowatt-hour. For the more traditional "shared solar" model, the program is likely to be stymied by bill credits of around 8¢ per kilowatt-hour, far less than the retail electricity prices.

Ultimately, shared solar is a relatively new tool with ample opportunity to improve. Despite the relatively large number of states with programs and voluntary utility-provided programs, there are just over 100 megawatts of community solar projects online (a tiny fraction of total U.S. electric generating capacity).

Community Group Purchasing

Acting collectively doesn't always mean collective ownership, and one successful tool has been to organize individual homeowners and businesses to buy into solar together. The "SUN" chapters of the **Community Power Network**, for e**xample,** organize cooperative associations of homeowners to collectively bid for solar installations on their homes, lowering prices by as much as 25%.[49]

The notion was pioneered by the Mt. Pleasant Solar Cooperative in Washington, DC.[50] This local effort helped get solar installed on 10% percent of properties in the neighborhood, and spawned several buying cooperatives in other DC neighborhoods.[51] By 2015, the Network served communities in D.C., Maryland,

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[48] Trabish, Herman. "Inside California's plans to jump-start community solar development." Utility Dive. March 5, 2015. Accessed April 10, 2016. http://bit.ly/1UU7G55.

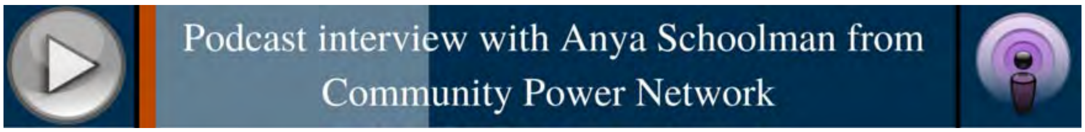
[49] Farrell, John. "Distributed, Small-Scale Solar Competes with Large-Scale PV." The Institute for Local Self-Reliance. October 19, 2010. Accessed April 11, 2016. http://bit.ly/1XrqhDo.

[50] Farrell, John. "Anya Schoolman: Episode 1 of Local Energy Rules Podcast." The Institute for Local Self-Reliance. January 16, 2013. Accessed April 11, 2016. http://bit.ly/1Q3n2wi.

[51] Ibid.

Virginia, and West Virginia. In total, it has aided low-cost installation of nearly 6.5 megawatts of solar for thousands of participants.[52]

Below is our 2013 podcast interview with Anya Schoolman from the Community Power Network.



Another example is the **"Solarize"** model started on the opposite coast, in Portland, OR. "The Solarize approach allows groups of homeowners or businesses to work together to collectively negotiate rates, competitively select an installer, and increase demand through a creative limited-time offer to join the campaign."[53] Solarize campaigns are now operating in California, Connecticut, Maryland, Massachusetts, New Hampshire, New York, North Carolina, Oregon, Pennsylvania, Rhode Island, Texas, Utah, Vermont, Washington, and Wisconsin.[54] Several of these campaigns are government or utility sponsored and, cumulatively, the various Solarize efforts have installed over 20 megawatts of solar, at a modest price discount to individuals acting alone.[55]

For more information on group purchase programs, see the Solarize Guidebook published by the NW SEED in partnership with the National Renewable Energy Laboratory.[56]

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52 Community Power Network. "CPN Solar Co-ops & Solar Bulk Purchases." Accessed April 11, 2016. http://bit.ly/1XrqBCf.

53 Solar Outreach Partnership. "About Solarize." SunShot. Accessed April 11, 2016. http://bit.ly/1N4NNFW.

54 Ibid.

55 Condee, Nellie and Hausman, Nate. "Clean Energy States Alliance Guidebook." SunShot. September 2014. Accessed April 11, 2016. http://bit.ly/1KWL405.

56 Grove, Jennifer; Irvine, Linda; and Sawyer, Alexandra. "The Solarize Guidebook: A community guide to collective purchasing of residential PV systems." SunShot. February 2011. Accessed April 11, 2016. http://1.usa.gov/1Ue1DVJ.

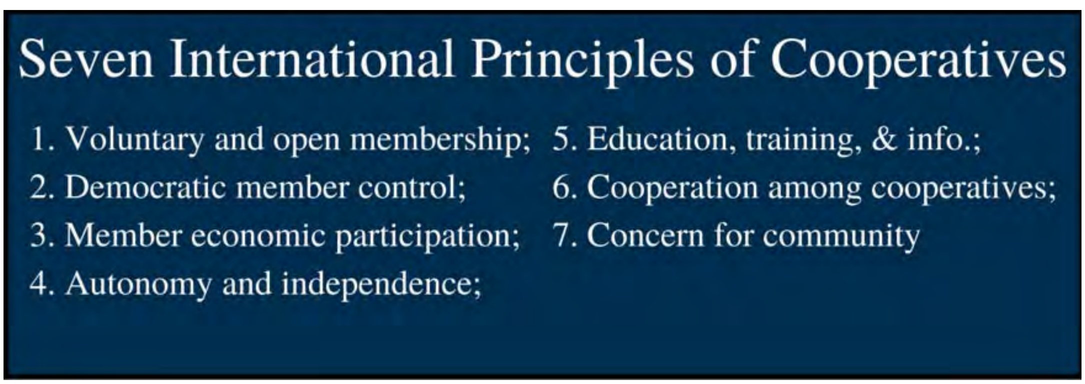
Selling on a De-Monopolized Grid

Another possibility is that community renewable energy projects will become wholesale power providers. In this case, the community-owned project simply sells power into the competitive market, with revenue shared among participants. As more states consider de-monopolizing the distribution grid, in particular, there may be greater opportunities for sales at the local level, replacing the need to share electricity output with a simpler revenue-sharing model.

Cooperatives

It may seem odd to distinguish between "community" and "cooperative" renewable energy projects. However, "community" can describe geographic or ethnic or simply solar-loving groups of people, whereas a cooperative is a formal legal structure with a history of democratic governance and equitable distribution of benefits.

Cooperatives are common in other economic sectors but in electricity are almost entirely represented by decades-old and conservative monopoly rural electric cooperatives. Despite this, the cooperative structure—used to first bring electricity to many communities that would have otherwise gone without—could be last century's gift to solve this century's problems of organizing community renewable energy projects.



There are unfortunately few examples of cooperatives in the renewable energy field. There are a few are worker-owned cooperatives, owning an enterprise that provides renewable energy services but not developing community renewable energy projects. At PV Squared, a solar installation company [in the Pioneer Valley of Massachusetts], the workers make the decisions about the direction of the company and share in the profits.[57] Namaste Solar is also a worker-owned energy services companies, and it is also a part of the Amicus buying cooperative (discussed below) for solar installers.[58]

Cooperatives can also pool their buying power for consumers or businesses. Cooperative Community Energy is a member-owned solar and energy services company in California. Members get access to bulk discounts on hardware, the cooperative lobbies for more favorable policy, and members get a dividend check if the cooperative turns a profit.[59] The Acorn Renewable Energy Cooperative in Vermont provides bulk purchase benefits on a variety of renewable resources, including wood chips, heat pumps, and solar.[60] Amicus Solar is a cooperative of dozens of solar installation companies, giving them a collective purchasing power that can compete with the largest installers in the country, without having to merge companies.[61] Cooperative Energy Futures is a small, for-profit cooperative in Minneapolis that has organized households to provide energy efficiency and solar energy services with bulk purchasing.[62] In 2014, they began offering a solar leasing program and in 2016 they plan to offer their first community solar project under the state's community solar program.

In many European countries, there are hybrid electricity cooperatives where the cooperative owners are consumers of power, but also producers.

"In the 1970's, three rural Danish families banded together and installed a wind turbine, creating the world's first green energy co-op. Today, the 10,000-member Middelgrunden co-op owns and operates the world's largest offshore wind farm outside Copenhagen harbour." Overall, 80% of Danish turbines are cooperatively owned by over 150,000 families.[63]

The success of wind cooperatives in Denmark is based on a history of cooperative ownership of utilities and very favorable policy. Beginning in 1979,

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57 Pioneer Valley Photovoltaics. "Our Work." Accessed April 10, 2016. http://bit.ly/1TLoJoV.

58 Namestè Solar. "Mission. Values. Pillars." 2014. Accessed April 10, 2016. http://bit.ly/1MoJ2ah.

59 Community Cooperative Energy. "Company Member Benefits." Accessed April 10, 2016. http://bit.ly/1UUgSGG.

60 Acorn Energy Cooperative. "Home Page." Accessed April 10, 2016. http://bit.ly/1Yos0tB.

61 Amicus Solar. "Home Page." Accessed April 10, 2016. http://bit.ly/20tNFCh.

62 Cooperative Energy Futures. "Insulation." Accessed April 10, 2016. http://bit.ly/1qCJzeG.

63 Farrell, John. "Feed-in Tariffs in America: Driving the Economy with Renewable Energy Policy that Works." April 9, 2009. Accessed April 10, 2016. http://bit.ly/1RNJ8sc.

wind projects could get a 30% capital subsidy, a policy that morphed over time into a fixed payment for production (a feed-in tariff). The fixed payments were supplemented with an income tax exemption (with tax rates exceeding 50%) for revenue from cooperatively-owned wind projects.[64] In the U.S., challenges with accessing renewable energy incentives have meant most "cooperative" ownership models for renewable energy have used limited liability corporations, like MinWind.[65]

Cooperative in Principle

Community-owned renewable energy projects such as MinWind in Minnesota act as co-ops (one member/one vote) but may not be incorporated under the cooperative regulations. Co-op values and processes are reflected in the bylaws of these organizations

There are also advantages to cooperatives being used for community renewable energy. Timothy Den-Herder Thomas of Minnesota-based Cooperative Energy Futures notes that the cooperative structure can solve the securities challenges that face typical projects because they can raise unlimited amounts of capital from members. Cooperatives also don't have to file separate securities registration, cutting the cost to raise capital by 90% or more. In his November 2015 interview with ILSR, Timothy also warned that the use of cooperatives can't just be for the purposes of raising capital. Cooperatives can only raise capital from members, who have to be "materially involved in the cooperative… you can't become a member just to invest."[66]

Not coincidentally, Cooperative Energy Futures is one of the first non-utility cooperatives to develop community renewable energy projects (along with Acorn Renewable Energy Cooperative in Vermont and Vineyard Power in Massachusetts).

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[64] Ibid.

[65] Commission for Environmental Cooperation. "Guide to Developing a Community Renewable Energy Project in North America." March 2010. Accessed April 10, 2016. http://bit.ly/1Lm5IBJ.

[66] Grimley, Matt. "Sunshine and Ownership: A Cooperative Solar Garden Blooms in North Minneapolis – Episode 34 of Local Energy Rules." *The Institute for Local Self-Reliance*. April 18, 2016. Accessed April 11, 2016. http://bit.ly/1oZtbn9.

In addition to solving securities issues, the upside of cooperatives is that they increase the potential community energy project value for participants. In the case of the Shiloh Temple project in Minneapolis (organized by Cooperative Energy Futures), member-subscribers will get electric bill credits but also dividends should the project turn a profit.[67] It's likely to, since most solar developers offering community solar projects earn a profit on the difference between subscription fees and the project cost, and member-owned Cooperative Energy Futures is both owner and developer. After project debt is retired in the first 10-15 years, the organization may have additional revenue to distribute.

Cooperatives won't automatically solve the challenge of accessing federal tax incentives, although they are at no greater disadvantage to other typically non-taxable entities. For one, cooperatives can act as for-profits, distributing profits (and tax credits) through to members, although this would likely trigger the same passive income barrier mentioned earlier. Cooperatives could also secure a tax equity partner to absorb the tax credits, as have other non-profit organizations. In the next few years, however, the federal tax incentives will sunset, and cooperatives may prove even more advantageous in addressing the remaining barriers.

[67] Ibid.

EXCEPTIONAL COMMUNITY ENERGY PROJECTS

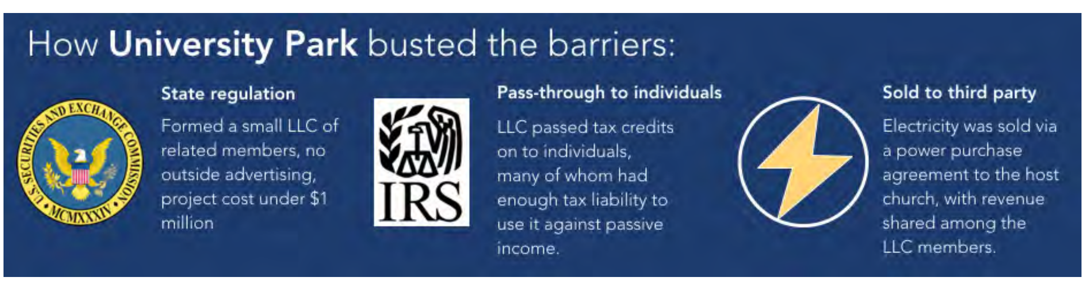
Despite the challenging legal and financial barriers facing community renewable energy, a surprising number of projects and project models have succeeded. These projects have brought together hundreds of people into ownership of renewable energy, often saving them money, and keeping more of the money they spend on energy in their own community.

The models range from forming independent limited liability companies to municipal ownership to donations. Unfortunately, many are not easily replicable, taking advantage of unique circumstances from now-expired incentives to pro bono legal or financial expertise. But they illustrate the many ways communities can come together to take charge of their energy future.

The following graphic illustrates the range of community renewable energy projects, on the basis of ownership, with examples drawn from the following pages.

University Park Solar is a 35-member, private limited liability company in Maryland formed to share the economic benefits of electricity production from solar panels on the University Park Church of the Brethren started with the technical assistance of Community Power Network. The 23-kilowatt solar array cost $130,000 to install in 2010, financed with the purchase of shares by the 35 members, at $1,000 apiece. Electricity from the solar array serves 100% of the church's electricity needs, with excess sold to the grid.

FIGURE 23. HOW UNIVERSITY PARK BUSTED THE BARRIERS



In addition to federal and state tax incentives received at the time of construction (including a state grant), the community solar investors receive revenue from the sale of electricity to the church, to the grid, and the sale of the solar renewable energy certificates in the Maryland market (1 certificate for each megawatt-hour of electricity produced). Ongoing costs include panel maintenance, insurance, and bookkeeping. Through 2015, net of expenses, each member had recouped about 60% of their upfront investment.[68]

Although University Park Solar is a single project, it has inspired three other projects of similar design. Sun Harvester Community Solar LLC is a forthcoming project for an urban farm in Baltimore. It will not only generate revenue for members, but also make the farm carbon neutral.[69]

Greenbelt Community Solar is a 22-kilowatt solar array, producing power on the roof of and with electricity sold to the Greenbelt Baptist Church. The 34 members received nearly $11,000 from the state of Maryland and the 30% federal solar tax credit (in the form of a $34,000 grant) to reduce project costs. The project has ongoing revenue from electricity sales to the church ($3,800 in 2012) and from the sale of solar renewable energy credits in the Maryland market ($4,700 in 2012).[70] Assuming a similar installed cost to University Park solar, the project will make back the upfront investment in about 10 years with electricity and credit sales.

Community Solar Thermal is unique for selling therms rather than electric kilowatt-hours. It's a 30-member effort to offset gas use at a local restaurant, selling therms at a 10% discount to the utility's prices to the restaurant. The purchase agreement covers 13 years, and then the project will sell the equipment to the restaurant at 10% of the original cost.[71]

MinWind was one of the first successful community wind projects, but also serves as a cautionary tale for community ownership. The Minnesota-based 13.5-megawatt wind project was completed in two phases, attracting over 300 mostly local investors to put up $5,000 per share.[72] Ownership was limited to Minnesota residents, but diversified with at least 85% from rural areas and a cap of 15% on the ownership share of any one investor.[73]

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68 University Park Community Solar LLC. "Annual Summary of Operations, Year of 2014." March 21, 2015. Accessed April 10, 2016. http://bit.ly/20x7REv. Email with David Brosch.

69 Email with David Brosch, 2016.

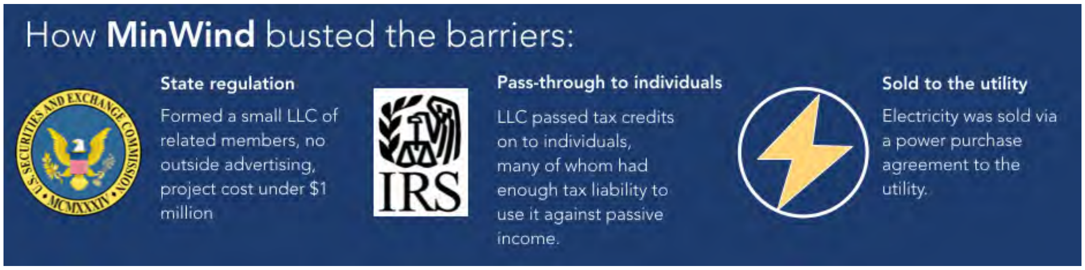
70 Greenbelt Community Solar. "Annual Reports." Accessed April 10, 2016. http://bit.ly/1SaZbIl.

71 Email with David Brosch, 2016.

72 Buntjer, Julie. "MinWind files for bankruptcy." Daily Globe. January 14, 2015. Accessed April 11, 2016. http://bit.ly/1Xre5m9.

73 Windustry. "Minwind III – IX, Luverne, MN: Community Wind Project." Accessed April 11, 2016. http://bit.ly/1W4CVIh.

FIGURE 24. HOW MINWIND BUSTED THE BARRIERS



The 9-turbine project (each organized as an independent LLC) benefitted from a state wind production incentive of 1.5¢ per kilowatt-hour (paid over 10 years) and U.S. Department of Agriculture grants worth $178,000 apiece for the final 7 turbines. The option to capture the federal Production Tax Credit was passed through to individual owners based on their own tax liability (although ILSR's research suggests few would have been able to fully use it).[74][75]

The project successfully generated revenue for nearly a decade without major incident, but the turbines were damaged in an ice storm in 2013, and the owners didn't immediately have the capital to complete repairs. The financial shortfall became a crisis in 2014, when the Federal Energy Regulatory Commission informed the project owners that they were delinquent on filing eight years of reports required of "qualified facilities" under the 1978 PURPA. Under threat of $1.91 million in fines, the MinWind owners filed for bankruptcy in early 2015.[76]

The idea for **Green Energy Farmers** began back in 2007, when Randy Caviness had an idea to build two wind turbines for the rural electric cooperative serving nearby Iowa farming communities. With grants from the U.S. Department of Agriculture rural development program, 10-year Iowa production tax credits, and federal tax incentives taken as a cash grant, the two turbines were built by 2010.

[74] Ibid.

[75] Farrell, John. "Broadening Wind Energy Ownership by Changing Federal Incentives." April 2008. Accessed April 11, 2016. http://bit.ly/1SkPYkB.

[76] Windustry. "Minwind III – IX, Luverne, MN: Community Wind Project."

FIGURE 25. HOW GREEN ENERGY FARMERS BUSTED THE BARRIERS

Seizing on a one-year extension of the cash grant program through 2011, Randy and his fellow energy farmers made plans to erect six more turbines, financed by 180 local investors. Shares in the projects were sold to friends and neighbors in the community. Most of the investors live within 30 miles of the turbines they own, and the dividends, tax-credits, and economic benefits remain in the community.

The legal work was complicated, but not insurmountable. The state tax credits were capped at 2.5 megawatts, per owner, so each of the wind turbines are financed and owned by separate LLCs. Randy, along with local banks, was instrumental in setting up the financing schematics for all eight turbines.

Each turbine provides revenue from tax incentives, land lease royalty payments, property taxes and dividends totaling $1.08 million annually over a period of 10 years.[77] Unfortunately, the expiration of the federal cash grant means there are limited opportunities to replicate the projects.

South Dakota Wind Partners took shape in the shadow of the rural cooperative Basin Electric's proposed wind farm near Crow Lake, SD, with local farmers and other South Dakotans interested in joining in.[78] The result was a community-based carve out of the 100+ megawatt facility: 7 turbines owned by over 600 farmers and local residents, each investing $15,000 per share. The turbines were constructed as part of the larger wind farm, and the Wind Partners organization contracted with the cooperative electric utility for operations,

[77] Farrell, John. "Randy Caviness and Community Wind in Iowa: Episode 4 of Local Energy Rules Podcast."The Institute for Local Self-Reliance. March 7, 2013. Accessed April 11, 2016. http://bit.ly/1UW2Wfe.

[78] Basin Electric Power Collective. "Home page." Accessed April 11, 2016. http://bit.ly/1Q3e9mj.

maintenance, and purchase of the electricity.[79] Like Green Energy Farmers, South Dakota Wind Partners was able to take the federal tax credits as a cash grant.

FIGURE 26. HOW SOUTH DAKOTA WIND PARTNERS BUSTED THE BARRIERS

Financial ownership took two forms: an equity share allowing the investor to share tax credits, and a debt share allowing the investor a fixed rate return on investment.[80] Individual investors were aided by $80,000 in early seed money from four participating organizations: the local East River Electric Cooperative, the South Dakota Corn Utilization Council, South Dakota Farm Bureau and South Dakota Farmers Union.[81]

[79] Farrell, John. "600 Investors in South Dakota's Premier Community Wind Project: Episode 7 of Local Energy Rules Podcast." The Institute for Local Self-Reliance. April 17, 2013. Accessed April 11, 2016. http://bit.ly/1RANOCU.

[80] Ibid.

[81] Windustry. "Crow Lake Wind – Community Owned Portion (White Lake, SD)." Accessed April 11, 2016. http://bit.ly/20vEtgB.

At least one other community wind project has been inspired by South Dakota Wind Partners. Black Oak Wind is a proposed 16-megawatt wind project in upstate New York, and currently has over 150 investors.[82]

Community Wind South is a 5% community owned, 95% developer owned 30-megawatt wind project in southwestern Minnesota.[83] It raised over $3 million in community capital and uses a standard flip arrangement where an outside investor holds a controlling interest for several years.

FIGURE 27. HOW COMMUNITY WIND SOUTH BUSTED THE BARRIERS

The project started in 2003, but was caught waiting for a 5-year resolution of cost allocation debate over expansion of transmission power lines for wind within the Midwest Independent System Operator. Finally, in 2011, investor Juwi purchased its share and some turbine components to make the project eligible for the expiring federal tax credit (available as a cash grant). Shares were sold to 28 landowners and nearby residents.[84]

Although successful, the project has faced a few challenges. Federal rules allow a clawback of the cash grant if there is too much participation from non-qualified investors. Additionally, local investors wanted specific financial benefits for the community (beyond the state's production tax), but such benefits can't be secured until the project flips to local ownership after year 6.

[82] Byeon, Joe. "Some residents object to $40 million wind farm in small Tompkins town." The Ithaca Voice. December 8, 2015. Accessed April 11, 2016. http://bit.ly/1XrgMUU.

[83] Windustry. "Community Wind South (Nobles Co., MN)." Accessed April 11, 2016. http://bit.ly/1S5wCTQ.

[84] Buntjer, Julie. "Minn. wind farm holds commissioning ceremony." Prairie Business. December 6, 2012. Accessed April 11, 2016. http://bit.ly/1N4FlX7.

Vineyard Power Cooperative is an interesting mix of electric cooperative working to develop renewable energy in a competitive electricity market. Most electric cooperatives have a monopoly service territory within which they serve all electric customers, but Vineyard is one of several choices available to customers on the small island of Martha's Vineyard off of Cape Code, Massachusetts. It was incorporated in 2009 and now has over 1,300 members. The difference between Vineyard and other suppliers is that Vineyard customers are also members that will elect directors of the cooperative.

The cooperative has developed about 300 kilowatts of solar projects on parking lots and capped landfills, and aspires to develop offshore wind. Like other suppliers, it can purchase power on the wholesale market when its own projects aren't generating sufficient power for its customers.

CITY AS COMMUNITY

Collective ownership of renewable energy doesn't have to be one-off or small scale. Cities have a long history of being energy providers to their residents and businesses, with over 2,000 municipal electric utilities. A few of these city-owned utilities have invested heavily in renewable energy resources.

Georgetown, TX, recently made headlines when it contracted to get 100% of its electricity supply from wind and solar energy, with plans to sell excess generation to the Texas electric grid.[85] The wind power will come from a share of a new wind power plant being constructed near Amarillo and the solar energy will be supplied by a new 150 MW solar project being built by SunEdison in 2016.[86] Just 4 hours up I-35, the municipal utility in Denton, TX, has already reached 40% renewable energy in its supply through a 60 MW wind power project 30 miles north of town.[87] In late 2015, the city announced plans to acquire part of a new solar power facility to increase the share of renewables to 70% of the electricity supply.[88]

The following map was inspired by Georgetown, TX, and looks at the approximate cost for municipal utilities to purchase solely wind and solar electricity for their municipal grids.[89]

[85] Farrell, John. "Can Other Cities Match Georgetown's Low-Cost Switch to 100% Wind and Sun?" The Institute for Local Self-Reliance. April 14, 2015. Accessed April 11, 2016. http://bit.ly/1Q3ovCL.

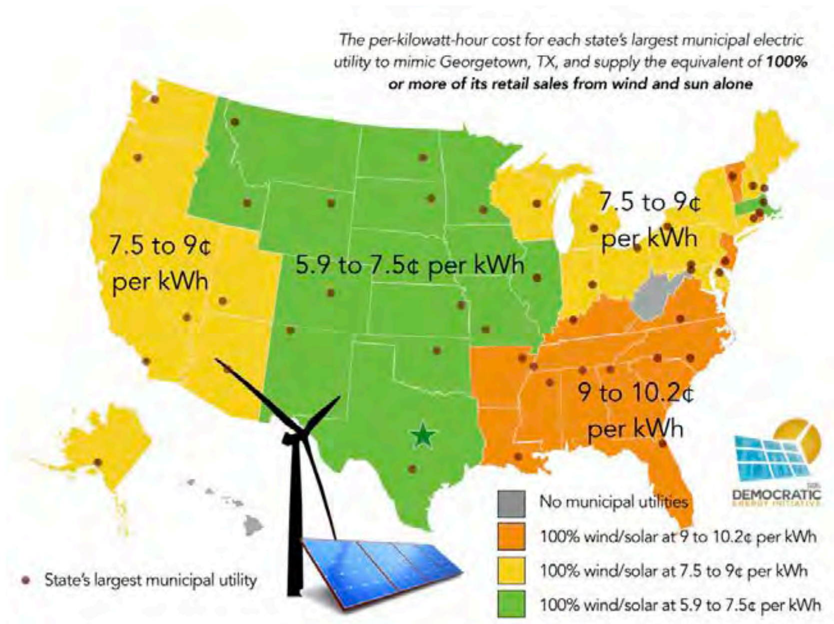
[86] SunEdison, Inc. "SunEdison To Provide the People of Georgetown Texas with 150 Megawatts of Solar Power." PR Newswire. March 18, 2015. Accessed April 11, 2016. http://prn.to/1Wo1bH.

[87] Farrell, John. "Texas Muni Utility Explains How They Are Already 40% Renewable." The Institute for Local Self-Reliance. June 11, 2013. Accessed April 11, 2016. http://bit.ly/1RPz5Tv.

[88] Dearman, Eleanor. "Denton Announces Renewable Energy Plan." The Texas Tribune. October 6, 2015. Accessed April 11, 2016. http://bit.ly/1MgL5X4.

[89] Farrell, John. "Can Other Cities Match Georgetown's Low-Cost Switch to 100% Wind and Sun?" The Institute for Local Self-Reliance. April 14, 2015. Accessed April 11, 2016. http://bit.ly/1Q3ovCL.

FIGURE 28. COMPARING COSTS OF REACHING 100% RENEWABLE LIKE GEORGETOWN, TEX



Municipal utilities can also pool their resources to own energy generation. Currently, most municipal utilities source their energy from jointly-owned municipal power agencies (such as Wisconsin Public Power Inc. Energy) or federal power agencies (such as the Tennessee Valley Authority). Power from either is typical sourced from aging fossil fuel-fired power plants, nuclear power plants, and hydro dams. But municipal utilities can also team up to purchase renewable energy. The Berkshire Wind project, for example, is a cooperative 15-megawatt wind power project owned by a municipal power agency and 14 additional municipal utilities.[90] The Kimball Wind Project near Lincoln, NE, provides 10.5 MW of wind power for the 57 communities represented by the municipal power agency.[91] The Delaware Municipal Electric Corporation has installed almost half the state's 58 megawatts of solar capacity on behalf of its

[90] Berkshire Wind Power Co-op. "Berkshire Wind Power Facts." Accessed April 11, 2016. http://bit.ly/1SbYqsC.

[91] MEAN Wind Project at Kimball. "MEAN About Us." Municipal Energy Agency of Nebraska. Accessed April 11, 2016. http://bit.ly/1SZWyjR.

municipal members, and the Indiana Municipal Power Agency has also installed several solar farms.[92][93]

While cities can be more responsive to local demands for renewable energy, they also operate at the same disadvantage as cooperatives, unable to use federal tax incentives for renewable energy. And although some prominent exceptions have been noted, most municipal utilities or their power agencies have procured little more clean energy than what is required by state law, despite it being very cost effective.

Cities without municipal utilities have to be more creative in their pursuit of clean energy. In six states (and a pilot in a seventh), a policy called community choice aggregation allows local governments (or groups of local governments) to join together to make energy purchasing decisions on behalf of residential and small business customers in their community. In practice, it means that cities can choose their energy suppliers on the basis of cost, pollution, and local economic benefits, without having to own and maintain the electric grid.

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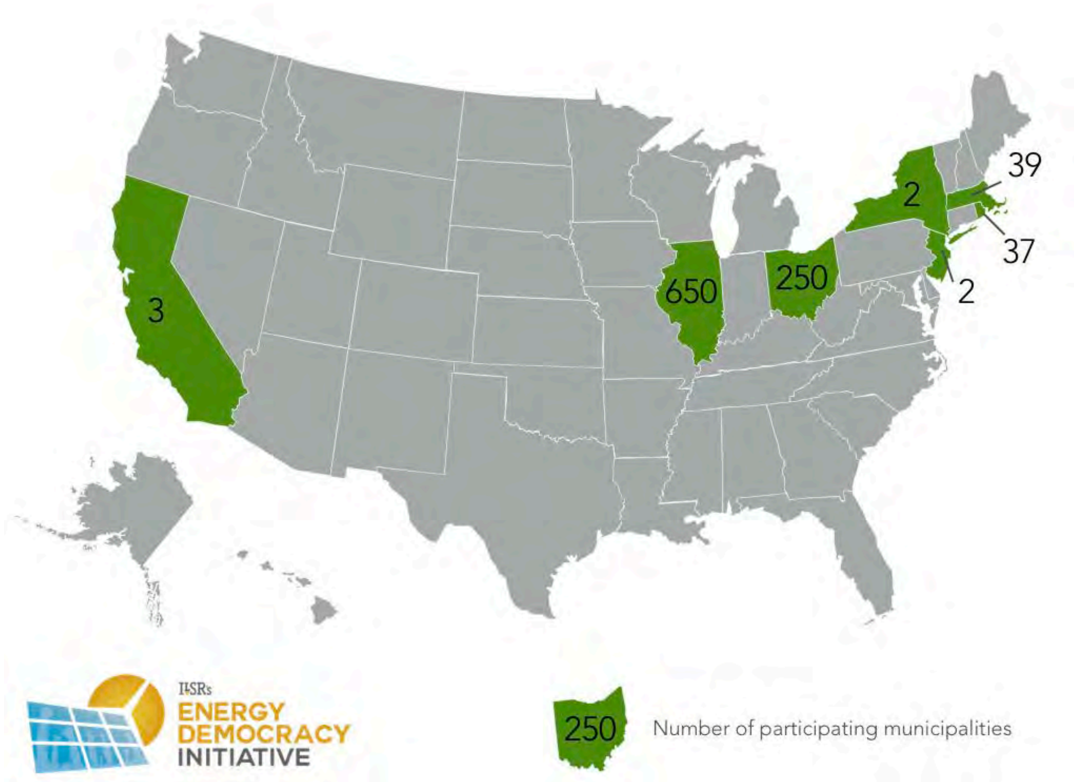
[92] Solar Outreach Partnership. “Delaware Municipal Electric Corporation’s McKees Solar Park Community Solar.” Solar Electric Power Association. 2015. Accessed April 11, 2016. http://bit.ly/1YqcVHT.

[93] Indiana Municipal Power Agency. “Indiana Municipal Power Agency and Crawfordsville Electric Light and Power celebrate new 3 MW solar park.” September 21, 2015. Accessed April 11, 2016. http://bit.ly/1Q3qeYz.

FIGURE 29. STATES ALLOWING COMMUNITY CHOICE AGGREGATION



In most states, local aggregation has little to do with clean energy, but gives cities purchasing power to procure electricity at lower prices. In California, however, local energy choice is being deployed much as its forebears had hoped. **Marin Clean Energy**, launched in 2011 after a 10-year and multi-million-dollar battle with the incumbent electric utility.[94] Through its purchasing power, the aggregation of several cities and counties north of San Francisco was able to procure electricity supply that was 27% renewable at comparable price to the half-as-renewable electricity available from incumbent Pacific Gas & Electric.[95] Although a small part of its portfolio so far, the local utility is using

[94] Farrell, John. "The Leading Community Energy Aggregator – Episode 19 of Local Energy Rules." The Institute for Local Self-Reliance. April 3, 2014. Accessed April 11, 2016. http://bit.ly/1NlcXuJ.

[95] Ibid.

funds from a green pricing program to help with pre-development of local solar projects, has signed contracts for several other small wholesale solar projects, and offered a solar feed-in tariff.

Sonoma Clean Power serves communities in Sonoma County, Marin's northern neighbor. Launched in 2014 with 20,000 customers, the local utility will offer a default supply of 33% renewable electricity (50% greater than the incumbent utility) at a lower rate. The power option was made possible in part by a geothermal power plant able to provide 15% of the utility's needs, but the utility is also offering a price premium on net metering for excess power production and a feed-in tariff to procure more local solar energy.

The city of Lancaster has plans to launch its aggregation soon, and the city of San Diego, San Francisco and Alameda County (among others) are investigating.[96][97][98]

Unfortunately, expansion of community choice aggregation is likely limited, as it is viewed by most electric utilities as a competitive threat. It took nearly a decade from the time the policy was authorized for Marin Clean Energy to launch its energy services, for example, due to millions of dollars incumbent Pacific Gas & Electric spent lobbying to undermine the local aggregation.

Municipalities don't have to own a utility to develop renewable energy projects, although they may be limited by laws granting utilities exclusive rights to serve local customers. As shown in our recent Public Rooftop Revolution report, major cities in 25 states could host nearly 5 gigawatts of solar power on municipal property, at minimal cost.[99] And there are several other prominent examples of municipal activity on renewable energy.

In **St. Paul, MN**, the city partnered with nonprofit organizations and the downtown business district to create a hot water district heating system. In the decades since the 1983 demonstration project, the system has grown, incorporated cooling as well as heating, and is now primarily powered by a steam plant fueled with urban wood waste, generating heat and electricity.[100]

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[96] Ibid.

[97] Farrell, John. "Marin Clean Energy Illustrates the Benefits of Local Energy Self-Reliance." The Institute for Local Self-Reliance. May 12, 2011. Accessed April 11, 2016. http://bit.ly/1S1AH9f.

[98] Farrell, John. "Local. 33% Renewable. And Lower Prices. Sonoma Clean Power 'CCA' Launches." The Institute for Local Self-Reliance. May 8, 2014. Accessed April 11, 2016. http://bit.ly/1S1ALpD.

[99] Farrell, John. "Public Rooftop Revolution Report." The Institute for Local Self-Reliance. June 1, 2015. Accessed April 11, 2016. http://bit.ly/1T00r8d.

[100] District Energy St. Paul. "History." Accessed April 11, 2016. http://bit.ly/1qjRAVl.

In **New Bedford, MA**, the city contracted with a solar company to provide solar electricity from municipal rooftops and nearby solar arrays. The investment saves $6 to 7 million per year on electricity expenses.

In **Lancaster, CA**, the city similarly contracted with a third party to install 9 megawatts of solar, enough to serve electricity demands of all its schools and 90% of use for five municipal buildings. The city is also investigating forming a local energy aggregation.[101]

In **West Union, IA**, a revitalization plan for downtown included a district geothermal loop system to provide heating and cooling for commercial businesses. The city formed a separate limited liability company to manage the system, which has successfully connected about 20 businesses (of a potential 60). The company is leasing the system from the city for five years, after which the city may take control of management.[102]

[101] Farrell, John. "Public Rooftop Revolution Report."

[102] Geerts, Jeff. "Update: West Union, Iowa geothermal district heating system." District Energy. October 9, 2014. Accessed April 11, 2016. http://bit.ly/1Su5nz8.

A COMMUNITY RENEWABLE ENERGY GOLD STANDARD

The wide range of structures and benefits suggests a need for core principles for community renewable energy projects. ILSR and many allies working on community solar have adopted four key principles: tangible economic benefits for participants, flexibility in project design and ownership, additive clean energy, and access to all customers.

Tangible benefits mean that customers should see energy savings or profits commensurate with their level of risk and the benefits of distributed clean energy (such as fixed fuel costs and minimal losses in transmission). In Minnesota's community solar program, for example, participants receive bill credits worth about 14¢ per kilowatt-hour, 2¢ premium more than they are paying for electricity. In Massachusetts, virtual net metering means customers subscribing to solar will get the same value in bill credits as those with a solar array on their own rooftop.

In contrast, California utilities allow customers to "subscribe" to solar projects at a premium of 15 to 35% more than they would pay for regular electricity.[103] In Washington, DC, the Public Service Commission set a bill credit rate for community solar subscriptions at about half the rate folks with solar on their rooftops receive.[104] These are poorly designed community energy programs.

Flexibility means that there should be many forms of project ownership, including options for and even encouragement of non-utility and community ownership.

The **Additive** principle means that community or shared solar programs should not be used to shift customers away from self-generation. For example, two utilities in Arizona, Tucson Electric Power and Arizona Public Service, have introduced utility-owned distributed solar programs while also lobbying the state Commission to reduce compensation for net metering customers.[105]

[103] Trabish, Herman K. "Inside California's plans to jump-start community solar development." Utility Dive. March 5, 2015. Accessed April 11, 2016. http://bit.ly/1T8zJeC.

[104] DC Solar United Neighborhoods. "Community Renewables Energy Act of 2013." March 21, 2016. Accessed April 11, 2016. http://bit.ly/1T03pJZ.

[105] Farrell, John. "If You Can't Beat 'Em, Own 'Em – Utilities Muscle in to Rooftop Solar Market." *The Institute for Local Self-Reliance*. August 11, 2015. Accessed April 11, 2016. http://bit.ly/1Q3ug3d.

Access means that shared solar should be available to electric customers regardless of race or income. Given historical disparities, this means policy makers must require utilities and community solar market participants to make proactive efforts to reach historically marginalized customers, especially people of color and those on low-income energy assistance.

There are numerous ways to help:

- The federal government can allow energy assistance dollars to be redirected into long-term bill reduction through community solar.
- Cities, utilities, and shared solar developers can identify ways to extend financing to customers with otherwise higher credit risk, including on-bill repayment programs such as rural electric cooperatives are using for energy efficiency.

GRID Alternatives, a nonprofit organization based in Colorado, has shown how community solar can have a double benefit to low-income communities by providing jobs and energy savings for those communities. Grand Valley Power is just one of dozens of projects (comprising nearly 20 megawatts) that the organization has developed.[106]

[106] SunShot. “Closing the Solar Income Gap.” August 12, 2015. Accessed April 11, 2016. http://bit.ly/1Suaakg.

CONCLUSION

Community renewable energy is decades old, but the opportunity for growth is now. Dramatically falling costs have made shares of clean energy projects affordable for many Americans, subscriber models have removed much of the risk, and financing has made participation easier than ever. Given the challenges, a surprising number of enterprising models have emerged for community-owned renewable energy.

The barriers are falling or being evaded. Federal tax incentives can be accessed through third parties and subscriber models. The scheduled expiration of the federal tax credits will drive more potential lenders to support development models that don't rely on tax equity. Federal and state crowdfunding laws offer new safe harbors for community-based projects to raise capital from their neighbors. Cooperatives, popular in food and other sectors, may yet become a tool for capturing more local economic benefits of renewable energy. Municipal and local energy aggregation offers new local authority over energy purchasing, and can drive greater local ownership of renewable energy. New community solar (and potentially community renewable) policies and virtual net metering can expand access to solar for those without a sunny rooftop.

The view isn't entirely rosy. Utilities have fought back against net metering rules and reduced compensation for solar owners, and some utility "community solar" programs seem to be a harmony to the anti-solar melody by reducing the benefits of going solar. Subscription models also reduce community control, shrinking the opportunity to use community energy projects to accomplish social goals such as quality employment for disadvantaged populations. Low-income folks still struggle to access shared renewable energy just as they have individually owned systems, and policies continue to erect financial barriers. Finally, community solar has been a stand-in for community renewable energy, which should be broadened to include all renewable energy technologies.

But community renewable energy is growing and it's a remarkable opportunity to re-localize the economic benefits of and control over the electricity system. The policies to enable it are just beginning to grow and we have the opportunity to make sure they uphold the best principles of community-centered, community-owned, and distributed power.

APPENDIX

Community Wind Power Estimates

Windustry reports that community wind represented over 4% of total wind power capacity in 2010, but figures after that date come from AWEA, which included utility-owned projects if the utility was a cooperative or municipal utility. Using that definition, 650 MW of community wind was added in 2011-12, 3% of the nearly 20,000 MW added in that timeframe.[107] In 2014, AWEA reports 2.5% of the 4,800 MW added to the grid was community wind.[108]

Federal Crowdfunding Rules

The adopted federal crowd financing rules will, finally, allow:[109]

- An entity to raise up to $1 million per year.
- Ordinary individuals to invest $2,000 or 5% of their annual income (or net worth) in crowd financing ventures, whichever is greater.
- Wealthy individuals to invest up to 10% of their annual income or net worth, or $100,000, whichever is less.

The federal rules facilitate raising money from many "unsophisticated" investors (e.g. regular people) but still require substantial disclosure and reporting requirements. Crowdfunded projects must:[110]

- Provide prospective investors and the Securities and Exchange Commission (SEC) with the "offering and its business, [including] financial statements."
- Promptly disclose to the SEC when it has raised 50% and 100% of its offering.
- File an annual report with the SEC and publish it publicly.

[107] American Wind Energy Association. "Home page." Accessed April 11, 2016. http://bit.ly/1VjKKgi.

[108] Bolinger, Mark and Wiser, Ryan. "2014 Wind Technologies Market Report. *US Department of Energy: Energy Efficiency & Renewable Energy*. August 2015. Accessed April 11, 2016. http://bit.ly/1NliH7E.

[109] Dorsey and Whitney. "Crowdfunding Part 1 – An Overview." November 17, 2015. Accessed April 11, 2016. http://bit.ly/1VjLcuU.

[110] Ibid., *and* Dorsey and Whitney Law Firm. "Crowdfunding Part 2 – Initial and Ongoing Disclosure Requirements." November 19, 2015. Accessed April 8, 2016. http://bit.ly/1S2dB4A. A full list of crowd-funding disclosure requirements is explained by Dorsey and Whitney.

- Host the offering on an SEC-approved crowdfunding platform, such state-approved Michigan Funders.[111]
- Limit outside advertising to the terms of the offering, factual information about the project (e.g. name/address), and references to the crowdfunding platform site.

State Crowdfunding Laws

Most states follow a similar template in their crowdfunding laws, including the offering limit, benefits, and limitations. The following are typical in many state crowdfunding laws.:[112]

- Available for offerings under $1 million (limit varies)
- Benefits include:
  - Exemption from audited financial statements (depending on offering size)
  - Allowing for solicitation via internet
  - Allowing non-accredited or ordinary investors (those with less than $200,000 in annual income)
- Limitations include:
  - Only soliciting to investors within their state
  - Collecting $10,000 or less (typically) from non-accredited investors
  - Advertising only on licensed sites, e.g. CraftFund, and not on general social media

Details on crowdfunding laws in three selected states are shown below, for Michigan, Kansas, and Georgia.

Michigan's crowdfunding law was adopted in 2013 and includes:[113]

- $1 million limit for businesses without audited financial statements
- $2 million limit for businesses with audited financial statements
- Non-accredited investors can put in up to $10,000. Accredited have no limits.
- Intrastate
- Must use escrow account at financial institution

[111] Michigan Funders. "Home page." Accessed April 11, 2016. http://michiganfunders.com/

[112] Counselor at Law. "Investment crowdfunding exemptions, State by State." May 20, 2014. Accessed April 11, 2016. http://cl.ly/1N183Q2U1k04.

[113] McGlade, Alan. "Michigan Governor Signs Intrastate Crowdfunding Exemption." Forbes. December 31, 2013. Accessed April 11, 2016. http://onforb.es/1VOoZUj.

Michigan also provides a guide for potential project developers.[114][115]

The Kansas crowdfunding law, adopted in 2011, includes:[116]

- Option to sell securities to accredited and non-accredited investors
- For-profits can raise up to $1 million per year
- $1000 per company limit for non-accredited investors
- Can advertise to Kansas residents
- Has only been used by 6 companies in 2 years

The **Georgia** crowdfunding law, also adopted in 2011, is very similar to Kansas, but with a $10,000 limit for non-accredited investors. However, like Kansas, it is rarely used, with only 6 companies tapping it in all of 2013.[117]

More detail on crowdfunding laws can be found at the following links for **Wisconsin**, **Oregon**, and **Vermont**.[118][119][120][121][122]

Common Exemptions to Federal Securities Registration

- Regulation D – Rule 506(b) and (c), and Rule 504, "private placements" or "nonpublic offering."[123]

[114] Konkle, Dave. "A Guidebook for Community Solar Programs in Michigan Communities." Great Lakes Renewable Energy Association. October 2013. Accessed April 11, 2016. http://1.usa.gov/1J6KJSX.

[115] Johnson, Cat. "Michigan Law Brings the Power of the Crowd to Entrepreneurs." Shareable. March 5, 2014. Accessed April 11, 2016. http://bit.ly/1njP6zQ.

[116] Clark, Patricia. "Kansas and Georgia Beat the SEC on Crowdfunding Rules. Now Others Are Trying." Bloomberg. June 20, 2013. Accessed April 11, 2016. http://buswk.co/1hHYlu0.

[117] Ibid.

[118] Sterling Funder. "Browse Campaigns." Accessed April 11, 2016. http://bit.ly/1Xs28N9.

[119] Jake's Cafe. "Wisconsin Top State for Crowdfunding." November 21, 2013. Accessed April 11, 2016. http://bit.ly/25W0NE6.

[120] Oregon's Secretary of State Office. "Amendment to Renewable Energy Cooperative Corporations." October 6, 2014. Accessed April 11, 2016. http://bit.ly/1qLFpBC.

[121] SunShot. "Community Shared Solar: Review and Recommendations for Massachusetts Models." March 28, 2013. Accessed April 11, 2016. http://1.usa.gov/1Pv0CVa.

[122] Vermont Department of Financial Regulation. "Solar/Utility No-Action Securities Exemption Docket No. 14-023-S." July 21, 2014. Accessed April 11, 2016. http://bit.ly/1Q3PMF4.

[123] Investopedia. "Marketing and Sales Presentations – Regulation A, D, and Rule 147." Accessed April 11, 2016. http://bit.ly/1VP8UxA.

  - 506(b) uses accredited investors and up to 35 non-accredited investors "so long as they have a certain amount of financial sophistication and are provided a certain disclosure document." No advertising.
  - 506(c) – Accredited only, advertising allowed.
  - Rule 504 – Up to $1 million only, state requirements. General solicitation and advertising usually not permitted.
  - Intrastate (Rule 147) – within state. 80% of proceeds in state. Only advertise in state. State regulations. 100% of the purchasers are residents of the state. 80% of the company's assets are located in the state. 80% of the offering proceeds will be used on facilities within the state.
  - Nonprofits – not often used.
- Regulation A – up to $5 million, "small public offering." Benefits: "simpler financial statements that do not have to be audited, no Exchange Act reporting requirements until the company has more than $10 million in assets and more than 500 shareholders, and the choice of three formats to prepare the offering circular."[124]

[124] Investopedia. "Regulation A." Accessed April 11, 2016. http://bit.ly/25W2hy1.

Community Solar With an Equity Lens: Generating Electricity and Jobs in North Minneapolis — Episode 57 of Local Energy Rules Podcast

BY MARIA MCCOY | DATE: 24 JUL 2018 |

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Shiloh Temple, a church two miles from downtown Minneapolis, serves more than just the spiritual needs of the community. After a recent update to its roof, this church in North Minneapolis now serves some of the community's energy needs, as well.

The church roof is covered with solar panels that **Cooperative Energy Futures**, an energy efficiency and community-owned clean energy cooperative, designed as the first of their many community solar projects. At 200 kilowatts, these panels will power the temple and 20 homes that have subscribed to the project. Plus, thanks to the vision of Cooperative Energy Futures, the panels have done more than provide a source of clean energy — they have created jobs, trained local workers for these jobs, and above all,

KEY RESOURCES

Energy Self-Reliant States

John Farrell's blog visualizing a distributed renewable energy future

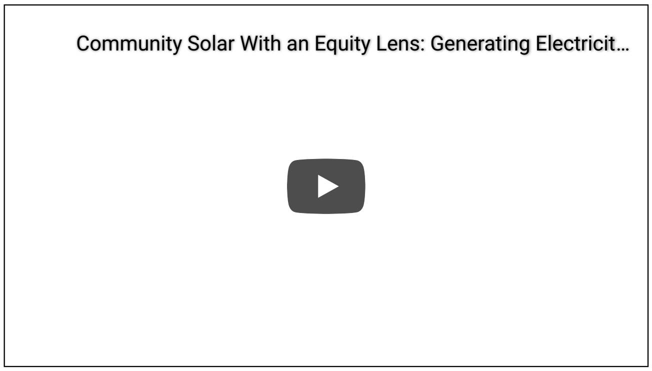
Local Energy Rules Podcast

Sharing powerful stories of successful local renewable energy

Community Power Map

In May, John Farrell visited the solar garden and interviewed Timothy DenHerder-Thomas, general manager of Cooperative Energy Futures. The two discussed final stages of the project, the justice perspective that makes it unique, and other projects Cooperative Energy Futures has lined up.

See video footage of the array and highlights of the podcast:



Project Beginnings

The process to create a solar garden on top of Shiloh Temple began three years ago and was just completed this spring.


Timothy DenHerder-Thomas and John Farrell

Like most community solar programs, this garden sells subscriptions to electric customers, who then get bill credits for the amount of electricity that their subscription generates. (Shiloh Temple, like many other projects, was enabled by **Minnesota's landmark community solar law**). However, the vision for the Shiloh Temple garden extends well beyond that of other community solar to emphasize equity and maximize local benefits.

Now that the project is complete, DenHerder-Thomas and Cooperative Energy Futures can say that they have not only met their goals, but surpassed many of them.

*For a more detailed history of the Shiloh temple project, listen to **this 2016 podcast.***

Bringing Equity to the Solar Industry

Racial injustice has always been a part of the U.S. energy system. For example, within the coal industry, it is well-known that low income communities and communities of color are statistically **more likely to live near coal plants**. This has direct consequences to these vulnerable communities because of the toxic pollution and resulting health problems associated with living near coal plants.

Many of these inequalities were established long ago, but they are still being reinforced today. Even as more of our energy supply moves to renewables, there is no guarantee that the transition will right past wrongs or solve existing inequities — in fact, it is quite possible that this transition will perpetuate existing

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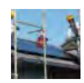
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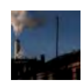
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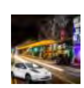
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disparities. Decisions regarding where renewable energy is built, who has access to it, and who is hired to construct it, affect whether the energy system is equitable. The reality is, even today, disparities in the renewable energy sector exist and can be measured.

According to the **2017 U.S. Energy and Jobs Report** by the U.S. Department of Energy, the majority of solar photovoltaic workers are white (70.2 percent) and two-thirds are male. Black or African American people represent 25% fewer workers in the solar industry than their presence in the national workforce. For women, the disparity is nearly 30 percent. The data for Black or African American people is especially alarming because they are **disproportionately unemployed**.

Solar Workforce Demographics

Demographics	Solar Photovoltaic	Concentrating Solar Power	National Workforce Averages
Male	67.4%	67.4%	53%
Female	32.6%	32.6%	47%
Hispanic or Latino	21.5%	21.0%	16%
Not Hispanic or Latino	78.5%	79.0%	84%
American Indian or Alaska Native	1.2%	1.1%	1%
Asian	9.7%	9.7%	6%
Black or African American	9.0%	6.8%	12%
Native Hawaiian or other Pacific Islander	1.4%	1.5%	>1%
White	70.2%	73.2%	79%
Two or more races	8.6%	7.7%	2%
Veterans	11.1%	10.6%	7%
55 and over	12.9%	10.8%	22%
Union	3.4%	4.7%	11%

(Source: 2017 U.S. Energy and Jobs Report, U.S. Department of Energy)

If workforce disparities are not addressed intentionally, the established patterns will continue to be.

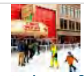
When planning the Shiloh Temple solar garden, Cooperative Energy Futures required that their installation contractor used “at least 50 percent minority labor,” said DenHerder-Thomas. “And actually the installer that we used, innovative power systems, has used a crew that is actually closer to 90 percent minority labor, including a number of folks from here in North Minneapolis.”

As part of their effort to address racial disparities in the solar workforce, Cooperative Energy Futures is working with **Renewable Energy Partners** to develop a **job training program** in North Minneapolis. This will ensure that “more people are qualified for those jobs as we create demand for the hiring,” said DenHerder-Thomas.

In addition to the work of Cooperative Energy Futures and Renewable Energy Partners, **Minnesota Interfaith Power and Light** helped engage other faith communities in the project. **Shiloh Temple International Ministries** and Kwanzaa Community Church have brought their congregations into the project and encouraged them to be subscribers. **The North Star Chapter** of the Sierra Club and Neighborhoods Organizing for Change helped with community organizing.

Access to Community Solar

Community solar, despite all of its benefits, has traditionally been out of reach for many. Due to the location of the gardens themselves and credit score requirements for subscribers, “low-income families,



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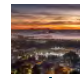

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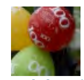

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However, people with lower incomes spend the **highest percentage of their income on energy**. "The people who have the most to save from the financial benefits of community solar have largely been excluded across the state from participating," said DenHerder-Thomas.

Cooperative Energy Futures plans to change this by specifically **reaching out to renters and lower-income community members** when looking for subscribers:

> *"We've really focused on engaging residents of North Minneapolis, which is a generally low-income community, as subscribers in this garden really so that the benefits of community solar are staying local."*

They allowed residents of North Minneapolis or members of Shiloh Temple to subscribe before opening the program up to others, while also having no minimum credit score to become a subscriber.

Want to know more strategies to broaden access to community solar? ***See here.***

Community Solar in Minnesota

While Minnesota could do more to ensure equal access to solar energy and its benefits (see ILSR's comments **here**), the state has key policies that enable projects like the Shiloh Temple community solar array.

Minnesota is one of 16 states that currently allow shared renewables, also enabled by "**virtual net metering.**" When a state allows virtual net metering, electric customers can offset their consumption by electricity generation that is located off-site — as long as the generation is happening within the utility company's area of service.

For more information on shared renewables and which states have this policy, see the ***Community Power Map***.

In the interview, DenHerder-Thomas discussed another key Minnesota policy: Minnesota requires Xcel energy to connect community solar projects to the grid and provide adequate bill credits.

Thanks to these policies, as of summer 2018, **Minnesota had 379 megawatts of installed community solar capacity**.

DenHerder-Thomas suggested that Minnesota's most important policy was "the compensation rate that energy users get, being adequate to make it a good financial deal for them, is really key to ensure that the compensation for community solar is fair and that these projects get built."

DenHerder-Thomas is skeptical about the recent proposal to shift community solar from net metering policy to **value of solar**. According to him, installations that are similar to the Shiloh Temple garden will receive less money per kilowatt-hour. (ILSR also has some **concerns about the value of solar**, because it may not account for the customer acquisition and management costs of community solar.)

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For monthly updates on Community Solar in Minnesota, see ***here.***

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The Future of Cooperative Energy Futures

The Shiloh Temple solar garden is just the first of many solar installations for Cooperative Energy Futures. They also have rooftop projects planned for Edina and Eden Prairie, along with four ground-mounted community solar installations in greater Minnesota.

Lastly, Cooperative Energy Futures is working on a large canopy solar installation over Parking Ramp A in downtown Minneapolis. The parking ramp is right next to Target Field, giving it the potential to serve as a public education resource, in addition to providing a substantial amount of power. According to DenHerder-Thomas, the total capacity of the cooperative's eight arrays is 6.7 megawatts, or 33 times the capacity of Shiloh Temple.

Once all of these planned projects are completed, Cooperative Energy Futures will be powering up to 700 households throughout Minnesota. More importantly, they will set the standard for how to do community solar for the maximum community benefit, equitably.

Photos and footage by Marie Donahue, Energy Democracy Research Associate

Video production by Maria McCoy, Energy Democracy Intern

Additional photo credit: **[bmw]** via Flickr

This article originally posted at ***ilsr.org****. For timely updates, follow* ***John Farrell*** *or* ***Marie Donahue*** *on Twitter, our energy work on* ***Facebook****, or sign up to get the* ***Energy Democracy weekly*** *update.*

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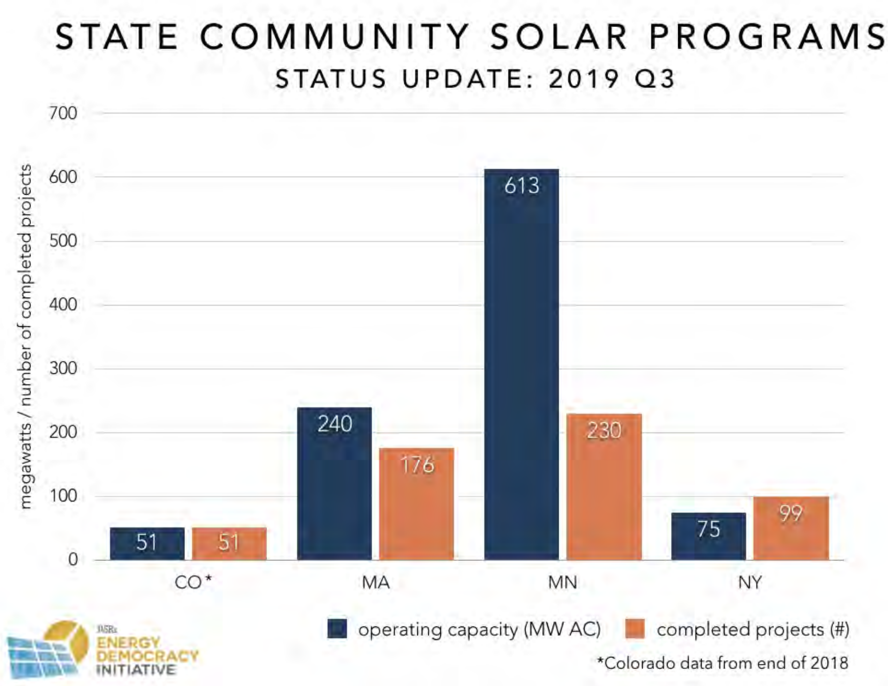
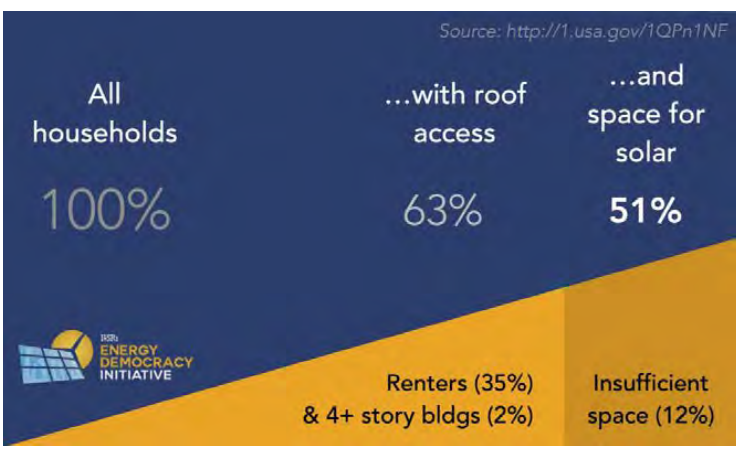


How are Community Solar Garden programs doing across the country?

For decades, rooftop solar has allowed homeowners to generate their own renewable energy — reducing their dependence upon grid energy and lowering their energy bills. However, solar rooftops are not an option for many people. What about those who can't afford it? Or people renting their homes? Only about half of buildings have roofs that are large enough, face the right direction, and get enough sun for solar energy production.



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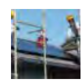
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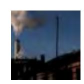
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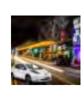
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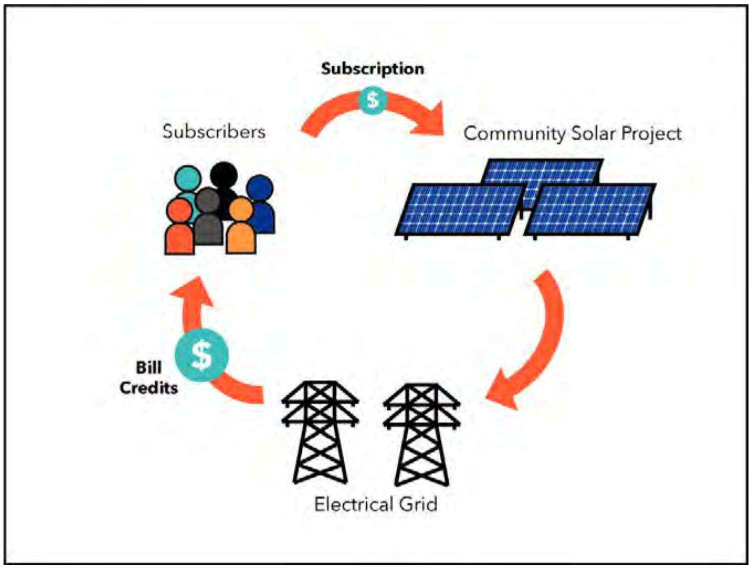
Through community solar, individuals subscribe to a portion of a nearby solar project and get credits on their energy bill for the electricity it produces. This way, people without the financial means for solar on their rooftops and people who don't own suitable rooftops can still reap the benefits of renewable energy. Local governments and installers can go even further to include subscribers with poor credit, or use local installers on the project.



Community solar can and has been installed on places of worship, in brownfields, and over parking lots.

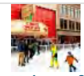
*For more details on the benefits of community solar, see **this report** from Vote Solar, MnSEIA, and the Institute for Local Self-Reliance.*

We report on Minnesota's community solar program every month in **this blog post**, but community solar is gaining traction in other states, too. Community solar can happen in any state sharing two key market characteristics: **virtual net metering** and requirements for utilities to connect distributed solar to the grid (interconnection rules). Community solar program legislation can include both elements.

16 states have passed legislation enabling community shared solar gardens, but only four have active programs with multiple installations. This post will be updated quarterly with the number of projects and megawatts of installed capacity in each state with a formal community solar program that allows non-utility ownership. Although rural electric cooperatives have built a **significant amount of community solar**, the programs do not allow non-utility ownership and may differ from state-based programs that are structured to provide bill savings to customers.

Colorado

After a successful **pilot program** in 2010, Colorado finally saw an expanded community solar garden program in 2016. The program still has a cap of 105 MW, a figure grown out of **Xcel's settlement deal**. The Colorado community solar program has always had a goal of inclusivity. Since the 2010 pilot, the program has had a 5% carveout for low-income customers. Now, advocates hope this percentage can be dramatically increased as the state **continues to update the program**.



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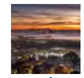

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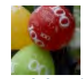

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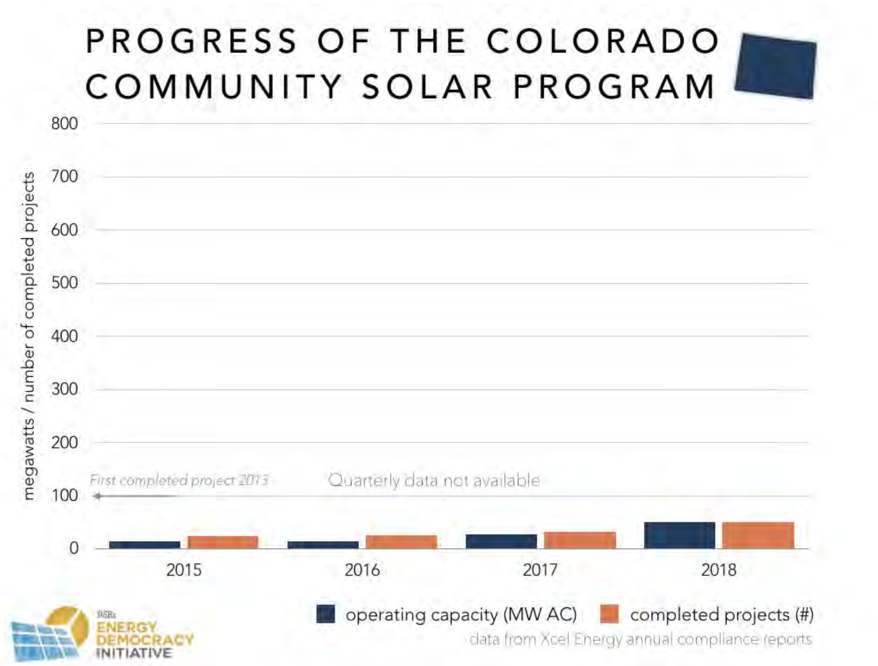
At the end of 2018, Colorado's community solar program hit 51 completed projects with 51 total megawatts of operational capacity.



Massachusetts

Although the Massachusetts Senate passed a virtual net metering bill in 2008, it didn't begin tracking community solar projects until 2014. Community solar programs qualify for two Massachusetts Department of Energy Resources programs: RPS Solar Carve-out II and Solar Massachusetts Renewable Target (SMART).

In the third quarter of 2019, Massachusetts's community solar program hit 176 completed projects with 240 total megawatts of operational capacity. The program grew by one project this quarter, which has a capacity of five megawatts.

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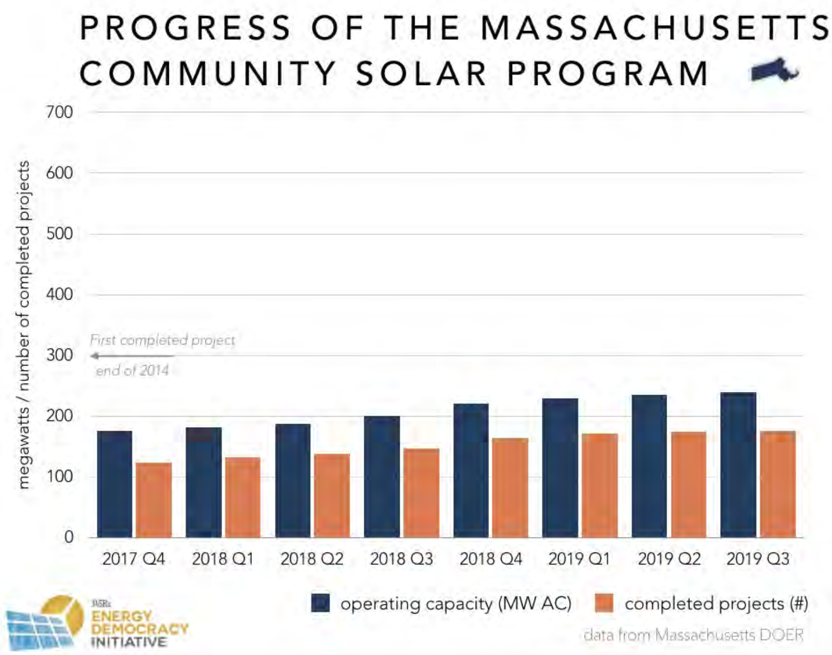

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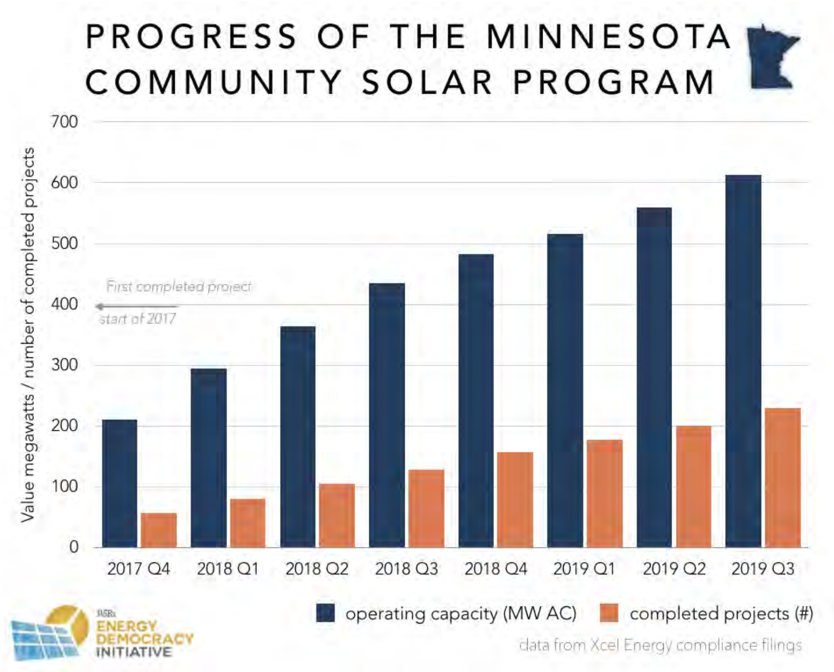
Minnesota

Minnesota's community solar program launched in December of 2014, with the first full megawatt of projects installed in January 2017. The program has since taken off to become the most successful in the country. The success of the program in Minnesota can largely be attributed to its design, which places no caps on community solar project development. It is also carefully constructed to make solar economically viable. According to **ILSR's analysis**, the program has saved Xcel Energy customers millions of dollars.

In the third quarter of 2019, Minnesota's community solar program hit 230 completed projects with 613 total megawatts of operational capacity.



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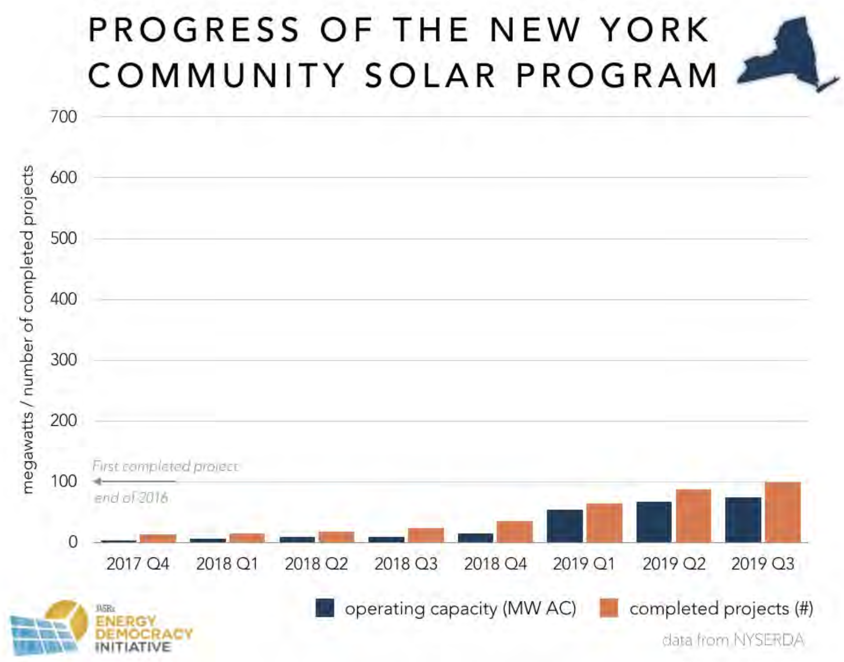
New York

In 2017, New York's Public Service Commission passed the Value of Distributed Energy Resources (VDER) tariff. Meant to replace net metering, VDER credits distributed solar with a monetary value based on the many values that it provides to the system, including avoided fuel costs and avoided future power plant construction costs (for a deep dive, see our **2018 VDER coverage**). Big utilities have supported VDER because, in some cases, the **compensation rate of VDER** is much lower than net metering. On top of this, it has made community solar programs **confusing for developers and customers**. In 2018, community solar advocates tried to put a **moratorium on VDER**, likening it to the **Darth Vader** of the community solar world. The Public Service Commission hopes **a 2019 update** will improve the program and make way for more community solar.

In the third quarter of 2019, New York's community solar program hit 99 completed projects with 75 total megawatts of operational capacity.



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Where is Community Solar Going?

Each program has been constantly evolving. Several of the programs have had to loosen restrictions, increase individual project size limits, and expand the overall size of the program. New programs would do well to build these changes into their programs from the beginning.

To date, Minnesota has seen the most success with community solar. Massachusetts and Minnesota had close to the same installed capacity in quarter three of 2017, 114 MW and 116 MW respectively, but the Massachusetts program has not been able to achieve the same rate of growth as Minnesota. This is, again, because the Minnesota program has no caps and secures an economical payout for installations.

Colorado and Minnesota are served by the same utility company. Xcel in Colorado (the Public Service Company of Colorado), however, has maintained severe program caps on Solar Rewards Community Gardens. The Colorado Public Utilities Commission has approved each program cap in a series of expansions. Despite the Colorado state legislation passing one of the first community solar bills in 2010, the program has struggled to grow within its confines.

Additional States

Hawaii, Illinois, and Maryland all have budding community solar programs, but have yet to see many interconnected projects. Return to this page for updates on these programs as they get started, in addition to quarterly progress of the original four.

Other ILSR Resources on Community Solar

Interactive:

- The **Community Power Toolkit**, which includes community solar as one of 20+ tools communities can use to build energy democracy

Reports:

- **Why Minnesota's Community Solar Program is the Best**, which tracks Minnesota's Community Solar Program monthly since 2015
- 2019 Report **Minnesota's Solar Gardens: the Status and Benefits of Community Solar**
- 2016 report **Beyond Sharing — How Communities Can Take Ownership of Renewable Power**

For podcasts, videos, and more, see ILSR's **community renewable energy archive**.

*This article originally posted at **ilsr.org**. For timely updates, follow John Farrell on **Twitter** or get the **Energy Democracy weekly** update.*

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SHINING REWARDS

The Value of Rooftop Solar Power for Consumers and Society

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Executive Summary

Solar energy is on the rise in the United States. Through September 2016, more than 31 gigawatts of solar electric capacity had been installed around the country, enough to power more than 6 million homes. The rapid growth of solar energy in the United States is the result of forward-looking policies that are helping the nation reduce its contribution to global warming and expand its use of local renewable energy sources.

One policy in particular, net energy metering, has been instrumental in the growth of solar energy, particularly on homes and small businesses. Net energy metering enables solar panel owners to earn fair compensation for the benefits they provide to other users of the electricity grid, and makes "going solar" an affordable option for more people. Net energy metering works by providing customers a credit on their electric bill that offsets charges for energy consumption. As solar energy has taken off in recent years, however, utilities and other special interests have increasingly attacked net metering as an unjustified "subsidy" to solar users.

A review of 16 recent analyses shows that individuals and businesses that decide to "go solar" generally deliver greater benefits to the grid and society than they receive through net metering. Decision-makers should recognize the great value delivered by distributed solar energy by preserving and expanding access to net metering and other programs that ensure fair compensation to Americans who install solar energy.

Net metering is not a new idea. It has been the policy in some states for more than 30 years. The concept has been tested in the courts and in regulatory proceedings in the states and at federal agencies like the Federal Energy Regulatory Commission and the Internal Revenue Service. Net metering is the law of the land in 41 states today.

Net metering has been critical to solar energy's rapid expansion in the United States.

- Net metering offsets costs for solar panel owners and credits them for providing excess power to the grid at a set price, usually at the same retail price they pay to buy electricity.
- Net metering is conceptually simple (it essentially allows consumers to run their electric meters backwards), easy to administer, requires a minimum of utility system investment, and ensures that customers receive compensation that tracks with electricity prices over time.
- Net metering also makes solar energy more economically attractive for residents and businesses, and accessible and affordable to low and middle income Americans.

Solar energy creates many benefits for the electricity grid.

- **Avoided energy costs**: Solar energy systems produce clean, renewable electricity on-site, reducing the amount of electricity utilities must generate or purchase from fossil fuel-fired power plants. In addition, solar photovoltaic (PV) systems reduce the amount of energy lost in generation, long-distance transmission and distribution, which cost U.S. ratepayers about $21 billion in 2014.

- **Avoided capital and capacity investment:** By reducing overall demand for electricity during high-load daytime hours that form the peak period for most utilities, solar energy production helps ratepayers and utilities avoid the cost of investing in new power plants, transmission lines, distribution capacity, and other forms of electricity infrastructure.
- **Reduced financial risks and electricity prices:** Because the price of solar energy tends to be stable over time, while the price of fossil fuels can fluctuate sharply, integrating more solar energy into the grid reduces consumers' exposure to volatile fossil fuel prices. Also, by reducing demand for energy from the grid, solar PV systems reduce its price, saving money for all ratepayers.
- **Increased grid resiliency:** Increasing distributed solar PV decentralizes the grid, potentially safeguarding people in one region from other areas that are experiencing problems. Emerging technologies, including smart meters and small-scale battery storage systems, will enhance this value.
- **Avoided environmental compliance costs:** Increasing solar energy capacity helps utilities avoid the costs of installing new technologies to clean up fossil fuel-fired power plants or meeting renewable energy requirements, and avoid the cost of emission allowances where pollution is capped.

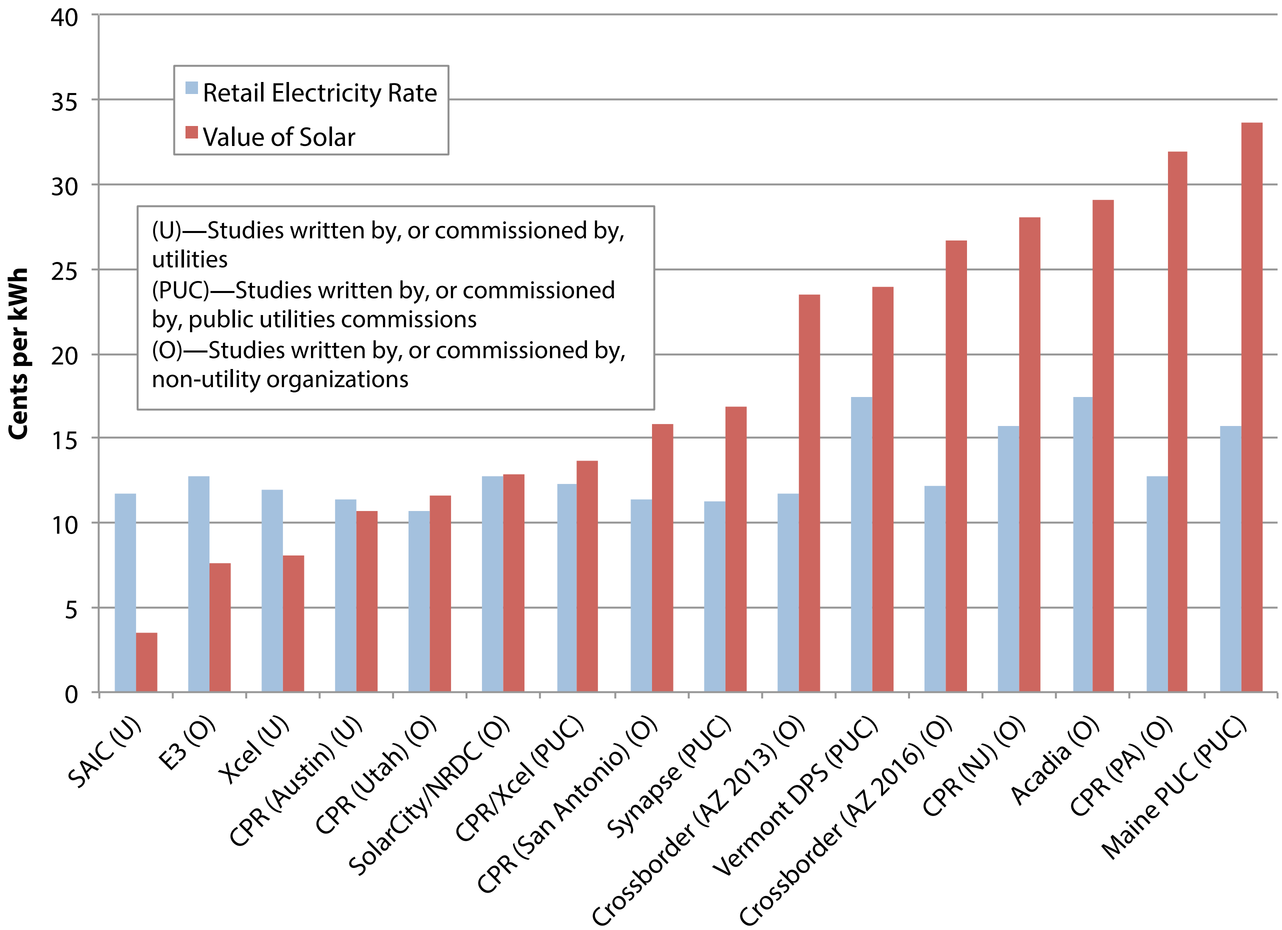
Solar energy also creates valuable benefits for the environment and society at large.

- **Avoided greenhouse gas emissions:** In 2014, the electricity sector was the largest source of global warming emissions—responsible for 30 percent of all total U.S. greenhouse gas pollution. Generating energy from the sun provides a renewable source of energy that produces no greenhouse gas emissions. In 2015, distributed solar energy alone – just solar panels on households and businesses – averted approximately 8 million metric tons of carbon dioxide emissions.
- **Reduces air pollution that harms public health:** According to the American Lung Association, 44 percent of Americans live in a place where pollution often reaches dangerous levels**.** Expanding the nation's ability to obtain clean electricity from the sun reduces our dependence on fossil fuels, and lessens the amount of harmful emissions that flow into the air we breathe.
- **Creates jobs and spurs local economies:** The American solar energy industry is growing rapidly, creating new jobs and businesses across the nation. In 2015, the solar energy industry added jobs at a rate 12 times that of the overall economy, and as of November 2015 employed more than 208,000 people.

The benefits solar homeowners provide to the grid, and to society generally, are often worth more than the benefits they receive through net metering.

- All 16 analyses reviewed here found that solar energy brought net benefits to the grid.
- 12 analyses out of 16 found that the value of solar energy was worth more than the average residential retail electricity rate in the area at the time the analysis was conducted. Three of the four analyses that found different results were commissioned by utilities. (See Figure ES 1.)
- Of these 16 analyses, the median value of rooftop solar energy was 16.35 cents per kWh, while the average residential retail electricity rate in included states was 13.05 cents per kWh.
- The studies that estimated lower values for solar energy often undervalued, or did not include, important environmental and societal benefits that come from generating electricity from the sun.

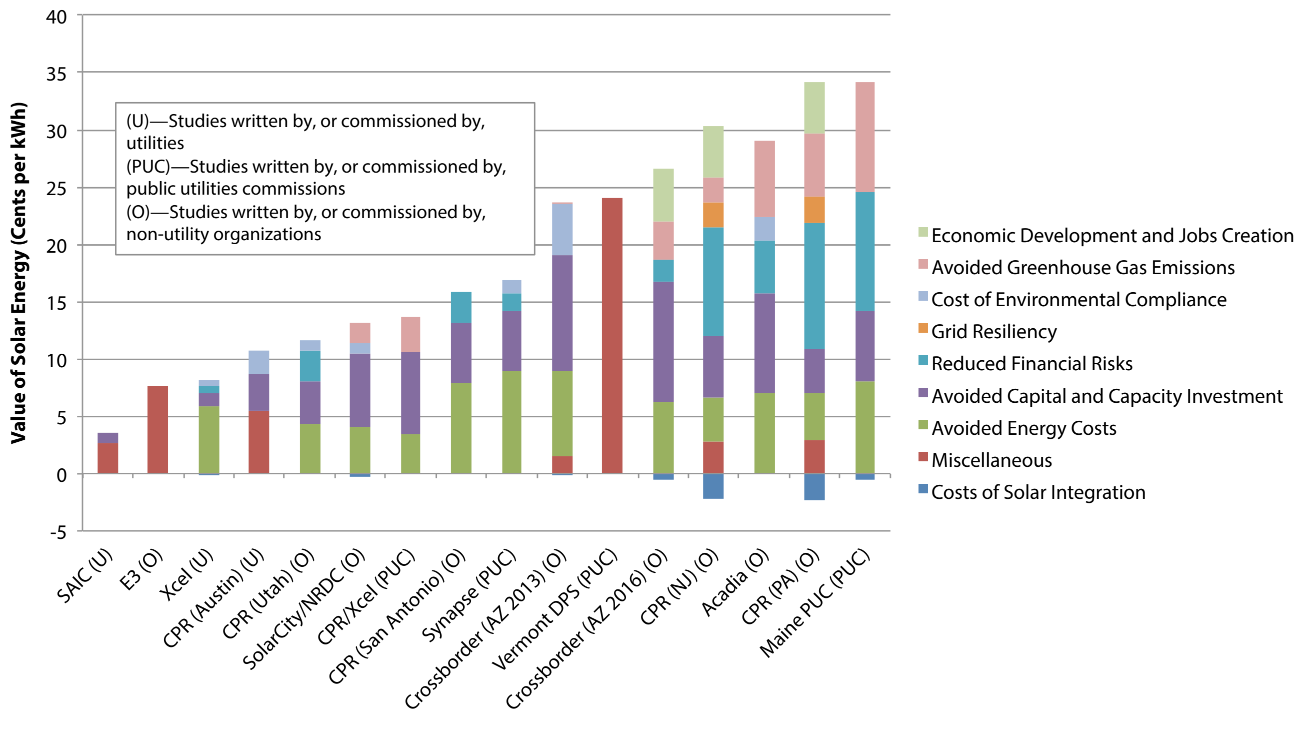
Figure ES-1: Retail Electricity Rates and the Values of Solar Energy in 16 Cost-Benefit Analyses.



Net metering policies have been critical to the growth of solar energy in the United States. To maintain America's momentum toward a clean energy future, policy-makers should continue and expand net metering policies. Specifically:

- States should lift arbitrary caps that limit availability of net metering in fast-growing solar markets.
- State or local governments that evaluate the benefits and costs of net metering should include a full range of benefits of solar energy, including environmental and societal benefits.
- State and local governments should consider the simplicity of net metering when evaluating programs that compensate customers for the solar electricity they provide to the grid.
- State and local governments should reject alternatives to net metering that do not provide residential and business customers full and fair compensation that reflects all the benefits that they provide.
- State and local governments should ensure that all people can take advantage of net metering policies, including multifamily homes or homes without sunny roofs, by implementing virtual net metering programs.

Figure ES-2: A Comparison of Cost-Benefit Analyses of Solar Energy by Study and Category.



Introduction

In 2015, America saw its 1 millionth solar installation. The vast majority of those installations were built on rooftops, parking lot canopies and for community solar gardens, and on homes, apartment buildings, businesses, farms, schools, government offices and more – a category known as distributed solar energy.

It is still the early days of America's transition to clean energy. Those who have "gone solar" so far are in the vanguard – and their decisions to invest time and money in solar projects are often driven by the desire to do their part in reducing the threat of global warming. Their efforts are working. In 2015, the energy generated by rooftop and other distributed solar energy averted 8.4 million metric tons of greenhouse gas pollution, equivalent to taking nearly 2 million passenger vehicles off the road, burning 20 million fewer barrels of oil, or shutting down two coal plants.[1]

Yet early solar adopters have done more than just reduce global warming emissions. They have also supported local jobs, improved public health, and paved the way for a future of cheaper and easier solar installations. And they have driven forward the American solar industry, which is creating jobs 12 times faster than the rest of the economy and now employs three times as many people as the U.S. coal-mining industry.[2]

This report reviews a growing body of research on solar energy's value to society, and to the electric grid in particular – and finds that those who have "gone solar" are likely not only fighting global warming, but also providing financial benefits to fellow utility ratepayers, even when accounting for support provided by state policies like net metering.

By realizing the full benefits provided by those who "go solar," and supporting homeowners and businesses that choose to invest in a cleaner and healthier future, America can continue to fuel the growth of clean solar energy for years to come.

Pro-Solar Policies Are Fueling a Solar Revolution in America

The United States has witnessed a decade of impressive growth in solar energy. By September 2016, the United States had 31.6 gigawatts of solar electric capacity, enough to power more than 6 million average U.S. homes.[3]

Solar power is growing exceptionally fast, but the United States is nowhere near the limit of its solar potential. The United States has the technical potential to install enough solar electricity capacity to meet the nation's electricity needs more than 100 times over.[4]

America's ability to tap that potential grows as solar energy prices continue to fall. The price of a typical solar PV system has declined an average of 6 to 8 percent annually since 1998, providing more Americans with the opportunity to generate their own electricity at home or at their business.[5]

Continued declines in the price of solar energy, coupled with Americans' increasing familiarity with this clean energy source, could lead to a continued boom in solar power. But that is only likely to happen if the United States retains stable public policies that provide a solid foundation for solar energy.

Net Metering Has Been Critical to the Expansion of Solar Energy

Net energy metering is a simple, easily understood, easy-to-administer system designed to ensure that solar panel owners are fairly compensated for the benefits they provide to the grid. Under net energy metering, solar panel owners are compensated for the extra power they supply to the grid at a fixed rate, normally the retail cost of electricity – the amount that a residential customer would pay to draw a unit of electricity from the grid. Stated simply, net energy means that the customer meter spins forward for every bit of electricity the customer uses, and spins backwards at times when solar power production exceeds on-site needs. The balance, or the "net," is what the customer is charged or credited for at the end of the month. As a result, over the course of a year, a customer with a solar photovoltaic system pays for only the *net* amount of electricity used over a 12-month period (electricity consumed minus electricity produced), plus utility service charges.

Net metering is not a new idea. It has been the policy in some states for more than 30 years, and is currently offered in 41 states and Washington, D.C.[6] Of the top 10 states with the most solar energy capacity per capita, all but one had a strong net metering policy through 2015.[7]

Historically, the relationship between power generators and consumers had been a one-way street. Utilities generated the power and customers bought it. Utilities simply sent customers a monthly bill for the amount of power they consumed. Utilities were granted a franchise and exclusive monopoly to serve an area in return for a reasonable opportunity to make a profit. The price of power was set at a level designed to recover the utility's cost of building and operating the power plants, power lines and distribution systems needed to supply electricity to consumers.

Technologies like solar panels, however, enable electricity consumers to also be electricity producers. Because solar panels generate more electricity than needed at certain times of day and less than is needed at others, most solar homeowners are both producers and consumers of electricity from the grid, depending on the time of day and season of the year.

Charging solar panel owners based on their net consumption of electricity is not the only possible option for compensating them for the power they supply to the grid. Even in the absence of net metering, federal law requires utilities to purchase any excess power from customer-owned solar photovoltaic systems at a state-regulated rate based on the "avoided cost" of the electricity the utility would have otherwise had to generate or purchase – a figure usually far lower than the retail rate.[8] Some states and localities have adopted other methods for calculating compensation, such as "value of solar" rates that attempt to pay solar panel owners based on the estimated value of the benefits they supply to the grid.

Unfortunately, net metering is often misunderstood as a "subsidy" to solar homeowners, rather than as a system for compensating them for the benefits they provide to the grid and to society. A series of studies in recent years has shown that those benefits are significant.

Rooftop Solar Energy Provides Clear Benefits to Electricity Consumers and to Society

Solar energy provides a wide variety of benefits for the grid and for society in general. These benefits can be divided into two categories: benefits to the grid (and, by extension, all electricity consumers) and benefits to the environment and society. The value of distributed solar power should not be compared to the cost of power from a fossil-fueled central generating station. A new, clean resource that produces all of its output during the high-load daytime hours and is delivered to the system at the distribution grid level is fundamentally different – and in some ways superior to – a fossil-fired power plant located far from the customer base.

Grid Benefits

Avoided Energy Costs

Of all the benefits that solar energy creates for electricity ratepayers, reduced expenditure for power generation is perhaps the most obvious. Solar energy systems produce clean, renewable electricity on-site, reducing the amount of electricity utilities must generate or purchase from fossil fuel-fired power plants.

The value of this avoided electricity consumption is often greatest in the summer months, when demand for electricity rises due to increased air conditioning demand and solar energy production is near its peak. Adding solar energy to the system reduces the need to power up expensive, often inefficient generators that run only a few times a year, or to purchase expensive peak power on wholesale markets, reducing the cost of electricity for all ratepayers.

Reduced Line Losses

Our nation's electricity grid was built around large, centralized power plants, with power transmitted over long distances to our homes and businesses. As it travels from the power plant to our sockets, a portion of the electricity is "lost" as heat and never arrives at its destination.

The Energy Information Administration estimated that the United States lost about $21 billion worth of electricity in 2014, or 5 percent of the total amount of electricity transmitted and distributed that year.[9] These losses cause us to generate more electricity than we need, increasing costs for ratepayers. Solar PV systems drastically reduce the amount of system losses by producing electricity on-site, thereby reducing the amount of electricity transmitted and distributed through the grid.

Solar power is particularly effective in reducing line losses because it reduces demand on grid infrastructure at times when line losses are highest. Line losses increase with the square of the load on the distribution system, so they are highest during the high-load hours when most solar output is delivered. On-peak losses can be as high as 30 percent, so the benefits of distributed solar energy may be disproportionately high.[10]

Avoided Capacity Investment

Expanding the amount of electricity we generate from the sun can defer or eliminate the need for new grid capacity investments, particularly because demand for energy from the grid is currently often highest during the day when the sun is shining (although this may change with increasing deployments of rooftop solar). By reducing overall demand, expanding solar energy production helps ratepayers and utilities avoid the cost of investing in new power plants, transmission lines, reserve capacity and other forms of electricity infrastructure.

Reduced Financial Risks and Electricity Prices

Price volatility in the fossil fuel market has long been a concern for utilities and ratepayers alike, but the risk has become greater as power companies have shifted from coal to natural gas – a fuel with a history of price volatility.[11] Because solar panels, once installed, do not incur fuel costs, integrating more solar energy capacity onto the electric grid can reduce exposure to sudden swings in the price of fossil fuels or wholesale electricity. Utilities commonly engage in strategies to hedge against fossil fuel price volatility – such as by securing long-term contracts, where possible, for fossil fuels or electricity – for which utilities are often willing to pay a premium. Solar energy can help meet these same needs to increase price stability, a contribution with financial value for utilities and grid users.[12]

In competitive energy markets, distributed solar energy also reduces the *price* of electricity by reducing overall demand on the grid. In these areas, ratepayers not only benefit when utilities must purchase less electricity to satisfy demand, but they also gain because each unit of electricity purchased becomes cheaper.[13] These demand reduction-induced price effects can represent an important value to ratepayers.

Grid Resiliency

The centralized nature of our power grid leaves it vulnerable to frequent and prolonged outages. In 2003, four downed power lines in Ohio left more than 50 million people in eight states and Canada without power and cost $6 billion in economic damage.[14] Increasing distributed solar PV capacity and energy storage options not only reduces the demand that combines to overload the system, but it also decentralizes our grid, potentially safeguarding people in one part of the country from other areas that are experiencing problems. Additionally, advances in smart inverter technology allow higher percentages of solar energy to be safely integrated into the grid, increasing grid resiliency and reliability.[15] This will be enhanced as distributed battery storage expands.

Avoided Environmental Compliance Costs

Adding solar energy to the grid allows local utilities and municipalities to avoid some of the growing costs of compliance with environmental regulations. Many states have air quality and water quality regulations and 29 states and Washington, D.C., have Renewable Electricity Standards that require states to source a certain percentage of their energy demand from renewable resources, including from the sun.[16] Increasing solar energy capacity helps utilities avoid or reduce the costs of installing new technologies to curb air and water pollution or installing renewable energy. Solar also assists with compliance with regulations on criteria pollutants like sulfur dioxide and nitrogen oxides, and also helps states to comply with the proposed federal Clean Power Plan.

Environmental and Societal Benefits

Taking on Climate Change

In 2014, the electricity sector was the nation's largest source of global warming emissions – responsible for 30 percent of all total U.S. greenhouse gas pollution.[17] Coal is the most carbon intensive of the fossil fuels we burn for electricity, accounting for 77 percent of carbon dioxide emissions from the electricity sector. The combustion of natural gas, while emitting less carbon dioxide than coal, has now been shown to emit large amounts of methane – a gas that traps approximately 86 times more heat in the atmosphere than the same amount of carbon dioxide, over a 20-year time frame.[18]

Conservative studies suggest that every metric ton of carbon dioxide released into the air causes $37 of economic and social damage.[19] In 2015, the United States electric power sector emitted nearly 2 billion metric tons of carbon dioxide emissions, equivalent to more than $70 billion in economic and social damages.[20] Solar energy, however, is a renewable source of energy that produces emission-free electricity.

Rooftop solar in particular is also fast and flexible to implement, making it an important tool for taking on climate change. Residential rooftop projects typically take just a few months from initial deposit to power generation, while utility-scale solar projects can take years.[21] Distributed solar energy can also be installed in a wide variety of urban settings, including rooftops and parking lot canopies, making it well-suited for densely populated and energy-intensive regions.

Reduced Public Health Threats

Solar energy will not only reduce greenhouse gas emissions and help to mitigate the worst impacts of climate change, but it will also reduce emissions of dangerous air pollutants such as nitrogen oxides, mercury and particulate matter that harm public health.[22]

According to a new report by the American Lung Association, 44 percent of Americans live in a place where air pollution often reaches dangerous levels.[23] Air pollution is linked to increased incidence of asthma and chronic bronchitis, and has also been shown to cause hundreds of thousands of premature deaths per year.[24] A typical coal-fired power plant without technology to limit emissions sends 170 pounds of mercury —an extremely harmful neurological toxin – into the air each year.[25]

Expanding the nation's ability to source clean electricity from the sun reduces our dependence on fossil fuels, and lessens the amount of harmful emissions that flow into the air we breathe.

Job Creation and Economic Development

The solar energy industry is rapidly growing, creating new jobs and businesses across the nation. In 2015, the solar energy industry added jobs at a rate nearly 12 times that of the overall economy, and now employs more than 208,000 people.[26] Many of these jobs are in installation and maintenance, jobs that cannot be sent overseas. In addition, these jobs are well-paid, with installation jobs paying a median wage of $21 per hour.[27] In Colorado, for example, the solar energy industry has added $1.42 billion to the state economy since 2007, while creating 10,700 full-time jobs.[28] Because rooftop solar installations take place in our communities, they create opportunities for local businesses, and serve as visible reminders of the local economic benefits of clean energy.

Solar Energy is Worth More than the Benefits from Net Metering

Net metering is intended to compensate the owners of solar energy systems for the value they provide to the grid. In recent years, however, as solar energy has spread across the United States, utilities and fossil fuel interests have begun to argue that net metering represents an unfair subsidy that shifts costs onto other electricity ratepayers.

This report reviews 16 of those analyses, and seeks to compare the studies by author, categories valued and perspective. It shows that all of the studies find that solar energy brings net benefits to the grid and to society. It also finds that non-utility analysts generally value solar energy at higher rates than utilities and public utilities commissions, that the majority of analyses find solar energy to be worth more than the credits offered to solar energy system owners through net metering, and that studies that find lower values for solar energy often exclude consideration of key benefits that solar panel owners provide to the grid and society.

Many factors can affect the value of rooftop solar, from the time of day when electricity is generated, to location-specific factors like peak demand rates and a region's generation capacity. The value of rooftop solar will also change over time as the grid evolves and as rooftop solar becomes a more substantial part of our energy system. Nevertheless, the evidence suggests that today, in the majority of cases, net metered rooftop panels provide a net benefit to electric ratepayers, and to the rest of society.

The Value of Solar Power Is More than Just Avoided Costs

A key difference between studies that valued solar energy at lower levels and those that valued it at higher rates concerned the types of benefits considered in the analysis: did the report consider the ways that solar created benefits that accrue to all of society, or did it only consider a limited number of direct benefits to the grid and the utility?

The most basic way to value solar, and the most commonly presented by electric utilities, is to calculate the avoided costs that result from its expansion.[29] In other words, what costs do ratepayers and the utility avoid or defer as more solar energy is integrated into the grid? The avoided costs most commonly used in a solar cost-benefit analysis are: avoided energy costs, avoided capacity and capital investment, costs of market price fluctuation and avoided environmental compliance costs. The majority of the studies reviewed in this report included all or most of these avoided costs. (See Figure 1)

Equating avoided costs with the value of solar, however, does not capture all of the benefits that solar energy creates, such as reduced greenhouse gas emissions, improved public health, increased job creation and economic development, and the potential for increased resiliency of local electric grids with greater levels of distributed generation. Analyses that considered these additional benefits consistently calculated higher values of solar energy than reports that did not.

Table 1: A List of Studies Reviewed in this Report (by Date Published)

Author	Abbreviation Used in Graphs	Organization that Commissioned the Report	Geographic Area Covered	Date
Clean Power Research	CPR (NJ, PA)	Prepared for the Mid-Atlantic Solar Energy Industries Association and the Pennsylvania Solar Energy Industries Association	Examined four different fleet locations and seven different locations in New Jersey and Pennsylvania	Nov 2012
Clean Power Research and Solar San Antonio	CPR (San Antonio)	Written by Clean Power Research, a consulting and research group, and Solar San Antonio, a non-profit	CPS Energy service territory	Mar 2013
SAIC Energy, Environment and Infrastructure, LLC	SAIC	Arizona Public Service Company, an investor-owned utility	Arizona Public Service territory	May 2013
Xcel Energy, Inc.	Xcel	Written by Xcel Energy, a local utility	Xcel Energy service territory in Colorado	May 2013
Crossborder Energy	Crossborder Energy (2016 AZ)	Written by Crossborder Energy, a consulting group.	Arizona Public Service territory	May 2013
Clean Power Research	CPR (Austin)	Commissioned by Austin Energy, the incumbent investor-owned utility.	Austin Energy service territory (Texas)	Dec 2013
Clean Power Research	CPR (Utah)	Utah Clean Energy, a non-profit group.	Rocky Mountain Power service territory	Jan 2014
Clean Power Research and Xcel Energy	CPR/Xcel (Minnesota)	Calculated by Xcel Energy using methodology developed by Clean Power Research for the Minnesota Department of Commerce.	Xcel Energy service territory in Minnesota	Apr 2014
Synapse Energy Economics, Inc.	Synapse	Prepared for the Public Service Commission of Mississippi	State of Mississippi	Sep 2014
Vermont Department of Public Services	Vermont DPS	Written by the Vermont Department of Public Services, as directed by Act 99 of the 2014 Vermont legislative session.	State of Vermont	Nov 2014
CPR (Maine)	Maine PUC	Prepared for the Maine Public Utilities Commission	State of Maine	Mar 2015
Acadia Center	Acadia	Written by Acadia Center, a non-profit research and advocacy group	State of Massachusetts	Apr 2015
Crossborder Energy	Crossborder Energy (2016 AZ)	Written by Crossborder Energy, a consulting group.	Arizona Public Service territory	Feb 2016
SolarCity and the Natural Resource Defense Council	SolarCity/NRDC	Written by SolarCity and the Natural Resource Defense Council.	State of Nevada	May 2016
Energy and Environmental Economics, Inc.	E3	Written by Energy and Environmental Economics, Inc. and requested by the Nevada Legislative Committee on Energy. This was a follow up to a 2013 value of solar study was commissioned by the Nevada Public Utilities Commission.	State of Nevada	Aug 2016

Table 2: Categories of Benefits and Costs Included in Each Solar Energy Cost-Benefit Analysis.*

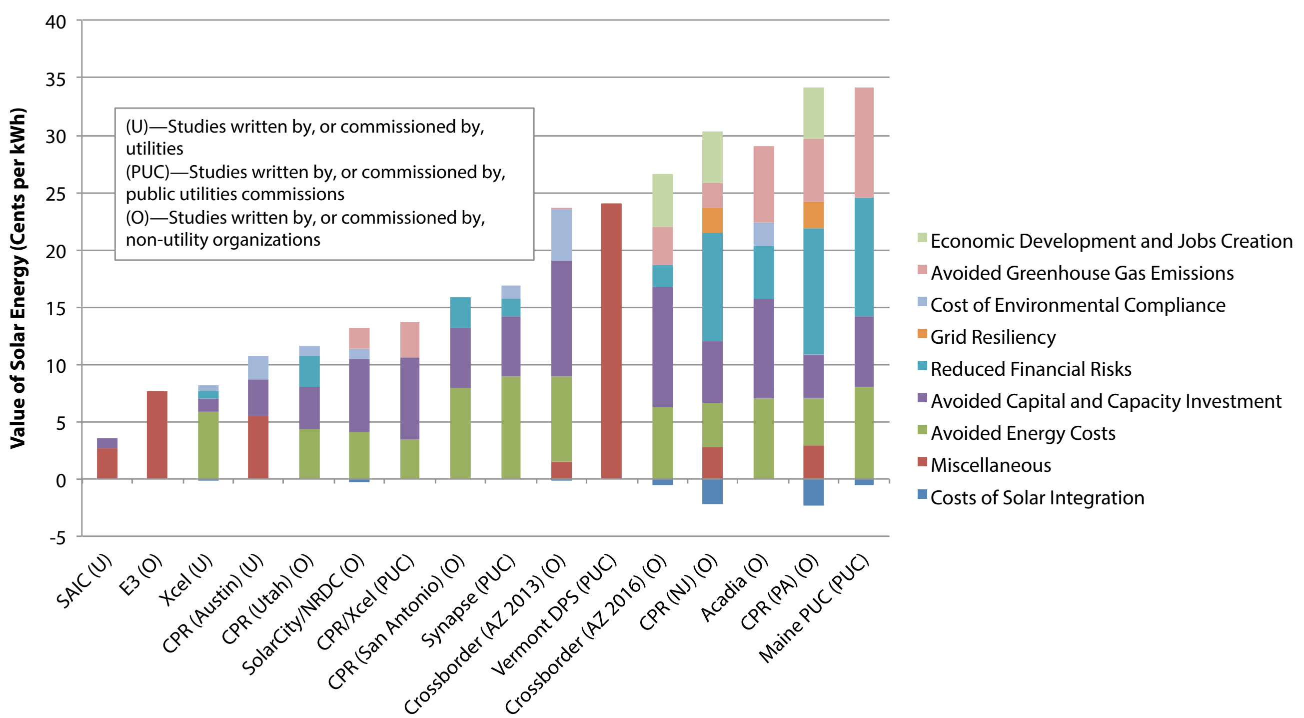
Author	Costs of Solar Integration	Avoided Energy Costs	Avoided Capital and Capacity Investment	Reduced Financial Risks	Grid Resiliency	Cost of Environmental Compliance	Avoided Greenhouse Gas Emissions	Economic Development	Total(cents per kWh)
SAIC		■	■			■			3.56
E3†		■	■			■	■		7.60
Xcel	■	■	■	■		■			8.04
CPR (Austin)		■	■	■		■			10.70
CPR (Utah)		■	■	■		■			11.60
SolarCity/NRDC	■	■	■			■	■		12.90
CPR/Xcel		■	■				■		13.64
CPR (San Antonio)		■	■	■					15.80
Synapse		■	■	■		■			16.90
Crossborder (AZ 2013)	■	■	■			■			23.50
Vermont DPS†		■	■	■		■			24.00
Crossborder (AZ 2016)	■	■	■	■			■	■	26.15
CPR (NJ)‡	■	■	■	■	■		■	■	28.10
Acadia		■	■	■		■	■		29.06
CPR (PA)	■	■	■	■	■		■	■	31.90
Maine PUC‡	■	■	■	■			■		33.60

*Colored cells represent categories that were included in the solar energy cost-benefit calculation.

† Reports do not list individual values for each of the values accounted for in avoided cost calculation.

‡ Reports include additional category "Long Term Societal Value," for details see Methodology.

Figure 1: A Comparison of Solar Energy Cost-Benefit Analyses by Report and Category.



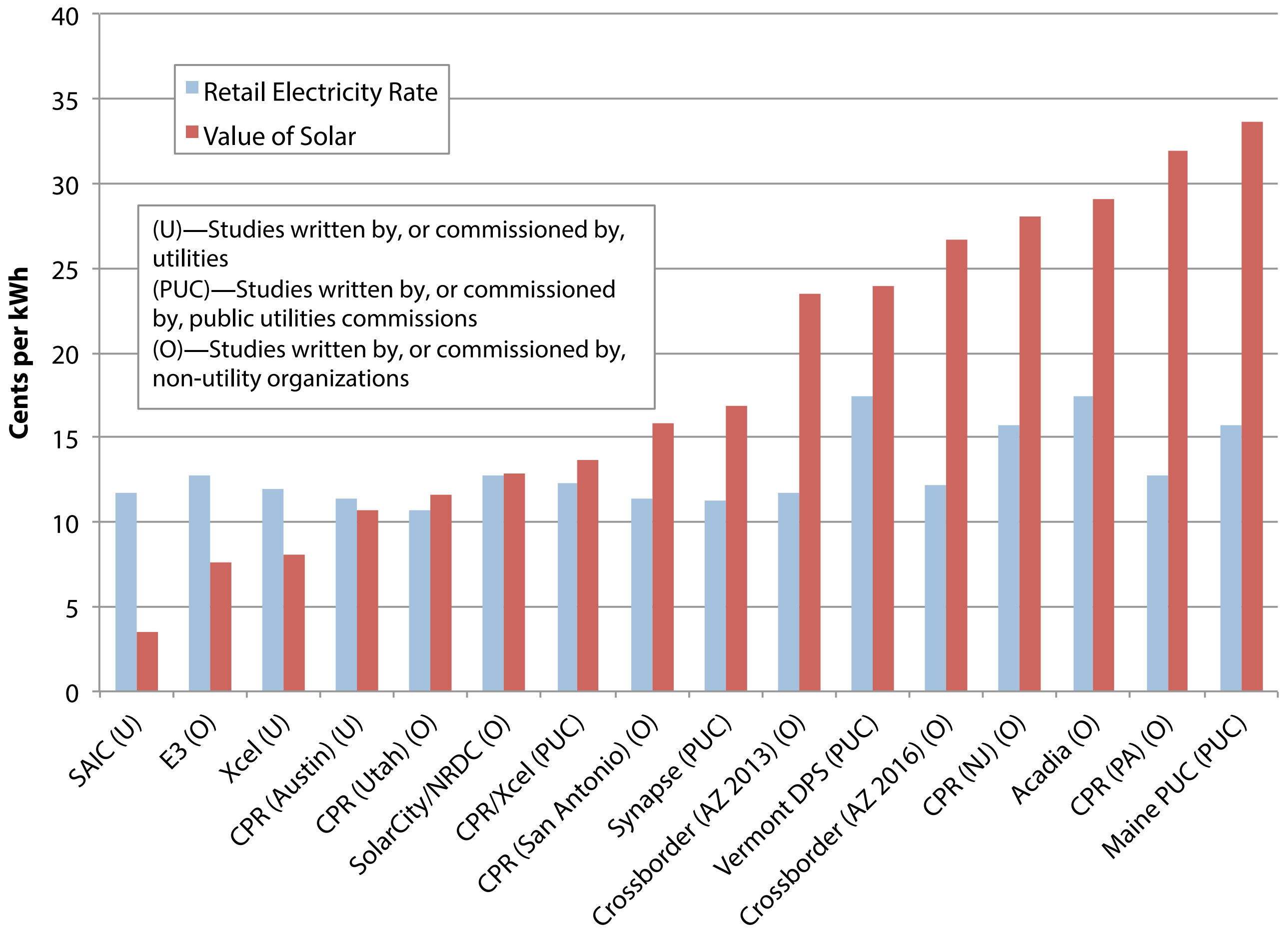
Value Provided by Solar Energy Usually Exceeds Benefits from Net Metering

Nearly all analyses that consider a full range of solar energy benefits find that the value provided by installing solar energy exceeds local retail electricity rates. In other words, far from being an overly generous subsidy, net metering often *under-compensates* solar energy system owners for the benefits they provide to all customers and to society. Of these 16 analyses, the median value of rooftop solar energy was 16.35 cents per kWh, while the average residential retail electricity rate in included states was approximately 13 cents per kWh.[30]

Non-Utility Analysts Value Solar Power at Higher Rates than Utilities

Studies of the value of solar conducted by utilities routinely arrive at estimates lower than those of studies conducted by public utilities commissions and other organizations. One reason for this is the tendency of utility-produced studies to exclude benefits of solar energy accruing to the environment and society by focusing only on costs and savings that affect the direct costs of operating the grid. Out of the 16 analyses reviewed in this report, those authored by non-utility groups consistently included valued environmental categories at a higher rate than utilities, while analyses conducted by public utilities commissions were inconsistent in this treatment. In fact, 12 of the 13 non-utility value-of-solar studies evaluated here found that solar energy delivered greater value than retail electricity rates, while none of the three studies commissioned by utilities came to that conclusion.

Figure 2: Average Retail Residential Electricity Rates Compared to the Values of Solar in 16 Cost-Benefit Analyses.[31]



Conclusion: A Clean Energy Future Depends on Full and Fair Compensation for Homes and Businesses that "Go Solar"

The benefits of increased solar energy capacity are clear: reduced greenhouse gas emissions, lower monthly electricity bills, and cleaner air, to name just a few. It is also clear that pro-solar policies, such as net metering, are critical to the success of solar energy.

Recently, however, net metering has come under attack. Utilities and fossil fuel interests, along with allied legislators and regulators, have sought to portray the program as an unfair subsidy to solar energy system owners.

Most analyses – especially those that consider the full range of benefits that solar energy delivers to the grid and to society – find that the value to all customers created by installing solar panels on a home or business generally exceeds the private benefits received through net metering by customers who invest in solar.

Net metering is a critical tool to ensure fair compensation for owners of solar energy systems and to continue to fuel the growth of solar energy. Public officials should support and strengthen net metering as sound public policy to stimulate private investment and job growth, and to encourage utilities to diversify and strengthen the grid. Specifically:

- States should lift arbitrary caps that limit availability of net metering in fast-growing solar markets.
- State or local governments that evaluate the benefits and costs of net metering should ensure that a full range of benefits is considered, including environmental and societal benefits. This isn't just good policy for solar energy – utility decision-making should fully account for the costs and benefits of all resource options.
- State and local governments should consider the simplicity of net metering when evaluating programs that compensate customers for the solar they provide to the grid.
- State and local governments should reject alternatives to net metering that do not provide residential and business customers full and fair compensation for the value they provide to the grid and society.
- State and local governments should ensure that all people can take advantage of net metering policies, even those who do not live in single-family homes, by implementing virtual net metering programs.

Local, state and federal governments should adopt other policies to encourage the growth of solar energy.

- State and local regulators should reject rate designs that incorporate high fixed charges or other rate design elements that shift costs to small users, including customers with solar installations.
- States should set aggressive goals for solar energy adoption, and implement policies that will encourage homeowners and businesses to meet them.
- States should remove other financial and regulatory hurdles to solar energy that slow down installation and discourage homes and businesses from investing in solar energy systems.
- The federal government should use its regulatory powers to promote solar energy, and should lead by example by rapidly adopting solar energy to meet its own energy needs.
- Local governments should ensure that every homeowner and business with access to sunlight can exercise the option of generating electricity from the sun, and should make "going solar" as easy as possible by removing unnecessary red tape, reducing fees, and speeding the permitting process.
- Local governments should set ambitious local clean energy goals, and should lead by example by installing solar energy systems on public buildings. They should also establish programs that help citizens and businesses get better access to solar power, such as solar co-ops or solarize programs.

Methodology

This report reviewed 16 analyses of the value of solar energy in states across the country. Each analysis is unique, using its own methodology and setting its own parameters. As such, in order to enable a fair comparison of the studies, we created a standard set of categories for the various benefits and costs of solar power addressed in the studies. A few analyses used categories that were not translatable into our categories, or for which individual costs were not available. In those cases, we created a "Miscellaneous" category, and the details of that can be found in the methodology of those analyses.

Details of how the benefits and costs of solar energy in each report were allocated are described below.

Acadia Center

Report Citation: Acadia Center, *Value of Distributed Generation: Solar PV in Massachusetts*, April 2015.

This study assessed the grid and societal value of six solar PV systems to better understand the overall value that solar PV provides to the grid. We used the 25-year levelized value of the system labelled "South Facing—Fixed, 35 Degrees." Other orientations of solar panels produce different estimates of value, ranging from 29.28 cents per kWh to 34.26 cents per kWh. The total value of solar found for this system is 29.06 cents per kWh.

A. **Avoided Energy Costs:** consists of the category "Avoided Energy Costs" (7.07 cents per kWh).

B. **Avoided Capacity and Capital Costs**: calculated by adding the category "Avoided Capacity Costs" (4.41 cents per kWh), the category "Avoided Transmission Costs" (2.43 cents per kWh) and the category "Avoided Distribution Costs" (1.81 cents per kWh). The total value for this category is 8.65 cents per kWh.

C. **Reduced Financial Risks and Electricity Prices**: calculated by adding the category "Demand Reduction Induced Price Effects-Energy" (3.66 cents per kWh) and the category "Demand Reduction Induced Price Effects-Capacity" (1.55 cents per kWh.) The total value for this category is 5.21 cents per kWh.

D. **Avoided Environmental Compliance Costs**: calculated by adding the category "Avoided CO_2 Compliance Costs" (2.04 cents per kWh) and the category "Avoided NO_x Compliance Costs" (0.0006 cents per kWh). The total value for this category is 2.0406 cents per kWh.

E. **Avoided Emissions Costs**: calculated by adding the category "Net Social Cost of CO_2" (3.11 cents per kWh), the category "Net Social Cost of SO_2" (2.86 cents per kWh) and the category "Net Social Cost of NO_x" (0.71 cents per kWh). The total value for this category is 6.68 cents per kWh.

CPR (Austin)

Report Citation: Thomas E. Hoff and Ben Norris, Clean Power Research, *2014 Value of Solar Executive Summary,* 12 December 2013.

This report is part of an annual update conducted by Austin Energy and Clean Power Research that calculates the value of solar in Austin Energy's territory and is used as input in decisions over the following year's

Value of Solar tariff. We used the Distributed PV Value for each category, which equals the "Economic Value (levelized $/kWh) times Load Match (%) (for capacity related components) times 1 plus Loss Savings (%)." As in the report, we then added each category together to arrive at a total value of solar of 10.7 cents per kWh.

A. **Avoided Energy Costs and Avoided Capital and Capacity Investment**: consists of the category "Guaranteed Fuel Value" (5.5 cents per kWh). In Figure 1 and Figure ES-2 this category is included under "Miscellaneous" because it includes both current *and* future avoided energy costs (which, in other cases, we put into the "Reduced Financial Risk and Electricity Prices" category).

B. **Avoided Capacity and Capital Costs:** calculated by adding the category "Plant O&M Value" (0.5 cents per kWh), the category "Generation Capacity Value" (1.7 cents per kWh), the category "Avoided Transmission Capacity Cost" (1.0 cents per kWh), and the category "Avoided Distribution Capacity Cost" (0.0 cents per kWh). The total value for this category is 3.2 cents per kWh.

C. **Avoided Environmental Compliance Cost:** consists of the category "Avoided Environmental Compliance Costs" (2.0 cents per kWh).

CPR (NJ and PA)

Report Citation: Richard Perez, Benjamin L. Norris and Thomas E. Hoff, Clean Power Research, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania,* November 2012.

This report analyzed the value of solar at seven different locations across New Jersey and Pennsylvania. The analyses represent the levelized value of PV for a "fleet" of PV systems. Four different fleet configurations were evaluated at each of the seven locations. We used the highest values from each state – Newark, New Jersey, and Scranton, Pennsylvania. Other orientations of solar panels produce different estimates of value, ranging from 25.6 cents per kWh to 31.5 cents per kWh.

Scranton, Pennsylvania:

A. **Cost of Solar Integration:** consists of the category "Solar Penetration Cost" (-2.3 cents per kWh).

B. **Avoided Energy Costs:** consists of the category "Fuel Cost Savings" (4.1 cents per kWh).

C. **Avoided Capacity and Capital Costs:** calculated by adding the category "O&M Cost Savings" (2.0 cents per kWh), the category "Generation Capacity Value" (1.7 cents per kWh), and the category "T&D Capacity Value" (0.1 cents per kWh). The total value for this category is 3.8 cents per kWh.

D. **Reduced Financial Risks and Electricity Prices:** calculated by adding the category "Fuel Price Hedge Value" (4.2 cents per kWh) and the category "Market Price Reduction Value" (6.9 cents per kWh). The total value for this category is 11.1 cents per kWh.

E. **Grid Resiliency:** consists of the category "Security Enhancement Value" (2.3 cents per kWh).

F. **Avoided Emissions Costs:** consists of the category "Environmental Value" (5.5 cents per kWh).

G. **Economic Development Value:** consists of the category "Economic Development Value" (4.5 cents per kWh).

H. **Miscellaneous:** this study contains a cost category "Long Term Societal Value" (2.9 cents per kWh), which the report defines as "potential value (defined by all other components) if the life of PV is 40 years instead of the assumed 30 years." In Figure 1 and ES-2 this category is included under the label "Miscellaneous."

Newark, New Jersey

A. **Cost of Solar Integration:** consists of the category "Solar Penetration Cost" (-2.2 cents per kWh).

B. **Not Specified:** consists of the category "Long Term Societal Value" (2.8 cents per kWh), which the report defines as "Potential value (defined by all other components) if the life of PV is 40 years instead of the assumed 30 years."

C. **Avoided Energy Costs:** consists of the category "Fuel Cost Savings" (3.9 cents per kWh).

D. **Avoided Capacity and Capital Costs:** calculated by adding the category "O&M Cost Savings" (1.9 cents per kWh), the category "Generation Capacity Value" (2.6 cents per kWh), and the category "T&D Capacity Value" (0.8 cents per kWh). The total value for this category is 5.3 cents per kWh.

E. **Reduced Financial Risks and Electricity Prices:** calculated by adding the category "Fuel Price Hedge Value" (4.4 cents per kWh) and the category "Market Price Reduction Value" (5.1 cents per kWh). The total value for this category is 9.5 cents per kWh.

F. **Grid Resiliency:** consists of the category "Security Enhancement Value" (2.2 cents per kWh).

G. **Avoided Greenhouse Gas Emissions**: consists of the category "Environmental Value" (2.2 cents per kWh).

H. **Economic Development Value:** consists of the category "Economic Development Value" (4.4 cents per kWh).

CPR (San Antonio)

Report Citation: Ben Norris, Clean Power Research, Nic Jones, Solar San Antonio, *The Value of Distributed Solar Electric Generation to San Antonio*, March 2013.

This report conducted analyses on four different solar PV systems, each facing a different direction and placed at different angles. We used the value from the analysis conducted on the system labelled "West-15."

A. **Avoided Energy Costs:** consists of the category "Fuel Cost Savings" (7.9 cents per kWh).

B. **Avoided Capacity and Capital Costs:** calculated by adding the category "O&M Cost Savings (2.7 cents per kWh), the category "Generation Capacity" (1.9 cents per kWh), the category "Transmission and Distribution Capacity" (0.4 cents per kWh), and the category "Reserve Capacity" (0.3 cents per kWh). The total value for this category is 5.3 cents per kWh.

C. **Reduced Financial Risks and Electricity Prices:** consists of the category "Fuel Price Hedge" (2.6 cents per kWh).

CPR (Utah)

Report Citation: Clean Power Research, *Value of Solar in Utah*, 7 January 2014.

We used the Distributed PV Value for each category from this report, which, according to the report, is the economic value modified using "Load Match" factors "to reflect the match between PV production profiles and utility loads." To arrive at the distributed PV value, the study then applied a "Loss Savings" factor "to reflect the distributed nature of the resource." The final value is 11.6 cents per kWh. This value is a levelized value representing all avoided costs over a 25-year assumed PV life.

A. **Avoided Energy Costs:** consists of the category "Fuel Value" (4.3 cents per kWh).

B. **Avoided Capacity and Capital Investment**: calculated by adding the category "Plant O&M Value" (1.3 cents per kWh), the category "Generation Capacity Value" (1.4 cents per kWh), and the category "Avoided T&D Capacity Cost" (1.1 cents per kWh). The total value for this category is 3.8 cents per kWh.

C. **Reduced Financial Risks and Electricity Prices**: consists of category "Fuel Price Guarantee" (2.6

cents per kWh).The total value for this category is 2.6 cents per kWh.

D. **Avoided Environmental Compliance Costs**: consists of category "Avoided Environmental Cost" (0.9 cents per kWh). The total value for this category is 0.9 cents per kWh.

Crossborder Energy (2013 AZ)

Report Citation: R. Thomas Beach and Patrick G. McGuire, Crossborder Energy, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service,* 8 May 2013.

The scope of this report is limited to assessing how demand-side solar will impact Arizona Public Service's ratepayers. The total value of solar found in this report is 23.5 cents per kWh.

A. **Costs of Solar Integration**: consists of the category "Integration Costs" (-0.2 cents per kWh).

B. **Avoided Energy Costs**: consists of the category "Energy" (7.5 cents per kWh).

C. **Avoided Capacity and Capital Costs:** calculated by adding the categories "Generation Capacity" (7.6 cents per kWh), "Transmission" (2.3 cents per kWh), "Distribution" (0.2 cents per kWh), and "Ancillary Services and Capacity Reserves" (1.5 cents per kWh). The total value for this category is 11.6 cents per kWh.

D. **Avoided Environmental Compliance Costs:** consists of the category "Avoided Renewables" (4.5 cents per kWh).

E. **Avoided Emissions Costs**: consists of the category "Environmental" (0.1 cents per kWh).

Crossborder Energy (2016 AZ)

Report Citation: R. Thomas Beach and Patrick G. McGuire, Crossborder Energy, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (2016 Update),* 25 February 2016.

The scope of this report is limited to assessing how demand-side solar will impact Arizona Public Service's ratepayers. The total value of residential solar found in this report is 26.2 cents per kWh – the value of commercial solar was not included in this analysis.

A. **Costs of Solar Integration**: consists of the category "Integration Costs" (-0.2 cents per kWh).

B. **Avoided Energy Costs**: consists of the category "Energy" (6.2 cents per kWh).

C. **Avoided Capacity and Capital Costs:** calculated by adding the category "Capacity" (7.0 cents per kWh), the category "Transmission" (1.3 cents per kWh) and the category "Distribution" (2.4 cents per kWh). Values were averaged between South and West-facing orientations. The total value for this category is 10.6 cents per kWh.

D. **Avoided Emissions Costs**: consists of the category "Carbon" valued at 3.3 cents per kWh.

E. **Economic Development and Jobs Creation**: consists of the category "Local economic benefit." (4.7 cents per kWh.)

Maine PUC

Report Citation: Benjamin L. Norris, et al., *Maine Distributed Solar Valuation Study*, 1 March 2015.

This report calculated a 25-year Levelized Distributed PV Value for the Central Maine Power service territory. The total value of solar found in this report is 33.7 cents per kWh.

A. **Costs of Solar Integration**: consists of the category "Solar Integration Costs" (-0.5 cents per kWh).

B. **Avoided Energy Costs**: consists of the category "Avoided Energy Cost" (8.1 cents per kWh).

C. **Avoided Capital and Capacity Costs**: calculated by adding the category "Avoided Generation Capacity Costs" (4.0 cents per kWh), the category "Avoided Reserve Capacity Costs" (0.5 cents per kWh), and the category “Avoided Transmission Capacity Costs” (1.6 cents per kWh). The total value for this category is 6.1 cents per kWh.

D. **Reduced Financial Risks and Electricity Prices:** calculated by adding the category “Market Price Response” (6.6 cents per kWh) and the category “Avoided Fuel Price Uncertainty” (3.7 cents per kWh). The total value for this category is 10.3 cents per kWh.

E. **Avoided Emissions Costs**: calculated by adding the category “Net Social Cost of Carbon” (2.1 cents per kWh), the category “Net Social Cost of SO_2” (6.2 cents per kWh) and the category “Net Social Cost of NO_x” (1.3 cents per kWh). The total value for this category is 9.6 cents per kWh.

SAIC

Report Citation: SAIC Energy, Environment and Infrastructure, LLC, *2013 Updated Solar PV Value Report*, 10 May 2013.

We used the “present value” from this analysis. The present value, as calculated by the report, “is the 2025 nominal value using the APS discount rate of 7.21 percent.” This report calculated the overall value using different categories than many other reports did, and aggregated many values that are separate in other reports. As a result, the review of this report has a category called “Miscellaneous” that makes up a large percentage of the overall value and includes many of the categories that were calculated separately in other reports. The total value of solar found in this report is 3.56 cents per kWh.

A. **Miscellaneous**: calculated by adding category “Fixed O&M, Gas Transportation” (0.13 cents per kWh) and category “Fuel, Variable O&M, Emissions, Purchased Power” (2.57 cents per kWh). The total value for this category is 2.7 cents per kWh.

B. **Avoided Capital and Capacity Costs:** calculated by adding the category “Generation” (0.72 cents per kWh), the category “Distribution” (0.0 cents per kWh) and the category “Transmission” (0.14 cents per kWh). The total value for this category is 0.86 cents per kWh.

Synapse

Report Citation: Elizabeth A. Stanton, et al., Synapse Energy Economics, Inc., *Net Metering in Mississippi*

Costs, Benefits, and Policy Considerations, 19 September 2014.

We used the “Levelized Avoided Cost Value,” which levelized the value of solar over a 25-year period.

A. **Reduced Financial Risks:** consists of the category “Avoided Risk” (1.5 cents per kWh).

B. **Avoided Energy Costs**: calculated by adding the category “Avoided Energy Costs”(8.1 cents per kWh) and the category “Avoided System Losses” (0.9 cents per kWh). The total value of this category is 9.0 cents per kWh.

C. **Avoided Capital and Capacity Costs:** calculated by adding the category “Avoided Capacity Costs” (1.2 cents per kWh) and the category “Avoided Transmission and Distribution Costs” (4.0 cents per kWh). The total value for this category is 5.2 cents per kWh.

D. **Environmental compliance Costs:** consists of the category “Avoided Environmental Compliance Costs” (1.2 cents per kWh).

Xcel Energy

Report Citation: Xcel Energy, Inc., *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System,* 23 May 2013.

This study examined the first 59 MW of distributed solar generation (“DSG”) installed on the Public Service of Colorado system as of 30 September 2012, in addition to a projection of an additional 81 MW of DSG being installed by 31 December 2014, for a total of 140 MW. We used the levelized net avoided cost value calculated under the “Base Gas” scenario. The total value of solar found in this report is 8.04 cents per kWh.

A. **Avoided Energy Costs**: calculated by adding the category "Avoided Energy Costs" (5.21 cents per kWh) and the category "Avoided Line Losses" (0.62 cents per kWh). The total value for this category is 5.83 cents per kWh.

B. **Avoided Capacity and Capital Costs**: calculated by adding the category "Avoided Capacity & 7FOM (fixed operation and management) costs" (1.15 cents per kWh), the category "Avoided Distribution Upgrades" (0.05 cents per kWh), and the category "Avoided Transmission Upgrades" (0.02 cents per kWh). The total value for this category is 1.22 cents per kWh.

C. **Reduced Financial Risks and Electricity Prices**: consists of the category "Fuel Hedge Value" (0.66 cents per kWh).

D. **Avoided Environmental Compliance Costs**: consists of the category "Avoided Emissions Cost" (0.51 cents per kWh).

SolarCity and NRDC

Report Citation: SolarCity and NRDC, *Distributed Energy Resources in Nevada,* May 2016.

This study conducted a cost-benefit analysis of distributed energy that will be installed in Nevada during 2017-2019, using the *Nevada Net Energy Metering Public Tool* developed by Energy + Environmental Economics in July 2014.

A. **Costs of Solar Integration:** calculated by adding the categories "Program Costs" (0.1 cents per kWh) and "Integration Costs" (0.2 cents per kWh). The total value for this category is 0.3 cents per kWh.

B. **Avoided Energy Costs**: calculated by adding the category "Avoided Energy Costs" (3.7 cents per kWh) and the category "Line Losses" (0.4 cents per kWh). The total value for this category is 4.1 cents per kWh.

C. **Avoided Capacity and Capital Costs**: calculated by adding the categories "Generation Capacity" (2.6 cents per kWh), "Ancillary Services" (0.1 cents per kWh), "Transmission & Distribution Capacity" (2.8 cents per kWh) and "Voltage Support" (0.9 cents per kWh). The total value for this category is 6.4 cents per kWh.

D. **Avoided Environmental Compliance Costs**: consists of the category "CO2 Regulatory Price" (0.9 cents per kWh).

E. **Avoided Greenhouse Gas Emissions:** consists of the categories "Criteria Pollutants" (0.1 cents per kWh) and "Environmental Externalities" (1.7 cents per kWh). The total value for this category is 1.8 cents per kWh.

E3

Report Citation: Snuller Price et al., Energy and Environmental Economics, Inc., *Nevada Net Energy Metering Impacts Evaluation 2016 Update*, August 2016.

This study calculated the costs and benefits of renewable generation systems under Nevada's net metering law. The study calculated the avoided cost to be 7.7 cents per kWh. E3 accounts for the following components in its avoided cost calculation: distribution capacity, transmission capacity, system capacity, ancillary services, criteria pollutants, line losses, and carbon energy. The report does not provide costs for each component in its avoided cost calculation, therefore these costs are included under the label "Miscellaneous" in Figure 1 and Figure ES-2. The report does not include integration costs or RPS compliance value in its utility avoided costs calculation, although those values are accounted for in cost-benefit calculations elsewhere in the report.

Vermont DPS

Report Citation: Vermont Department of Public Service, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014 (revised)*, 7 November 2014.

This study conducted an evaluation of net metering and the value of solar in Vermont as directed by Act 99 of the 2014 Vermont legislative session. Data for the benefit of solar was taken from section *3.3.2.1 - 4 kW fixed solar PV system, net metered by a single residence*, which calculated the benefit of solar for such a system at 23.7 cents per kWh for ratepayers (the study provides a higher benefit provided to society as a whole). The study includes the following components in its avoided utility cost analysis: avoided energy, avoided capacity, avoided regional transmission, avoided transmission and distribution infrastructure, market price suppression, and potential future regulatory value. The report does not provide costs for each component in its avoided cost calculation, therefore these costs are included under the label "Miscellaneous" in Figure 1 and Figure ES-2.

Clean Power Research / Xcel Energy

Report Citation: Xcel Energy, submission to Minnesota PUC at Docket No. E002/M-13-867, *VOS Calculation Compliance*, 2 March 2015.

This value of solar estimate was calculated by Xcel Energy using a methodology created by Clean Power Research for Minnesota's Department of Commerce. The study calculated the value of solar as 13.6 cents per kWh in Xcel territory.

1. **Avoided Energy Costs:** 3.5 cents per kWh, from category "Avoided Fuel Costs."
2. **Avoided Capital and Capacity Investment:** 7.1 cents per kWh, from categories "Avoided Plan O&M – Fixed," "Avoided Plan O&M – Variable," "Avoided Gen Capacity Cost Avoided Reserve Capacity Cost Avoided Trans Capacity Cost" and "Avoided Distribution Capacity Cost."
3. **Avoided Greenhouse Gas Emissions:** 3.04 cents per kWh, from category "Avoided Environmental Cost."

Notes

1 Distributed solar generation data: EIA, *Electricity Data Browser*, accessed at eia.gov/electricity/data/browser/ on 14 September 2016; pollution calculation: EPA, *Greenhouse Gas Equivalencies Calculator*, accessed at epa.gov/energy/greenhouse-gas-equivalencies-calculator on 14 September 2016.

2 The Solar Foundation, *National Solar Jobs Census 2015,* January 2016.

3 SEIA, *U.S. Solar Market Insight Q3 2016 press release*, archived at http://web.archive.org/web/20160915043842/http://www.seia.org/research-resources/us-solar-market-insight.

4 This includes potential solar power generation from rooftop solar panels, large utility-scale solar installations, and concentrating solar power plants. Judee Burr and Lindsey Hallock, Frontier Group, Rob Sargent, Environment America Research & Policy Center, *Star Power: The Growing Role of Solar Energy in America*, November 2014.

5 National Renewable Energy Laboratory, *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections, 2014 Edition*, 22 September 2014.

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7 In mid-2015, Nevada and Hawaii eliminated traditional net metering for newly installed solar energy systems. Top ten states for per capita solar capacity: Gideon Weissman, Frontier Group, Bret Fanshaw and Rob Sargent, Environment America Research & Policy Center, *Lighting the Way 4: The Top States that Helped Drive America's Solar Energy Boom in 2015,* July 2016.

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17 EPA, *Sources of Greenhouse Gas Emissions*, archived at web.archive.org/web/20160915201031/https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.

18 Gunnar Myhre et al., "Anthropogenic and Natural Radiative Forcing," in T.F. Stocker et al. (eds.), Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (Cambridge, United Kingdom and New York, NY, USA: Cambridge University Press, 2013), 714.

19 Peter Howard, Environmental Defense Fund, Institute for Policy Integrity and the Natural Resources Defense Council, *Omitted Damages: What's Missing from the Social Cost of Carbon,* 13 March 2014.

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21 SEIA, *Siting & Permitting*, archived at web.archive.org/web/20160916220218/http://www.seia.org/policy/power-plant-development/siting-permitting.

22 U.S. Environmental Protection Agency, *Air Pollutants,* accessed at: www.epa.gov/air/airpollutants.html, 1 June 2015.

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24 Ibid.

25 Union of Concerned Scientists, *Environmental Impacts of Coal Power: Air Pollution*, accessed at www.ucsusa.org/clean_energy/coalvswind/c02c.html#.VW5vus9Viko, 2 June 2015.

26 See note 2.

27 Ibid.

28 The Solar Foundation, *An Assessment of the Economic, Revenue, and Societal Impacts of Colorado's Solar Industry,* October 2013.

29 This methodology is the most common because many utility-commissioned reports only seek to calculate the costs of benefits of solar energy to the utility or to the non-participating ratepayer, and often only in the short-run of ten years or less.

30 Electricity rates are from the year the study was conducted in. For studies conducted in 2016, retail rates were used from 2015, the latest year rate information was available. Retail rates of electricity downloaded from: U.S. Energy Information Administration, *Electricity Data Browser,* accessed at www.eia.gov/electricity/data/browser, 14 September 2016. Several of the studies calculated values on a levelized basis, which makes comparing the value to a retail electricity rate from a single year problematic. This is, however, a way to show the comparison between current rates under net metering in most places, and the true value of solar.

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Solar Power Generation in the US: Too expensive, or a bargain?

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Abstract

This article identifies the combined value that solar electric power plants deliver to utilities' rate payers and society's tax payers. Benefits that are relevant to utilities and their rate payers include traditional, measures of energy and capacity. Benefits that are tangible to taxpayers include environmental, fuel price mitigation, outage risk protection, and long-term economic growth components.

Results for the state of New York suggest that solar electric installations deliver between 15 to 40 cents per kWh to ratepayers and taxpayers. These results provide economic justification for the existence of payment structures (often referred to as incentives) that transfer value from those who benefit from solar electric generation to those who invest in solar electric generation.

Introduction

"Economically viable" solar power generation remains a remote and elusive goal for the solar energy skeptics because the cost of unsubsidized solar power appears to be much higher than the cost of conventional generation. Indeed, it does take a revenue stream of around 20-30 cents per kWh to justify a business investment in small to medium distributed solar electrical generation today. Large centralized solar installations in the southwestern US are below a breakeven range of 15 cents per kWh.

A mix of federal and state incentives, whether tax-based, or ratepayers-levied, can make solar an attractive investment in many parts of the US; feed-in-tariffs (FITs) have been particularly effective in

Europe and Asia. Without incentives, however, the needed revenue stream for solar generation is still considerably higher than the least expensive way to generate electricity today, i.e., via unregulated, mine-mouth coal generation. This large apparent "grid-parity gap" can hinder constructive dialogue with key decision makers and constitutes a powerful argument to weaken political support for solar incentives, especially during tight budgetary times.

In this paper, we approach the apparent grid parity gap question on the basis of the full value delivered by solar power generation. We argue that the real parity gap – i.e., the difference between this value and the cost to deploy the resource -- is considerably smaller than the apparent gap, and that it may well have already been bridged in several parts of the US. This argumentation is substantiated and quantified by focusing on the case of PV deployment in the greater New York City area. Since this is not one of the sunniest places in the US, this paper should serve as an applicable case to other regions and/or solar technologies.

Solar Resource Fundamentals

It is useful to first review a couple of fundamental facts about the solar resource that are relevant to its value.

<u>Vast potential</u>: First and foremost, the solar energy resource is very large (Perez et al., 2009a). Figure 1 compares the current annual energy consumption of the world to (1) the known planetary reserves of the finite fossil and nuclear resources, and (2) to the yearly potential of the renewable alternatives. The volume of each sphere represents the *total* amount of energy recoverable from the finite reserves and the *annual* potential of renewable sources.

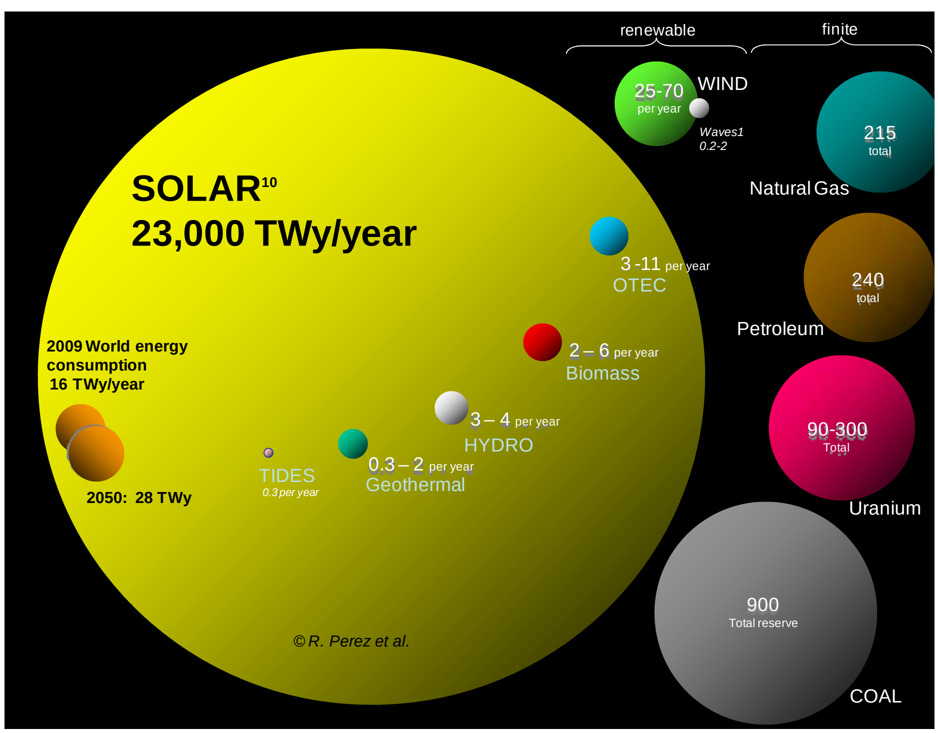

Figure 1: Comparing finite and renewable planetary energy reserves (Terawatt-years). Total recoverable reserves are shown for the finite resources. Yearly potential is shown for the renewables (source: Perez & Perez, 2009a)

While finite fossil and nuclear resources are very large, particularly coal, they are not infinite and would last at most a few generations, notwithstanding the environmental impact that will result from their full exploitation if now uncertain carbon capture technologies do not fully materialize. Nuclear energy may not be the carbon-free silver bullet solution claimed by some: putting aside the environmental and proliferation unknowns and risks associated with this resource, there would not be enough nuclear fuel to take over the role of fossil fuels[1].

The renewable sources are not all equivalent. The solar resource is more than 200 times larger than all the others combined. Wind energy could probably supply all of the planet's energy requirements if pushed to a considerable portion of its exploitable potential. However, none of the others – most of which are first and second order byproducts of the solar resource -- could, alone, meet the demand. Biomass in particular could not replace the current fossil base: the rise in food cost that paralleled recent rises in oil prices and the demand for biofuels is symptomatic of this underlying reality.

On the other hand, exploiting only a very small fraction of the earth's solar potential could meet the demand with considerable room for growth. Thus, leaving the cost/value argumentation aside for now, logic alone tells us, in view of available potentials, that the planetary energy future will be solar-based. Solar energy is the only ready-to-mass-deploy resource that is both large enough and acceptable enough to carry the planet for the long haul.

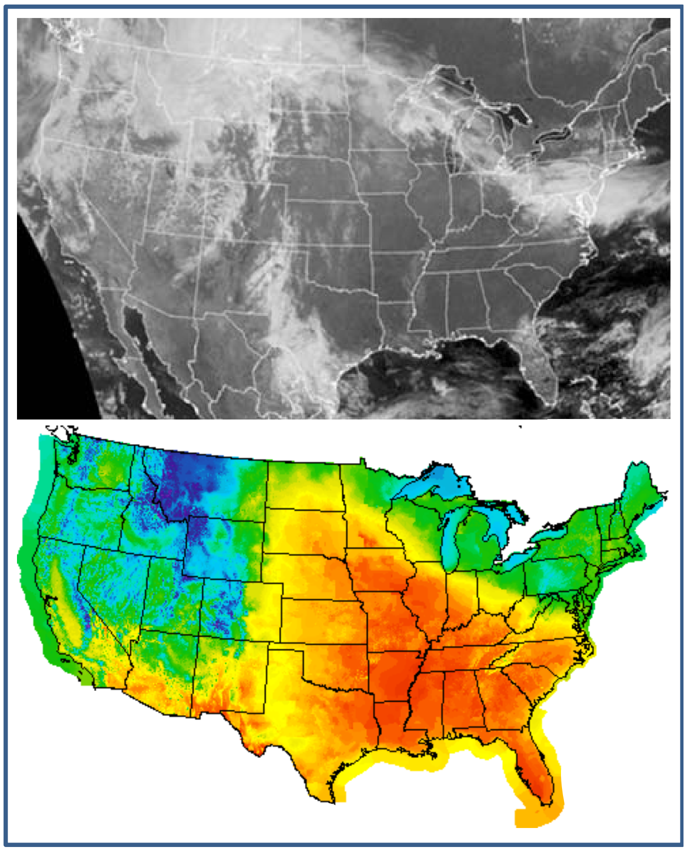

Figure2: Cloud cover during a heat wave in the US

Built-in peak load reduction capability: For a utility company, Combined Cycle Gas Turbines (CCGT) are an ideal source of variable power generation because they are modular, can be quickly ramped up or down and answer the question: "*is power available at will*?" As such CCGT have a high *capacity value*.

Solar generators, distributed PV in particular, are not available at will[2], but they often answer a similar question: "*is power available when needed*?" and as such can capture substantial *effective capacity value* (Perez et al., 2009b). This is because peak electrical demand is driven by commercial daytime air conditioning (A/C) in much of the US reaching a maximum during heat waves.

[1] Of course this statement would have to be revisited if an acceptable breeder technology or nuclear fusion became deployable. Nevertheless, short of fusion itself, even with the most speculative uranium reserves scenario and assuming deployment of advanced fast reactors and fuel recycling , the total finite nuclear potential would remain well below the one-year solar energy potential (ref1)

[2] Concentrating Solar Power (CSP) technology has several hours of built-in storage and could be partially available at will.

The fuel of heat waves is the sun; a heat wave cannot take place without a massive local solar energy influx. The bottom part of Figure 2 illustrates an example of a heat wave in the southeastern US in the spring of 2010 and the top part of the figure shows the cloud cover at the same time: the qualitative agreement between solar availability and the regional heat wave is striking. Quantitative evidence has also shown that the mean availability of solar generation during the largest heat wave-driven rolling blackouts in the US was nearly 90% ideal (Letendre et al. 2006). One of the most convincing examples, however, is the August 2003 Northeast blackout that lasted several days and cost nearly $8 billion region-wide (Perez et al., 2004). The blackout was indirectly caused by high demand, fueled by a regional heat wave[3]. As little as 500 MW of distributed PV region-wide would have kept every single cascading failure from feeding into one another and precipitating the outage. The analysis of a similar subcontinental-scale blackout in the Western US a few years before that led to nearly identical conclusions (Perez et al., 1997).

In essence, the peak load driver, the sun via heat waves and A/C demand, is also the fuel powering solar electric technologies. Because of this natural synergy, the solar technologies deliver hard-wired peak shaving capability for the locations/regions with the appropriate demand mix -- peak loads driven by commercial/industrial A/C -- that is to say, much of America. This capability remains significant up to 30% capacity penetration (Perez et al., 2010), representing a deployment potential of nearly 375 GW in the US.

<u>Renewable energy breeder</u>: The mainstream (crystalline silicon PV) solar electric technology has a proven record of low degradation (<1%/year) and long life (Chianese et al., 2003). After 50 years of operation, a well-built PV module should still generate at least 60% of its initial rating. In addition, the energy embedded in the manufacture a PV system today would be recovered in less than 3 years if it operated in a climate representative of the central US. Several other PV technologies and CSP are capable of producing tens of times their embodied energy during their operating lifetime.

Thus, in effect, solar generators are efficient *energy breeders*, and after a startup period relying on finite energies for initial deployment, a solar economy could easily supply the energy necessary to fuel its own growth.

Too Expensive?

When posing the cost/value question, it is important to identify the relevant parties: i.e., who pays for, and who receives what.

The three parties involved in a solar electric transaction can be summarized as:

(1) The investor/developer who purchases/builds a plant;

[3] The High A/C demand in the northeast required large power transfers (7 GW) from the South and West into the Northeast. These transfers and the inattention of the grid operators caused power lines to overload and disconnect, leaving fewer and fewer energy transfer paths open as the afternoon progressed, until the point when the last major link, near Cleveland, failed and the path closing failure accelerated exponentially, leaving the northeast as an electrical island disconnected from the rest of the continent with 7 GW power generation deficit – the text book example of a blackout. The solar resource region-wide at the time of the blackout was nearly ideal, representing a text-book example of heat wave conditions (Ref3)

(2) The utility and its ratepayers who purchase the energy produced by the plant;[4]
(3) The society at large and its taxpayers who contribute via public R&D and tax-based incentives and receive benefits from the plant.

The transaction is often perceived as one-sided in favor of the investor/developer whose return on investment – e.g., the necessary 20-30 cents breakeven cash flow-equivalent for distributed PV -- is forced upon the two other parties. However, these parties do receive tangible value from solar generation.

Value to the utility and its ratepayers accrues from:

- <u>Transmission (wholesale) energy, 6-11 ¢/kWh:</u> energy generated locally by solar systems is energy that does not need to be purchased on the wholesale markets at the *Locational-based Marginal Pricing* (LMP). Perez & Hoff (2008) have shown that in New York State, the value of transmission energy avoided by locally delivered solar energy ranged from 6 to 11 cents per kWh, with the lower number applying to the well-interconnected western NY State area, and the higher number applying to the electrically congested New York City/Long Island area. This is more than the mean LMP in both cases (respectively 5 and 9 cents per kWh) because solar electricity naturally coincides with periods of high LMP.
- <u>Transmission capacity, 0-5 ¢/kWh:</u> because of demand/resource synergy discussed above, PV installations can deliver the equivalent of capacity, displacing the need to purchase this capacity elsewhere, e.g., via demand response (Perez & Hoff, 2008). In the above study, Perez et al. calculated the effective capacity credit of low penetration PV in metropolitan New York and showed that PV could reliably displace an annual demand response expense of $60 per installed solar kW, i.e., amounting to 4.5 cents per produced solar KWh[5].
- <u>Distribution energy (loss savings), 0-1 ¢/kWh</u>: distributed solar plants can be sited near the load within the distribution system – whether this system is radial or gridded – therefore, they can displace electrical losses incurred when energy transits from power plants to loads on distribution networks (this is in addition to transmission energy losses). This loss savings value is of course dependent upon the location and size of the solar resource relative to the load, and upon the specs of the distribution grid carrying power to the customer. A detailed site-specific study in the Austin Electric utility network (Hoff et al., 2006) showed that loss savings were worth in average 5-10% of energy generation. In the case of New York this would thus amount to 0.5-1 cent per kWh.
- <u>Distribution capacity, 0-3 ¢/kWh</u>: As with transmission capacity, distributed PV can deliver effective capacity at the feeder level when the feeder load is driven by industrial or commercial A/C, hence can reduce the wear and tear of the feeder's equipment – e.g., transformers -- as well as defer upgrades, particularly when the concerned distribution system experiences growth. As above, this distribution capacity value is highly dependent upon the feeder and

[4] Sometimes this entity may be replaced by a direct customer as is done in power purchase agreements (PPAs) however, because the utility grid is always the buffer/conduit of solar energy generation, PPA or not, the "big-picture" cost value equation remains the same.
[5] 1 kW of PV in New York State generates on ~ 1,350 KWh/year. Therefore $60 per kW per year amounts to 4.5 cents per kWh produced.

location of the solar resource and can vary from no value up to more than 3 cents per generated solar KWh (e.g., see Shugar & Hoff, 1993, Hoff et al., 1996, Wenger et al., 1996 and Hoff, 1997).

- Fuel price mitigation, 3-5 ¢/kWh: Solar energy production does not depend on commodities[6] whose prices fluctuate on short term scales and will likely escalate substantially over the long term. When considering figure 1, it is hard to imagine how the cost of the finite fuels underlying the current wholesale electrical generation will not be pressured up exponentially as the available pool of resources contracts and the demand from the new economies of the world accelerates. The cost of oil may be the most apparent, but all finite energy commodities, including coal, uranium and natural gas, tend to follow suit, as they are all subject to the same global energy demand contingencies. Even before the 2011 Middle East political disruptions, in a still sluggish economy, energy commodity prices had ramped up past their 2007 levels when the world economy was stronger (see fig. 3). Solar energy production represents a very low risk investment that will probably pan out well beyond a standard 30 year business cycle (Zweibel, 2010). In a study conducted for Austin Energy, Hoff et al. quantified the value of PV generation as a hedge against fluctuating natural gas prices (Hoff et al., 2006). They showed that the hedge value of a low risk generator such as PV can be assessed from two key inputs: (1) the price of the displaced finite energy over the life of the PV system as reflected by futures contracts, and (2) a risk-free discount rate[7] for each year of system operation. Focusing on the short term gas futures market (less than 5 years) of relevance to a utility company such as Austin Energy, and taking a stable outlook on gas prices beyond this horizon, they quantified the hedged value of PV at roughly 50% of current generation cost -- i.e., 3-5 cents per kWh in the context of this article, assuming that wholesale energy cost (see above) is representative of generation cost.

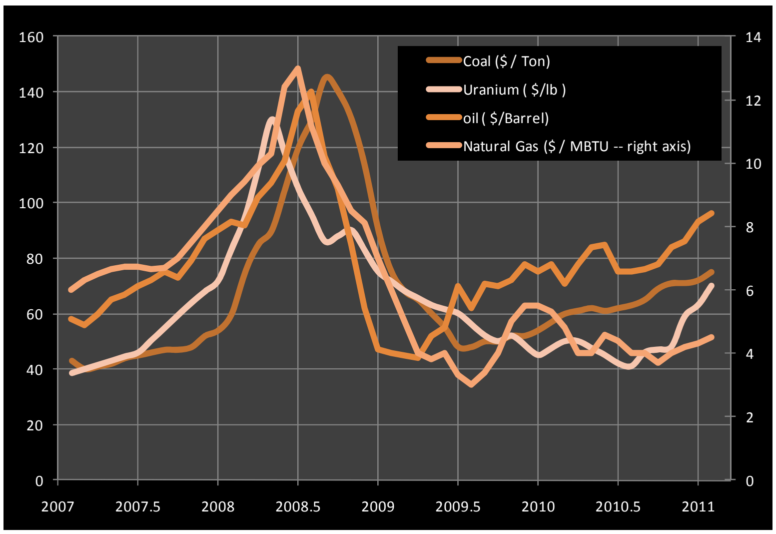

Figure 3: Finite energy commodity price trends 2007-2011

[6]Conventional energy is currently required for the manufacture of solar systems but, as argued above, this input will eventually be displaced because of the resource's breeder effect.

[7]Discount rates are used to measure the present decision-making weight of future expenses/revenues as a function of their distance to the present. A high discount rate minimizes the impact of future events such as fuel cost increases, while a low rate gives more weight to these events (e.g., see Ref 15). From an investor's stand point, the discount rate represents the return of a hypothetical investment against which to benchmark a particular venture. Low risk investments are characterized by low return rates (e.g., T-bills) while high risk ventures require high rates to attract prospective investors.

There are additional benefits that accrue to the society at large and its tax payers:

- Grid security enhancement, 2-3 ¢/kWh: because solar generation can be synergistic with peak demand in much of the US, the injection of solar energy near point of use can deliver effective capacity, and therefore reduce the risk of the power outages and rolling blackouts that are caused by high demand and resulting stresses on the transmission and distribution systems. The capacity value of PV accrues to the ratepayer as mentioned above. However, when the grid goes down, the resulting goods and business losses are not the utility's responsibility: society pays the price, via losses of goods and business, compounded impacts on the economy and taxes, insurance premiums, etc. The total cost of all power outages from all causes to the US economy has been estimated at $100 billion per year (Gellings & Yeager, 2004). Making the conservative assumption that a small fraction of these outages, say 5-10%, are the of the high-demand stress type that can be effectively mitigated by dispersed solar generation at a capacity penetration of 20%, it is straightforward to calculate that the value of each kWh generated by such a dispersed solar base would be worth around 3 cents per kWh to the New York tax payer (see appendix).
- Environment/health, 3-6 ¢/kWh: It is well established that the environmental footprint of solar generation (PV and CSP) is considerably smaller than that of the fossil fuel technologies generating most of our electricity (e.g., Fthenakis et al., 2008), displacing pollution associated with drilling/mining, and emissions. Utilities have to account for this environmental impact to some degree today, but this is still only largely a potential cost to them. Rate-based Solar Renewable Energy Credits (SRECs) markets that exist in some states as a means to meet Renewable Portfolio Standards (RPS) are a preliminary embodiment of including external costs, but they are largely driven more by politically-negotiated processes than by a reflection of inherent physical realities. The intrinsic physical value of displacing pollution is very real however: each solar kWh displaces an otherwise dirty kWh and commensurately mitigates several of the following factors: greenhouse gases, Sox/Nox emissions, mining degradations, ground water contamination, toxic releases and wastes, etc., which are all present or postponed costs to society. Several exhaustive studies emanating from such diverse sources as the nuclear industry or the medical community (Devezeaux, 2000, Epstein, 2011) estimate the environmental/health cost of 1 kWh generated by coal at 9-25 cents, while a [non-shale[8]] natural gas kWh has an environmental cost of 3-6 cents per kWh. Given New York's generation mix (15% coal, 29% natural gas), and ignoring the environmental costs associated with nuclear and hydropower, the environmental cost of a New York kWh is thus 2 to 6 cents per kWh. It is important to note however that the New York grid does not operate in a vacuum but operates within – and is sustained by -- a larger grid whose coal footprint is considerably larger (more than 45% coal in the US) with a corresponding cost of 5-12 cents per kWh. In the appendix, we show that pricing one single factor – the greenhouse gas CO_2 – delivers at a minimum 2 cents per solar generated PV kWh in New York and that an argument could be made to claim a much

[8] Shale natural gas is believed to have a higher environmental impact than conventional natural gas, including greenhouse gas emissions (Howarth, R., 2011).

higher number. Therefore taking a range of 3-6 cents per kWh to characterize the environmental value of each PV generated KWh is certainly a conservative range.

- Long Term Societal Value, 3-4 ¢/kWh: Beyond the commodity futures' 5-year fuel price mitigation hedge horizon of relevance to a utility company and worth 3-5 ¢/kWh (see above), a similar approach can be used to quantifying the long term finite fuel hedge value of solar generation, from a societal (i.e., taxpayer's) viewpoint in light of the physical realities underscored in figure 1. Prudently, and many would argue conservatively, assuming that long-term, finite, fuel-based generation costs will escalate to 150% in real terms by 2036, the 30-year insurance hedge of solar generation gauged against a low risk yearly discount rate equal the T-bill yield curve amounts to 4-7 cents per kWh (see appendix). Further, arguing the use of a lower "societal" discount rate (Tol et al., 2006) would place the hedge value of solar generation at 7-12 cents per kWh (see appendix). Taking a middle ground of 6-9 cents per kWh, the long term societal value of solar generation can thus be estimated at 3-4 cents per kWh (i.e., the difference between the societal hedge and short-term utility hedge already counted above).
- Economic growth, 3+ ¢/kWh: The German and Ontario experiences, where fast PV growth is occurring, show that solar energy sustains more jobs per kWh than conventional energy (Louw et al., 2010, Ban-Weiss et al., 2010, and see appendix). Job creation implies value to society in many ways, including increased tax revenues, reduced unemployment, and an increase in general confidence conducive to business development. Counting only tax revenue enhancement provides a tangible low estimate of solar energy's multifaceted economic growth value. In New York this low estimate amounts to nearly 3 cents per kWh, even under the extremely conservative, but thus far realistic, assumption that 80% of the manufacturing jobs would be either out-of-state or foreign (see appendix). The total economic growth value induced by solar deployment is not quantified as part of this article as it would depend on economic model choices and assumptions beyond the present scope. It is evident however, that the total value would be higher than the tax revenues enhancement component presently quantified.

Cost: It is important to recognize that there is also a cost associated with the deployment of solar generation on the power grid which accrues against the utility/rate payers. This cost represents the infrastructural and operational expense that will be necessary to manage the flow of non-controllable solar energy generation while continuing to reliably meet demand. A recent study by Perez et al. (2010) showed that in much of the US, this cost is negligible at low penetration and remains manageable for a solar capacity penetration of 30% (less than 5 cents per KWh in the greater New York area at that high penetration level). Up to this level of penetration, the infrastructural and operational expense would consist of localized (demand side) load management, storage and/or backup operations. At higher penetration, localized measures would quickly become too expensive and the infrastructure expense would consist of long distance continental interconnection of solar resources, such as considered in projects such as Desertec (Talal et al., 2009).

Bottom line

Table 1 summarizes the costs and values accruing to/against the solar developer, the utility/ratepayer and the society at large represented by its tax payers. The combined value of distributed solar generation to New York's rate and tax payers is estimated to be in the range of 15-41 cents per kWh. The upper bound of the range applies to solar systems located in the New York metro/Long Island area and the lower bound applies to very high solar penetration for systems in non-summer peaking areas of upstate New York. In effect, Table 1 shows that grid parity already exists in parts of New York -- and by extension in other parts of the country -- since the value delivered by solar generation exceeds its costs. This observation justifies the existence of (or requests for) incentives as a means to transfer value from those who benefit to those who invest.

TABLE 1

	Developer/Investor	Utility/Ratepayer	Society/Taxpayer
Distributed solar* system Cost	20-30 ¢/kWh		
Transmission Energy Value		6 to 11 ¢/kWh	
Transmission Capacity Value		0 to 5 ¢/kWh	
Distribution Energy Value		0 to 1 ¢/kWh	
Distribution Capacity Value		0 to 3 ¢/kWh	
Fuel Price Mitigation		3 to 5 ¢/kWh	
Solar Penetration Cost		0 to 5 ¢/kWh	
Grid Security Enhancement Value			2 to 3 ¢/kWh
Environment/health Value			3 to 6 ¢/kWh
Long-term Societal Value			3 to 4 ¢/kWh
Economic Growth Value			3+ ¢/kWh
TOTAL COST / VALUE	**20-30 ¢/kWh**	**15 to 41 ¢/kWh**	

Centralized solar has achievd a cost of 15-20 cents per kWh today. However less of the above value items would apply. The distribution value items would not apply. Transmission capacity, and grid security items would generally be towards the bottom of the above ranges, while penetration cost would be towards the top of the ranges because of the burden placed on transmission and the possible need for new transmission lines -- nevertheless, a value of 14-30 cents per kWh could be claimed.

Conservative estimate: It is important to stress that this result was arrived at while taking a conservative floor estimate for the determination of most benefits, and that a solid case could be made for higher numbers particularly in terms of environment, fuel hedge and business development value. In addition, several other likely benefits were not accounted for because deemed either too indirect or too controversial. Some of these unaccounted value adders are worth a brief qualitative mention:

- No value was claimed beyond 30 year life cycle operation for solar systems, although the likelihood of much longer quasi-free operation is high (Zweibel, 2010)
- The positive impact on international tensions and the reduction of military expense to secure ever more limited sources of energy and increasing environmental disruptions was not quantified.
- The fact dispersed solar generation creates the basis for a strategically more secure grid than the current "hub and spoke" power grid in an age of growing terrorism and global disruptions concerns was not quantified.
- Economic growth impact was not quantified beyond tax revenue enhancement.
- The question of government subsidies awarded to current finite energy sources (i.e., displaceable taxpayers' expense) was not addressed.

Tax payer vs. rate payer: Unlike conventional electricity generation, the value of solar energy accrues to two parties. This may explain why the perception of value is not as evident as the above numbers would suggest. In particular, public utility commissions are focused on defending the interests of utility ratepayers, and if only the utility/ratepayers' value is considered, the case for solar is marginal at best (4-25 cents of value per kWh). However, focusing on the ratepayers' interest alone ignores the fact that ratepayers and the taxpayers are one and the same. Supporting one to the exclusion of the other ends up penalizing the whole person.

Tangible Value: Another reason why perception of value is not evident is because those who pay for the costs that solar would displace are often not aware of these costs. For the ratepayers items (energy & capacity), the tradeoff is obvious, but not so for the other items. However, costs are incurred in many indirect, diffuse, but nevertheless very real ways -- e.g., insurance premiums, higher taxes to mitigate impacts, deferred costs (environment, future replacements of short term infrastructures, energy increases), and missed economic growth opportunities.

Stable value: One of the characteristics of the solar resource is its ubiquity and stability: it is present everywhere and does not vary much from one year to the next although short term variability (clouds, weather, seasons) often tend to overshadow this perception (Hoff & Perez, 2011). Similarly, the value delivered by solar generators is very stable and predictable.

The two primary factors that do determine value per kWh produced are (1) location and (2) solar penetration[9]. Location is important because the value delivered by solar generation in terms of transmission and distribution energy and capacity, as well as blackout protection is location-dependent: a system in winter-peaking rural upstate New York will deliver less value than a system in a growing commercial sector of Long island. Penetration is important, because some of the benefits, in particular the capacity benefits, tend to erode with penetration; and the cost to locally mitigate this erosion increases (see, Perez et al., 2010).

[9] Technology and solar system specs (e.g., array geometry) are also relevant: highest value in NYC would be for systems delivering near maximum output at 4 PM – i.e., fixed tilt, oriented SW.

Therefore, if one were to design an effective system to provide solar generation with the fair value it deserves from rate/taxpayers, it would have to be a stable and predictable system that accounts for the location and penetration factors. Auction-based SRECS could be engineered to meet these criteria, but a smart value-based FIT that is stable and tunable by design, appears to be a more logical match[10].

Very high penetration solar?

Some of the benefits identified in this article apply roughly up to 30% solar penetration. This already represents a 375 GW high-value solar deployment opportunity for the US -- a very large prospective market with a large national payoff; but what happens beyond that point? At very high penetration, the issues facing solar would become similar to wind generation's issues, albeit with a much smaller and more [aesthetically] acceptable footprint. Many of the value items mentioned above would remain (long-term, wholesale energy, fuel price hedge, environment) while others would not (regional and localized capacity). The solutions envisaged today, including large scale storage and continental/international interconnections to mitigate/eliminate weather, seasons and daily variability, are currently on the drawing board (e.g., Perez, 2011, Lorec, 2010, Talal et al., 2009).

Final Word: The Value of Solar

It is clear that some possibly large value of solar energy is missed by traditional analysis. Most of us recognize this in our perception of solar as more sustainable than traditional energy sources. The purpose of this article is to begin the quantification of this value so that we can better come to terms with the difficult investments we may make in solar despite its apparent grid parity gap with conventional energy. Society gains back the extra we pay for solar. It gains it back in a healthier, more sustainable world, economically, environmentally, and in terms of energy security.

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[10] It is important to state that we are talking here about a value-based FIT, where the FIT is the instrument to transfer value from those who benefit to those who invest. This is unlike FIT implementations in other parts of the world, notably in Spain, where FITs were primarily designed to provide a boost to solar business development.

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APPENDIX

Grid security enhancement: 20% US penetration would represent roughly 250 GW of solar generating capacity. Using a New York-representative production level of 1,350 kWh per KW per year, the solar production would thus amount to 375 billion kWh/year, worth $5-10 billions in outage prevention value under the conservative assumption selected here, amounting to 2-3 cents per kWh.

Estimating solar CO2 mitigation value: The value of solar generation towards CO2 displacement may be gauged using several different approaches.

(1) By starting from the carbon tax /cap-and-trade penalty levels that are being envisaged today -- at $30-40/ton of CO2 (e.g., Nordhaus, 2008). Given the energy generation mix in a state like New York, each locally displaced kWh (i.e., solar generated) would remove 500-600 grams of CO2, and thus would be worth nearly 2 cents.
(2) By starting from the figure of 1.5% of world GDP per year advanced by the IPCC as the minimum necessary to prevent a runaway climate change (IPCC, 2007). 1.5% of GDP represents $900 billions. Global CO2 emissions are ~ 30 billions tons. Displacing 2/3rds of these emissions to bring us back to a 1960's level, and again, and taking New York's current generation mix as an emission reference amounts to a value of 3 cents for each kWh displaced by solar generation.
(3) Also by starting from the 1.5% GDP figure, but recognizing that solutions to displace green house gases need to be primed and encouraged before they can be effective and reach their mitigation objectives. If we assume, very conservatively, that solar energy represents only 10% of the global

warming solution[11] and should thus be fully encouraged to the tune of 0.15% GDP, then given the current installed solar capacity of 20-30 GW and the current installation rate approaching 20 GW annually worldwide, encouraging the development of solar would amount to distributing ~ 150 cents per kWh to each existing and new solar system. This value would then decrease gradually over the years as the installed solar capacity grows, ultimately reaching a value commensurate with points (1) and (2).

Long term fossil fuel price mitigation/ societal value: The long term fuel price mitigation value of a solar kWh is the present value of the difference between what one would have to pay for energy escalating over the life of the solar system and what one would have to pay if energy cost remained constant. Under the assumptions of this article – 150% increase of finite energy in 25 years and a present value assessed using a yearly low risk discount rate equal to the T-Bill yield curve, this difference is about 60%. Hence, taking the solar-coincident wholesale generation cost of 6-11 cents as gauge of current energy production cost, the long term mitigation value of a solar kWh is 4 to 7 cents per kWh. Interestingly, this estimate is commensurate with the International Energy Agency's contention that a CO_2 tax worth $175 per ton should be necessary to encourage the development of renewables and displace fossil fuel depletion (Tanaka, 2010) while mitigating their depletion and keeping their long term prices near the present range. Based on the New York's generation mix, $175 per ton amounts to 9-10 cents per kWh. It is important to remark that alternative and less conservative approaches can be considered and defended to determine the value of the low risk/long life solar investment to society. In particular, comparing the difference between solar savings assessed with a business as usual discount rate and a societal discount rate provides a measure of the long term society's benefit that is not taken into account using short-term oriented business as usual approaches. Even when using a very modest business-as-usual discount rate of 7%, the present value of conventional generation appears reasonable: future operating costs increase but do not matter much because they are discounted – at 7% the weight of expense/revenue 30 years into the future in terms of present-decision making is discounted by nearly 85% (at 10% discount rate, the weight would be discounted by over 95%). However, this practice heavily penalizes future generations. It also penalizes solar: Solar power plants are upfront-loaded with relatively high installation costs, and the quasi free energy they will produce for the long term is not valued as it should, since it is heavily discounted. Nevertheless, the intergenerational, long-term societal value of present-day solar installation is very real. As a remedy to this dichotomy, "societal" discount rates are sometimes used by governments to justify investments which are deemed appropriate for the long term well being of the society (Tol et al., 2006) – solar generation clearly fits this definition. Comparing a 2% societal discount rate and a 7% business-as-usual rate and calculating the value of solar as the present difference of the two alternatives, the societal hedge value of solar energy generation would be 7-12 cents per kWh.

Tax revenue enhancement: The German experience indicates that each MW of PV installed implies 10-15 module manufacturing jobs, 8-15 installation jobs and 0.3 maintenance jobs, as confirmed by recent numbers from Ontario (Louw et al., 2010, Peters, 2010). Solar jobs represent more than ten times

[11] Given the potentials shown in Figure 1, it is probably much higher than that. A higher percentage would yield a higher solar value.

conventional energy jobs per unit of energy produced – i.e., ten new solar jobs would only displace one conventional energy job.

Although these numbers may be skewed by the fact that a still expensive and nascent solar industry is overly job-intensive, a quick reality check reveals that the relative higher price of the solar technology today also implies a higher job density: the necessary 20-30 c/kWh solar revenue stream underlying discussions in this article corresponds to a turnkey cost of $4 million per solar MW. In the case of PV, this cost can be assumed to divide evenly between technology (modules/inverters) and system installation (construction, structures) representing $2M per MW for each. Conservatively assuming that 50% of technology and 75% of installation costs are directly traceable to solar-related jobs and assuming a job+overhead rate of $100K/year, this simple reality check yields 10 manufacturing and 15 construction-related jobs. Demonstrating that the solar job density of the solar resource is higher than that of conventional energy is also straightforward to ascertain from first principles: comparing a $4/Watt turnkey solar system producing 1,500 kWh/KW/year to a $1/Watt turnkey CCGT producing 5,000 kWh/kW/year, and assuming that the job density per turnkey dollar is the same in both cases, yields 13 times more jobs for the solar option per kWh generated.

As the turnkey cost of solar systems expectedly goes down, the job density will of course be reduced, but, more importantly, so will the necessary breakeven revenue stream.

For now, given the premise of this paper -- a required solar energy revenue stream of 20-30 cents per solar kWh -- let us calculate the value that society receives under this assumption.

The following assumptions are used for this calculation:

- Each new solar MW results in 17 new jobs. There are 2 new manufacturing jobs (it is assumed that 80% of the manufacturing jobs are foreign - and do not generate any federal or state tax revenue) and there are 15 new installation jobs.
- Solar systems are replaced after 30 years, so the amount of jobs corresponding to each installed MW is the present value of a 30 year job replacement stream. With a discount rate of 7%, 17 jobs times an annualized factor of 0.08 translates to 1.36 jobs per MW per year.
- System maintenance-related jobs amount to 0.3 jobs per MW[12] (German experience)
- The total amount of sustained jobs per MW is therefore equal to 1.66.
- Assuming that ten solar jobs displace one conventional energy job, the net sustainable new jobs per solar MW are therefore equal to 1.49 (90% of 1.66).
- The salary for each solar job is $70K/year.
- Current federal and New York tax rates for an employee making $70,000 per year pays a combined effective income tax rate of 23%.
- 1 MW of PV generates 1,500,000 kWh per year.

[12] This corresponds to a very reasonable O&M rate of 0.5% under the assumptions of this study.

- Finally, direct job creation translates to the additional creation of indirect jobs. It is conservatively assumed that the indirect multiplier equals 1.7 (i.e. every solar job has an indirect effect in the economy of creating an additional 0.7 jobs).[13]

Putting the pieces together, the tax benefit from job creation equals about 3 cents per kWh.

[13] Indirect base multipliers are used to estimate the local jobs not related to the considered job source (here solar energy) but created indirectly by the new revenues emanating from the new [solar] jobs.

REVERSE POWER FLOW

How Solar+Batteries Shift Electric Grid Decision Making from Utilities to Consumers

John Farrell

July 2018

ILSR INSTITUTE FOR Local Self-Reliance

EXECUTIVE SUMMARY

For 100 years, most decisions about the U.S. electric grid have been made at the top by electric utilities, public regulators, and grid operators. That era has ended.

Small-scale solar has provided one-fifth of new power plant capacity in each of the last four quarters, and over 10 percent in the past five years. One in 5 new California customers of the nation's largest residential solar company are adding energy storage to their solar arrays. Economic defection––when electricity customers produce most of their own electricity––is not only possible, but rapidly becoming cost-effective. As the flow of power on the grid has shifted one-way to two-way, so has the power to shape the electric grid's future.

The shift of power into customer hands is already having three, unintended consequences:

1. Legacy, baseload power plants are becoming financially inferior to clean energy competitors.
2. Electricity sales have stagnated as customers reduce use and produce electricity for themselves.
3. Communities are reaping greater economic rewards from power generation, as electric customers, individually and collectively, produce more locally.

Almost no utility or utility regulator is adequately planning for this fundamental shift. Dozens of utilities across the country have proposed new gas-powered generation that has little chance of remaining online through the end of its economic life due to stiff competition from solar-plus-storage. Some have been approved despite substantial gaps in the economic analysis.

Utility have also made reactionary moves, or made gestures inadequate to address the magnitude of system change. **There tend to be three inadequate utility responses to the reversed flow of decision-making power**:

1. Utilities have damaged their reputations by resisting customer interest in distributed energy resources, sending lobbyists to preempt or curtail policies that reward customer-sited and customer-owned power generation.
2. Utility investments in large-scale renewable energy have addressed environmental concerns, but these low-cost power purchases have not delivered reduce electricity prices for end users nor assuaged the interest in over 70 cities of reaching 100% renewable electricity more rapidly.
3. Utilities have deployed utility-owned distributed energy resources, but in ways that withhold much of the economic or financial benefit from customers.

Regulators and state legislators cannot expect incumbent utilities to respond adequately because the rise of economical solar-plus-storage challenges the century-old assumption of a natural electricity distribution monopoly. Instead, electricity market rules should facilitate fair compensation for distributed energy resources and market participants where technology already allows them to compete.

This report details recommendations for changing utility oversight and modifying electricity markets to transition from the dying utility distribution monopoly to a vibrant, democratic energy system where customers have the opportunity to choose distributed energy options that benefit themselves and the greater grid.

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John Farrell, jfarrell@ilsr.org

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Since 1974, the Institute for Local Self-Reliance (ILSR) has worked with citizen groups, governments and private businesses to extract the maximum value from local resources.

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SOLAR + STORAGE COMES TO MARKET

Utilities don't have time to prepare for a future with economical, distributed energy storage because it's on the doorstep. In 2016, the first hints of a storage-driven transformation of the electricity business came as a "postcard from the future" in Hawaii. Sunrun offered their Brightbox, a combination solar-plus-battery product with a price of 19 cents per kWh, almost 50 percent cheaper than grid electricity. Sunrun began offering its Brightbox service in California in December 2016. By 2018, 1 in 5 new residential Sunrun solar customers in California were choosing to add storage.

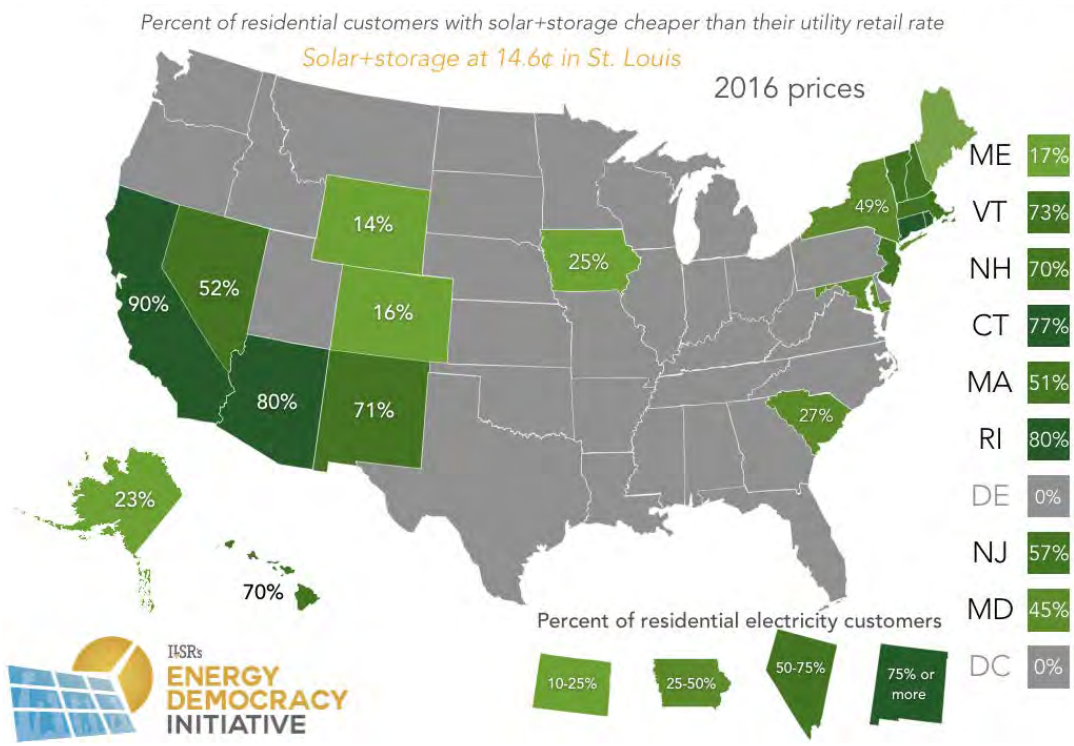
These early adopter states just scratch the surface of the competitive landscape.

Based on a proxy measure of electricity prices, the combination of on-site solar and energy storage can already compete with the price of serving nearly 26 million residential electricity customers in 19 states.1 The ILSR model compares customers installing a 7-kilowatt-hour Tesla Powerwall and a 5-kilowatt solar array to utility electricity prices, with the percentage of each state's customers who can generate cheaper power themselves shown on each state:2

[1] Average revenue per kilowatt-hour (not the same as electricity rates, and not factoring rate design elements such as fixed charges). Rate structures can matter a lot. One customer with a $100 per month electric bill may have a $40 fixed charge regardless of their energy use (or use of solar and energy storage) while another with the same total monthly cost may have a fixed charge as low as $10 (allowing solar and storage to do much more to reduce their energy bill).

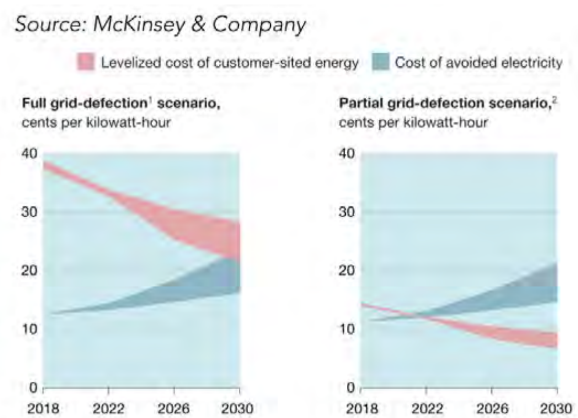
[2] Using NREL System Advisor Model, default PVWatts model with property tax removed, 10 year loan term instead of 25 years, 5% interest rate, real discount rate of 2.5%. Costs include a 7-kWh Powerwall ($3,000) plus 5-kW solar array ($17,500) for a total cost of $20,500.

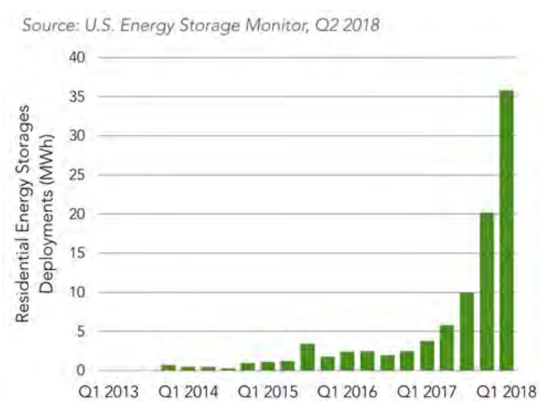
FIGURE 1. WHERE SOLAR + STORAGE WORKS NOW



ILSR's analysis isn't alone. According to McKinsey, within three years an Arizona electric customer would be able to serve 80 to 90% of their electricity needs with solar and battery storage, at a lower price than by buying electricity from the utility company.

FIGURE 2. RAPIDLY FALLING BATTERY COSTS; A SURGE IN RESIDENTIAL ENERGY STORAGE





Storage prices have fallen remarkably fast, as illustrated by the remarkable price declines for battery storage technology in the last three years (measured in the cost of energy averaged over the expected life of the battery).

Customers have responded to the falling costs, with a surge in new installations of residential energy storage in the past year.

Although few residential customers would find it practical, full grid defection--or cutting the cord to the grid—could be at price parity within 10 years.

Business customers managing larger facilities have it even better. A 2017 analysis of solar and storage for affordable housing facilities in Chicago found that adding energy storage reduces the payback for solar from 20 years to 6 years by helping manage facility demand charges.

A broader report, also from 2017, suggests that commercial storage (alone) could be economic for one in four commercial electricity customers nationwide. Many commercial electricity customers have a demand charge, a portion of the electric bill based on a one-hour window of peak energy use each month, and representing half of many businesses' bills.[3] Solar energy alone is insufficient to avoid this charge, but a relatively small battery can lower that peak. The following map from the report shows particularly robust opportunity in the Southwest (coinciding with excellent solar resources), but also in the Upper Midwest, West Virginia, and much of New England.

FIGURE 3. BROAD OPPORTUNITY TO AVOID DEMAND CHARGES

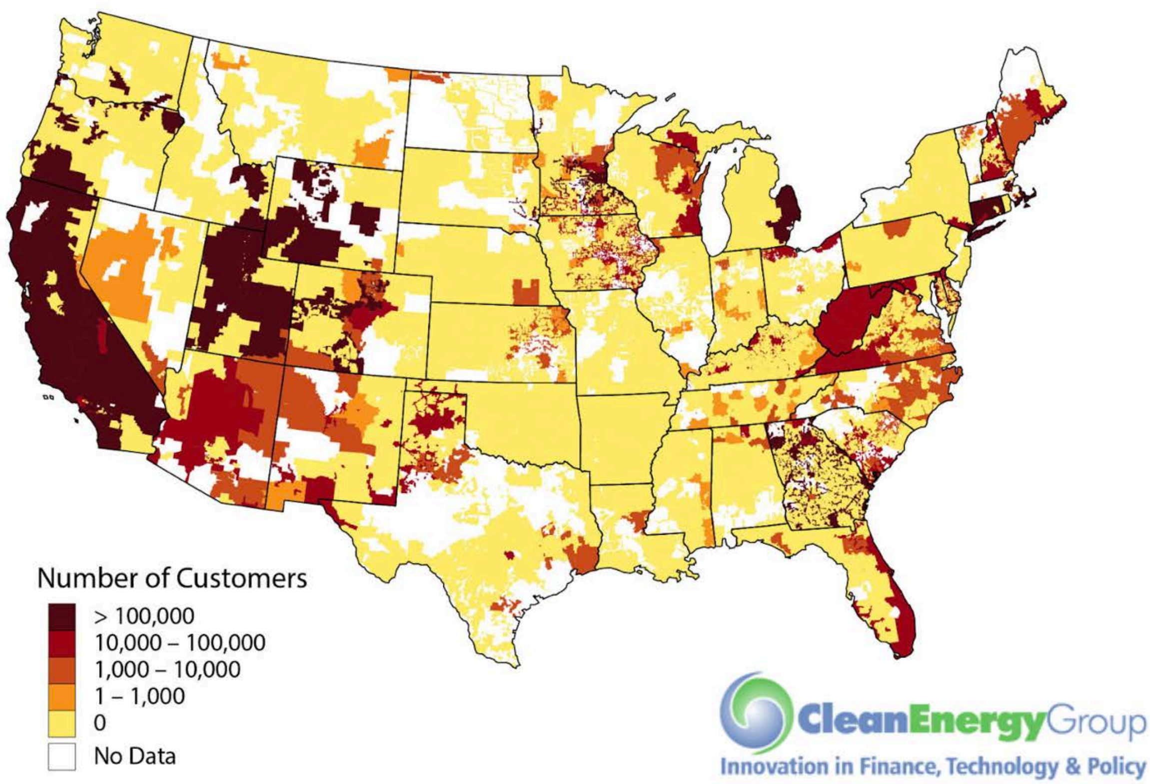
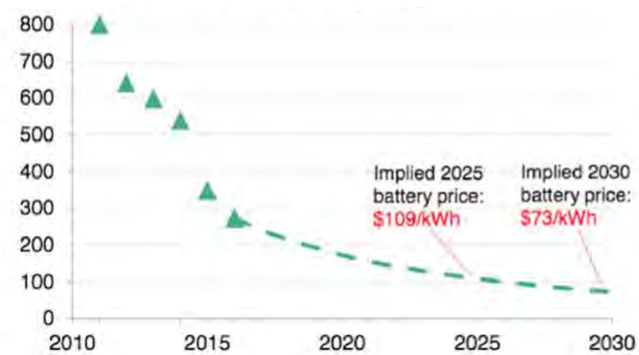


Figure 1. Number of commercial electricity customers who can subscribe to tariffs with demand charges in excess of $15/kW.

[3] Demand charges may be a poor reflection of actual grid costs if utilities assess fees on "non-coincident demand," or energy use that does not coincide with the system-wide period of highest energy use.

The prospects for solar+storage are even more remarkable in the near future. The following chart shows forecast steep declines in battery costs--by half in the next five years, and by two-thirds by 2030.

FIGURE 4. ROSY BATTERY PRICE FORECASTS

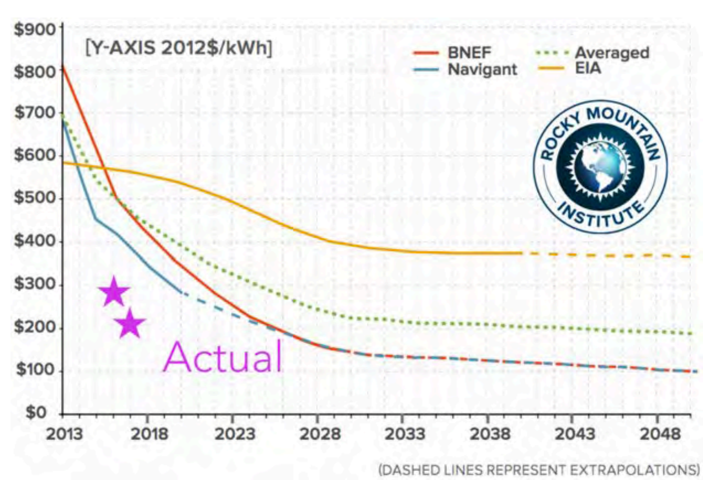


Source: Bloomberg New Energy Finance

Batteries aren't just getting cheaper, they're doing so at a rate far outstripping predictions. A 2014 report from Rocky Mountain Institute featured several battery price projections, including one from Bloomberg. At the time, Bloomberg projected batteries crossing the $300 per kilowatt-hour threshold in 2022. Three years later, Bloomberg showed that batteries reached that price point in 2016; by 2017, battery pack prices had fallen another 30%.

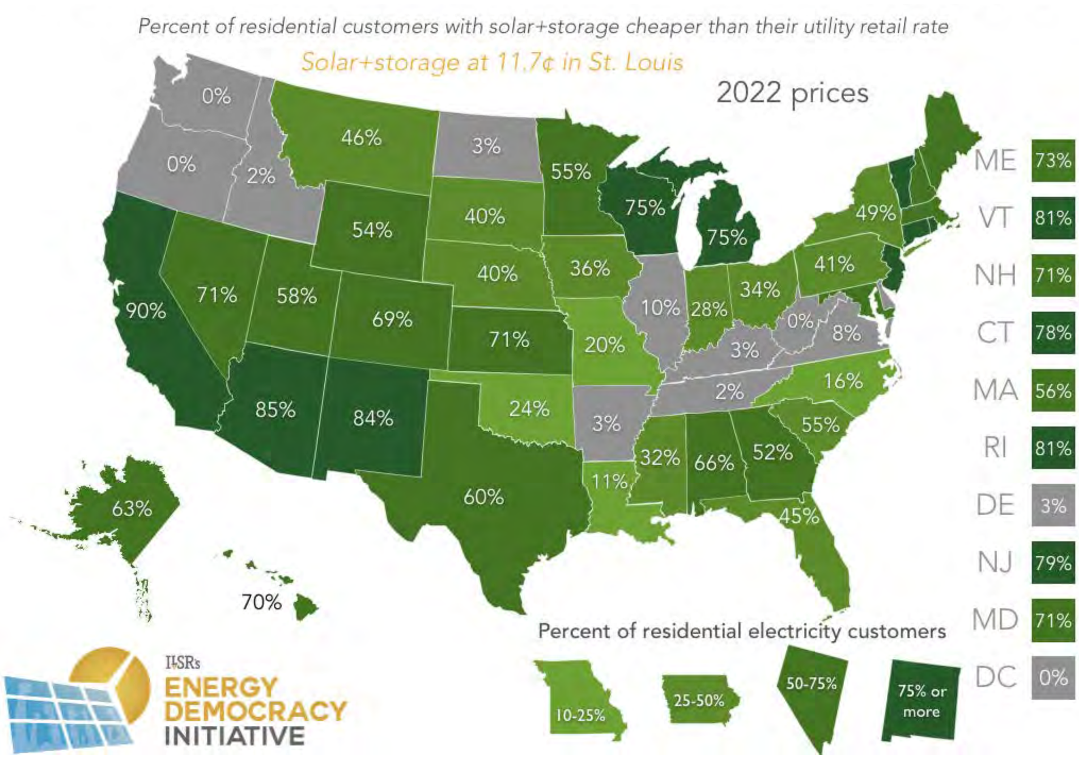
How do rapidly falling costs change the calculus of solar plus storage?

FIGURE 5. BATTERY PRICES DROP FASTER THAN PROJECTIONS



If the Powerwall cost forecast by GreenTech Media comes true--halving the cost--and solar continues a modest 3-4% reduction in the cost per year, in 2022 nearly half of all residential electricity customers (in all but 4 states) will be able to get electricity as affordably from their rooftop and a battery than from the utility company.[4] The following map provides a stunning contrast to the one based on today's prices (page 3).

FIGURE 6. WHERE SOLAR + STORAGE WORKS SOON



Storage costs and forecasts are a clear warning to utilities that customers will be able to leverage batteries (and solar) for much more control of their energy bills than ever before.

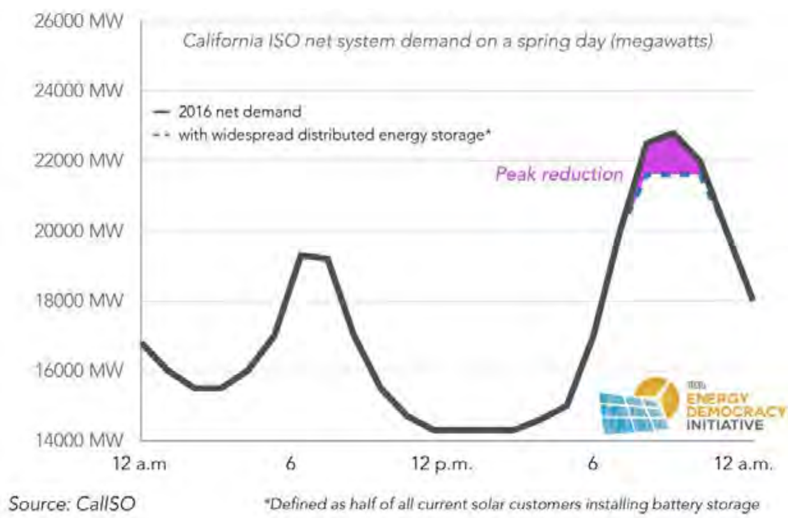
[4] *As with the first map, based on average residential utility revenue per customer, and not factoring in rate structures*. A 5-kilowatt solar array combined with a 7-kilowatt-hour battery will cost $15,800, a levelized cost of 11.7¢ per kilowatt-hour. Calculated using NREL System Advisor Model, default PVWatts model with property tax removed, 10 year loan term instead of 25 years, real discount rate of 2.5%. Costs include a 7-kWh Powerwall ($1500) plus 5-kW solar array ($14,300) for a total cost of $15,800.

Grid Implications

Energy storage increases the value of rooftop solar installations to customers-- providing resiliency to utility outages and allowing them to avoid new utility fees. It’s no wonder that, as noted earlier, 1 in 5 Sunrun solar customers in California opted for storage in 2017.

The collective decision of California customers also offers valuable grid services. For example, California residents and businesses already host nearly 6 gigawatts of solar. If half of these existing solar households added a Tesla Powerwall (with 7 kilowatt-hours of storage and a maximum draw of 2 kilowatts) and half of solar businesses added a 50-kilowatt Tesla Powerpack (with 210 kilowatt-hours of storage), California electric customers could provide 1.19 gigawatts of power for 3.5 hours. That’s enough to significantly reduce the state’s evening grid peak during its full duration. The chart below illustrates:

FIGURE 7. WIDESPREAD DISTRIBUTED STORAGE COULD CUT CALIFORNIA'S PEAK



Electric cars, adopted for their ability to cut the cost of car ownership, could do far more. If connected to the grid in a way allowing for their batteries to be tapped, "The 1.5 million electric cars California expects by 2025 would have a maximum energy demand of about 7,000 megawatts, more than double the capacity needed to substantially smooth the current afternoon rise in peak energy demand."

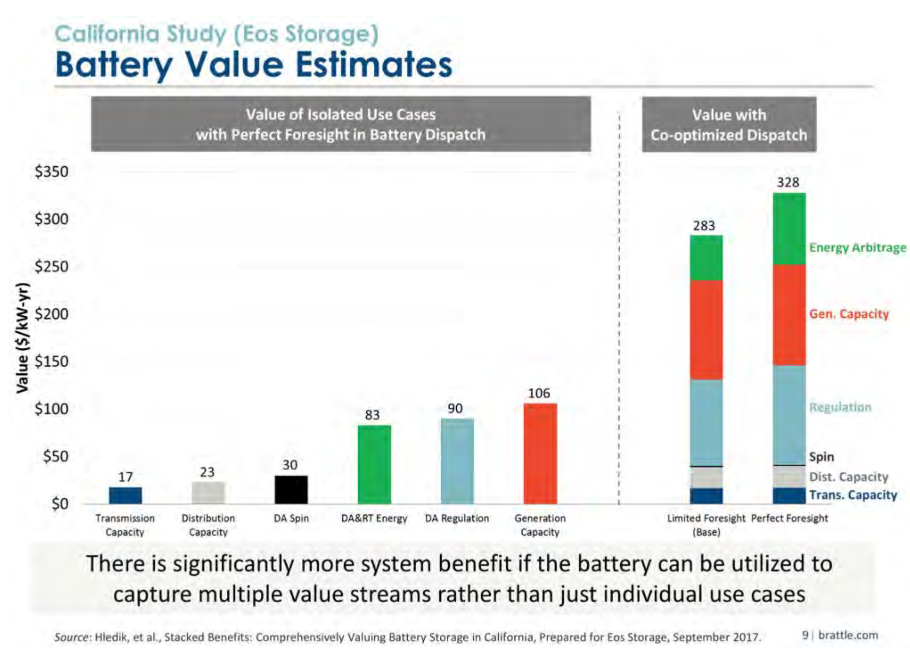
Batteries can also supplant fossil fuel generators in helping stabilize the grid. An electric grid requires a delicate balancing act of supply and demand, every second of every day. One technological advantage of battery storage over most other grid resources is that batteries act fast, nearly instantaneous. Batteries supply short bursts of power to keep the grid's voltage and frequency steady at a lower cost than big power plants and turbines operating on standby.[5]

[5] A gas power plant on standby will be burning fuel, heating water, and making steam to spin its turbines but not be sending electricity to the grid. In other words, it's incurring almost all operation costs but without generating any revenue.

In the U.S. Mid-Atlantic region, the grid operator PJM requested such "ancillary services" that included markets for frequency and voltage regulation markets for smaller producers (a minimum size of 100 kilowatts). The lucrative prices--$40 to 50 per megawatt-hour--and low threshold for participation supported development of dozens of energy storage projects. Several hundred megawatts of battery storage entered the PJM market in response to the opportunity, many doing double-duty by providing crucial services to their owners, not just the grid.

Changes in market rules and reduced costs for gas competitors have since reduced the financial opportunity in the Mid-Atlantic, but batteries can still provide value to their customers and the grid in other ways. A study for the

FIGURE 8. BATTERIES OFFER GRID VALUE IN SEVERAL WAYS



California market showed no fewer than six value streams for battery operators aiding the grid, as illustrated on the previous page. The first two bars represent the value of additional capacity freed up on the transmission and distributed system by storing excess local energy. The third bar is the ability to provide reserve energy on a moment's notice, and the fourth represents the value of actually delivering that energy. The fifth bar shows the value of helping regulate the grid's voltage and frequency to keep it stable. The final bar represents the reduced need for power generation capacity that can be supplied by storage.

In addition to the Mid-Atlantic and California examples, markets are likely to open in other regions soon. A 2017 directive from the Federal Energy Regulatory Commission requires all grid operators to adopt rules recognizing the many values of energy storage and allowing firms to aggregate many small storage projects into large ones.

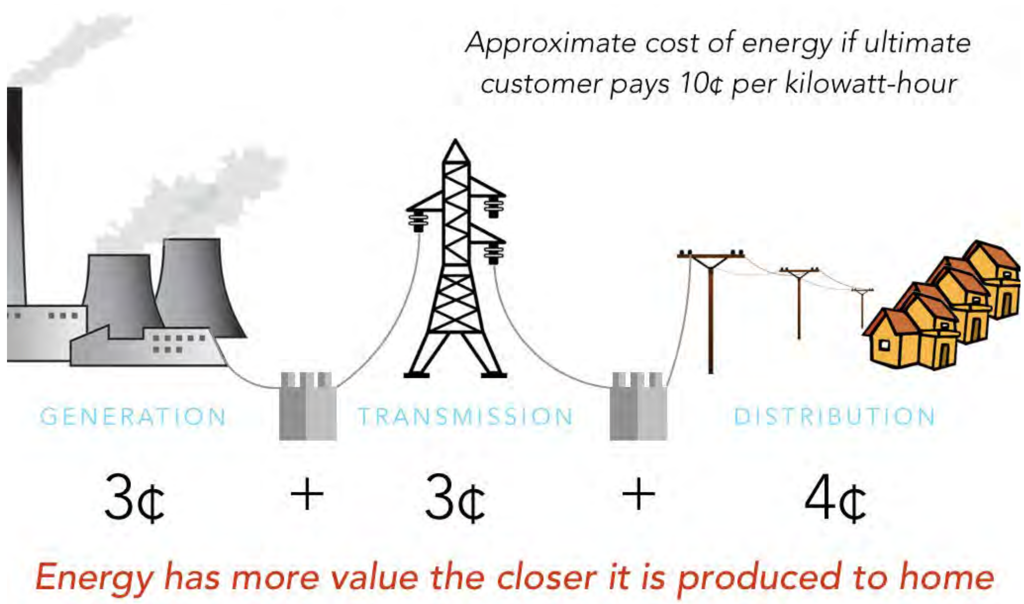
If customer-sited distributed energy resources can access the financial compensation for their value, customers will likely take opportunities to reduce their energy costs through greater self-reliance. The implication for utilities is clear: be wary of making substantial, centralized infrastructure investments when decentralized technology has significant advantages, can be online sooner, with decisions made by folks outside your boardroom. The following section explores the implications of the competition from distributed energy resources.

AN INADVERTENT TRIPLE THREAT

Locally generated power from solar-plus-storage can undercut the century old utility model--centralized power plants sending electricity long distances over high voltage transmission lines--in three ways.

First, it has higher value. If the cost of delivering electricity to the ultimate customer is 10 cents per kilowatt-hour, a typical utility's costs are split between generation (about 3 cents), transmission (about 3 cents), and distribution (about 4 cents). Power produced at the power plant is worth far less than energy delivered into the customer's home or business. The following graphic offers an approximation of the typical utility's cost structure for delivered electricity.

FIGURE 9. COST OF DELIVERED ELECTRICITY BY LOCATION



Second, distributed energy resources can be deployed more quickly, in months rather than years, and the price often decreases in the time it takes to plan and finance a centralized power plant.

Third and most striking, the decision to deploy distributed resources is relatively independent of centralized power plant development. Utilities don't do distribution planning and customers don't consult utilities when installed distributed energy resources, despite clear effects on one another.

California provides a powerful illustration of how the combination of thousands of individual actions presents the collective triple threat. Over 700,000 solar arrays in California were installed because of simple economics--rooftop energy generation from sunshine costs customers less than utility power and customers and third party marketers were given a chance to access that value. Most of these arrays were built in the last 10 years, less than a typical utility's 15-year resource plan and in much less than the average power plant lifespan (40 years or more). Unused to competition or planning on such a short timescale, California utilities were caught flat-footed.

Death of "Baseload" and Fossil Fuel Power Plants

The economics of coal and nuclear power plants have for years relied on operating at high capacities around the clock. But with energy efficiency and distributed energy lowering demand; utility-scale solar and wind cutting into sales with cheaper, cleaner electricity; and now, with the advent of energy storage, these power plants struggle to compete. Utilities operating non-competitive plants in Ohio and Illinois have sought subsidies to keep these "baseload" plants operating. Some power companies have even lobbied the federal government to provide a backdoor subsidy by rewarding power plants with on-site fuel storage (a backhanded swipe at wind and solar that could misfire as these systems add battery storage). The competitive threat also applies to new power plants, where the rapidly falling costs of distributed energy make slow-to-build, long-term investments very risky.

A Nuclear Plant Retires

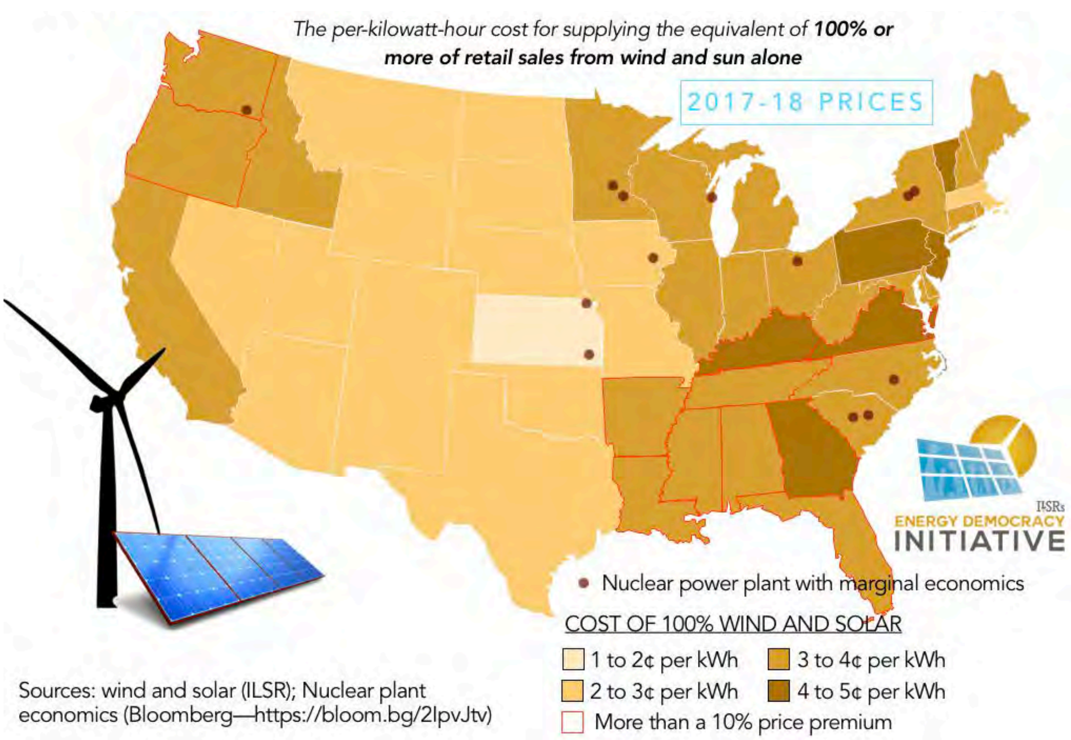
The Diablo Canyon nuclear power plant, in San Luis Obispo County, Calif., is a prime example of threat to incumbent power plants and the potential for innovative solutions.

Completed in 1985 and 1986, the Diablo Canyon facility provides close to 9% of the electricity used in California. Operating licenses for the two reactors expire in 2024 and 2025, with the utility seeking license renewals. However, as the state's electricity market has become increasingly dominated by low-cost wind and solar resources (with very low operating costs), the nuclear plant's electricity was no longer competitive (five other nuclear reactors were shuttered nationwide in 2013 and 2014 alone). The combination of poor revenue outlook and pressure from environmental organizations led the utility to a settlement agreement in 2016. Per the proposed settlement, the utility would retire both units and replace their capacity with "a combination of renewable energy, efficiency and energy storage."

Unfortunately, the settlement agreement was undercut by an early-2018 order from the Public Utilities Commission. Commissioners removed community transition funds (focused on replacing lost property tax revenue) and employee retention; instead, the state legislature has taken up these issues. The Commission order also deferred the replacement power decision to the utility's next resource planning process. It's an illustration of how siloed decision-making in the electricity business makes it hard to plan for an orderly retirement of legacy power plants.

The following map provides some indication that this case study is more than a California problem for legacy power plant owners. It shows the cost of a 100% electricity supply overlaid with nuclear power plants Bloomberg has identified as having marginal economics.[6] In today's grid, with significant reserves of on-demand power plant capacity, solar and wind can entirely replace a retiring baseload power plant like Diablo Canyon.

FIGURE 10. WIND AND SOLAR PROVIDE AFFORDABLE REPLACEMENT POWER



[6] 100% electricity supply cost calculated by ILSR using Level10's PPA 2018 PPA report and Berkeley Labs 2016 Utility-Scale Solar report for solar costs, and Energy Information Administration data on average wind capacity factors to estimate wind costs. In general, two-thirds of electricity was presumed to come the cheaper of the wind and solar resource. This annual average cost does not account for daily, monthly, or seasonal resource variation.

The stunning result is that renewable replacement power is very low priced, at 3 to 4 cents per kilowatt hour or lower, in every state with a nuclear power plant operating on the margins. Replacement power from new renewables is likely cheaper than most existing generation in all but eleven states (bordered in red).[7] Even in those states, the difference is less than a penny per kilowatt-hour.

As the grid shifts toward renewables, wind and solar energy alone won't suffice to provide round-the-clock supply. But as subsequent sections of this report reveal, the past and future cost declines for storage make renewables a potent threat to existing (and planned) centralized power plants.

A Gas Plant Evaporates

In 2015, NRG Energy asked California state regulators to certify the need for a new 262-megawatt gas power plant in response to a request from Southern California Edison. The Johnson City, Calif., combustion turbine "peaking" power plant was meant to replace existing capacity from power plants that could no longer comply with new state water use rules. By early 2018, it looked like the power plant proposal was dead. What happened in those three years?

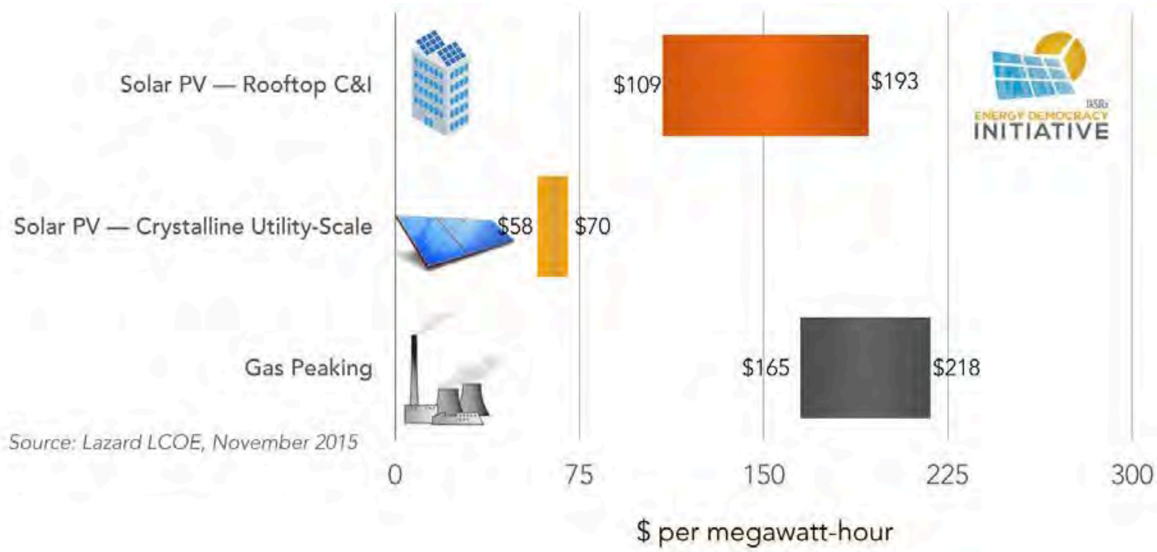
In short, a dramatic drop in the cost of storage.

Even at the time of its proposal, the Johnson City gas plant was up against low-cost renewable energy, as was the Diablo Canyon nuclear plant. This chart, from the 2015 annual cost of energy analysis by investment bank Lazard, shows that solar PV was much cheaper than a gas peaking plant like the one proposed by NRG. Peaking plants run infrequently but are used to fill in power

[7] *Using a proxy of 30% of the average residential retail revenue per customer. See earlier chart on Cost of Delivered Electricity.*

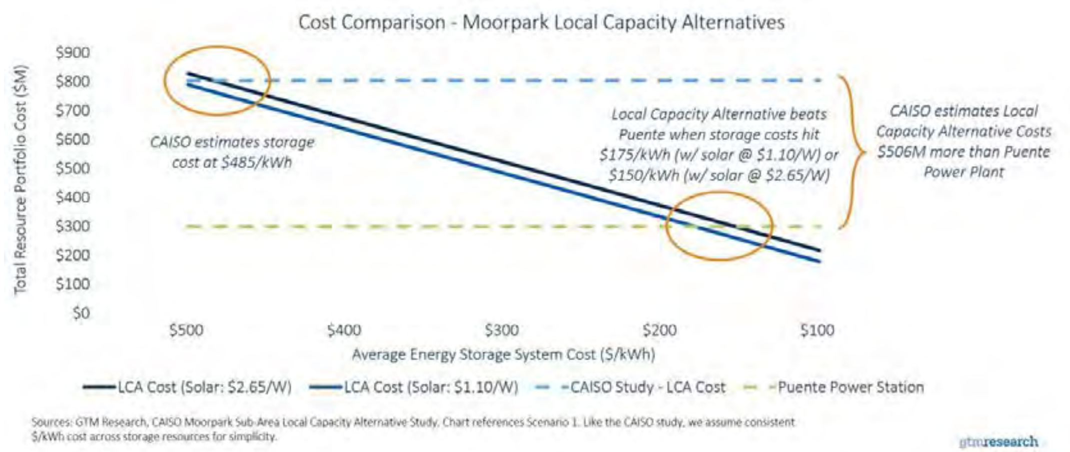
supply during periods of high demand. Even rooftop scale projects were competitive with the proposed peaker on a cost of energy basis, but utility-scale solar electricity was half as expensive.

FIGURE 11. SOLAR UNDERCUTS PEAKING GAS PLANTS



Given the relative costs, the state's grid operator, CAISO, ordered an analysis of alternatives to the gas plant including distributed energy and energy storage. The report came back with dramatically negative conclusions: the cost of alternatives was as much as three times higher to fulfill the capacity need at the nearby Moorpark substation. But analysts from Greentech Media pounced on the results, noting that the cost estimates were as much as three years old, in a market that changes rapidly. Their analysis was more nuanced and much better for the alternatives to the gas peaking plant: If the upfront cost of electricity storage could hit $175 per kilowatt-hour or lower (depending on the cost of solar), the non-gas alternatives including solar would actually be the less expensive resource. The following chart illustrates:

FIGURE 12. CURRENT COSTS FOR SOLAR AND STORAGE FAR LOWER THAN ESTIMATES



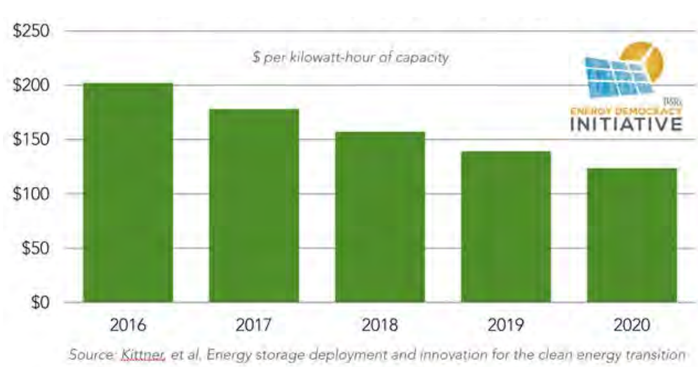
Lower costs for both solar and storage contributed to Greentech Media's results. In its 3rd quarter 2017 report, the Solar Energy Industries Association reported utility-scale solar costs of $1.10 per Watt or less, and costs for non-residential solar (think large rooftops) of $1.55 per Watt. The cost of solar has been falling and falling faster than the cost of gas-produced electricity. A 2017 update to the Lazard cost-of-energy illustrates (next page).

Energy storage is also relatively inexpensive and becoming even more so. In a late 2017 update, a Bloomberg analysis priced battery packs at $209 per kilowatt-hour, less than half as expensive as the CAISO model for the Johnson City Plant.

FIGURE 13. SOLAR COSTS FALLING FASTER THAN GAS POWER

A new study published in Nature by professors from University of California Berkeley lent more fuel to the fire, skewering prior battery price forecasts as too conservative and suggesting that by 2018 battery packs would already be inexpensive enough--well under $175 per kilowatt-hour--to affordably supplant the Johnson City gas plant. The prices (right) indicate the upfront cost per kilowatt-hour of capacity.

FIGURE 14. FORECASTED BATTERY PACK PRICES WITH TWO-FACTOR LEARNING MODEL



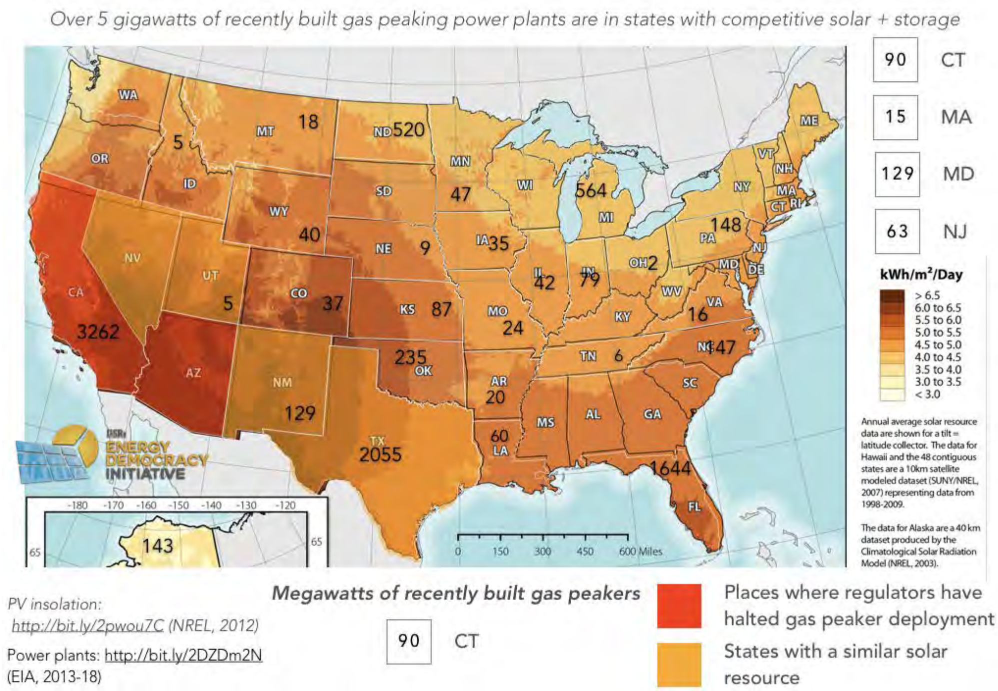
Given the new data, in October 2017, CAISO recommended a new request for proposals to allow for renewable energy and storage to bid in at more current prices. NRG has suspended its application for the plant.

The Johnson City plant may be the "canary in the gas plant" for the economic threat of "preferred resources" (renewables and storage) to replace gas peakers. In Minnesota in 2015, state regulators gave the green light to a solar project rather than a utility-proposed expansion of gas. In January 2018, the California Public Utilities Commission ordered Pacific Gas & Electric to seek storage and renewable energy replacements for three existing gas peaker plants. Combination wind or solar plus battery storage systems responding to an Xcel Energy Colorado request in early 2018 had levelized cost offers far less than $100 per megawatt-hour (although storage duration was not disclosed). In February 2018, Bloomberg reported on another bid won by solar plus storage:

> *"In just the latest example, First Solar Inc. won a power contract to supply Arizona's biggest utility when electricity demand on its system typically peaks, between 3 p.m. and 8 p.m. The panel maker beat out bids from even power plants burning cheap gas by proposing to build a 65-megawatt solar farm that will, in turn, feed a 50-megawatt battery system."*

Johnson City may also hint at problems for recently built gas power plants. Over 5 gigawatts of gas peakers were recently deployed in states that have, or will have soon, economical competition from solar and energy storage. Customers in California, Nevada, Arizona, and New Mexico can already access solar and storage combinations competitive with utility power prices. Regulators in two of these states, California and Arizona, have recently slowed or halted gas peaker deployment in response to these cost-competitive threats from distributed and centralized renewable energy plus storage.

FIGURE 15. EXISTING GAS PEAKERS IN TROUBLE



The long timeframe for planning, constructing, and operating large-scale power plants doesn't do the industry any favors. The Johnson City, Calif., plant wouldn't have started producing electricity until 2022 and would have saddled electric customers with expenses for 40 years. Alternatives--including distributed solar, demand response, and energy storage--can be constructed in a much shorter timeframe (months, instead of years), and have been getting cheaper every year.

Pain for Utility Balance Sheets

Competition from distributed energy may also sharply reduce sales. High electricity prices drove nearly 20% of Hawaiian Electric customers to install solar arrays [by late 2017](). With help from public regulators, the utilities won a reduction in compensation for rooftop solar producers. But within months, third parties started offering island customers combination solar and energy storage packages capable of providing electricity cheaper than the utility offered.

With competitive solar plus storage, Hawaiian electricity companies could be reluctantly mailing “postcards from the future” about the financial challenges of accommodating customers with less expensive options.

If just 2 in 10 Hawaiian residential and commercial electricity customers exercised their choice and had solar plus storage (either by retrofitting a battery onto their existing solar or buying a bundled system) it could cause a net reduction in Hawaiian Electric Company electricity sales of nearly 950 gigawatt-hours per year, or just over 10% of total sales. At today’s electricity prices (and ignoring many other benefits of avoiding oil-based power generation) it would cost the company over $250 million per year in lost revenue (about 11% of total revenue and more than the utility’s $167 million net income for 2017).

Bigger Local Economic Returns for Communities

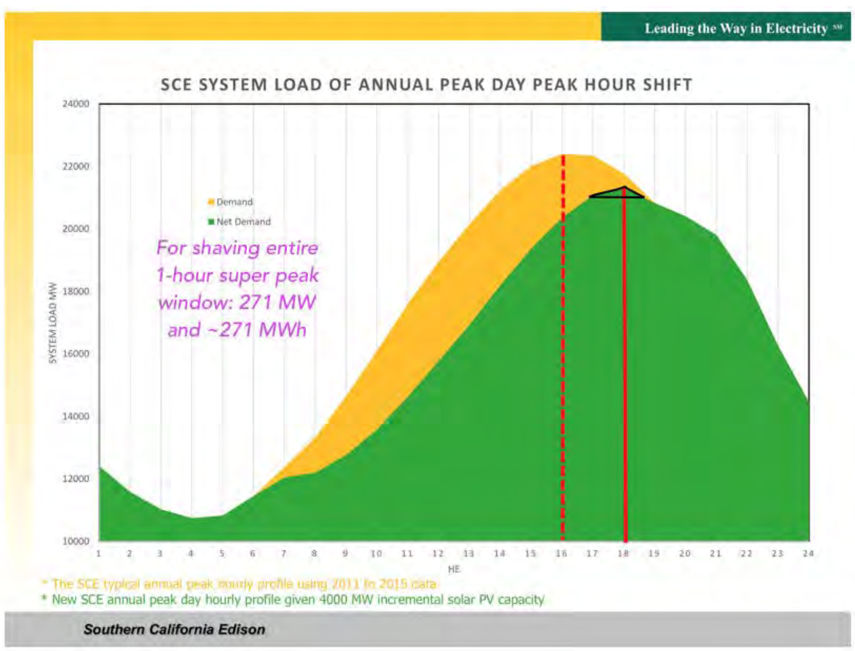
Distributed solar and storage not only undercut the economics of centralized utility power plants, they can boost local economies in ways utility-built power plants don’t. The failed Puente gas plant provides a powerful example.

The proposed gas peaker would have supplied 271 megawatts of peak power for an upfront cost of $250 million dollars (and millions more for fuel consumed). The cost of energy from the plant would have been above $150 per megawatt-hour, with at least half of that energy cost leaving the community to pay for imported fuel.

ILSR modeled distributed solar and storage replacement options for the Puente gas plant and found a solar and storage hybrid with a higher upfront cost but much lower lifetime cost, and substantial local economic benefits.

The key element is replacing the peak energy supply from the proposed Puente plant. To understand what is needed, the following chart from Southern California Edison illustrates their peak energy demand on a summer afternoon, shown below in green. The tiny black triangle shows the area, up to 271 megawatts, at the peak of the curve, that the Puente gas project would likely have fulfilled.

FIGURE 16. PUENTE PEAKING POWER PLANT ROLE



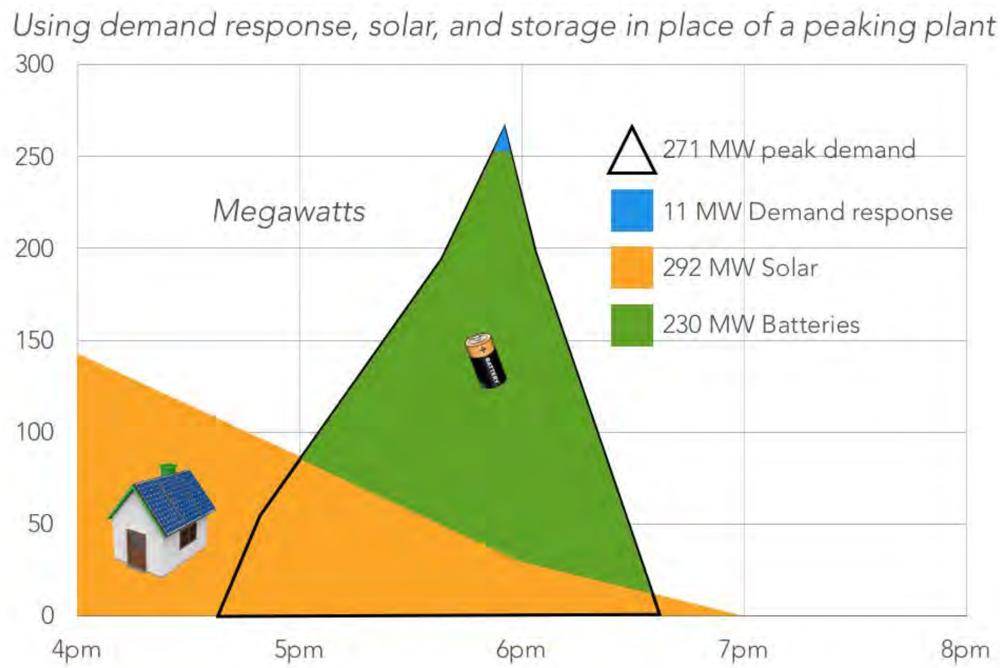
ILSR modeled three, combined strategies to meet the 271-megawatt peak: demand reduction, solar energy, and battery storage.

We assumed there were sufficient opportunities to reduced energy demand by about 11 megawatts, equivalent to 4% of the Puente capacity. This is based on ILSR's research on peak demand opportunity and is certainly conservative (this model only factors in residential demand response, despite commercial demand response opportunities being much larger). Demand reduction was priced at $300 per kilowatt, based on California utility demand response programs.

Of the remaining 260 megawatts of capacity, solar energy can only fulfill 30 megawatts of the peak energy use during the peak hours, because south-facing panels have limited production at that time of day. So, we modeled the installation of 292 megawatts of solar using the low sun angle to provide 30 megawatts of peak-time power as well as 230 megawatts of solar energy that could be stored for later use. ILSR assumed a split of 80% non-residential solar arrays and 20% residential solar, with a weighted average solar installed cost of $1.88 per Watt ($1.60 per Watt non-residential, $3.00 per Watt residential). The total cost for this distributed solar power plant is about $550 million.

The final piece for this modeled scenario is 230 megawatts of battery storage, assumed to cost $175 per kWh, for a total cost of approximately $40 million. Given the favorable economics under California's "Net Metering 2.0," it's assumed that energy storage is co-located with all non-residential solar projects (about 64 megawatts). If half of residential solar customers also opted for storage (e.g. a Tesla Powerwall), it would account for a further 11 megawatts of storage.

FIGURE 17. PUENTE PEAKING POWER PLANT ALTERNATIVES



The total cost for the solar and storage alternative is $589 million (about twice the upfront cost of the proposed Puente plant), but with a levelized cost nearly two-thirds lower, less than $50 per megawatt-hour.[8]

In addition to these energy cost savings, the distributed solar and storage solution also offers premium jobs and local economic benefits. The following table compares the construction and operations jobs and cash flows from the two options. A peaking gas plant offers a handful of more long-term jobs, but that value is swamped by the enormous economic benefit to customers whose solar and storage systems cut their energy costs.

[8] Using NREL System Advisor Model with default settings for Commercial PV Watts unless otherwise noted. Solar resource for Oxnard, CA, airport; solar installed cost of $1.88 per Watt; battery cost of $175 per kWh; 100% debt for 10 years at 7% interest; real discount rate of 2.5%; 0% property tax. *Note: lower costs could likely have been achieved with west-facing (rather than south-facing) solar panels to capture more peak-time sun.*

FIGURE 18. ECONOMIC IMPACT COMPARISON, GAS PEAKER V. DISTRIBUTED SOLAR+STORAGE

	Puente Gas Plant	Solar + Storage alternative
Construction jobs	81	934
Construction cost	$250 million	$590 million
Ongoing jobs	4	Minimal
Levelized cost of energy	$150 per MWh	$45 per MWh
Operations local dollars (annual)	$4.3 million (payroll, accounting, contracting)	$65.6 million (customer energy savings)
Property taxes (annual)	$2.3 million	$0 million
Local resiliency	No	Yes

[9] Economic data for Puente taken from the CPUC filing and Utility Dive. Economic data for solar and energy storage taken from the National Solar Jobs Census 2016 (jobs), Solar Energy Industries Association (installed costs), NREL System Advisor Model (levelized cost), Sunrun and GreentechMedia (operations local dollars).

REVERSING THE POWER FLOW

The combination of solar and energy storage won't mean every customer is their own utility, but it reverses 100 years of top-down decision making by granting customers much greater choice. The reversal brought about by affordable energy storage akin to a fourth horseman of a utility business model apocalypse.[10] As with the mythical riders, energy storage joins energy efficiency, distributed solar, and information technology to threaten the utility's economic monopoly.[11]

10 The four horsemen are described in Revelations in the Biblical New Testament, representing four major forces of a divine apocalypse: pestilence, war, famine, and death. They are often used in fictional works to illustrate the coming of apocalyptic change.

11 The other business model threats are described in detail elsewhere, but included stalled electricity sales growth, the rise of competitive distributed solar, and distributed information technology like smart thermostats.

Energy storage doesn't end the utility of the electric utility, but--combined with distributed rooftop solar--it continues the shift away from monopoly power toward energy democracy. In particular, promises to nearly sever the reliance of electricity customers on a central utility company because it allows customers to avoid utility-imposed charges and to arbitrage (buy at low prices, sell at high prices) the time-of-day differential in the cost of electricity generation. It also gives them unprecedented access to grid value and revenue streams. Utilities will need to offer customers a reason to stay connected.

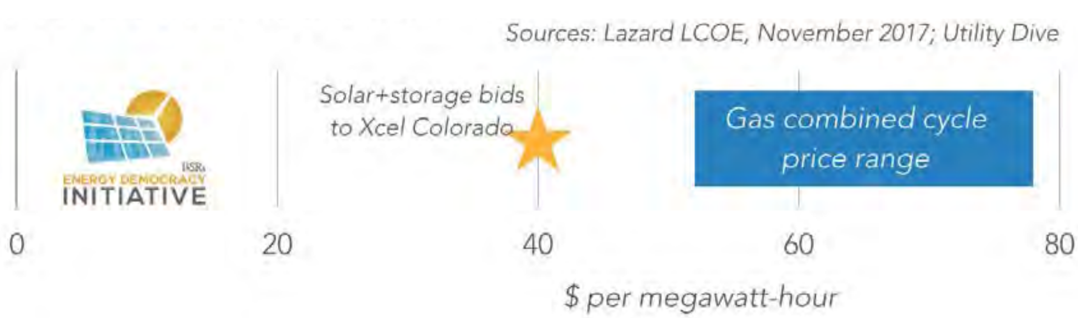
Unfortunately, many are doing the opposite.

ANOTHER BONFIRE OF RISKY SPENDING?

Despite the evidence that economics and customers will continue to drive distributed energy, many utilities are forging ahead with major power plant construction plans. Across the country, utilities have over 60 gigawatts of new gas power plant capacity in the queue for the next four years alone, 50 percent more capacity than is expected to be retired counting nuclear, gas, and coal combined.[12]

This planned gas capacity will have stiff competition. On one hand, distributed generation will reduce the demand for conventional energy generation, both baseload and peak, as well as ancillary services. On the other hand, bids for utility-scale renewable energy combined with storage are coming at prices unimaginably low. When Xcel Energy in Colorado received bids for new power plants slated to start delivery in 2023, it found it could buy wind or solar paired with storage for less than $40 per megawatt-hour, far less than the expected cost of energy from a new gas combined cycle power plant.

FIGURE 19. SOLAR+STORAGE PRESENTS STIFF COMPETITION FOR GAS GENERATION



12 (EIA Electric Power Monthly, Table 6.5)

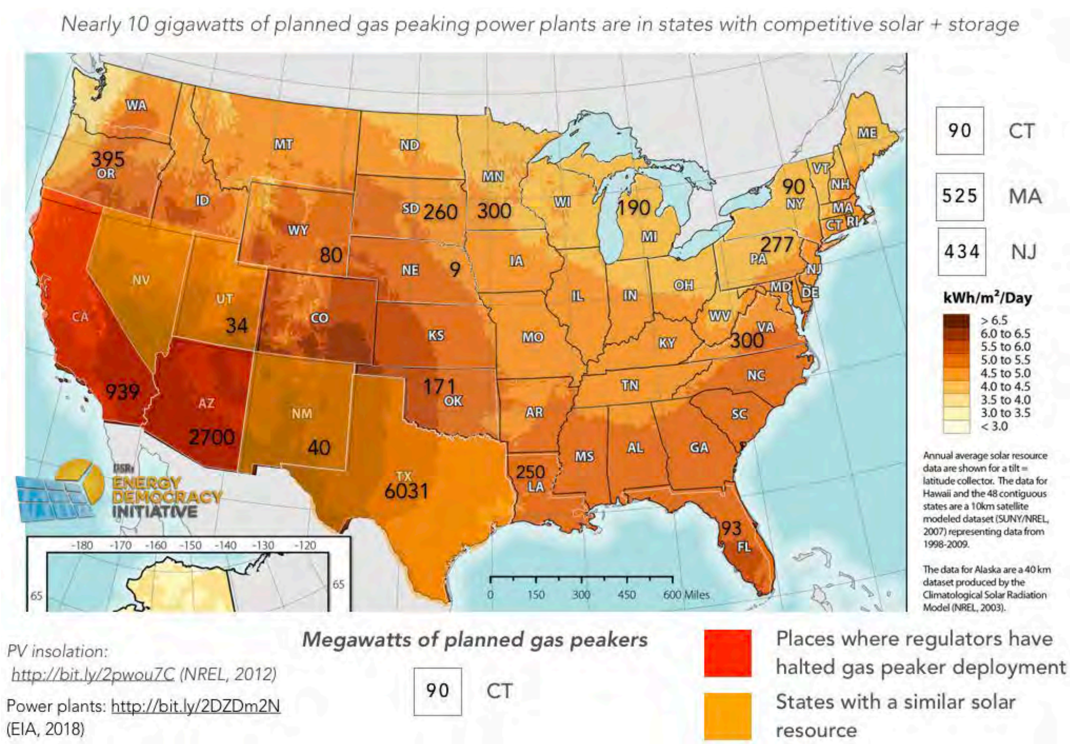
The competitive threat also applies to "peaker" plants that provide capacity during periods of peak demand but operate at relatively low efficiencies. Almost three-quarters of the 13 gigawatts in planned capacity is scheduled for states with competitive solar and energy storage now or in the near future. Writ large, Greentech Media analysts suspect that energy storage alone will compete with gas peakers on price by 2022, and beat them consistently within a decade.

Already, regulators are increasingly challenging company plans to build new gas plants:

> *Some utility companies have scrapped plans for new natural-gas plants in favor of wind and solar sources that have become cheaper and easier to install. Existing gas plants are being shut because their economics are no longer attractive. And regulators are increasingly challenging the plans of companies determined to move forward with new natural-gas plants.*
>
> *"It's the No. 1 Power Source, but Natural Gas Faces Headwinds."*
> *New York Times, March 28, 2018*

The following map shows the capacity of planned gas peaking plants across the country, highlighting states that have a solar resource similar to states--California and Nevada--that have halted gas plant development to consider economical solar plus storage alternatives.

FIGURE 20. PLANNED GAS PEAKERS IN TROUBLE



Some planned plants have already died. As mentioned earlier, California regulators have ordered a recent gas plant proposal (Johnson City) back to the drawing board to take competitive bids from renewable sources and energy storage, and energy company NRG recently announced retirement of three other gas peakers for "economic reasons." Arizona regulators recently put a moratorium on gas plant construction to come to grips with economical solar and storage alternatives.

When independent power producers plan new power plants, they have to decide whether the market will buy their product in the long run. But many utilities have captive customers. When their plants fail to pay back, they become “stranded assets.” Journalists in the U.S. Southeast recently broke a major story on a $40 billion “bonfire of risky spending” by monopoly utility companies on nuclear power plants and carbon-capture coal power plants that will never produce a kilowatt-hour, but will cost their customers for decades.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TOP STORY

Power Failure: How utilities across the U.S. changed the rules to make big bets with your money

By Tony Bartelme tbartelme@postandcourier.com Dec 10, 2017 (...) 24 min to read

In the 30 states where public regulators must approve new power plant construction, especially states like California and Florida, where utilities have big plans, commissioners should be very cautious about any new capacity proposals. New gas could be very expensive, weighing down those who can’t finance an escape from utility charges via rooftop solar and on-site storage.

UTILITIES RESPOND INCONSISTENTLY

Responses by utilities to the changing technological and political landscape vary widely. Some are aggressively hostile, trying to shut down their emerging distributed competitors. Some are building utility-owned solar and storage facilities. Some are establishing utility-owned rooftop solar systems.

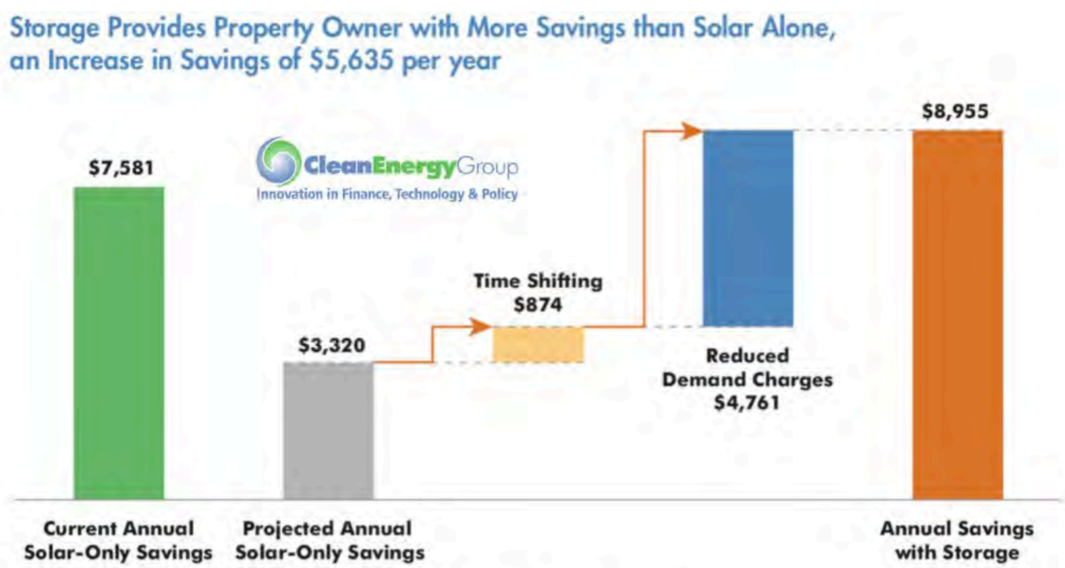
Stopping Distributed Clean Energy Competition

The most common response of utilities to distributed energy options like solar and energy storage has been to try to stop them. Countermeasures include legislation to remove net metering (or other rules that guarantee customers fair compensation on their utility bills for installing solar) with 31 states considering policies related to distributed generation compensation in 2017 alone. With regulatory approval, utilities have also levied special fees on the electric bills of solar customers (19 utilities pushed proposals in 10 states in 2017). Finally, many utilities have proposed raising the fixed portion of the electric bill high enough to limit energy savings from any on-site resources, whether efficiency or solar energy.

Battery storage may undermine the utility playbook on stopping distributed energy. In Iowa, Alliant Energy's standby tariff and high utility demand charges drove Luther College to examine how energy storage could continue its pursuit of a clean, resilient energy supply. A study by the National Renewable Energy Laboratory found that "Luther College could save approximately $25,000 in energy costs for each of the next 25 years if it installs a 1.5 [megawatt] solar array and a 393 [kilowatt] battery," due in large part to the ability to avoid excessive demand charges by Alliant, totaling as much as 40% of the college's monthly bill.

In California, changes to net metering compensation lower the financial value of distributed solar, sometimes significantly. But adding storage to projects can restore many of the lost savings. The following chart from a study by Clean Energy Group walks through the process. The first bar shows solar savings in the current regime, while the second shows the markedly reduced value of solar alone in the new regime. The two floating bars show the added monetary value of storage in time-shifting when the customer draws power from the grid and in reducing demand charges. The final bar shows the result, with greater savings by combining solar and storage than with solar alone.

FIGURE 21. STORAGE REVERSES REVENUE LOSSES FROM NET METERING CHANGES



Adding a 60-kilowatt/90-kilowatt-hour battery system to the 52-kilowatt PV system analyzed in Figure 3 can completely offset the loss in solar bill savings due to proposed rate changes (represented by the difference between current [green] and adjusted [grey] annual saving). The combination of reduced demand charges and shifting solar use from low-cost to high-cost electricity periods increases annual savings by more than $5,000, with over 85 percent of the savings coming from reductions to demand charges.

In some cases, storage may allow affordable housing or other commercial rate customers to switch to rate plans without demand charges, increasing energy savings by two or three times.

Adopting Clean Energy at Utility Scale

Utilities convinced of competitive solar and storage sometimes embrace large-scale, utility-owned systems. Utilities have installed nearly 25 gigawatts of utility-scale solar and 600 megawatts of energy storage in the past five years. Over 85% of utilities expect increases in utility-scale solar and energy storage in Utility Dive's 2018 annual survey.

This strategy has two benefits for utilities: many can still make money with large capital investments, and it weakens environmentally-driven arguments against the utility company's monopoly.

On the other hand, utility-scale renewable energy investments compete with distributed solar and storage only to a degree. Some crucial grid services--helping maintain a consistent voltage--are best provided near load. Centralized solar and energy storage have a limited ability to meet such needs. If centralized renewable energy projects don't lower the ultimate price of electricity, they also won't address the customer who can produce cheaper electricity on-site or who values other benefits of local production, such as resiliency in the face of grid outages. Finally, many communities have now made commitments to get 100% renewable electricity, often within the next 15 years. If utilities don't keep pace, their customers may move on without them.

Deploying Utility-Owned Distributed Clean Energy

Some utilities go beyond utility-owned large-scale clean energy facilities to embrace utility-owned distributed solar and storage. Several investor-owned utilities have muscled into the rooftop solar market, offering a roof rental fee to customers for hosting utility-owned solar panels. The offering aims to address customer demand for solar while keeping ownership, and profits, within the utility.

Our 2015 analysis revealed that utility-operated rooftop solar programs kept as much as two-thirds of the financial benefit typically seen by customers that owned solar on their rooftops (fortunately, in the case of Tucson Electric Power and others, utility-owned programs are small relative to the non-utility market). Notably, two of the utilities muscling into the rooftop solar market––Arizona Public Service and Tucson's utility––have also tried to reduce compensation for customer-owned solar.

Other utility efforts operate in a gray area because the utility itself is customer-owned. Rural electric cooperatives have addressed customer interest in solar with options for customers to subscribe to solar projects not on their property. In some cases, these subscription models allow more customers to share in the economic benefit of solar and offer significant savings. In other cases, customers are simply asked to pay more for electricity when they could have saved significantly with their own solar installation.

Green Mountain Power stands virtually alone as an investor-owned utility offering distributed options for its customers. This Vermont utility finances Tesla Powerwall home battery packs for $37 per month and has boosted compensation for rooftop solar producers. It may be no coincidence that it's also a B-Corporation, with a commitment to provide social and environmental benefits to customers and not just financial rewards to shareholders. As it happens, the two goals align well.

The problem with utility-provided distributed energy resources is less about the individual benefit to customers and more about customer choice. Utilities act as gatekeepers to the benefits of distributed energy resources through interconnection policies, rate structures, pricing, and market access for selling services like grid voltage or frequency. If offered in a competitive market, utility distributed energy services are a welcome addition to the customer's choices. If not, they're an extension of the monopoly to services that don't require monopoly control.

A combination of the three tactics may slow the spread of distributed energy generation and storage. Anti-distributed energy policy can slow customer adoption. Building utility-owned clean energy at scale may undermine the sense of urgency in the environmental advocacy community. Offering utility-owned distributed generation can assuage customer interest in local clean energy and cut competitors out of the market.

The tension between customer-empowering solar+storage and the distribution grid monopoly market structure makes good rules imperative.

SOLAR + STORAGE RULES THAT LEAD TO ENERGY DEMOCRACY

Strong economics don't make a distributed solar and energy storage revolution inevitable. As noted, utilities have already made efforts to weaken competition from customer-owned power generation. The following policy recommendations would allow the maximum grid and local economic benefit from the distributed solar and energy storage opportunity.

Utility Targeted Recommendations

Electric utilities must demonstrate their continued value in a competitive market —one in which their customers can choose cost effective alternatives to grid-delivered power. Energy market regulators and state legislatures should take the following actions on behalf of electric utilities and their customers:

- Issue a moratorium (like Arizona) on construction of new, large-scale fossil fuel power plants and require competitive bids from distributed energy resources to supply any new capacity needs
- Sharply increase requirements for utility acquisition of economical demand response (see Xcel Energy Minnesota 2016 resource plan requirements) and energy efficiency, and require utilities to offer tariff-based inclusive financing to break down barriers to customer adoption
- Require utilities to engage in distribution system planning to accommodate solar and energy storage deployments (and electric vehicles) by doing a full value analysis of distributed energy resources, modeling to optimize distributed energy deployment, and desiging appropriate policies (other ideas here)
- Require utilities to acquire energy storage, with an obligation to test multiple vendors and technologies, but allow customers access to the

same rate structures or interconnection accommodations provided to utility-owned systems

Market-Targeted Recommendations

Because utilities retain enormous control of the electricity system in most states, preserving monopolies over the distributed grid or even vertical monopolies over the entire system, energy regulators and state legislatures must provide more opportunities for competitive access to energy solutions that don't require monopoly control. Energy market rules can be affected primarily at the regional, state, and local levels. At the regional level, federal authorities write rules and recommendations for regional grid systems. Crucial rules for capturing the value of solar and energy storage include (many gleaned from FERC Order 841):

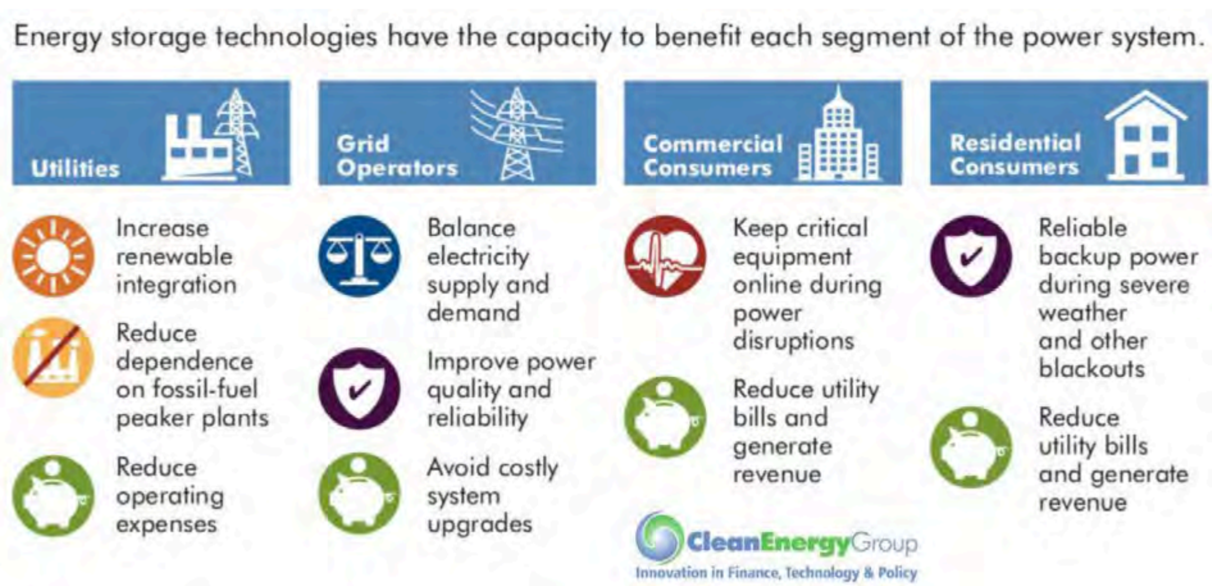
- Lowering thresholds for selling grid services into markets to 100 kilowatts
- Valuing both capacity and response speed in ancillary services markets to support system voltage and frequency
- Offering pricing and participation over short intervals to capture small movements in price
- Allow aggregated energy production and storage to participate in capacity, energy, and ancillary services markets, so that projects like the South Australia 50,000-home virtual power plant could capture value in U.S. markets.

State regulators and legislatures can also provide rules to improve access for solar and energy storage. Key rules include:

- Join 12 states (graded "A") in adopting modern and streamlined interconnection rules for distributed energy resources.

- Adopt rules to allow energy storage to participate in net metering, as with rules under consideration or adopted in Massachusetts and Colorado.
- Join six other states in mandating utility purchase of energy storage from a variety of vendors, with a variety of technologies, and at a variety of scales.
- Establish transition funds for communities that host fossil fuel power plants likely to retire that address lost property tax revenue as well as labor retention, retraining, and retirement (see proposal for Diablo Canyon in California, community transition funds for a coal plant closure in Buffalo, New York; as well as worker transition ideas in this ILSR piece).
- Allow energy storage to "value stack" by capturing revenue for a variety of uses (examples below from Clean Energy Group).

FIGURE 22. THE VALUE OF STORAGE



Local officials can also enable solar and energy storage in several ways:

- Sponsor bulk purchasing programs for solar and energy storage, such as Boulder County, Colo., did with electric vehicles and solar panels.
- Invest in electric vehicle charging infrastructure and revise zoning and codes to accommodate charger deployment.
- Simplify permitting for distributed energy resources to avoid, for example, New York City's effective murder of a virtual power plant project due to restrictive permitting for battery installation.
- Procure energy storage for public facilities to test market opportunities, identify qualified contractors, and provide resilient power during grid outages at community buildings

CONCLUSION

The combination of distributed energy storage and distributed solar is reversing the power flow, allowing customers and communities to generate most of their energy at home or nearby. It's also reversing the political power in the system, enabling customers to evade most utility strategies for curtailing competition. In short, it's a technology shift that enables energy democracy, where electric customers can--individually and collectively--have greater choice over the source and structure of their energy system.

But with much of the electricity system handed over to monopoly utility companies one hundred years ago, achieving energy democracy requires policy action.

Federal and state regulators must open markets to affordable distributed energy resources, and require any participant in markets (utilities or otherwise) to show that their infrastructure investments result in the most affordable energy and the greatest local economic benefit. State and local policy makers must adopt policies to allow communities to capture the economic opportunity from distributed energy resources, and rethink notion of utility monopolies in technology markets that are increasingly not. Local officials can also act, using public properties to demonstrate the value of distributed energy resources and enabling more residents and businesses to capture the value.

Energy storage is a 4th horseman to last century's electricity system, providing a once-in-a-generation opportunity to rethink its structure. Technology has enabled a bottom-up revolution in power generation and management, and the question is whether policy makers will enable energy democracy or allow the incumbent energy monopolies to stand in the way.

GLOSSARY

Ancillary services

Those services necessary to support a steady voltage and frequency of the transmission of electric power from where it is produced to where it is purchased. Such services maintain reliable operations of the interconnected transmission system. Ancillary services supplied with power generation include load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services.[13]

Baseload power generation unit

An electric power plant, or generating unit within a power plant, that is normally operated continuously to meet the base load of a utility; historically, powered by fossil fuel or nuclear energy sources.[14]

Commercial electricity demand charge

An additional electricity billing charge typically calculated by looking at the greatest amount of power (measured in kilowatts) needed by a consumer during "demand intervals" that make up a billing cycle. In most instances, a demand meter measures (and averages) the power "demand" in 15-minute time frames throughout the month and reports this information back to the electric

[13] Federal Energy Regulatory Commission (FERC). 2016. "Glossary." URL: https://www.ferc.gov/market-oversight/guide/glossary. ILSR. 2017. "Report: Choosing the Electric Avenue – Unlocking Savings, Emissions Reductions, and Community Benefits of Electric Vehicles." URL: https://ilsr.org/report-electric-vehicles

[14] FERC, op. cit.

utility. This reported peak-kilowatt level is then multiplied by a specific rate, which determining billed demand charges.

"Coincident" demand charges only bill customers when their peak energy demand coincides with periods of peak energy use on the system at large.[15]

Demand response

An automated or manual response by an electricity customer to reduce energy consumption when the utility asks. It can include an individual delaying when they wash clothes in response to a text alert, a factory shifting production to a different time of day, or air conditioners being cycled automatically by a utility on radio control to reduce demand.

Distributed Energy Resources (DER)

General or umbrella term for a variety of decentralized renewable energy technologies that enable consumers to produce or store electricity locally or even on-site. Common models of DER include but are not limited to solar Photovoltaic (PV) rooftop or ground-mounted arrays on residential and commercial properties, community solar gardens, and battery storage, which may or may not be grid-connected. The scale and ownership models of DER contrast with larger, utility-scale power generation sources that generally include centralized fossil fuel combustion or nuclear power plants connected to consumers through extensive transmission and distribution networks. DER may include energy reduction, as well, as through demand response.

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[15] Sunpower. 2017. "A closer look at commercial electricity demand charges, and how to lower them." URL: http://businessfeed.sunpower.com/articles/commercial-electricity-demand-charges

Electric utility

All enterprises engaged in the production and/or distribution of electricity for use by the public, including incumbent and regulated investor-owned electric utility companies; cooperatively-owned electric utilities; and government-owned electric utilities (municipal systems, federal agencies, state projects, and public power districts).[16]

Home energy battery storage

Battery technology that enables storage of electricity produced on-site by solar PV arrays for residential customers. Existing storage technologies are currently made with one of three chemical compositions: lead acid, lithium ion, and saltwater. Storage capacity in kilowatt hours (kWh) among battery technologies vary. Many batteries for home energy storage are now designed to be "stackable," which allows multiple batteries to be connected to a solar-plus-storage system to supply extra capacity. A battery's power rating is the amount of electricity that a battery can deliver at one time, measured in kilowatts (kW). Commercially available, proprietary battery systems for home energy storage include but are not limited to the Tesla Powerwall, Sonnen eco, Sunrun Brightbox, LG Chem, and Pika Energy Harbor Smart Battery.[17]

Microgrid

Areas operating independently from the regulated electricity grid with technologies that include on-site power generation, smart electric devices, and energy storage, that are designed to maximize reliability and resilience. Places

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16 FERC, op. cit.

17 EnergySage. 2018. URLs: https://www.energysage.com/solar/solar-energy-storage/what-are-the-best-batteries-for-solar-panels & https://news.energysage.com/tesla-powerwall-vs-sonnen-eco-vs-lg-chem

that have historically operated microgrids include military bases and hospitals, where reliable power is needed in the event of outages on the interconnected electrical grid.[18]

Net metering

A billing mechanism for electricity that credits owners of distributed energy systems for electricity produced, resulting in a "net" payment for electricity consumed or for electricity produced in excess of consumption. Generally used with small, on-site electric generators such as wind or solar energy.

When a customer-generator is both producing and consuming electricity at the same time, the laws of physics dictate that the electricity being produced flows to where it is being used ("net-zero" when producing the same amount of energy as is being used). But what about when electricity is being generated and none is being consumed? In these instances ("net-positive") net metering allows customer/generators to spin their meter backwards, in effect paying the customer-generator the retail rate for the electricity that they generate but don't immediately consume. If a customer generates more electricity than they consume over a period of time, they are typically paid for that net excess generation (NEG) at the electric utility's avoided cost or its wholesale rate.[19]

[18] ILSR. "Microgrid Hotspot." URL: https://ilsr.org/microgrids

[19] ILSR. 2011. "Net Metering." URL: https://ilsr.org/rule/net-metering. SEIA. 2018. "Net Metering." URL: https://www.seia.org/initiatives/net-metering

Peaking power plant / peaking capacity

Generating equipment normally operated only during the hours of highest daily, weekly, or seasonal loads, historically reliant on fossil fuel sources of energy such as liquified gas.[20]

Virtual power plant

A cloud-based or Internet-connected network of decentralized power generating technologies such as heterogeneous DER, including wind farms and solar parks, as well as flexible power consumers and batteries. The interconnected units are dispatched through a central control room but nonetheless remain independent in their operation and ownership. A key objective of this model is to relieve the load on the grid by smartly distributing the power generated by individual units during periods of peak load. Such networks may also optimize trading and selling power on the open market.[21]

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[20] FERC, op. cit.

[21] Yale Environment 360. 2016. "The New Green Grid: Utilities Deploy 'Virtual Power Plants.'" https://e360.yale.edu/features/virtual_power_plants_aliso_canyon. Also, Kraftwerke. "Virtual Power Plant." https://www.next-kraftwerke.com/vpp/virtual-power-plant

Visualizing California's Booming Solar Market

BY MARIE DONAHUE | DATE: 15 AUG 2018 |

A decade ago, less than 30,000 unique commercial and residential solar projects dotted the California landscape. Today, that number has grown close to 750,000 projects, a whopping amount serving a greater area and share of California's electricity demand than ever before.

What is even more remarkable about this statewide growth in solar? Each of these projects were planned and installed, not in any particularly coordinated way by the state's investor owned utilities or public utility commission, but instead by individual actors. An increasing number of homes and businesses in California see distributed solar as the smart economic choice for **themselves** and **their community**.

To drive this point home, we visualized the significant growth of solar projects in California over time, drawing on a unique, publicly available dataset of the state's interconnected solar installations. **Our end product? The animated map below that you do not want to miss.**

ENERGY HOME PAGE

Choose Energy Resources

KEY RESOURCES

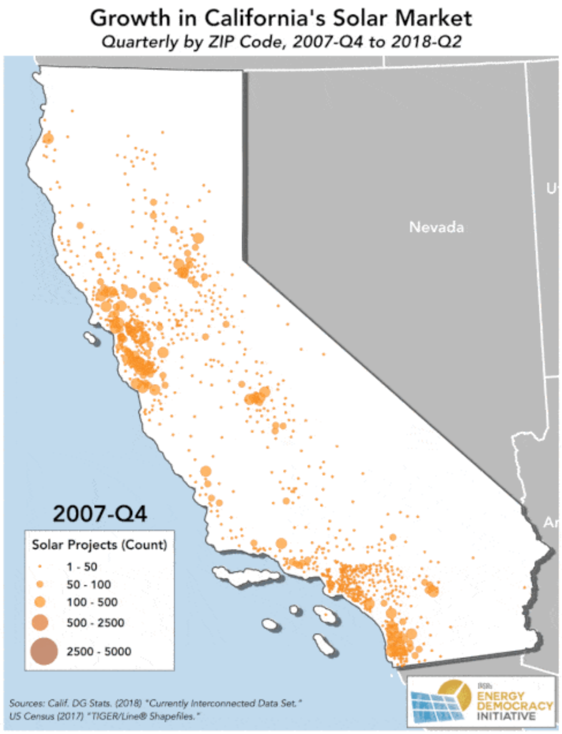
Energy Self-Reliant States

John Farrell's blog visualizing a distributed renewable energy future

Local Energy Rules Podcast

Sharing powerful stories of successful local renewable energy

Community Power Map



Animated map (GIF) of solar projects in California via ILSR

For a state with plans to **adopt a 100 percent renewable energy target** and one that has taken the lead by adopting **another landmark policy** requiring all new homes built starting in 2020 to be outfitted with solar panels, the growth in solar is good news for the future of local energy in California and unlikely to reverse course anytime soon.

We encourage you to share this post and animated map (GIF) on social media!

Assumptions and Calculations

The California Distributed Generation Statistics group publishes and maintains the **data which underpin this map**, as outlined by the California Public Utilities Commission Decision **(D.)14-11-001**.

The comprehensive, publicly available database ("Distributed Generation NEM Currently Interconnected Data Set") provides information on all interconnected or net energy metered solar photovoltaic systems within the service territories of California's major investor owned utilities: Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

While tracking each unique, currently interconnected project and excluding those that are pending or that have been decommissioned, the database also provides information about projects' interconnection address location and installation date. We aggregated these unique systems using ZIP code and installation date to create a new spatial database that could be used to display the total solar projects per ZIP code over time.

The solar installations displayed over time on this map are cumulative, with new installations being added to existing ones with each subsequent quarter. For example, the first map in the series contains data from the beginning of the dataset, which goes back until 1996, through to the end (fourth quarter) of 2007. The final slide in the series illustrates all solar installations from 1996 through the end of April 2018, when the most recent data are available.

Following these data processing and visualization steps, we created a series of distinct maps for each quarter and then combined them into a single, animated GIF to illustrate how solar installations have grown in California over time.

*This map (**CC BY-ND 2.0**) and article originally posted at **ilsr.org**. For timely updates, follow **John Farrell** or **Marie Donahue** on Twitter, our energy work on **Facebook**, or sign up to get the **Energy Democracy weekly** update.*

*Photo Credits: **Department of Energy Solar Decathlon** via Flickr (**CC BY-ND 2.0**)*

California, **Distributed Generation**, **economies of scale**, **Electricity**, **homepage feature**, **map**, **renewable energy**, **residential**, **Rooftop Solar**, **solar energy**

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Marie Donahue was a Research Associate with the Institute for Local Self-Reliance's Energy Democracy and Independent Business Initiatives in 2018-2019. She analyzed and wrote about the implications of corporate concentration and monopoly in these sectors.

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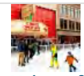

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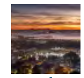

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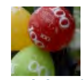

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ENERGY
How Cheap is 100% Renewable Electricity? Really Re…

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for **DTE ELECTRIC COMPANY** to fully comply with Public Acts 295 of 2008	Case No. U-18232 ALJ Sharon L. Feldman

CERTIFICATE OF SERVICE

I, Mark Templeton, certify that an electronic copy of the **QUALIFICATIONS AND DIRECT TESTIMONY OF JOHN FARRELL AND ACCOMPANYING EXHIBITS SOU 57 - SOU 64** was served electronically on the following on April 28, 2020:

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April 28, 2020

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