EARTHJUSTICE

ALASKA CALIFORNIA FLORIDA MID-PACIFIC NORTHEAST NORTHERN ROCKIES
NORTHWEST ROCKY MOUNTAIN WASHINGTON, D.C. INTERNATIONAL

May 19, 2014

Carlotta Stauffer, Director
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Re: Docket No. 130199-EI Florida Power & Light Company;
Docket No. 130200-EI Duke Energy, Florida, Inc.;
Docket No. 130201-EI Tampa Electric Company;
Docket No. 130202-EI Gulf Power Company

Dear Ms. Stauffer,

On behalf of the Southern Alliance for Clean Energy ("SACE"), I have enclosed the prefiled testimony and exhibits of Natalie Mims and Karl Rábago. Please file these documents in Docket Nos. 130199-EI, 130200-EI, 130201-EI, and 130202-EI. Please contact me if there are any questions regarding this filing.

Sincerely,

/s/ Alisa Coe
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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy and correct copy of the foregoing was served on this 19th day of May, 2014, via electronic mail on:

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DATED this 19th day of May, 2014.

/s/ Alisa Coe
Attorney

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission Review of Numeric Conservation Goals Florida Power & Light Company	))))	DOCKET NO. 130199-EI
In re: Commission Review of Numeric Conservation Goals Duke Energy Florida, Inc.	))))	DOCKET NO. 130200-EI
In re: Commission Review of Numeric Conservation Goals Tampa Electric Company	))))	DOCKET NO. 130201-EI
In re: Commission Review of Numeric Conservation Goals Gulf Power Company	))))	DOCKET NO. 130202-EI

DIRECT TESTIMONY OF NATALIE A. MIMS ON BEHALF OF SOUTHERN ALLIANCE FOR CLEAN ENERGY

May 19, 2014

Table of Contents

1. Introduction

Q. Please state your name, position and business address.

A. My name is Natalie Mims. I am Director of Energy Efficiency for Southern Alliance for Clean Energy ("SACE"), and my business address is P.O. Box 1842, Knoxville, TN 37901.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of SACE.

Q. Please summarize your qualifications and work experience.

A. I graduated from the Pennsylvania State University in 2002 with a Bachelor of Arts degree in English and Political Science. I received a Master of Environmental Law and Policy from the Vermont Law School in 2004. Since 2004, I have worked in the non-profit sector on a wide range of energy and environmental policy issues, including energy efficiency potential studies; energy efficiency program design and implementation; and evaluation, measurement and verification of efficiency programs.

I joined SACE in 2010, and became the Director of Energy Efficiency for SACE in 2013. I am the senior staff member responsible for SACE's utility energy efficiency advocacy across the Southeast, including Georgia, Alabama, Mississippi, Florida, North Carolina South Carolina, and Tennessee. In this capacity, I am responsible for leading dialogue with utilities and regulatory officials on issues related to energy efficiency policy, program design and evaluation. My work includes conducting detailed analysis of utility-run energy efficiency portfolios; providing written testimony and comments in regulatory proceedings; conducting presentations before regulators and interested stakeholders; and participating in energy efficiency stakeholder working groups, including Georgia Power's Demand Side Management ("DSM") Working Group, and Duke Energy Carolina's Energy Efficiency Collaborative. I have testified in energy efficiency proceedings in front of the North Carolina Utilities Commission, the South Carolina Public Service Commission and the Georgia Public Service Commission.

A copy of my resume is included as Exhibit SACE-NAM-1.

Q. Have you testified previously before the Florida Public Service Commission ("the Commission")?

A. No. This is my first time testifying before the Florida Public Service Commission, although I presented to the Florida Commissioners during an Internal Affairs meeting in January 2012 on the importance of robust evaluation, measurement and verification ("EMV") of DSM impacts.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present to the Commission my evaluation of Florida Power and Lighting ("FPL"), Duke Energy Florida ("DEF"), Gulf Power Company ("GPC") and TECO's (collectively, the "Utilities") Petition for Approval of Numeric Conservation Goals. Specifically, I will (1) discuss why it is inappropriate and against precedent and legislative intent to use the Ratepayer Impact Measurement ("RIM") test scores to set energy efficiency goals in Florida; (2) review the recommendations made in the recent review of the FEECA statute, and discuss the findings, (3) discuss the Utilities historic program costs, and show how they are inflated (4) explain why a two-year payback screen is an flawed proxy for free-ridership and is not used in any other state (5) discuss the flaws with the Utilities technical, economic and achievable potential; (6) discuss FPL and DEF's inadequate incorporation of energy efficiency into their resource plans and (7) make recommendations for policy and methodology improvements in Florida.

Q. Are you submitting exhibits along with your testimony?

A. Yes. I am submitting the following exhibits with my testimony:

- SACE-NAM-1: Resume of Natalie Mims
- SACE-NAM-2: Excerpt of Initial Comments of Sierra Club and Southern Alliance for Clean Energy in NCUC Docket E-100 Sub 137
- SACE-NAM-3: Excerpt of Direct Testimony of John D. Wilson on Behalf of Southern Alliance for Clean Energy in GPSC Docket 36498
- SACE-NAM-4: Excerpt of Direct Testimony of Natalie A. Mims on Behalf of Southern Alliance for Clean Energy in GPSC Docket 36498 and 36499
- SACE-NAM-5: National Action Plan for Energy Efficiency table of benefits and costs for each of the five benefit-cost tests
- SACE-NAM-6: Excerpt of Direct Testimony of Natalie A. Mims on Behalf of Southern Alliance for Clean Energy and South Carolina Coastal Conservation League in SC PSC Docket 2013-208-E.
- SACE-NAM-7: Excerpt of Direct Testimony of Jamie Barber, Richard F. Spellman, and John L. Kaduk on Behalf of the Georgia Public Service Commission in Docket 36498.
- SACE-NAM-8: SACE comment letter to Commission staff on technical potential update.
- SACE-NAM-9: Utilities technical, economic, achievable and proposed goals

2. Summary of Findings and Conclusions

Q. Please summarize the results of your review of the Utilities' Petitions for Approval of Numeric Conservation Goals.

A. Based on my review of the Utilities' Petitions for Approval of Numeric Conservation Goals ("Petitions") and the analysis I have conducted, I reach the following conclusions:

- The RIM test should not be used to determine the Utilities' energy efficiency goals. Rather, FEECA mandates that utilities use the total resource cost ("TRC") test and the

Commission has established the TRC test as the primary benefit-cost to determine energy efficiency goals.

- The Legislature identified the need for a report on FEECA, and one of the primary findings of the report was the FEECA continues to be in the public interest. The report identified improvements and make recommendations to implement those improvements. I recommend that the Commission should formally address each of the recommendations.
- Based on historic costs, more than a third of the program impacts associated with Utilities portfolios have costs that are significantly above the average cost of comparable programs. The Utilities inclusion of administrative costs and maximum incentive levels in their proposed goals continues this trend of inflated costs, which was identified in a recent Lawrence Berkeley National Lab report.
- Free-ridership should be considered in program planning, and the appropriate methodology for doing so involves using survey and billing data from customers that have participated in the Utilities energy efficiency programs. Using a payback period screen for a “proxy” of free-ridership; regardless of the number of years, is an archaic and inaccurate way to determine free-ridership.
- The Utilities’ Technical, Economic and Achievable Potential is conservative, and does not accurately depict the amount of energy efficiency the Utilities are able to cost-effectively capture in the 2015-2024 time period. Further, the methodology that the Utilities use to determine their proposed energy efficiency goals is flawed, resulting in underutilization of energy efficiency as a resource.
- FPL and DEF in adequately incorporate energy efficiency into their resource planning. FPL lacks transparency and analytical rigor in its resource planning, which raises concerns about the credibility of its resource planning. DEF’s modeling is

constrained in a manner that is very likely to understate its avoided costs and therefore screen out more DSM than is appropriate.

- There are policies that need to be put in place in Florida to allow the Utilities to fully support energy efficiency as a resource, including a lost revenue adjustment mechanism and performance incentives for achievement of DSM goals. The Commission has the authority to implement these policies, and should do so. There are methodology changes that need to be made in Florida, including using evaluation, measurement and verification to determine free-ridership rates and seek to balance free-ridership with market transformation (and spillover effects).

3. Utilities proposed goals do not align with Florida energy policy.

Q. What are the objectives of the Florida Energy Efficiency Conservation Act ("FEECA")?

A. As stated in the *Evaluation of Florida's Energy Efficiency and Conservation Act* report to the Florida Public Utility Commission in December 2012, the objectives are:[1]

> 1) reduce the growth rates for electricity demand at peak times, 2) reduce the consumption of electricity, and 3) conserve expensive resources, particularly oil used as fuel to generate electricity. FEECA's objectives have been amended over time to: 1) control (in addition to reduce) the growth rates of peak demand and consumption of electricity; 2) increase the overall efficiency and cost-effectiveness of electricity and natural gas production and use; 3) encourage development of demand-side renewable energy systems; 4) add greenhouse gases to the factors that could be considered in assessing the cost-effectiveness of FEECA programs; and 5) incorporate consideration of supply-side efficiency

[1] Galligan et al., *Evaluation of Florida's Energy Efficiency and Conservation Act*, December 7, 2012, p. 1, available at: http://warrington.ufl.edu/centers/purc/docs/FEECA_FinalReport2012.pdf

improvements. However, the original three objectives set forth in 1980 remain in the Act today and they continue to be the primary focus of the law.

Q. Does energy efficiency reduce the amount of money that consumers pay to the electric utility?

A. Yes. When customers install energy efficiency measures, it reduces the amount of energy they consume. All other factors being equal, this creates both total system savings that benefit all customers, and bill savings that benefit customers that install the efficiency measure. As a consequence, it reduces the amount of revenue a utility collects.

There is very little information available in the Utilities filing about system savings from energy efficiency. Our analysis of other Southeast states, where we have had access to better data, has indicated that the total system cost is less with higher levels of energy efficiency. In the Carolinas, for example, SACE analysis indicated that Duke Energy customers would save roughly $1 billion over the next 15 years if Duke Energy Carolinas and Duke Energy Progress selected a resource plan with higher levels of energy efficiency than base plans, as shown in SACE-NAM Exhibit 2.[2] Similarly, in Georgia, SACE analysis showed that Georgia Power customers could save $2.4 billion over the planning period by investing in higher levels of efficiency, as shown in SACE-NAM Exhibit 3.[3] These lower system costs result in lower costs for all customers.

We were unable to complete a similar estimate of savings for Florida utility customers because the Utilities did not provide data similar to those we were able to access in in the Carolinas and Georgia.

Q. When the total system cost is less for customers, does that result in lower bills?

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[2] North Carolinas Utility Commission, Docket No. E-100, Sub 137, *Initial Comments of Sierra Club and Southern Alliance for Clean Energy*, available at: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=11ddfb83-53ec-44ce-b44c-57f9c3b06cf1

[3] Georgia Public Service Commission, Docket No 36498 and 36499, *Direct Testimony of John D. Wilson*, available at: http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=148134

A. Yes. SACE conducted an analysis of Georgia Power's data and showed that higher amounts of efficiency (relative to the base case) reduces all customer bills, and that the average commercial and industrial customer energy efficiency participants could reduce their annual bills by 15-24% if the Company adopted a high efficiency portfolio as compared to the base case efficiency portfolio, as shown in SACE-NAM-Exhibit 4.[4]

Q. Is a bill impact analysis possible in Florida?

A. Yes. If the Commission is concerned about the system cost of energy efficiency, it could simply ask the Utilities to perform an analysis on the long-term impact of energy efficiency on rates and bills. In Georgia Power's most recent IRP and DSM planning docket, the Commission found:

> The Commission finds that it is important to understand the long term percentage rate impact of future demand-side programs when making decisions regarding future utility spending on such certified programs in an IRP docket. It is not sufficient for the Commission to simply be presented with the dollar rate impacts of future certified programs, as the dollar level of rate impacts alone does not provide any context for the Commission to understand the significance of these rate impacts to the total Company annual revenue requirements. Also, because the Commission's policy is that energy efficiency is a priority resource, the Commission needs to know and understand the long term percentage rate impacts of future certified programs as compared to the percentage rate impacts of other generation, transmission and distribution resources.[5]

Q. Do you recommend that the Utilities conduct a similar analysis in Florida?

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[4] Georgia Public Service Commission, Docket No 36498 and 36499, *Direct Testimony of Natalie Mims*, available at: http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=148133

[5] Georgia Public Service Commission, Docket No 36498 and 36499, *Final Order*, p. 29, available at: http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=148996

A. Yes. The Utilities should provide the long term percentage rate and bill impacts of future certified programs as compared to the percentage rate and bill impacts of other generation, transmission and distribution resources, taking care to identify the number of customers projected to participate in those programs as part of the analysis.

Q. What are the Utilities proposed energy efficiency goals?

A. The Utilities proposed energy efficiency goals in their applications. Tables 1-4 and Figure 1 show the Utilities Proposed Goals for the 2015-2019 time period.

Table 1. Utilities Proposed Incremental Energy Goals (GWh)

	015	016	017	018	019
Florida Power & Light					
Duke Energy Florida	0	7	3	7	1
Gulf Power					
TECO		0	3	5	7

Figure 1. Combined Utilities Historic Energy Savings and Proposed Incremental Energy Goals

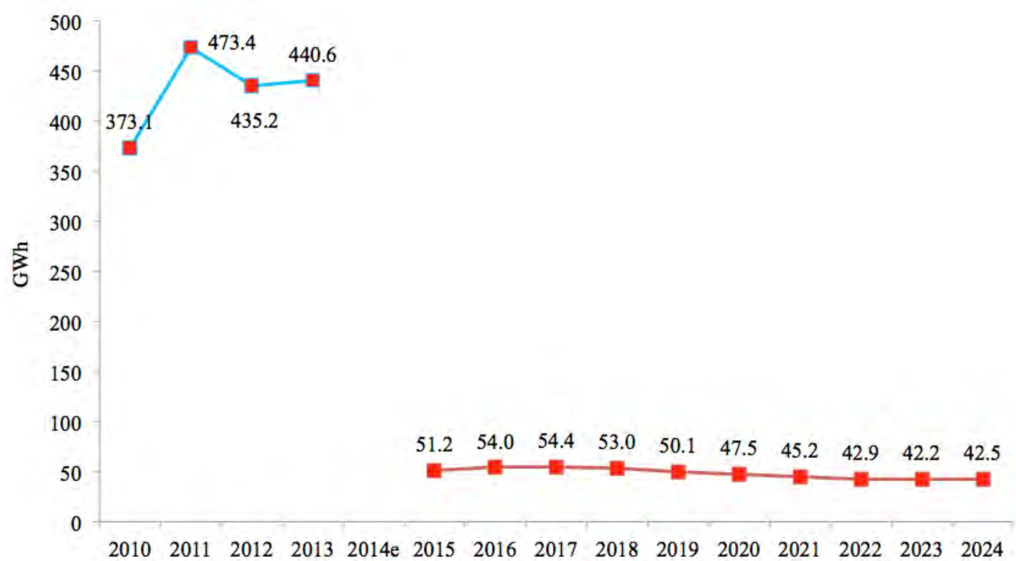


Table 2. Utilities Proposed Incremental Energy Goals (GWh Savings as a percent of retail sales)

	015	016	017	018	019
Florida Power & Light	.00%	.00%	.00%	.00%	.00%
Duke Energy Florida	.11%	.10%	.09%	.07%	.06%
Gulf Power	.03%	.04%	.05%	.06%	.07%
TECO	.03%	.05%	.07%	.08%	.09%

Figure 2. Individual Utilities Proposed Incremental Energy Goals 2015-2019 (GWh savings as percent of retail sales)

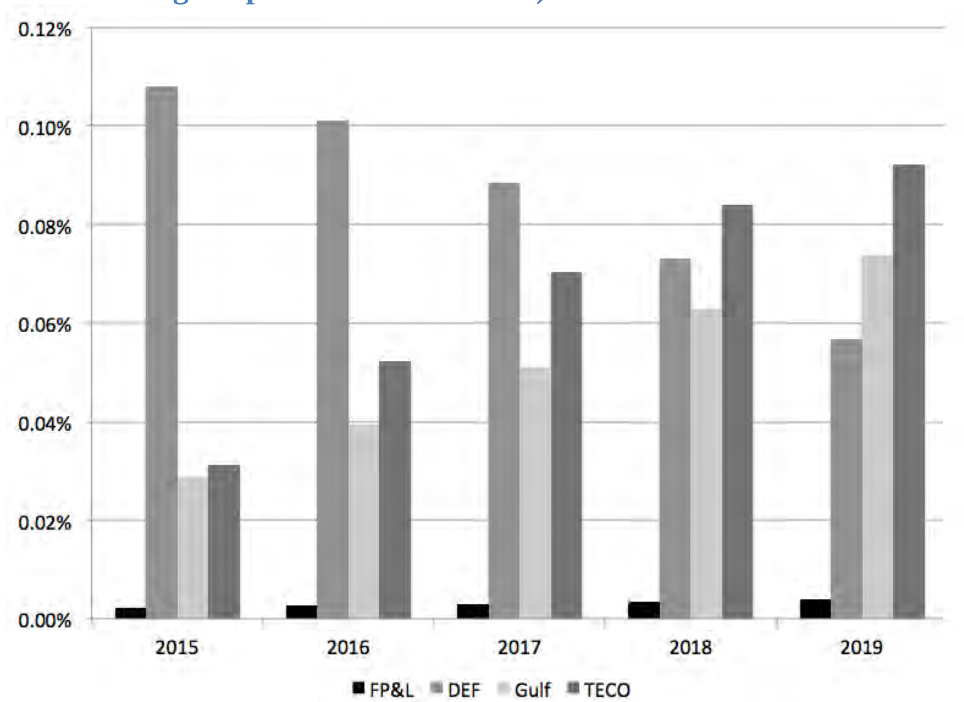


Figure 3. Combined Utilities Proposed Incremental Energy Goals 2015 -2019 (GWh savings as a percent of retail sales)

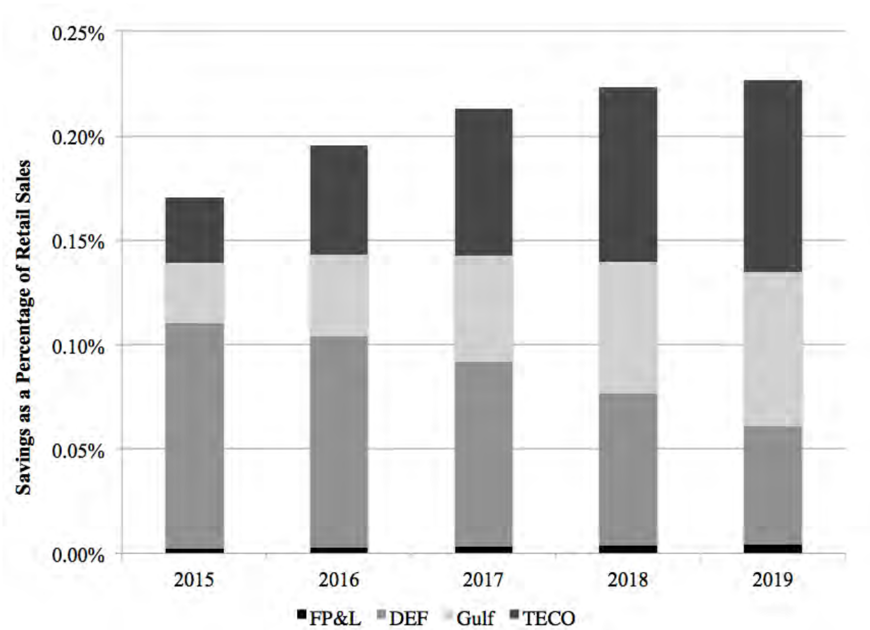


Table 3. Utilities Proposed Incremental Energy Goals (Winter MW)

	015	016	017	018	019
Florida Power & Light					
Duke Energy Florida	4	9	4	8	3
Gulf Power					
TECO					

Table 4. Utilities Proposed Incremental Energy Goals (Summer MW)

	015	016	017	018	019
Florida Power & Light	6	0	1	3	5
Duke Energy Florida	8	6	3	0	7
Gulf Power					
TECO					

These goals effectively eliminate the Utilities energy efficiency programs, as shown in

Figure 1, particularly for FPL.

Q. Do the Utilities' energy and peak demand reduction goals reflect the intent of the statute?

A. The Utilities argue that level of utility energy efficiency and peak demand reduction goals should be based on a very restrictive benefit-cost test, known as the Ratepayer Impact Measurement ("RIM") test. While I am not offering a legal interpretation, it seems to me that the narrow view taken by the Utilities will not result in significantly reducing the consumption of electricity nor conserving fuel used in the generation of electricity. The RIM test fails to achieve these objectives because it does not quantify all of the costs and benefits of conserving finite resources.

- **RIM is not the appropriate tool to use to assess Florida's energy goals.**

Q. What test did the Commission use to set the Utilities' efficiency goals in 2009?

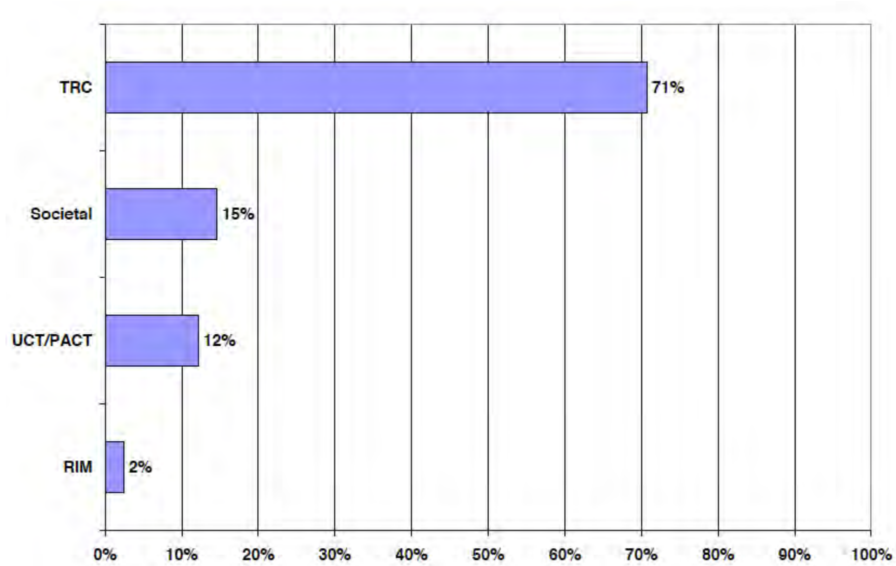
A. During the last goal-setting process, the Commission used the TRC test. In Order Number PSC-09-0855-FOF-EG, the Florida Public Service Commission stated,

> Therefore, we approve goals based on the unconstrained E-TRC Test for FPL, PEF, TECO, Gulf, and FPUC. The unconstrained E-TRC test is cost effective, from a system basis, and does not limit the amount of energy efficiency based on resource reliability needs.

Q. Is the RIM test used as the primary cost-effective test to make energy efficiency decisions by regulators in the United States?

A. No. Only one state, Virginia, relies on the RIM test as its primary benefit-cost test. 71% of states that have designated a primary cost-test use the Total Resource Cost ("TRC") test. Figure 4 shows the percentage of states that assign each benefit-cost test as its primary cost-test.

Figure 4. Primary Benefit-Cost Test (Percent of States) (n=41)[6]



Q. Should the RIM test be relied on to determine the level of energy efficiency investment in Florida?

A. No, I do not believe that the Utilities should rely on the Ratepayer Impact Measure Test (RIM) test to determine their *level* of efficiency investment. Looking elsewhere in the Southeast, in a 2010 IRP order, the Georgia Public Service Commission found, "Because the RIM test only indicates whether electric rates may increase if an energy efficiency measure or program is implemented, and not whether the impact may reduce a participant's overall electric bill, this test will screen out energy efficiency measures that can save significant amounts of electricity and can lower electricity bills."[7]

Further, as stated in the *Evaluation of FEECA*,

> This report recommends that cost-effectiveness criteria focus on two issues, namely whether program participants benefit and whether program benefits

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[6] Kushler, et al., *A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs*, February 2012, American Council for an Energy Efficient Economy Report Number U122, available at: http://www.aceee.org/research-report/u122

[7] Georgia Public Service Commission, Docket Nos 31081 and 31082, July 6, 2010, *Final Order at 12*,available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=148996

> exceed program costs for Florida as a whole.[8]

The report goes on to state that an emphasis on program benefits exceeding program costs could increase *rates*. This indicates that the report is not recommending the use of the RIM test, as the primary goal of the RIM test is to determine if *rates*, *<u>not costs or bills</u>*, *increases*.

Q. What cost test do other utilities in the Southeast rely on?

A. In North Carolina and South Carolina, Duke Energy Progress[9] and Duke Energy Carolinas[10] rely on the Utility Cost Test (UCT) test to evaluate cost-effectiveness, but provide all of the cost-test scores in filings. The Georgia Public Service Commission relies on the TRC test, and Georgia Power also provides all the cost-test scores in the filings.[11]

Further, the *Evaluating FEECA* report states,

> The TRC test focuses on a different objective than the RIM test, namely economizing on the cost of satisfying customers' energy demands, i.e. the value that customers place on the services they obtain from consuming electricity. Customers' energy demands can be satisfied by supplying energy and by providing improved methods for obtaining the valuable services that energy consumption provides…The TRC does this by comparing each program's costs to the projected costs of supplying the power that the program saves.[12]

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[8] Galligan et al., *Evaluation of Florida's Energy Efficiency and Conservation Act*, December 7, 2012, P. 29, available at: http://warrington.ufl.edu/centers/purc/docs/FEECA_FinalReport2012.pdf

[9] South Carolina Public Service Commission, Docket 2008-251-E, *Joint Proposed Order*, P. 7, available at: http://dms.psc.sc.gov/pdf/matters/8C5EA467-D24A-0C1C-BC0C1D3B49CA0C7D.pdf

[10] North Carolina Utilities Commission, Docket No E7 Sub 1032, *Order Approving DSM/EE Programs and Stipulation of Settlement. Settlement*, page 10, available at: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=c1692a27-e029-46ae-a502-400f0a38d511

[11] Georgia Public Service Commission, Dockets no 36498 and 36499, *Final order at 25*, July 11, 2013, available at: http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=148996

[12] Galligan et al., *Evaluation of Florida's Energy Efficiency and Conservation Act*, ,.December 7, 2012, p. 124, available at: http://warrington.ufl.edu/centers/purc/docs/FEECA_FinalReport2012.pdf

Q. What is the UCT?

A. While the primary goal of the RIM test is to determine if utility *rates* will increase, the primary goal of the Utility Cost Test, or UCT (also known as the Program Administrator Cost test) is to determine if utility *bills* will increase. It is also notable that the UCT is the best test to use to compare the cost-effectiveness of different methods of reaching customers. For example, a utility might consider switching from the use of high incentive payments to greater training of trade allies and promotion to customers. In this example, the UCT would change not only due to different program costs, but also due to changes in free-ridership, spillover and average savings per participant. I have included a description of the costs and benefit associated with each of the five benefit-cost tests from the National Action Plan on Energy Efficiency as SACE-NAM-Exhibit 5.[13]

Q. What are the cost and benefit inputs in the RIM test?

A. The benefits for the RIM (and TRC) test are calculated from two inputs. First, the energy costs avoided by not needing to produce a kWh (by saving a kWh). Second, the capacity-related costs avoided by the utility, including generation, transmission and distribution. The costs for the RIM test are calculated from four inputs: (1) program overhead costs, (2) utility incentive costs, (3) utility installation costs, and finally, (4) lost revenues due to reduced energy bills. If the costs, including lost revenues, are greater than the benefits, then the measure or program is not cost-effective under RIM.

- **The Utilities concerns with cross-subsidization are unfounded.**

Q. One of the concerns the Utilities express with using the TRC test as the primary

[13] Energy and Environmental Economics, Inc. and Regulatory Assistance Project., *National Action Plan for Energy Efficiency :. Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers.* http://www.epa.gov/eeactionplan

cost-effectiveness test in Florida is that cross-subsidization may occur. What is cross-subsidization?

A. In the energy context, it is when one customer pays for more, or receives less benefit, than another customer on the electric system.

Q. Does energy efficiency result in cross-subsidization?

A. As with any energy investment, not all customers that pay for the energy infrastructure will necessarily receive a comparable benefit. Investments in both the supply and demand side will cost customers money. However, unlike the supply side, customers have the option to participate in energy efficiency programs, and can lower their consumption and bills through their program participation. The customer has the opportunity to offset or eliminate the cost of the energy efficiency program. This is not the case with supply side investments.[14]

In addition, there are many benefits of energy efficiency that accrue to the entire electric system - making the cross-subsidization discussion moot. SACE's analysis of South Carolina Electric and Gas' energy efficiency portfolio demonstrated that increased levels of energy efficiency lower total system cost, providing a $50 million universal benefit to all customers on the system, as shown in SACE-NAM-Exhibit 6.[15] The system-wide, "universal" benefit occurs when efficiency reduces demand, average fuel costs are reduced, and system costs fall, which puts downward pressure on rates. Over the long term, as power plants are deferred or avoided entirely, the cost of building those power plants is not put into the rate base, placing further downward pressure on rates.

Q. Does cross-subsidization occur concerning supply- side resources?

[14] This assumes that energy efficiency programs are available for all customer classes.
[15] South Carolina Public Service Commission, Docket No 2013-208-E, *Testimony of Natalie Mims on Behalf of Southern Alliance for Clean Energy and South Carolina Coastal Conservation League*, available at: http://dms.psc.sc.gov/pdf/matters/020A97EA-155D-141F-2315BC8CD205AC3C.pdf

A. Yes. One example would be that the first rural customer did not have to pay for the full cost of stringing transmission and distribution lines to their home. Another example would be that a customer whose power is disconnected due to bad weather is not expected to pay overtime fees to linemen reconnecting their system the next day. A third example would be a customer who has lived in Florida for decades, without increasing household energy use (and perhaps self-funding energy efficiency improvements), but whose rates increase due to the cost of expanding service to meet growth in demand due to new customers and new businesses. Finally, customers that live closer to power plants or distribution substations do not generally pay lower rates even though delivering power to their home and business costs less due to the reduction in transmission, distribution and line losses.

Q. Have the Utilities conducted a bill analysis that quantifies the impact of cross-subsidization?

A. Not that I am aware of. The Utilities do provide the residential bill impacts of a customer consuming 1200 kWh a month, but this analysis does not evaluate the Utilities concerns regarding cross-subsidization. Further, the analysis is flawed because the Utilities use the same denominator (kWh consumed) for the TRC and RIM portfolios even though the TRC portfolio would result in less consumption.

- **RIM costs are higher than TRC costs because of lost revenues.**

Q. How do the RIM costs compare to the TRC costs in the Utilities applications?

A. FPL, Gulf Power and DEF did not provide either or both of RIM and TRC costs in their application, despite it being a primary component of the proposed goals. TECO estimated that the TRC portfolio would cost $53.5 million (nominal dollars) more than its RIM portfolio from 2015-2024.[16]

[16] Direct Testimony of Howard Bryant, Docket No. 13201, Exhibit No. HTB-1, Document No. 7.

Q. Which component of the costs drives the RIM test score in Florida?

A. The difference in the cost component of RIM and TRC, as I stated above, is lost revenues. "Lost revenue" is a term of art that is used in energy efficiency policy discussions to describe the revenue that the utility does not earn by saving energy instead of selling energy. Lost revenues should only apply to fixed costs, as variable costs will be reduced as energy is saved. It is important to note that lost revenues are not new costs, as energy efficiency program costs are. They are costs that have already been incurred through prior capital expansion by the utility, or sometimes called "sunk costs."

As it is in society's interest for the utility to remain financially health, some regulators allow utilities to recover some of the "lost revenue" from energy efficiency, through a lost revenue adjustment mechanism (LRAM). Simply put, a LRAM allows the utility to recovery a component of the electricity cost, even though the customer did not consume it, to ensure the financial stability of the utility.

Q. How much of the RIM costs are comprised from lost revenues?

Data supplied from Duke Energy Florida's commercial potential analysis indicated that ***over 90%*** of the costs in the RIM test are from lost revenues.[17] Similarly, in DEF's industrial potential analysis lost revenues contributed, on average, to 78% of the total measure cost. This was a significant factor in *all* industrial measure failing the RIM test. On average, DEF's residential lost revenue costs in the RIM test are 77% of total costs. Florida Power and Light, Gulf Power and TECO did not provide the cost inputs to its RIM test scores, so I was unable to determine how much of their cost was from lost revenues.

Q. How have other regulators addressed lost revenues?

[17] Duke Energy Florida, Inc. Response to SACE's First Request for Production of Documents, No. 5, *Com Achievable.xlsx; Ind Achievable.xlsx*, Apr. 16, 2014.

A. In North and South Carolina, Duke Energy Progress[18], Duke Energy Carolinas[19] and SCE&G[20] recover lost revenues for 36 months as part of their energy efficiency cost recovery proceeding. By limiting the amount of time the utilities can recover their "lost" revenues, regulators ensure that the consumers and the utilities both receive the benefit of energy efficiency.

It is important to note that, it is my understanding, that in the Florida Utilities' calculation of lost revenue for the RIM costs, they calculated lost revenues for the life of the energy efficiency measure, creating a very high numerical value on the cost side of the RIM equation.

Q. What are the other policy options to address lost revenues?

A. There are a variety of regulatory policies that the Commission could implement or explore to remove the Utilities disincentive to promote all cost-effective energy efficiency. In several states, utilities are decoupled, meaning that their revenues are no longer tied to their sales – they are tied to their customers. Another option is to more frequently review the utilities rates to ensure that they are adequately recovering their fixed costs even if sales are decline due to energy efficiency. It is my understanding that Sierra Club witness Woolf intends to discuss decoupling in his testimony, so I will not review this topic.

Another option is to more frequently review the utilities rates to ensure that they are adequately recovering their fixed costs even if sales are decline due to energy efficiency. For example, Georgia Power Company's rates are reviewed on a three-year cycle, which

[18] South Carolina Public Service Commission, Docket 2008-251-E. *Joint Proposed Order*, available at: http://dms.psc.sc.gov/pdf/matters/8C5EA467-D24A-0C1C-BC0C1D3B49CA0C7D.pdf
[19] North Carolina Utilities Commission, Docket No E-7 Sub 1032, *Order Approving DSM/EE Programs and Stipulation of Settlement*, available at http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=c1692a27-e029-46ae-a502-400f0a38d511
[20] South Carolina Public Service Commission, Docket No. 2013-208-E, *Order No 2013-826, a*vailable at http://dms.psc.sc.gov/pdf/orders/04AA654F-155D-141F-23A63DE824A1B66E.pdf

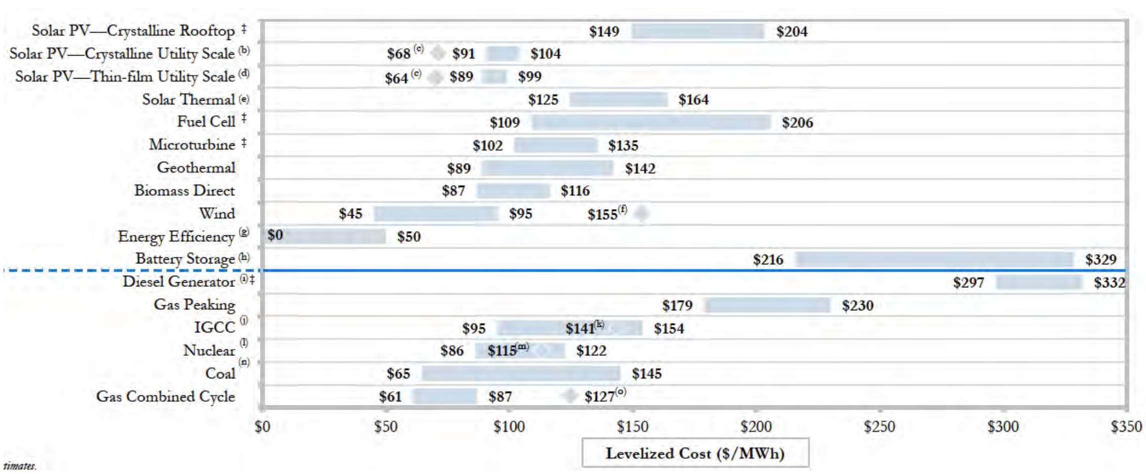
can help ensure that rates associated with the recovery of fixed costs do not result in substantial over- or under-collection of revenues.

Q. If you spread the same costs across less energy sales, won't that raise rates?

A. Generally, when a utility uses its capital to make additions to the electricity system; it asks its regulators to recover those costs. Regardless of whether the utility invests in supply side or demand side measures, there is a cost associated with that decision that will be passed along to the consumers. So it's a matter of what is causing rates to increase, and how that choice affects customer bills.

Energy efficiency is the lowest cost investment when compared to all other options, as shown in Figure 5. Energy efficiency levelized cost of energy[21] is approximately $0-50 per MWh, less than all other resources. Keeping costs down by investing in energy efficiency instead of more costly alternatives will also keep rates down.

Figure 5. Lazard 2013 Levelized Cost of Energy[22]



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[21] Levelized cost of energy is a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kilowatt-hour cost (in real dollars for the Lazard analysis) of building and operating a generating plant over an assumed financial life and duty cycle.

[22] Lazard's Levelized Cost of Energy Analysis – Version 7.0., August 2013, available at http://gallery.mailchimp.com/ce17780900c3d223633ecfa59/files/Lazard_Levelized_Cost_of_Energy_v7.0.1.pdf

In addition, if sales decline, *for any reason*, there will be fewer kilowatt-hours to spread costs across, which may cause a rate increase. Consumer motivated energy efficiency investments, codes and standards, mild weather, and economic factors all cause a decline in sales that results in the same costs being spread over fewer kilowatt-hours. Fortunately, the rate of electricity is not as important to most customers as the total amount on their bill. By keeping consumption lower, and choosing the least cost resource option, the Utilities can protect Floridians from high bills both now, and far into the future.

Finally, if sales were to decline significantly as a result of energy efficiency, there would have to be a large number of participants in the Utilities' energy efficiency programs. This means that there would be fewer non-participants, making the RIM argument of cross subsidization and the argument that it protects of non-participants irrelevant.

Q. What benefit-cost test should be the primary test to determine energy efficiency policy?

A. As the Commission ruled in 2009,[23] the total resource cost test. Further, the issue is not that RIM is "right" or "wrong", it is simply that, as a benefit-cost test: (1) it does not depict an appropriate picture of energy efficiency costs and benefits, and the impact of efficiency on utility system costs; (2) it does not reflect the intent of the Legislature or the Commission, and (3) it is a moot issue in this hearing. The Commission already determined what test to rely on in the last energy efficiency goals proceeding, and it is the Total Resource Cost test.

- **FEECA benefits Floridians and is cost-effective.**

Q. Did the Florida State Legislature release a report evaluating the FEECA Statute in 2012?

A. Yes. One of the primary findings of the report was that "FEECA continues to be in the

[23] Florida Public Service Commission, Order No. PSC-09-0855-FOF-EG, December 30, 2009.

public interest."[24]

Q. Does the report offer recommendations on the energy efficiency goal setting proceeding?

A. Yes. The report identified that the utility focus group found that there is uncertainty regarding the criteria used to set energy efficiency goals in Florida. The report recommended:

> To reduce such uncertainty, this report recommends that the goal-setting process be modified so that criteria for program approval are identified prior to the development of studies used for setting goals. This recommendation could be implemented through an FPSC rulemaking proceeding.[25]

Q. Are you aware of the criteria for program approval at this time?

A. No. There has not been a rulemaking proceeding in response to this recommendation, I am not aware of any informal steps that FPSC Staff may have taken to clarify the criteria for program approval prior to the development of studies used for setting goals.

Q. The report mentions transparency and the public's difficulty in engagement in FEECA. What recommendation was made?

A. The report recommended that:

> To improve data quality and accessibility, and to help improve the transparency of the analytical methods used in FEECA-related cost-benefit studies, this report recommends that the FPSC goal-setting process be modified so that utilities provide data electronically in a uniform manner and that these data be made accessible to the public, except for data that would be considered commercially

[24] Galligan et al. Evaluation of Florida's Energy Efficiency and Conservation Act, , December 7, 2012, p. 8, available at: http://warrington.ufl.edu/centers/purc/docs/FEECA_FinalReport2012.pdf
[25] *Id.* at p. 11.

> sensitive.

Q. Did the Utilities provide data electronically in a uniform manner in their applications?

A. The Utilities, at the request of the FPSC Staff, did provide their goal setting testimony exhibits and work papers in spreadsheets. This was helpful because it allows parties and interested stakeholders to more easily access the data the Utilities are using as the basis for their proposed energy efficiency goals.

However, the Utilities did not provide a uniform format in their filings. For example, the Utilities did not all provide the same information or did not report a variety of data in a uniform format: (1) provide the costs associated with the TRC and RIM cost tests, (2) calculate and/or incorporate administrative costs, (3) calculate and/or incorporate incentive costs (4) impact of free-ridership on energy efficiency impacts, and (5) impact of participation assumptions and incentive levels on energy efficiency impacts.

Q. Does the *Evaluating FEECA* report address the use of benefit-cost tests in Florida?

A. Yes, the report recommends:

> that cost-effectiveness criteria focus on two issues, namely whether program participants benefit whether program benefits exceed program costs for Florida as a whole. [26]

Q. What benefit cost test satisfies those two issues?

A. Section 366.82 (3), Florida Statute states in relevant part:

In developing the goals, the commission shall evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems. In establishing the goals, the commission shall take into consideration:

[26] *Id* at 12.

(a) The costs and benefits to customers participating in the measure.

(b) The costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions.

***

As SACE Witness Wilson stated in the 2009 FEECA goal setting proceeding,

> …there can be little doubt that the plain language of section 3(a) refers to the Participant Cost Test and section 3 (b) refers to the Total Resource Cost test. [27]

This appears to be the basis for the *Evaluating FEECA* recommendation above. As such, SACE does not have a different opinion of the statute than it did in 2009.

Q. Does the *Evaluating FEECA* report discuss performance incentives for Florida utilities?

A. Yes. The report states,

> Florida is among the states that authorize performance incentives. Florida's performance incentive appears to take the form of both shared benefits and rate of return. In terms of shared benefits, the FPSC is authorized to allow jurisdictional electric utilities that exceed their goals to receive financial rewards in the form of shared cost savings for generation, transmission, and distribution services related to energy conservation, energy efficiency and the addition of DSM and renewable energy systems. The FPSC may also provide other types of financial incentives. The Commission is authorized to allow an IOU an additional return on equity of up to 50 basis points if it exceeds 20 percent of its annual load-growth through energy efficiency and conservation measures. The additional return on equity must be established by the FPSC through a limited proceeding. In Florida, as in other states, authorization to grant such incentives does not mean that they will

[27] Direct Testimony of John Wilson, Florida Public Service Commission, Docket Nos. 080407-13, July 2009, p. 18.

necessarily be provided.

Q. Does the report make a recommendation on how to address financial incentive mechanisms for energy efficiency in Florida?

A. This report recommends that the Legislature consider including in FEECA criteria for making rewards or imposing penalties. Alternatively, the FPSC could adopt a rule identifying the criteria that would inform such decisions.

I would note that while the additional return on equity is capped at 50 basis points, the statute does not appear to explicitly require the Commission to award any incentive in the form of an increased return on equity. For example, the Commission could establish an incentive based on a percentage of customer savings (known as a "shared savings" incentive), as long as the actual amount of the incentive did not exceed the statutory limit.

Q. Are you aware of the Legislature or FPSC modifying statute or regulations to inform financial incentive mechanisms?

A. No. I am not aware of any rulemaking proceedings or informal guidance that have been provided since the report was released.

Q. Did any of the Utilities discuss any of the recommendations in the PURC report in their testimony?

A. The Utilities extensively discuss the benefit-cost test in their testimony; however, none of the utility witnesses discuss their conclusion in the context of the PURC report. The Utilities did not discuss improvements to the goal setting process, transparency, or financial incentive mechanisms.

Q. Do you agree with the recommendations of the PURC report, and believe they should be adopted?

A. Yes. As the Legislature identified the need for a report on FEECA, and the report identified improvements, I recommend that the Commission should formally address each of the recommendations.

4. Utilities' analyses are flawed and inaccurate

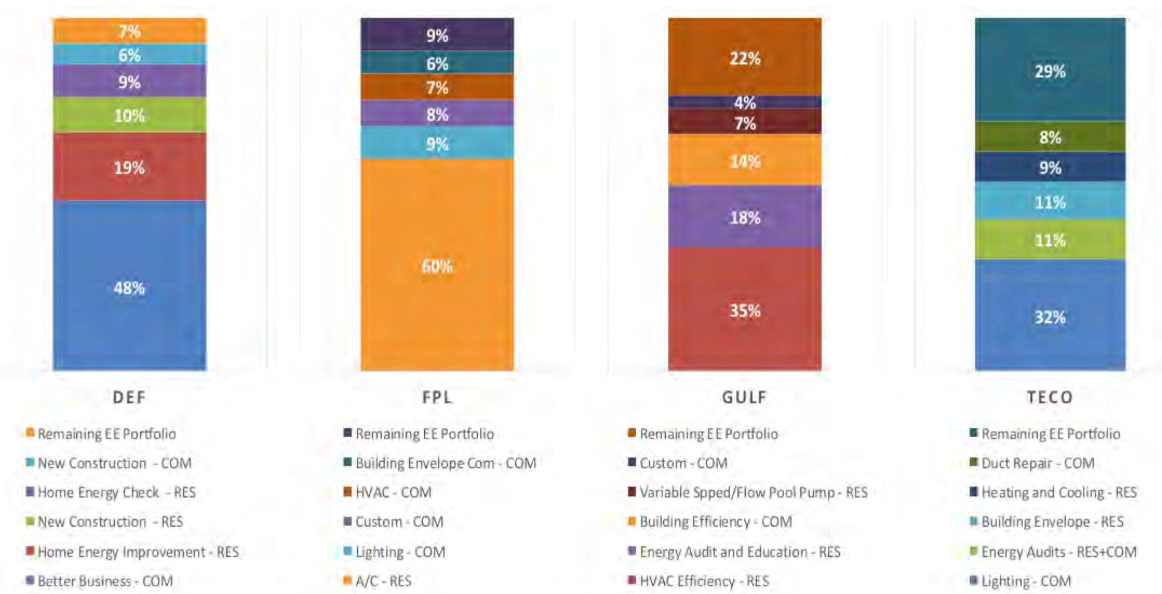
- **FEECA Utilities Costs Are Inflated, Resulting in Incorrect Benefit-Cost Scores**

Florida Utilities' Historic Costs Exceed Peers

Q. Considering the Utilities' current programs, how are the energy efficiency savings broken down by program?

A. During the first four years of the current program offerings, the top five programs generate 71-93% of the savings for each utility as shown in Figure 6. As discussed below, each of the Utilities has operated its programs to achieve results that are typically highly focused in terms of technologies supported and customers served.

Figure 6. Utilities Savings by Program, 2010-2013.



DEF's Better Business commercial energy efficiency saved about half of the portfolio savings each year, followed by the residential Home Energy Improvement program.

Together these programs comprise 67% of DEF's efficiency impacts from 2010-2013.

FPL's residential HVAC program dominates the Company's energy efficiency portfolio impacts. Approximately 60% of the energy efficiency impacts in the Company's portfolio came from this one program in 2010-2013. After the residential HVAC program, FPL's commercial lighting program has the next largest impacts, saving about 10% of the total portfolio savings.

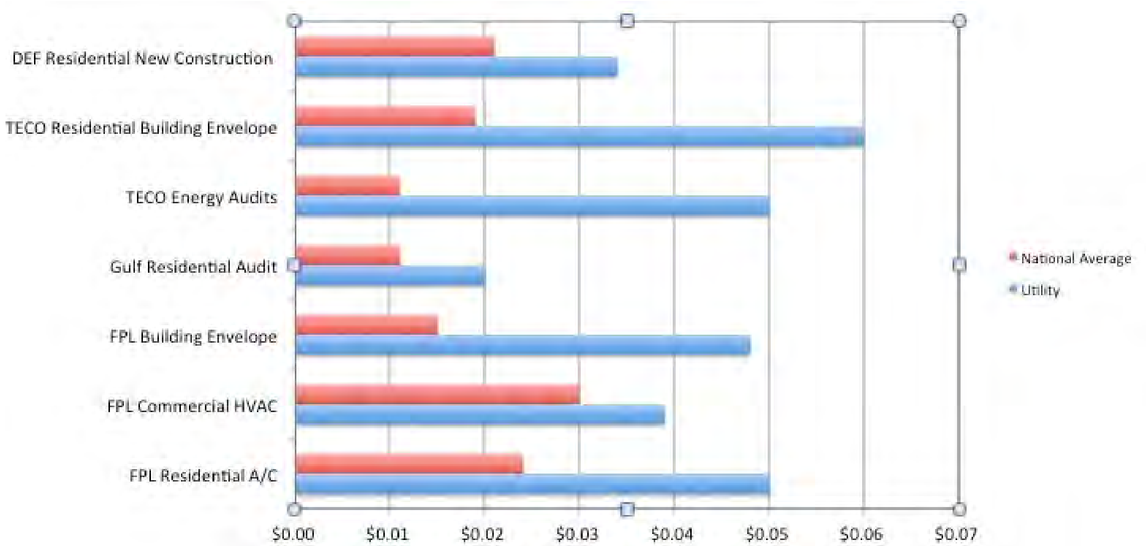
Gulf Power's savings were more diversified than FPL and DEF. Three programs produce the majority of the Company's savings: residential HVAC, residential energy audits and education and commercial building efficiency. Together these three programs comprise 67% of Gulf's efficiency impacts from 2010-2013.

Finally, TECO's portfolio, similar to Gulf, is more diversified. Commercial lighting, residential and commercial energy audits and education and residential building envelope are the three biggest programs, comprising just over half (54%) of TECO's efficiency impacts in 2010-2013.

Q. How did the Utilities program costs compare to the national average?

A. More than a third of the program impacts associated with Utilities portfolio have costs that are significantly above the average cost of comparable programs. Figure 7 illustrates the Utilities cost of saved energy based on their past filings and national average cost of saved energy for comparable programs.

Figure 7. Utilities Cost of Saved Energy and National Average Cost of Saved Energy



Q. What is the Cost of Saved Energy, and what is the significance of it?

A. Lawrence Berkeley National Lab defines cost of save energy (CSE) as, "comparable to the levelized cost of saved energy, which represents the per kilowatt hour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle." It is a valuable metric to use when comparing the cost of an efficiency program to supply side resources.

- ***Recent reports also indicate Florida's energy efficiency costs are inflated***

Q. **The Lawrence Berkeley National Lab released a report on the cost of saved energy in March 2014. Can you discuss the conclusions of that study?**

A. Yes. The Lawrence Berkeley National Lab ("LBNL") published a study in March 2014 on the initial findings of its Cost of Saved Energy Project. The study presents the initial program, sector and portfolio level results for the program administrator CSE for 2009-2011 using data collected from 31 states, including Florida.

One of the conclusions of the study is that regionally, there is a trend in the cost of saved energy, although there are a few outliers. In the Southeast, Florida is a clear outlier, and the cost of saved energy is approximately double what other Southeastern state's cost of saved energy is. As shown in Figure 8, Florida's cost of saved energy is about \$0.04/kWh while North Carolina's cost of saved energy is about \$0.015/kWh, and Maryland and Texas are at \$0.02/kWh.

Figure 8. LBNL Cost of Saved Energy values by state for electricity efficiency programs [28]

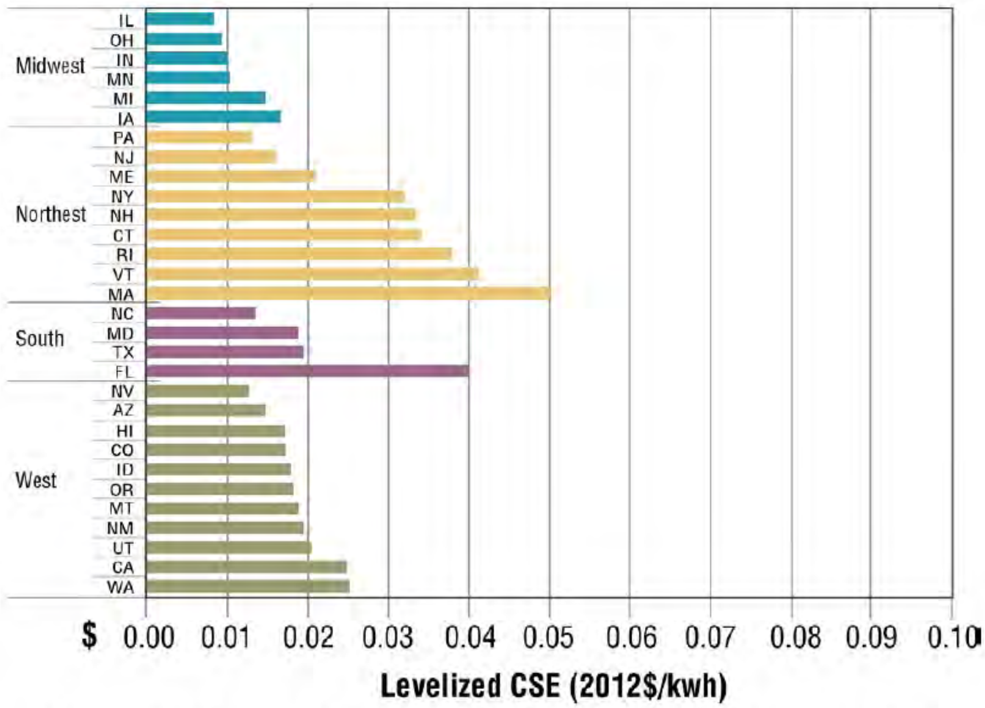


Figure 3-16. CSE values by state for electricity efficiency programs (excluding low-income programs)

Q. Did the LBNL report provide an explanation for why Florida's Cost of Saved Energy was higher than other Southeastern states?

A. No, the researchers were not able to identify why the costs were so much higher than other states in the states in the Southeast. As discussed above and shown in Figure 7, the

[28] Billingsley, et al. The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs. p37. Lawrence Berkeley National Lab. March 2014. Available at http://eetd.lbl.gov/news/article/57600/program-administrator-cost-of-s

Utilities excessive program costs from over a third of their energy efficiency impacts may provide some insight as to why Florida's costs are so much higher than other states in the Southeast.

- ***Administrative costs should not be included in goal setting costs***

Q. Should administrative costs be included in the measure level costs when evaluating for cost-effectiveness?

A. No. As discussed in SACE Witness Mosenthal's testimony in 2009, which is again applicable here:

> The selection of individual measures in terms of cost-effectiveness should only include the costs and benefits directly related to the measure. Once the list of cost-effective measures is determined, they can be mapped into programs. The programs and overall portfolio screening should include all program costs, including, but not limited to, that spent on marketing, administration, monitoring and evaluation, technical analysis, data tracking, and other necessary program costs (collectively referred to as program administrative costs). As noted earlier, Section 366.82(7) provides for the further review of costs at the program level, and therefore it is appropriate to exclude program costs at this point. [29]

Finally, the Utilities screened measures out of the energy efficiency potential based on cost-effectiveness -- inclusive of program administrative costs -- but did not take into account corresponding program benefits. This lopsided analysis results in measures being inaccurately removed from the Utilities energy efficiency potential.

Q. How much energy efficiency potential is removed based on the administrative cost screen?

[29] Direct Testimony of Philip Mosenthal, Florida Public Service Commission, Docket Nos. 080407-13, July 2009, p. 40.

A. TECO did not remove any energy efficiency measures from the potential based on the administrative cost when measures were evaluated using RIM or TRC.[30] FPL eliminated over 26,000 GWh of potential based on its "preliminary economic and screens", some component of which is the administrative screen.[31] Similarly, DEF eliminated over 7500 GWh of potential based on administrative cost, participant incentives and market penetration projections.[32] Gulf adds a administrative cost of $50/measure for residential measures; and $0.07/kWh for commercial and industrial measures.[33]

- **Utilities use of maximum incentive costs creates inflated total costs in benefit-cost tests**

Q. How do the Utilities determine the level of incentive that is appropriate for each measure when calculating their achievable potential?

A. The TECO,[34] DEF,[35] and Gulf[36] assume that they must reduce the payback period for all measures to two years when calculating their respective achievable potentials, and use that, or a RIM test of 1.0 to set their incentive level. FPL sets the incentive level to the level need to result in a Participant screen test benefit-cost ratio to 1.0, then runs the RIM test on the same measure, including the Participant incentive level, to determine if the measure passes RIM.[37]

Q. What reason did the Utilities provide for their incentive level?

TECO stated that it used a two year paypack period for its incentive to "maximize the achievable potential."[38] Gulf and DEF did not provide a reason for setting the incentive

[30] Direct Testimony of Howard Bryant, Docket No. 130201, April 2, 2014, pp. 19-21.
[31] Direct Testimony of Thomad Koch, Docket No. 130199, April 2, 2014, Exhibit TRK 4 and TRK 5.
[32] Direct Testimony of Lee Guthrie, Docket No. 130200 Exhibit 8 and Exhibit 13.
[33] Gulf Power Company's Response to SACE's First Request to Production of Documents, No.3, Final Econ w 30 yr lives – include prog costs, Apr. 16, 2014.
[34] Direct Testimony of Howard Bryant, at p. 22.
[35] Direct Testimony of Lee Guthrie at p. 31.
[36] Direct Testimony of John Floyd, Docket No. 130202, April 2, 2024, p. 17
[37] Direct Testimony of Steve Sim at p. 31.
[38] Direct Testimony of Howard Bryant at p. 22.

level to a two-year payback. FPL states that the incentive level will develop "a projection of maximum annual market penetration."[39]

Q. **What level of efficiency impacts do the Utilities anticipate achieving with this level of incentives?**

A. As shown at the beginning of my testimony in Tables 1-4, the Utilities are anticipating saving miniscule amounts of energy –less than 0.1% of retail sales annually.

Q. What is the impact of the Utilities assuming the maximum incentive level possible for the cost-tests?

A. It likely overstates the costs of achieving the Utilities proposed goals. This approach is like assuming that a hotel room is rented at the "rack rate," when in reality the hotel nearly always offers the room for a price that is much lower than the rate listed on the back of the hotel room door.

I did not receive granular enough information to assess exactly how overstated the Utilities' incentive levels are, but if the maximum available incentive level is assumed, then cost component cannot get any higher. The Utilities use this maximum incentive level is used regardless of the level of incentive that best practices would suggest is needed to motivate the customer to install an efficiency measure.

Q. Please summarize your conclusion on the cost of energy efficiency in Florida, and for the Utilities.

A. The Utilities energy efficiency programs have historically high costs, as shown through program data and independent reports. The Utilities energy efficiency planning costs in this goal setting proceeding are inflated because (1) the Utilities include the administrative cost, which is a program level cost, not a measure level cost and (2) the Utilities assume a maximum incentive, regardless of the level of incentive needed to

[39] Direct Testimony of Steve Sim at p. 39.

motivate a customer to adopt an efficiency measure.

- **Florida Utilities free-ridership methodology is flawed and outdated.**

Q. What is a free-rider?

A. A program participant who would have implemented the program's measure(s) or practice(s) in the absence of the program. Free-riders can be (1) total, in which the participant's activity would have completely replicated the program measure; (2) partial, in which the participant's activity would have partially replicated the program measure; or (3) deferred, in which the participant's activity would have partially or completely replicated the program measure, but at a future time beyond the program's time frame.[40]

Q. Are the Utilities required to evaluate free-ridership in the goal setting proceeding?

A. Yes. In regulation 25-17.0021, Florida Administrative Code, "[e]ach utility's projection shall reflect consideration of . . . free riders."

Q. What is EM&V?

A. EM&V stands for "Evaluation, Measurement and Verification," which is a critical component of the energy efficiency program cycle. EM&V allows the Utilities, regulators and interested stakeholders to understand how the energy efficiency programs are performing and what changes could optimize program implementation.

Q. Are the Utilities in Florida required to conduct EM&V on their energy efficiency programs?

A. Yes. Rule 25-170021(4)(i), F.A.C and Rule 25-170021(5)(1), F.A.C require a methodology for measuring savings, including actual efficiency impacts, and on-going measurement and evaluation results.

Q. What is the Two-Year Payback screen?

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[40] Department of Energy, *SEE Action Network. Energy Efficiency Program Impact Evaluation Guide*, Evaluation, Measurement and Verification Working Group. December 2012, available at: http://www1.eere.energy.gov/seeaction/pdfs/emv_ee_program_impact_guide.pdf

A. The Utilities use a "two-year payback" screen as an alleged proxy for free-ridership. There are no other utilities in the Southeast, or the country that use this methodology. Using a two-year screen as a proxy for free-ridership is ridership is a seriously flawed approach to addressing free-ridership.

Q. What is the origin of the "two-year payback" methodology?

A. This methodology originated from a 1994 Order. This method has not been defined in any formal administrative rulemaking. Suffice to say, since 1994, the EM&V of energy efficiency has developed considerably, yet the Florida Commission is still allowing the Utilities to use a methodology from 1994 to unnecessarily screen out cost-effective energy efficiency.

Further, in SACE's deposition of Dr. Sim, he acknowledged FPL created this methodology to address free-riders in 1994 and that he was part of that proceeding. However, Dr. Sim stated he was not aware of any other utilities in other states that used it, nor how FPL chose two years as the basis for the methodology.[41]

Q. Why is the two-year payback methodology flawed?

A. First, it uniformly applies the same free-ridership rate to every measure that is economic, which is too broad. There are no other utilities in the Southeast that use a blanket methodology to identify free-ridership for all measures. Second, it is also inaccurate because it eliminates entire measures because of the *potential* for free-ridership. This is also too broad, and again, there are no other utilities in the Southeast that eliminate entire measures from their achievable potential or energy efficiency programs because there *might* be free-ridership.

Every other regulated utility in the Southeast uses surveys and gather data through their EM&V process at the measure or program level to determine how much the utility

[41] Deposition of Steven Sim, Docket No. 130199, May 2, 2014, p. 79.

incentive influenced the customer's decision to purchase an energy efficiency measure.

Q. Did SACE support the two-year payback methodology in the last FEECA proceeding?

A. No, although SACE was a partner in the technical potential study with the Utilities, the Utilities chose to exclude SACE from formal decision-making authority in the economic and potential study. The Utilities decision was expressed by changes to the Itron contract that were made at the last minute. While SACE was allowed to participate in some conversations regarding the methods used in the economic and potential study, it is my understanding that our suggestions for alternative study approaches were rejected by the Utilities. Utility witnesses then unfairly criticized SACE for its critique of the two-year payback method in testimony.

Q. Gulf Power cited the National Energy Modeling System as justification for the two year payback screen. Is that a valid reference?

A. Gulf Power stated that the National Energy Modeling System documentation characterizes the use of a two-year payback level as being "based on general utility practice." Gulf Power did not provide a citation to the modeling documentation, nor is it easily available online.

Further, a Stanford University review of NEMS documented the use of the Load and Demand Side Management submodule as

> parameterized by two estimates of the relative importance of a capital and operating costs in consumer preferences. Thus in both [commercial and residential] sectors, the complexity of consumer choice is reduced to a set of input parameters that approximate the time value of money. This design choice makes it difficult to use the model to estimate (or account for) the variety of energy efficiency market failures and behavioral complexities identified in the academic

> literature (e.g., Gillingham et al., 2009, 2012; Shogren and Taylor, 2008). Addressing these topics would require a new set of input parameters that translate the barriers studied into the hurdle rate and logit framework used in NEMS.[42]

While I was unable to verify that NEMS documentation states that it is general utility practice to use the two-year payback level, the Stanford review clearly indicates that NEMS oversimplifies the factors that affect consumer choice to a "time value of money" decision. NEMS simplifies many aspects of energy markets and is not typically used by utilities for planning activities. If this is the only external source that the Utilities can point to as validation for the two-year payback level, there can be no basis for the claim that this is "general utility practice."

Q. What does TECO say about the two-year payback?

A. In response to SACE's first request for production of documents, no 7, TECO provided two documents in support of the two-year payback as an appropriate assumption for TECO to make regarding free-ridership. The response is not compelling or particularly applicable to this proceeding because TECO does not include an example of electric utilities using this assumption in planning. The documents in response are also 7 years old, which further reduces their credibility. In sum, the response TECO provided asserts that non-residential customers hurdle rate is approximately two years. However, given that the goal of FEECA is to cost-effectively reduce energy peak and sales, not overcome hurdle rates for businesses, the information in the response is inconsequential.

Q. Is it reasonable to assume that customers will purchase any efficiency measure that has a two year payback or less?

A. No. There is an entire body of evidence on market barriers to energy efficiency.[43] If all

[42] http://www.stanford.edu/~wilkejt1/Documents/End%20Use%20Technology%20Choice%20in%20NEMS.pdf
[43] *See* Golove, William; Eto, Joseph, *Market Barriers to Energy Efficiency: A Critical Reappraisal of the Rationale for Public Policies to Promote Energy Efficiency*, LBNL.March 1996, available at

customers were rational economic actors, the CFL saturation rate in Florida would be 100%. As I do not have access to the Utilities EM&V reports, I am not certain what the saturation rate is. However, in South Carolina, where utilities have been providing incentives for CFLs for several years, socket saturation is still only 18%. This means, even with an additional economic incentive, there are still non-financial barriers to efficiency measure adoption. Simply screening out measures based on an assumption that the technology will be adopted because it is economically rational is contrary to the history of energy efficiency barriers, and the policies to overcome those barriers in the United States for the last 40 years.

Q. What is the impact of using a two-year payback as a proxy for free-ridership?

A. Beyond being an ineffective and archaic policy, the two-year payback significantly reduces the achievable potential identified by the Utilities. TECO eliminated 583 GWh from its RIM portfolio and 1133 GWh from its TRC portfolio because of the two year payback.[44] FPL eliminated over 26,000 GWh of potential based on its "preliminary economic and screens," some component of which is the two year screen.[45] Similarly, DEF eliminated over 5309 GWh from its RIM portfolio and 4014 GWh from its TRC portfolio based on avoided cost and the two year payback screen.[46] Gulf eliminated 1069 GWh from its RIM portfolio and 2563 GWh from its TRC portfolio due to customer adoption projections and the two year payback screen.[47]

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http://emp.lbl.gov/sites/all/files/lbnl-38059.pdf; Vaidyanathan, Shruit et al, *Overcoming Market Barriers and Using Market Forces to Advance Energy Efficienc,*. ACEEE. March 2013, available at http://www.aceee.org/sites/default/files/publications/researchreports/e136.pdf; Ungar, Lowell et al., *Guiding the Invisible hand: Policies to Address Market Barriers to Energy Efficiency*. ASE. September 2012, available at: https://www.ase.org/sites/ase.org/files/guiding_invisible_hand_summerstudy2012_0.pdf; Austin, David, *Addressing Market Barriers to Energy Efficiency in Buildings: Working Paper* 2012-10. Congressional Budget Office. August 2012, available at http://www.cbo.gov/publication/43476.

[44] Direct Testimony of Howerd Bryant at pp. 21 -22,

[45] Direct Testimony of Thomas Koch, at Exhibit TRK 4 and TRK 5; *also* Direct Testimony of Steve Sim at p. 6.

[46] Direct Testimony of Lee Guthrie, at p. 33.

[47] Direct Testimony of John Floyd, at p. 17, Schedule 8 and 10.

Q. **Please summarize your recommendations for evaluating freeridership.**

A. Historically, it seems that this methodology was first used in the 1994 FEECA goal setting docket. However, it is an imprecise and antiquated methodology, and there is no reason to continue using it. Using a two-year payback as a proxy for free-ridership is inaccurate, and reduces cost-effective savings from the goal setting process unnecessarily. In addition, there is a large body of research on how utility customers are not rational economic actors. I recommend that free-ridership be accounted for as it is in the rest of the Southeast, through evaluation, measurement and verification.

- **The Utilities potential studies does not satisfy the statutory requirements, and are overly conservative, resulting in an underestimation of the efficiency potential in Florida**

Q. **What is the statutory guidance for the technical potential study in Florida?**

A. Section 366.82, F.S. directs the Commission to evaluate the technical potential of *all* demand side and supply side energy conservation measures, including demand side renewable energy systems.

A. **Did the Utilities perform a new technical, economic, and achievable potential study for this proceeding?**

A. No. The Utilities only updated their 2009 potential study. They eliminated measures that have become the baseline because of codes and standards and added in some new measures, and adjusted the participation and customer growth rates.

Q. **Is it appropriate for the Utilities to conduct a new energy efficiency potential study every three to five years?**

A. Yes. As the Georgia Public Service Commission Witnesses Barber, Spellman and Kaduk stated in their testimony in the 2013 Georgia Power IRP, there are many reasons to conduct a new potential study at the beginning of each IRP (which is a three year cycle). I have included an excerpt of the testimony as SACE-NAM-Exhibit 7.[48] Further, the Georgia Public Service Commission Staff found that there were significant differences in the potential studies used by Georgia Power in 2007 and 2012 (a five year period). The staff found:

> The avoided cost forecasts used in the two studies are very different. There are measures included in the 2012 study that are not included in the 2007 study. The annual kWh savings for many measures in the 2012 study are very different than what was used in the 2007 study. The total savings attributable to classes of measures are very different between the two studies. The 2007 study determined that the achievable savings potential over 10 years was 10 percent. The 2012 study determined that the achievable savings potential was 15 percent, 50 percent higher than the 2007 study.[49]

Q. Do the Utilities make conservative assumptions in their energy efficiency potential studies?

A. Yes. As I mentioned, the Utilities relied on the 2009 Itron technical potential study to craft the technical potential in this docket. As SACE Witness Mosenthal stated in the 2009 goal setting proceeding:

> I believe the technical potential study performed by Itron is a reasonable first cut of potential but on the conservative (i.e. low) side. First it ignores technology advancement future price reductions for efficiency opportunities…Secondly, the measures list, while large, does not fully include all potential opportunities nor fully incorporates important synergies between measures and systems that can

[48] Georgia Public Service Commission, Docket No 36498, *Staff's Direct Testimony of Jamie Barber, Richard F Spellman, and John L. Kaduk*, P. 21, available at: http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=147829
[49] *Id at p. 32*.

> result in very deep and cost-effective savings.

These concerns are still valid in this proceeding. In addition, as stated in Witness Mosenthal's 2009 testimony, generally, technical potential estimates are conservative because it is impossible to accurately account for every possible opportunity in every market segment.

Again, as in the 2009 study, the Utilities have excluded several measures from the technical (and therefore economic and achievable) potential. SACE reviewed the measures from the 2009 energy efficiency potential study and compared them to recent energy efficiency potential studies for TVA[50] and Georgia Power[51]. There are many measures that appear to have been excluded from the 2009 energy efficiency potential study that were included in the TVA and Georgia Power energy efficiency potential study. SACE has provided a list of these measures in SACE-NAM Exhibit 8.

Finally, as in the 2009 technical potential, there are several sectors excluded completely from the energy efficiency potential when the Utilities evaluated technical potential for the 2014 energy efficiency goals. As stated in the 2009 Itron technical potential study:[52]

> It should also be noted that energy and peak savings opportunities in a few end-use sectors were specifically excluded from this study. These sectors were agriculture, transportation, communications and utilities (TCU), construction, and outdoor/street lighting…the out-of-scope sectors accounted for just over 10% of total sales [for FEECA utilities].

Q. How do other utilities in the Southeast determine their economic and achievable potential?

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[50] Tennessee Valley Authority Potential Study. *Final Report*, December 21, 2011, Global Energy Partners, available at http://www.tva.gov/news/releases/energy_efficiency/GEP_Potential.pdf

[51] Achievable Energy-Efficiency Potentials Assessment. Submitted to Georgia Power Company by Nexant, January 31, 2012, available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=140174

[52] Itron, Inc., *Technical Potential for Electric Energy and Peak Demand Savings in Florida*. March 2009.

A. After calculating technical potential, Georgia Power,[53] TVA[54], and Duke Energy Carolinas[55] then compare energy efficiency measures to their avoided cost. All measures that cost less than avoided cost pass to the economic potential.

None of these utilities pre-screen benefit-cost tests. None of these utilities exclude measures from economic potential because of administrative costs or the potential for free-ridership, as discussed earlier in my testimony.

After calculating economic potential, the utilities determine their achievable potential and participation in a variety of ways.

- Georgia Power: Two step process of (1) performing a regression analysis on EIA Form 861 data and (2) determine the base value by reviewing reports with information on incentive levels and achievable percentages. The analysis indicated that roughly 50% of the economic potential can be achieved at an incentive level of 50% of incremental cost.
- TVA: Apply market acceptance rates and program implementation factors. Market acceptance rates embody customer awareness and willingness to adopt energy efficiency equipment and measures in light of perfect information about the technologies and measures and perfect implementation of programs by utilities. Program implementation factors take into account existing market, financial, political and regulatory barriers that are likely to limit the amount of savings that might be achieved through EE programs. High achievable potential estimates are created by applying Market Acceptance Rates to economic potential. Low achievable potential estimates are created by applying both

[53] Achievable Energy-Efficiency Potentials Assessment. January 31, 2012. Submitted by Nexant to Georgia Power Company.
[54] Global Energy Partners, *Tennessee Valley Authority Potential Study*. Report 1360. December 21, 2011.
[55] Forefront Economics Inc., *Duke Energy Carolinas: Market Assessment and Action Plan for Electric DSM Programs*. North Carolina.,. February 23, 2012.

Market Acceptance Rates and Program Implementation Factors.

- Duke Energy Carolinas and Duke Energy Progress: Achievable potential is determined given specific program designs and annual participation targets refined from experience.

Q. Do the Utilities provide a comparable level of detail as other Southeastern utilities regarding their technical, economic, and achievable potential?

A. No. While the Utilities' process to identify their technical potential is fairly straightforward, the Utilities descriptions of determining their economic and achievable potential are very convoluted and difficult to follow.

Q. **How did the Utilities determine the economic and achievable potential in their energy efficiency potential studies?**

A. In order to determine the economic and achievable potential the Utilities used 4-5 screens to eliminate measures. Table 5 describes the screens used.

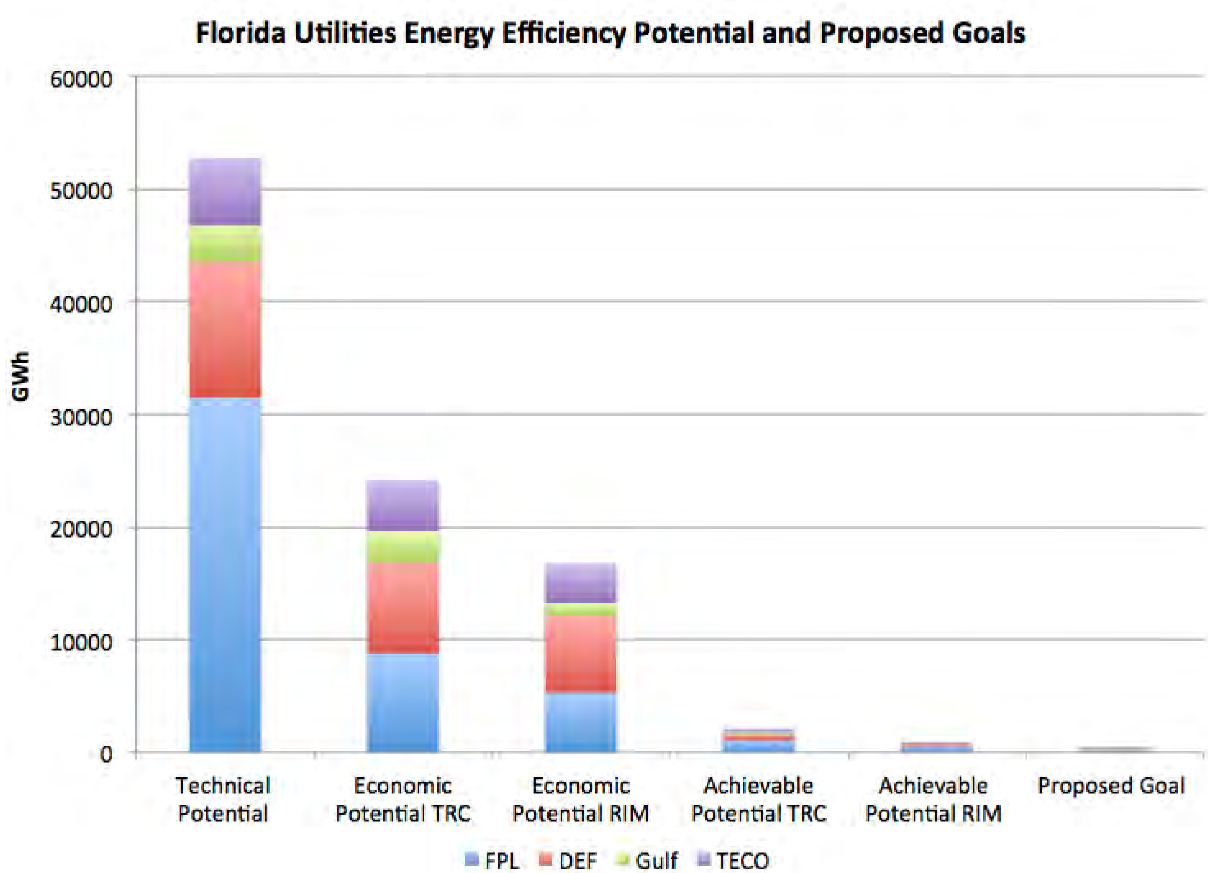
Table 5. Economic and Achievable Potential Screens

	Description
Pre benefit-cost screen	Run benefit-cost test with lost revenue requirements only in RIM; and participant cost only in TRC. Eliminate measures that do not pass RIM or TRC.
Administrative cost	Run benefit-cost tests with administrative costs only, eliminate measures that do not pass RIM or TRC.
Potential for Free-ridership	Run benefit-cost test to see if customer payback is <2 years in RIM and TRC. Eliminate measures with <2 year payback in RIM and TRC.
Incentive level	Determine incentive level by providing the lesser of a two year payback or the incentive level to take RIM or TRC to 1.05
Participation level	Varies by utility. Market penetration models for DEF and FPL.

Figure 9 displays each of the Utilities technical, economic, achievable and proposed goals. As shown, FPL's has the most significant reduction in its technical potential.

SACE-NAM-Exhibit 9 has figures with each of the Utilities technical, economic, achievable and proposed goals.

Figure 9. Florida Utilities Energy Efficiency Potential and Proposed Goals



Q. Do you have concerns about the screens the Utilities use to create their economic and achievable potential?

A. Yes, I have several: (1) the screens are opaque, (2) as I discussed earlier, administrative costs should not be included in a measure level analysis, and the two year screen should not be used as a proxy for free-ridership, (3) the incentive level should not be used as a screen to eliminate measures, (4) the Utilities are not considering the benefits of measures correctly, and (5) the obfuscation of participation data, a key component in the potential study, makes evaluation difficult.

Q. What makes you say that the Utilities economic and achievable screens are opaque?

A. There is little information provided by the Utilities regarding the impact of each of these screens, or the sizable difference between the achievable potential and the Utilities proposed goals. For example, I cannot determine the impact on the efficiency potential of: (1) administrative costs for Gulf, FPL or DEF, (2) participation levels, for any of the Utilities, (3) avoided cost for Gulf, FPL or DEF, (4) free-ridership for Gulf, FPL or DEF and (5) the total cost or benefits, in real or nominal dollars of the RIM and TRC tests for any of the utilities.

Q. Can you restate why administrative costs should not be included in measure level analysis?

A. The programs and overall portfolio screening should include all program costs, including, but not limited to, that spent on marketing, administration, monitoring and evaluation, technical analysis, data tracking, and other necessary program costs (collective referred to as program administrative costs). As noted earlier, Section 366.82(7) provides for the further review of costs at the program level, and therefore it is appropriate to exclude program costs at this point.

Q. Can you restate why the two-year payback is a poor methodology for evaluating free ridership?

A. First, it uniformly applies the same free-ridership rate to every measure that is economic, which is too broad. Second, it is also inaccurate because it eliminates entire measures because of the *potential* for free-ridership. Every other regulated utility in the Southeast uses surveys and gather data through their EM&V process at the measure or program level to determine how much the utility incentive have influenced the customer's decision to purchase an energy efficiency measure.

Q. Why is it inappropriate to use the incentive payment to eliminate efficiency measures from the potential study?

A. I am not aware of any utility that screens measures out of its potential based on incentive level. While I have not reviewed the methods for every utility in the country, my colleagues and I have reviewed many utility potential or program planning studies from utilities in every region of the country.

With respect to utilities in the Southeast, after determining the achievable potential, Georgia Power and TVA estimate participation levels based on incentive. These utilities do not eliminate measures because they cannot "cost-effectively" achieve a two-year payback. Notably, none of these utilities offered substantial energy efficiency programs when the Utilities began to use the two-year payback methodology. As each of these utilities (and their regulators) worked through the process of developing their planning methods, they did not choose to follow Florida's practices.

Well-planned energy efficiency programs do not focus exclusively on incentive payments as a planning and program design criterion. The best practice among utilities is to use a variety of criteria to determine the appropriate mix of technical assistance, marketing/education activities, trade ally training and incentive levels to overcome specific barriers to adoption for the measure and program.

Q. What is your concern with the benefit side of the benefit-cost tests?

A. The Utilities do not appear to take into account non-energy benefits, also known as Other Program Impacts (OPI). More specifically, OPIs are the costs and benefits that are not currently captured by the avoided cost or the energy efficiency savings.[56] Programs targeted to the low- and fixed-income sector have numerous OPIs; for example, reduced

[56] Woolf, Tim, et al. Energy Efficiency Cost-Effective Screening. RAP and Synapse Energy Economics. November 2012, available at: http://www.raponline.org/event/the-importance-of-effective-energy-efficiency-cost-effectiveness.

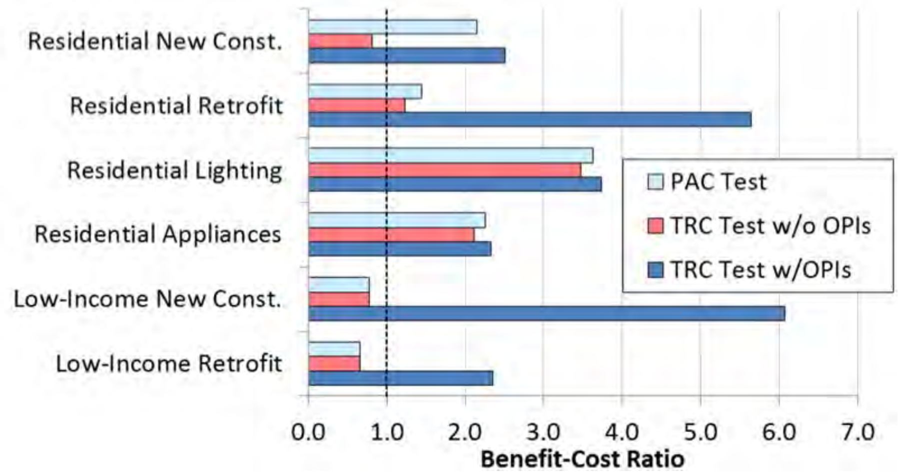
customer arrearages and reduced bad debt write-offs for utilities, as well as improved health and safety, increased comfort and aesthetics, and reduced maintenance costs for participants.

OPIs are particularly important when using the Total Resource Cost ("TRC") test, one of the standard tests used to determine program cost-effectiveness.[57] Currently, there are 12 states that account for OPIs in their TRC evaluation.[58] Florida is not one of those states. Accordingly, in the current TRC test as applied by the Utilities, OPI benefits are not accounted for and show up in the cost-test as having zero value—resulting in a TRC score that is skewed and misleading. The Commission should reconsider the inequitable result of counting of all costs, but not all benefits, as the current Total Resource Cost test does.

Figure 10, below, shows six Massachusetts energy efficiency program cost-test scores: first using the program administrator test, second using the total resource cost test without OPIs, and finally the total resource cost test with OPIs.[59] As the chart shows, when OPIs are considered in the cost-effective evaluation, the low-income new construction and low-income retrofit programs move from being uneconomic to cost-effective.

[57] Woolf, Tim, et al. Best Practices in Energy Efficiency Program Screening, Prepared for National Home Performance Council by Synapse Energy Economics, July 2012, available at: http://www.nhpci.org/images/NHPC_Synapse-EE-Screening_final.pdf
[58] Woolf, Tim, et al. Energy Efficiency Cost-Effective Screening, page 5. RAP and Synapse Energy Economics. November 2012, available at: http://www.raponline.org/event/the-importance-of-effective-energy-efficiency-cost-effectiveness.
[59] Excerpted from Woolf, Tim, et al. Energy Efficiency Cost-Effective Screening. RAP and Synapse Energy Economics. November 2012, available at: http://www.raponline.org/event/the-importance-of-effective-energy-efficiency-cost-effectiveness.

Figure 10. Massachusetts Energy Efficiency Program Cost-Test Scores[60]



Q. How do the utilities calculate participation rates?

A. The Utilities all appear to use different methodologies to calculate participation rates. FPL Witness Koch provides the most detail, stating that FPL employed a modeling tool on a measure-by-measure basis relying on a number of elements that reflect FPL's market experience:

- Participant's years-to-payback (using the maximum rebates);
- Payback Acceptance Curves
- Historical adoption rates
- Projected changes in market conditions
- Impacts of the delivery channel

However, there is no detail provided as to what market research was used to create payback acceptance curves, what empirical factors or qualitative factors affect historical adoption rates, and if there are any additional changes in market conditions beyond increasing codes and standards. Finally, instead of considering how best to work with participating independent contractors, FPL uses the inappropriately developed efficiency

[60] PAC refers to Program Administrator Cost Test, an alternative name for the Utility Cost Test.

potential to determine whether or not the contractors will participate in the program, and if the low efficiency potential it has created will further restrict customer access to the program. The circular logic is exhausting.

TECO mentions that it updated participation levels, but does not provide any detail about how or what the impact of the participation levels are. DEF Witness Guthrie states that DEF applied a market penetration analysis to estimate participation projections.[61] Gulf Power states that customer adoption projections were developed based on the level of economic benefit provided to the customer.[62]

Given the obfuscation of participation data by the Utilities, it is difficult to specifically critique this aspect achievable potential created by the Utilities.

Q. **What is the impact of these screens on the Utilities energy efficiency goal?**

A. As shown in NAM Exhibit 4, the Utilities proposed goals are less than 2% of the technical potential.

Q. Are the Utilities evaluating *all* cost-effective potential, as required by the statute?

A. No. The fact that sectors are explicitly excluded from the technical potential illustrates that not all potential was evaluated. In addition, the convoluted and inappropriate screens for the economic and achievable potential result in the Utilities not evaluating all cost-effective potential.

Q. What is an appropriate level of energy efficiency savings goals for Florida Utilities?

A. In the absence of meaningful analysis, Florida Utilities should aspire to achieve 1% of retail sales annually. Currently, 14 states are saving at least 1% of electricity sales each year, and the leading state saved upwards of 2% of electricity sales a year, based on the most recent data available (2011).[63] While it is not realistic to assume that the Florida

[61] Direct Testimony of Lee Witness Guthrie at pp. 31-32.
[62] Direct Testimony of John Floyd at p, 17.
[63] Downs, et al., *The 2013 State Energy Efficiency Scorecard,* November 2013.

Utilities could achieve 100% of cost-effective energy efficiency potential, 1% of sales is a reasonable annual savings target for what an innovative energy efficiency program could achieve over the next few years. Given that five states achieved this level of savings in 2009,[64] it does not seem unreasonable that Florida Utilities could achieve 1% in upcoming years. Gulf Power, in 2013 achieved 0.65% savings as a percent of sales – almost doubling its energy efficiency impacts from 2012. Certainly the other Florida Utilities could perform similarly. Furthermore, in the long run, it is likely that additional practices or technologies will be developed that offer further opportunities to achieve cost-effective energy savings, offering the opportunity to sustain high levels of annual program impacts for many years to come.

Q. Please summarize your recommendations on the Utilities' technical, economic and achievable potential.

A. The Utilities should conduct a new energy efficiency potential study for each goal-setting proceeding. A variety of inputs change over five years. When conducting the energy efficiency potential study, the Utilities should allocate funding to investigate measures for the technical potential instead of asking interested parties to provide granular details. The economic potential screen should only eliminate measures that cost more than the utility's avoided cost, and program level costs should not be evaluated, only measure level cost should be analyzed at this stage. The utility should provide a high, medium and low achievable potential based on varying penetration rates.

Q. What findings should the Commission reach with respect to the Utilities' technical, economic and achievable potential?

A. Based on the flawed nature of the technical, economic and achievable potential by the Utilities, I recommend that the Commission set energy efficiency goals of 0.75% of retail

[64] Sciortino, et al., *The 2011 State Energy Efficiency Scorecard*, October 2011.

sales for the Utilities, with the intent of ramping up to 1% in another year. I also recommend that the Commission require the Utilities to initiate a new proceeding at the conclusion of this proceeding. In this new proceeding, I suggest the Utilities conduct a full technical, economic and achievable potential study, in an open and transparent way that allows the residents of Florida to weigh in their energy future. Further, this new proceeding could be an opportunity for the Commission to explore a lost revenue adjustment mechanism and performance incentive to create the appropriate incentives for the Utilities to pursue all cost-effective energy efficiency.

5. FPL and DEF do not adequately incorporate energy efficiency into their resource planning, resulting in unnecessarily low efficiency goals

Q. How do the utilities incorporate energy efficiency in their resource planning in this proceeding?

A. Each of the Utilities has its own methodology. My review focuses on FPL and DEF because they are the larger utilities. I will start with my review of FPL's incorporation of energy efficiency in its resource plan.

Q. How does FPL incorporate efficiency into its resource planning?

A. According to FPL Witness Sim, Step 5 of FPL's DSM planning process involves creating a Supply Only resource plan as well as plans with some amount of DSM. One important aspect of Step 5 is that if DSM resources cannot meet projected needs then a supply option is added first and DSM resources are reduced to exactly meet FPL's need.

Q. What are your overall comments on FPL's resource planning process?

A. FPL's resource planning lacks analytical rigor and transparency, and therefore any credibility. What little optimization analysis FPL did perform did not examine any additional energy efficiency after 2014. Moreover, the value of FPL's limited analysis is questionable since FPL failed to provide SACE with the files it requested despite repeated communications with FPL.

Q. How does FPL's process lack analytical rigor?

A. Credible resource plans include analysis using what's known as a capacity expansion model. A capacity expansion model creates portfolios of resources to meet a utility's future needs. The benefit of a capacity expansion model over manually creating these portfolios is that it can eliminate portfolios that do not meet requirements such as reserve margin and it constructs those portfolios so as to meet some objective such as minimization of cost (revenue requirements).

FPL licenses a very popular capacity expansion model called Strategist, however, as Dr. Sim testified in his deposition in this case "We use a [sic] Strategist model in only one instance. In creating the supply only plan…"[65] The inputs and outputs for a single Strategist run can be reproduced in a series of reports.

Q. How does FPL's process lack transparency?

A. For example, of the more than 50 reports Strategist produces for each run, FPL gave SACE just three different Strategist reports pertaining to 16 different portfolios. We were able to ascertain that these reports relate to the single Strategist run FPL performed. But no other meaningful information could be garnered because FPL still failed to provide the full set of inputs and outputs we requested.

After further follow-up FPL stated that these were the only files related to SACE's request for Strategist files. This could only be true if FPL deleted the executable Strategist file after producing the reports it gave to SACE. FPL's inability to even provide the information we requested should leave this Commission with serious doubt about the credibility of FPL's planning process.

Q. Despite the fact that only limited reports were provided, is there anything that you

[65] Deposition of Steve Sim at page 39, lines 18-19.

can say about the one Strategist run related to this docket that FPL did perform?

A. The limited reports FPL provided suggests: (1) that FPL either limited the resources available for Strategist to choose such that a combined cycle unit in 2019 was always chosen or; (2) FPL forced Strategist to choose the combined cycle unit.

Q. That 2019 combined cycle unit is in fact FPL's avoided unit for purposes of screening DSM measures, correct?

A. Yes, it is. And as a result of the few Strategist report FPL gave SACE, it does not appear that FPL can demonstrate that its choice of this unit for avoided cost purposes was the best choice for the system and customers.

Q. Does the choice of the combined cycle in 2019 otherwise materially affect FPL's DSM goal setting?

A. Yes, it does. As I mentioned above, FPL Witness Sim states that DSM resources cannot meet projected needs then a supply option is added first and DSM resources are reduced to exactly meet FPL's need. As Dr. Sim describes at page 46, lines 4 through 13 of his testimony:

> For example, returning to Exhibit SRS-8 and looking at Columns 10 and 11 for the year 2020, a resource need of 1,512 MW (Supply) or 1,260 MW (DSM) is presented. However, if a new CC unit of 1,269 MW (Summer) is added in the year 2019 to meet the 2019 resource need, the projected remaining resource need for the year 2020 will be reduced to 243 (= 1,512 – 1,269) MW (Supply). The equivalent DSM MW value would become 203 MW (= 243/1.20) In this case, 203 MW of DSM could fully meet the remaining resource need in the year 2020 (if we temporarily set aside the question of whether this DSM addition is desirable from economic, non-economic, and reliability perspectives).

This approach is fatally flawed and completely ignores economic considerations. It has nothing to say about the cost-effectiveness of DSM instead relying entirely on the metric of whether peak needs are met or not. As a result, Dr. Sim has no basis upon which to conclude that "FPL could not have cost-effectively accommodated more than 337 MW of DSM in the 2015-2025 period"[66] since that conclusion is based solely on FPL's calculation of need remaining after considering the supply-side resources it intends to add, and not on the cost-effectiveness of resources.

Finally, this approach is even more illogical considering that FPL could build a combined cycle plant with total output less than 1,269 MW. Many other plants have been built at lower output, such as Duke Energy Carolina's recently approved Lee units.

Q. Does FPL have plans that evaluate more DSM than FPL's preferred amount?

A. In Step 5, FPL does include "non-conforming plans" that include more DSM. I would note that FPL calls these plans "non-conforming" because they do not always meet FPL's unnecessary generation-only reserve margin criteria. There is no evidence that the supply side additions to these plans are anything other than hardwired.

If the plans with higher levels of DSM were optimized appropriately then you might see Strategist choosing a smaller CC in 2019 for example, which would make these plans look more financially attractive than they currently do.

Q. How does FPL evaluate the financial viability of the plans in Step 5?

A. The plans were evaluated on the basis of levelized system average electric rate. This is illogical because customers care about their bills, not their rates and since bills are a function of consumption *and* rates, FPL is painting an incomplete economic picture.

Q. What is a more appropriate metric than levelized system average electric rate to evaluate DSM in Step 5?

A. The present value of revenue requirements (PVRR) is the best way to evaluate cost from

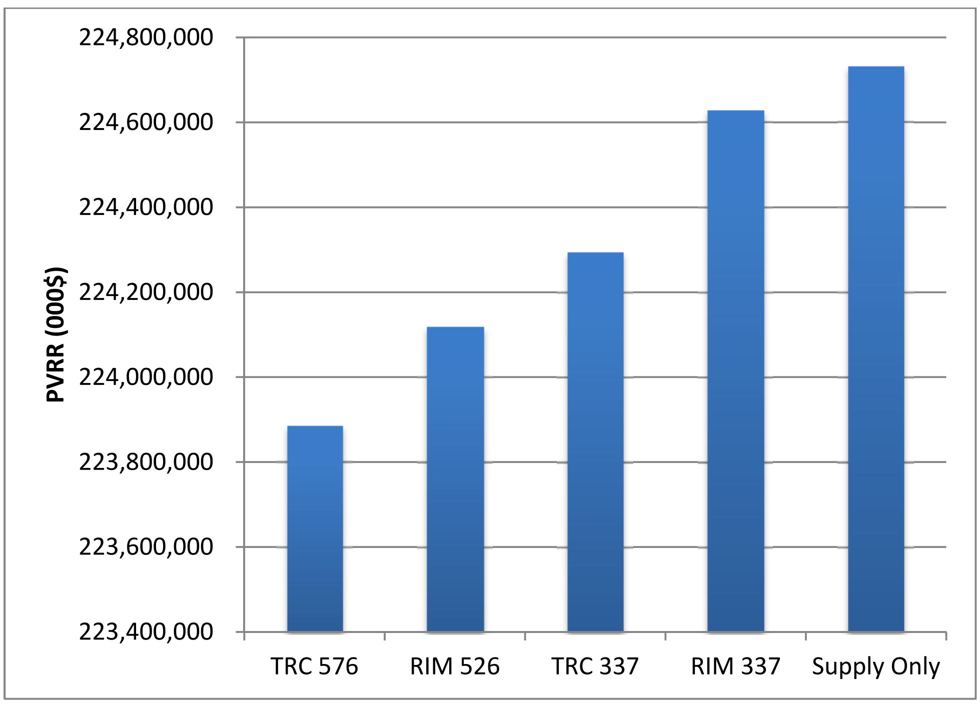
[66] Direct Testimony of Steve Sim at p. 50, lines 4-6.

the customers' perspective. However, as Dr. Sim testified in Docket No. 130009-EI "From an economic standpoint or perspective, we look at resource options that provide our customers reliable service at the lowest possible electric rates, ***not necessarily the lowest possible cost*** [emphasis added]."

Q. What, if anything, can you say about the PVRR of FPL's plans?

A. Despite the many flaws of FPL's DSM screening process, the PVRR results show exactly what one would expect – that higher levels of energy efficiency result in lower cost to customers.

Figure 11. Present Value Revenue Requirement of FPL's Five Plans



As Figure 11 demonstrates, the TRC 576 plan, with the highest level of DSM FPL analyzed in this step, results in the lowest cost to customers. I would note that while it's not entirely clear from Dr. Sim's testimony, it's my understanding that the difference between the TRC 337 and RIM 337 plans is that they include different measures.

Q. It appears that the differences in PVRR between all of these plans is small, is that correct?

A. Absolutely. But that is because the amount of energy efficiency in any of these plans is very small indeed, not because energy efficiency can't significantly reduce revenue requirements.

Q. What are your overall comments on DEF's resource planning process?

A. DEF uses a flawed resource planning process that does not appropriately estimate its avoided costs.

Q. Please explain.

DEF uses Strategist, a capacity expansion model, to create an avoided supply-side plan for screening against DSM measures. Strategist is a powerful tool compared to spreadsheet analyses, but its ability to produce useful information is also a function of the information it has to work with. In the case of DEF, the Strategist model was so constrained as to apparently give DEF the "answer" it wants rather than offering anything approaching an objective result.

Strategist allows the user to "hardwire" resources into its plan so that the model must include the specified resource in the year and in the quantity that the user dictates. Of the 5513 MW added by Strategist between 2014 and 2018, only 2323 MW was not hardwired. Of that 2323 MW, 1671 MW represents existing capacity at the Hines Energy Complex along with 220 MW arising from chiller upgrades from those units.[67] Of those remaining 652 MW that were not hardwired, two CT units (438 MW total) chosen by Strategist in 2016 and 2017 were not included in DEF's avoided cost for unexplained

[67] http://www.pennenergy.com/articles/pennenergy/2014/05/duke-energy-proposes-new-gas-power-projects-for-florida.html

reasons. That left just one 214 MW CT coming online in 2018 as the first avoided unit for purposes of DSM screening. The effect of this assumption is that there are no avoided generation capacity costs until 2018. This makes absolutely no sense and clearly biases DEF's analysis against DSM. On top of that the CT coming online in 2018 appears to be much lower in cost than the CT in 2016, again without explanation and therefore understating the avoided cost.

Even some of the hardwired resources ought to have been included in the avoided cost. Chiefly, the Citrus combined cycle units slated to come online in 2018 with a total of 1820 MW were forced into the supply-side plan, but excluded from the avoided cost despite the fact that DEF has not even filed for a certificate of need for these units.

- ***FPL's Generation Only Reserve Margin unnecessarily limits the EE potential.***

Q. Let's start with the reserve margin that applies to all Florida utilities. What reserve margin requirement must Florida utilities comply with?

A. FPL uses a 20 percent reserve margin. Though Duke Energy Florida and TECO do not say so in their testimony, it is my understanding that they also use a 20 percent reserve margin.

Q. What is the origin of the 20 percent requirement?

A. The 20 percent reserve margin requirement was established by order of this Commission in 1999.

Q. Given that the reserve margin requirement was established in 1999, does 20 percent seem like a reasonable reserve margin today?

A. No, it does not. Predicating today's reserve margin requirement on a stipulation agreed upon by FPL, Florida Power Corporation and TECO fifteen years ago is akin to using a DSM technical potential study from 1999. Today, best practice for developing a reserve margin requirement is based on a probabilistic standard such as Loss of Load Probability

(LOLP).[68] I've seen no evidence that the 20 percent requirement is based on such a standard. Indeed, FPL draws a distinction between the 20 percent reserve margin requirement and its Loss of Load Probability criterion of 0.1 days per year, [69] as does Duke Energy Florida.[70]

Q. How would you expect Florida's reserve margin requirement to change if it were based on a probabilistic study?

A. I would expect the reserve margin requirement to decrease. The 20 percent reserve margin requirement is higher than any other of which I'm aware with the exception of the Maritimes region of the Northeast Power Coordinating Council (NPCC). In addition, DEF stated in its 2014 Ten-Year Site Plan that "resource additions are typically triggered to meet the 20 percent Reserve Margin thresholds before LOLP becomes a factor."[71]

Q. But doesn't Florida's peninsular nature mean that it needs a higher reserve margin requirement to reliably serve load?

A. That's certainly possible, but absent the appropriate analysis, it is speculation to conclude that a 20 percent reserve margin is necessary to account for such factors.

Q. How is FPL's Generation-Only Reserve Margin different than its Reserve Margin?

A. FPL's reserve margin accounts for both generation and DSM resources, while the Generation Only Reserve Margin (GRM) does not include an incremental energy efficiency and load management in the calculation.

Q. Why does FPL assert a GRM is necessary?

A. FPL asserts that increasing amounts of EE and DSM may impact system reliability. It has identified the GRM as the appropriate way to study this impact on the system.

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[68] See for example, page 36 of NERC's August 2012 Reliability Assessment Guidebook.
[69] *See* Direct Testimony of Steven R. Sim, pp. 18 and 19.
[70] Duke Energy Florida's 2014 Ten-Year Site Plan at page 3-16.
[71] *Id*.

Q. Do you agree that FPL's GRM is necessary?

A. No. FPL concluded that a GRM was necessary for two reasons. First, because it reduces LOLP values. LOLP is thought to balance reliability and economics, so the point of the GRM should not be to minimize LOLP. Further, FPL gave no indication as to whether its LOLP standard would be compromised absent the GRM.

Second, FPL concluded that the GRM was beneficial because it increased reserves. The simple fact that more reserves are available at peak times does not mean that those reserves are needed or appropriately balance economics and reliability. Further, DSM would also reduce LOLP values and increase reserve margins, so it makes no sense to set a separate standard for generation based on these criteria.

Finally, the fact that FPL chooses not to apply the GRM until 2019 suggests to me that the standard is arbitrary. A planning reserve margin can change from year to year certainly, but I'm not aware of any reliability organization that simply chose to delay implementation of a reserve margin requirement until five years down the road. FPL have given no indication as to why reliability should not be compromised currently without the GRM but is necessary starting in 2019.

Q. What is the impact of FPL using a GRM on DSM in this proceeding?

A. FPL determined its RIM 526 MW and TRC 576 MW sensitivity case plans are were non-conforming, and thus not eligible under FPL's criteria to continue to be evaluated in the goal setting proceeding. Thus the GRM could have the effect of unnecessarily limiting FPL's DSM efforts.

6. Recommendations

Q. What are your recommendations regarding the use of benefit-cost tests in the FEECA goals setting proceeding?

A. I recommend that the Commission continue using the Total Resource Cost test. While the

Utilities have a preference for the RIM test, it is not an issue of whether RIM is "right" or "wrong", it is simply that, as a benefit-cost test: (1) it does not depict an appropriate picture of energy efficiency costs and benefits, and the impact of efficiency on utility system costs; (2) it does not reflect the intent of the Legislature or the Commission. Further, the Commission determined that the TRC test was the best tool to use in 2009.

Q. What are your recommendations regarding the *Evaluating FEECA* report recommendations?

A. I recommend that the Commission address the recommendations from the *Evaluating FEECA* report. In particular, I recommend that the Commission address: modifying the goal setting process so the criteria for program approval are developed prior to the development of studies; improve the transparency of the FEECA cost-benefit studies by requiring the Utilities to report data uniformly and electronically; and the adoption of a rule identifying criteria to address performance incentives.

Q. What are you recommendations on the Utilities program costs?

A. The Utilities energy efficiency programs have historically high costs, as shown through program data and independent reports. I recommend that the Commission instruct the Utilities to, through the evaluation, measurement and verification process, provide an explanation as to why their program costs are higher than the national average.

Q. What are your recommendations on Florida's free-ridership methodology?

A. I strongly recommend that the Commission adopt a free-ridership methodology that is based in the evaluation, measurement and verification process, as the rest of the Southeast and country do. The current methodology is very flawed because it uniformly applies the same free-ridership rate to every measure that is economic, and eliminates entire measures because of the *potential* for free-ridership.

Q. What are your recommendations on the Utilities technical, economic, and

achievable potential study and proposed goals?

A. Based on the flawed nature of the technical, economic and achievable potential by the Utilities, I recommend that the Commission set energy efficiency goals of 0.75% of retail sales for the Utilities, with the intent of ramping up to 1% in another year. I also recommend that the Commission require the Utilities to initiate a new proceeding at the conclusion of this proceeding. In this new proceeding, I suggest the Utilities conduct a full technical, economic and achievable potential study, in an open and transparent way that allows the residents of Florida to weigh in their energy future. Further, this new proceeding could be an opportunity for the Commission to explore a lost revenue adjustment mechanism and performance incentive to create the appropriate incentives for the Utilities to pursue all cost-effective energy efficiency.

Q. What are your recommendations on the FPL and DEF's inclusion of energy efficiency in their resource planning?

A. Based on SACE analysis, FPL's resource planning lacks analytical rigor and transparency, and therefore any credibility and DEF uses a flawed resource planning process that does not appropriately estimate its avoided costs. Further, FPL is proposing using an unnecessary GRM that may further limit the amount of efficiency it includes in its planning. These are all factors that contribute to the need for comprehensive energy planning in Florida. Florida has no integrated resource plan (IRP) filing requirement. The Florida planning process, in its present form, is composed of three components. These are: 1) the Ten-Year Site Plan; 2) the FEECA; and 3) the need determination for power plants.

At the heart of the Florida planning process is the Ten-year Site Plan. The Site Plan is submitted to the Florida Public Service Commission annually by electric generation utilities with a generating capacity greater than 250 MW.[72] The plans are filed with the Commission on the first working day of April of each year, and date from December 31 of the prior calendar year.

The process is not in itself an IRP, but a long range planning document that summarizes any internal resource planning and decisions made by the utility. The Florida Public Service Commission cannot require changes to the plans. As annual summaries of the utilities' resource decisions, the Ten-year Site Plan process does not consider alternatives offered by stakeholders (other than oral comments provided by the public at the annual Ten-year Site Plan workshop) and there is no docket established or opportunity for discovery by stakeholders.

The lack of an open, transparent and robust IRP process may be placing unnecessary risk and cost on Florida's electricity customers. An IRP process, structured correctly, offers the regulators the opportunity to ensure that state's electric utilities are pursuing least cost, least risk alternatives while still maintaining system reliability.

Q. Does this conclude your testimony?

A. Yes.

[72] R. 25-22.071, F.A.C.

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RELEVANT WORK EXPERIENCE

SOUTHERN ALLIANCE FOR CLEAN ENERGY
Energy Efficiency Director, January 2013 - current
Earlier position: Energy Policy Manager, October 2010– December 2012

- Testified as expert witness before the Public Service Commissions on energy efficiency cost recovery and financial incentive mechanisms in Georgia, North Carolina and South Carolina in 2013
- Responsible for ongoing energy efficiency portfolio and program level quantitative and qualitative research and analysis of major utilities in the Southeast
- Track and participate in energy efficiency regulatory proceedings. Current regulatory proceedings include IRP, cost-recovery filings, energy efficiency program pilots and existing program modifications
- Responsible for reviewing and writing comments for all major energy efficiency regulatory proceedings for utilities in Tennessee, North and South Carolina, Georgia and Florida
- Lead participant for SACE at TVA, Duke Energy and Georgia Power energy efficiency working groups

ROCKY MOUNTAIN INSTITUTE
Senior Consultant, July 2009 – October 2010
Earlier positions: Intern, Fellow, Analyst, and Consultant October 2004- July 2009

- Project manager for nine-person team creating energy efficiency component of national analysis to eliminate US fossil fuel consumption by 2050
- Project manager for company-wide energy efficiency strategy and development
- Lead on energy efficiency analysis for major southeastern IOU low-carbon strategy
- Lead author on published national analysis on electric productivity
- Member of senior leadership of Energy and Resources Team at the organization. Contributed to team strategy, resource planning and staffing for 12-20 person team and hiring as well as organizational professional development strategy
- Contributed to writing Hawaii Energy Strategy 2007 and planning Hawaii Biofuels Summit Contributed to RMI filings in Energy Efficiency docket before Hawaii Public Utility Commission
- Participated in Hawaii Energy Policy Forum Energy Efficiency working group
- Significant contributor to consulting and research projects including: national and state energy policies, utility revenue adjustment mechanisms, utility regulatory structures, private sector investment in energy efficiency, corporate carbon management strategy, renewable energy market assessments, large and small scale sustainable development projects, Hawaii agricultural sustainability barriers and solutions

PUBLICATIONS

- Legislative Options to Improve Transportation Efficiency. November 2005, RMI.
- Feebates: A Legislative Option to Encourage Continuous Improvements to Automobile Efficiency. February 2008, RMI.
- Plug-In Hybrid Electric Vehicles and Environmentally Beneficial Load Building: Implications on California’s Revenue Adjustment Mechanism, Presented at Association of Energy Service Professionals Conference, January 2008.
- Industrial Electric Productivity: Myths, Barriers, & Solutions. Presented at ACEEE Industrial Summer Study, July 2008.
- Assessing the Electric Productivity Gap and the U.S. Efficiency Opportunity. Presented at IEPEC, August 2009.

EDUCATION

MASTER OF ENVIRONMENTAL LAW & POLICY
Vermont Law School, South Royalton, Vermont
August 2004

- Relevant coursework includes: Environmental Justice, Environmental Law, Land Use, Water Law, Federal Natural Resource Law, Comparative Methods of Dispute Resolution, Environmental Law Principles, Extinction: The Endangered Species Act, Legal Research & Writing, Ecology
- Activities: Solutions Conference 2004

B.A. ENGLISH & B.A POLITICAL SCIENCE
The Pennsylvania State University, State College, Pennsylvania
May 2002

- Honors: Blue & White Scholarship; Dean's List five semesters; National Collegiate Honor Scholar
- Relevant coursework includes: Economics, Social & Developmental Psychology
- Activities: Shaver's Creek Outdoor School Camp Counselor, May 2001

gas plant. When that benchmark is reached (if not already), ***it is likely to be cost-effective for utilities to invest in several gigawatts of solar power.***

5. <u>Changes in Utility Load Forecasts Could Substantially Alter the Utilities' Capacity Plans.</u>

Recent statements by Duke Energy management suggest that its Carolinas operating utilities' load forecasts are down sharply since the spring 2013 load forecasts used in the 2013 IRPs. On a November 6, 2013 earnings call, Duke Energy CEO Lynn Good commented, "Long-term, we've have been planning for 0.5% to 1%. And we are actually challenging our team to think about an environment with that kind of load growth, even trending to flat over time potentially, as we think about sizing our O&M spending."[69]

In contrast to the low-growth future described by Ms. Good, the 15-year growth rate in the DEC and DEP plans combined is nearly 1.5%; simply reducing that growth rate to 1% would mean cutting cumulative 15-year growth from 24% to 16%. This suggests that not only could energy efficiency and renewable energy meet load growth over the next fifteen years, but DEC and DEP could continue to retire aging power plants with minimal need for conventional replacement capacity.

C. A Closer Examination of the Environmental Focus Scenarios Reveals That Higher Levels of Energy Efficiency and Renewable Energy Would Reduce Customer Costs and Price Risks.

The Environmental Focus Scenarios in the 2013 DEC and DEP IRPs demonstrate that more aggressive—but still achievable—levels of energy efficiency and renewable energy would save customers ***roughly $1 billion over the next 15 years*** across Duke

[69] Duke Energy, "Q3 2013 Duke Energy Corporation Earnings Conference Call," Earnings Call Transcript (November 6, 2013).

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Energy's service territory in the Carolinas as compared to each company's "preferred" plan, as summarized in Table 7.[70]

Table 7: Customer Cost Savings from Environmental Focus Scenarios

15- Year Revenue Requirement Forecast ($ billions present value)	**Duke Energy Carolinas**	**Duke Energy Progress**	**Duke Energy System**
Environmental Focus Case	$ 46.1	$ 29.3	$ 75.4
Base Case	$ 46.6	$ 29.9	$ 76.5
Potential Savings	**$ 0.5**	**$ 0.6**	**$ 1.1 billion**

Both DEC and DEP reject the Environmental Focus scenario because they calculate the present value of revenue requirements ("PVRR") as $1.3 and $0.1 billion higher, respectively, than each utility's Base Case, "even with deferral of the advanced CC and CT resources." Each IRP cites the same factors, "the higher CO_2 price projection, increased revenue requirements associated with higher EE and increased costs associated with doubling the amount of renewables," as causing the higher PVRR. (DEC p. 47, DEP p. 45, and DEC and DEP Supplement to 2013 IRPs (Mar. 7, 2014) p. 2). However, although the operating company IRPs imply that Duke Energy recommends against pursuing the Environmental Focus Scenario because of the "increased revenue requirements," Duke Energy later indicates that this comparison "is not intended for the selection of one portfolio over the other."[71]

DEC and DEP each reached the wrong total system cost estimate (i.e., PVRR) when evaluating the Environmental Focus Scenario. Together, DEC and DEP have

[70] Duke Energy made significant changes to its modeling for this IRP. Although some data were provided in a 40-year modeling time horizon, many data were provided for shorter periods. As a result, these comments focus on Duke Energy's 2014-2028 planning period. Accordingly, the $2 billion in cost savings identified in these comments is not directly comparable to the higher cost savings estimates identified in our comments on prior IRPs because those estimates were developed for a 50-year study period rather than this 15-year study period.
[71] SC Response to Comments p. 10.

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overestimated the combined cost of their Environmental Focus Scenarios by about $2.5 billion. Correction of three flaws in the utilities' modeling, discussed in further detail below, reveals that the PVRR for the Environmental Focus scenario is $1.1 billion lower than each utility's Base Case. Thus, rather than costing about $1.4 billion more than the Base Case, **the more aggressive energy efficiency and renewable energy resource strategy outlined in the utilities' Environmental Focus Scenarios could save their customers $1.1 billion over the next 15 years**, as summarized in Table 8.

Table 8: Customer Cost Savings from Environmental Focus Scenario

15- Year Revenue Requirement Forecast ($ billions present value)	**Duke Energy Carolinas**	**Duke Energy Progress**	**Duke Energy System**
EF Case as Reported by Duke	$ 47.9	$ 29.9	$ 77.8
- Use base case CO_2 prices	- 0.7	- 0.6	- 1.3
- Use base case fuel prices	+ 0.3	+ 0.1	+ 0.4
- Escalate EE costs at LBNL rate plus inflation	- 1.3	- 0.2	- 1.6
EF Case with Corrections	$ 46.1	$ 29.3	$ 75.4
Base Case	$ 46.6	$ 29.9	$ 76.5
Potential Savings	**$ 0.5**	**$ 0.6**	**$ 1.1**

The analytic flaws that resulted in grossly overstated costs for the Environmental Focus scenarios are discussed in the following sections.

1. <u>The Higher "Carbon Price" and Lower Fuel Price Forecast Used in the Environmental Focus Scenario Makes It Impossible to Compare Its Total Cost With That of the Base Case Scenario on an "Apples-to-Apples" Basis.</u>

The utilities forecast a "carbon price" of $20-45/ton in the Environmental Focus Scenario compared to $17-33/ton in the Base Case. DEC 2013 IRP at 21; DEP 2013 IRP at 21. The higher carbon price accounts for about $1.3 billion in increased costs in the

III. <u>Georgia Power Should Reduce the Cost and Risk of its Resource Mix</u>

Q. How can Georgia Power reduce costs and risks in its IRP?

A. Based on my analysis, I conclude that Georgia Power should adopt an Enhanced DSM Portfolio in lieu of its Proposed DSM Portfolio; cease purchasing power from Gaston Units 1-4 rather than pursue fuel switching; and develop an Enhanced Solar Portfolio instead of failing to include any new solar in its plan after ASI. Together, these changes will reduce system costs by about $2.4 billion.

Q. How would your recommendations reduce system costs by about $2.4 billion?

This cost savings estimate accounts for a wide range of utility costs, most of which derive from the Company's system planning model (Strategist), as described in detail in Exhibit SACE-JDW-3. Table 1 summarizes the Southern Company system costs and savings for the changes I recommend both individually and combined, as compared to the Company's Base Case Plan. Table 1 also summarizes the cost impact of the Company's No DSM sensitivity, as compared to its Base Case.

Table 1: Customer Savings in Alternative Resource Plans

Resource Plan	System Cost $billion	Savings (Cost) Relative to Base Case			
		Production	Capital*	DSM	**Total Savings**
Base Case	[redacted]				
Alternative Resource Cases:					
No DSM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] [redacted]
Enhanced Georgia Solar Portfolio	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] [redacted]
Gaston Removal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] [redacted]
Enhanced DSM Portfolio	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] [redacted]
SACE Recommended Enhancements:					
Enhanced DSM + Gaston Removal + Enhanced Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] [redacted]

*** Capital costs include Plant Gaston and Solar Portfolio costs, in addition to system capital costs.**

As Table 1 shows, most of the savings that accrue from the recommended changes to the IRP come from production costs, mainly fuel savings. In addition, the following additional findings from this analysis provide important context for my recommendations:

- Solar power is primarily an energy resource. About [redacted] of the system cost savings associated with solar power are fuel and related cost savings. The remaining [redacted] are capital cost savings, roughly equivalent to the cost of the Enhanced Georgia Solar Portfolio. Net rate reductions resulting from the 2,000 MW portfolio could occur as soon as 2023, or even sooner if fuel prices grow faster than forecast by the Company.
- Production costs are actually slightly higher with Plant Gaston Units 1-4 in operation than without those units being available to the model. There is no benefit to the conversion project.

- The additional benefit of our recommended Enhanced DSM portfolio over the Company's Proposed portfolio is substantial. More than 75% of the additional costs, as projected by Ms. Mims, are offset by capital cost savings (unnecessary power plants). This is one reason that rate impacts of our recommendation are so low. Even in the unlikely event that the cost of the portfolio exceeds our projections by 35%, the benefit to customers would continue to be more than double the cost.

In summary, each of the changes we recommend to the system plan offers unique benefits to the Company's present and future customers.

Q. In addition to the system cost savings associated with your recommendations, what other financial benefits could they provide to Georgia utility customers?

A. In addition to saving **about $2.4 billion**, SACE's recommendations would reduce the risks of future, unmanageable price increases that are passed on to customers. Unlike traditional supply-side generation, once installed, neither energy efficiency nor solar energy has significant ongoing operational or maintenance costs, and of course these resources are fuel-free.

Furthermore, because these resources can be built and deployed gradually, the Commission can put in place safeguards to ensure that if costs are higher than expected, the programs can be curtailed while design changes are made. As experience shows, cost overruns at power plants due to design problems can become unmanageable even before the projects deliver any benefit to utility customers. In contrast, because of the modular and incremental nature of energy efficiency and solar, cost overruns can be more easily controlled and contained.

Energy efficiency and solar power are particularly worthwhile energy investments in this this IRP because Georgia Power has no identified capacity needs for eight or nine years. If costs are higher than anticipated, then program expansion can be scaled back without triggering the need to rush forward plans for new capacity.

Q. What types of risk should Georgia Power analyze when making resource decisions?

A. There are several different types of risk that utilities should consider when evaluating resources. A recent paper[1] by former Colorado PUC Chairman Ron Binz provides an extensive list of the categories of risk that should be considered by electric utilities, in conjunction with cost considerations. The risk categories examined in the report include:

- **Construction Cost Risk**: unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk**: fuel cost and availability, as well as operation and maintenance cost
- **New Regulation Risk**: air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk**: state or federal limits on greenhouse gas emissions
- **Water Constraint Risk**: availability and cost of cooling and process water
- **Capital Shock Risk**: availability and cost of capital, and risk to firm due to project size
- **Planning Risk**: inaccurate load forecasts, competitive pressure

[1] Binz, Ron et al., *Practicing Risk-Aware Energy Regulation, What Every State Regulator Needs to Know*, Ceres (April 2012).

Enhanced Portfolio achieves 70% more savings, and has an economic benefit to rate impact of eight to one. Further, the Enhanced DSM Portfolio produces lower cost of saved energy and more customer participation and savings than the Company's Proposed Portfolio.

Q. You have discussed rate impacts, but how does the Enhanced DSM Portfolio impact customer bills?

A. SACE's analysis of Georgia Power's data shows that more efficiency reduces all customer bills. Table 2 shows both the non-participant and participant bill savings under the Proposed Portfolio and Enhanced DSM Portfolio. The Enhanced DSM Portfolio results in 70% more total savings, and approximately *five times* more participants than in the Proposed Portfolio. Consequently, there are much fewer non-participants in the Enhanced DSM Portfolio, which reduces the amount of upward pressure on bills compared to the Proposed Portfolio.

Table 2. Net Present Value of Non-Participant and Participant Bill Savings due to Energy Efficiency in Proposed Portfolio and Enhanced DSM Portfolio

	Non-Participant Bill		Participant Bill	
	Proposed Portfolio	Enhanced DSM Portfolio	Proposed Portfolio	Enhanced DSM Portfolio
Residential	[redacted]	[redacted]	[redacted]	[redacted]
Commercial	[redacted]	[redacted]	[redacted]	[redacted]
Industrial	[redacted]	[redacted]	[redacted]	[redacted]

Q. How did you determine the bill impact?

A. SACE integrated several models to calculate the bill impacts. SACE conducted a bill impact analysis to determine the impact of energy efficiency on the bills of both participants and non-participants. Our analysis covers the Company's Proposed DSM Portfolio and SACE's recommendation, the Enhanced DSM Portfolio. SACE contracted with Synapse Energy Economics, Inc. to develop an Energy Efficiency Program Participation Model (Exhibit SACE-NAM-5). The participation model estimates the total number of participating and non-participating customers during a specified period of time.

Q. How will the commercial and industrial customers benefit from Georgia Power's energy efficiency portfolio?

A. Based on our analysis, as shown in Exhibit SACE-JDW-2, the average commercial and industrial customer participants in energy efficiency programs under the Enhanced DSM Portfolio could reduce their annual bills by 15-24%.

V. <u>Commercial and Industrial Customers</u>

Q. What role do commercial and industrial programs play in the energy efficiency portfolio overall?

A. Commercial and industrial programs play a critical role in energy efficiency portfolios as they often deliver the lowest cost energy efficiency. This also holds true for Georgia

Table 3-1. Summary of Benefits and Costs Included in Each Cost-Effectiveness Test

Test	Benefits	Costs
PCT	*Benefits and costs from the perspective of the customer installing the measure*	
	▪ Incentive payments ▪ Bill savings ▪ Applicable tax credits or incentives	▪ Incremental equipment costs ▪ Incremental installation costs
PACT	*Perspective of utility, government agency, or third party implementing the program*	
	▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution	▪ Program overhead costs ▪ Utility/program administrator incentive costs ▪ Utility/program administrator installation costs
RIM	*Impact of efficiency measure on non-participating ratepayers overall*	
	▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution	▪ Program overhead costs ▪ Utility/program administrator incentive costs ▪ Utility/program administrator installation costs ▪ Lost revenue due to reduced energy bills
TRC	*Benefits and costs from the perspective of all utility customers (participants and non-participants) in the utility service territory*	
	▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution ▪ Additional resource savings (i.e., gas and water if utility is electric) ▪ Monetized environmental and non-energy benefits (see Section 4.9) ▪ Applicable tax credits (see Section 6.4)	▪ Program overhead costs ▪ Program installation costs ▪ Incremental measure costs (whether paid by the customer or utility)
SCT	*Benefits and costs to all in the utility service territory, state, or nation as a whole*	
	▪ Energy-related costs avoided by the utility ▪ Capacity-related costs avoided by the utility, including generation, transmission, and distribution ▪ Additional resource savings (i.e., gas and water if utility is electric) ▪ Non-monetized benefits (and costs) such as cleaner air or health impacts	▪ Program overhead costs ▪ Program installation costs ▪ Incremental measure costs (whether paid by the customer or utility)

Source: Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.

programs. Currently, customers who opt in are permitted to opt back out beginning five years after the date of receiving a payment from SCE&G as part of a DSM program. Under the Company's proposal, customers that opt in to the DSM programs on or after December 1, 2013 cannot opt back out for as long as SCE&G continues to offer DSM programs. Effectively, industrial customers who opt in will be locked into participation indefinitely. The proposed modification will likely act as a deterrent to customers opting in, because many industrial customers may be hesitant to bind themselves to long-term participation if they are uncertain about the long-term benefits. In his direct testimony, Company Witness Kenneth Jackson gives the Company's rationale for the proposed modification, describing a way in which industrial customers could potentially manipulate the existing opt out process to their advantage. Direct Testimony of Kenneth R. Jackson at 12-13. However, the Company has not presented any evidence demonstrating that this type of manipulation is actually occurring.

Q. WHY IS IT IMPORTANT FOR SCE&G TO CONTINUE TO PURSUE INDUSTRIAL AND LARGE COMMERCIAL CUSTOMERS?

A. There are two main reasons. First, industrial and large commercial customers have significant energy efficiency impacts, and capturing those impacts will help position SCE&G to reach annual energy savings of 1% of sales and higher. A recent analysis by Duke University and the U.S. EPA shows that if the average industrial facility moves from the 50th percentile of energy efficiency to the 75th percentile, it will save 20-30% of its energy. This is a huge opportunity that will not be captured without appropriate action to overcome barriers to industrial energy efficiency. This analysis is attached as Mims Exhibit 2.

Second, industrial and large commercial customers that opt out of energy efficiency programs are receiving the system benefits of efficiency without paying for them. Increased levels of energy efficiency lower total system cost, providing a universal benefit to all customers on the system, including large customers who opt out (and thus do not have to bear any of the cost of energy efficiency). A system-wide, "universal" benefit occurs when efficiency reduces demand, average fuel costs are reduced, and system costs fall, which puts downward pressure on rates. Over the long term, as power plants are deferred or avoided entirely, the cost of building those power plants is not put into the rate base, placing further downward pressure on rates.[37]

Q. WHAT IS YOUR ESTIMATE OF THE UNIVERAL BENEFIT OF ENERGY EFFICIENCY TO SCE&G'S SYSTEM?

A. At the levels of energy efficiency impacts included in the Company's application, the universal benefit of energy efficiency will reduce system costs by about $50 million. This universal benefit does not include about $132 million in bill reductions that accrue to program participants. At a 1% annual savings level, both the participant benefits and the universal benefits of energy efficiency would be significantly greater.

[37] While some or all of the downward pressure on rates results from deferring or avoiding building power plants, this is counteracted by lost revenues assocated with fixed costs from existing plants. However, opt-out customers, because they do not pay for lost revenues, are not affected by this and are effectively subsidized by all other customers.

Q. HOW DID YOU CALCULATE THE UNIVERSAL BENEFIT OF ENERGY EFFICIENCY?

A. As illustrated in Table 6, below, the universal benefit is calculated as total system benefits, adjusted for two factors. First, some benefits are only received by participants: the portion of participant bill savings associated with fuel costs (and other variable costs) is not shared with other system customers. Second, another effect of energy efficiency is that some of the revenue requirement associated with fixed costs is no longer collected from program participants, referred to as lost revenues. This calculation assumes that the Commission would approve a mechanism through which the Company is able to collect three years of net lost revenues. Once those two adjustments are made, the $50 million in remaining cost savings are universal benefits that accrue to all customers regardless of participation, customer class or opt-out status.

Table 6: Universal Benefit of Energy Efficiency[38]

Benefit & Adjustment	Amount ($M NPV)
Total System Benefits (avoided cost)	$182.1
Lost Revenues, fuel only (adjustment 1)	$47.8
Gross Universal Benefit	$134.3
LRAM (adjustment 2)	$84.0
Net Universal Benefit	**$50.3**

[38] Data for this calculation were obtained from the Company through data requests, except for certain data that it was necessary to estimate because either the Company reported that it did not possess such information, or it provided data that were not directly responsive to the specific request. Specifically, lost revenues were calculated based on the forecast for cumulative energy savings (retail sales losses) provided by the Company and a rate forecast derived from the Company's most recent rate case application, SC Docket 2013-150-E, Application Exhibit G. All data are net of free riders.

It is also possible to calculate an alternative value for the universal benefit of energy efficiency that relies upon a more accurate estimate of the benefits of energy efficiency. In its 2013 Integrated Resource Plan, SCE&G estimated the benefits of energy efficiency at $0.092 per kWh on a levelized basis.[39] This estimate is more appropriate than the lower estimate used by SCE&G for purposes of the current application, because it takes into account the full impact of energy efficiency on system costs.

Regardless of how individual measures are valued for energy efficiency, the use of the IRP estimate for valuing the benefit of energy efficiency offers a superior basis for estimating portfolio benefits. Using that estimate, the total system benefits of the Company's proposed energy efficiency programs are $196 million and the universal benefit is $64 million.

Q. DO YOU HAVE ANY RECOMMENDATIONS FOR ACTIONS THAT SCE&G COULD TAKE TO INCREASE SAVINGS FROM INDUSTRIAL CUSTOMERS?

A. Yes. I propose a modification to the opt-out process that is designed to increase energy savings from industrial customers and to provide the Commission with assurance that customers who opt out are actually installing DSM/EE measures. Under my proposed modification, industrial customers who wish to opt out would be required to certify to the Company that they have implemented, or will implement, specific DSM/EE measures, and to provide the annual demand (kW) or energy (kWh) savings achieved or expected, as certified by a

[39] See SC PSC Docket 2013-9-E, Application at 31.

DSMWG members felt that they needed to know what measures were going to be included in the proposed case before they could provide input into the aggressive case.

Q. HOW WERE THE CONCERNS OF THE DSMWG MEMBERS ADDRESSED?

A. To alleviate the concerns of the DSMWG members, the Company provided a list of all of the measures that was going to be used by the Company in their economic screening.

Q. IN THIS DOCKET, IS THE COMPANY PROPOSING ANY CHANGES TO THE NINE STEP PROCESS?

A. Yes. The Company states that several steps in the Nine Step Process are redundant and are no longer needed. The Company is proposing to eliminate Step two, which requires the Company to utilize a technical and economic potential study for Georgia Power's service territory to assist in targeting DSM programs in the areas where the highest market potential exists. Secondly, the Company is proposing to eliminate Step five, which requires the Company to collect and share customer data/feedback with the DSMWG. Third, the Company is proposing to no longer specify the manner in which active and passive DSM programs are evaluated for cost effectiveness (Step 6). The Company further states that requiring a comparison to system tools is unnecessary.

Q. DID THE COMMISSION'S ORDER IN THE 2004 IRP DOCKET REQUIRE THAT THE COMPANY PREPARE AN EFFICIENCY POTENTIAL STUDY FOR USE IN THE DEVELOPMENT OF THE 2007 IRP?

A. Yes. The Commission required the Company to prepare an energy efficiency potential study for the 2007 IRP.

Q. DID THE COMPANY PREPARE ENERGY EFFICIENCY POTENTIAL STUDIES IN 2007 AND 2012 IN PREPARATION FOR THE DEVELOPMENT OF THE 2010 AND 2013 IRP FILINGS WITH THIS COMMISSION?

A. Yes. The Company completed an energy efficiency potential study during 2007 and a second one in 2012. Both studies were prepared by Nexant, a consultant to the Company.

Q. PLEASE EXPLAIN WHY IT IS IMPORTANT FOR THE COMPANY TO DEVELOP A FRESH ENERGY EFFICIENCY POTENTIAL STUDY WHEN DEVELOPING A NEW IRP.

A. There are many reasons why it is essential to develop a fresh study with each IRP:

- As time progresses, new energy efficiency technologies become commercially available (examples include light-emitting diode ("LED") lighting, T5 fluorescent lighting and smart strips.)
- Manufacturers continue to improve the baseline energy efficiency level of existing technologies thus impacting estimates of energy savings potential.

- The costs of many energy efficiency technologies decrease over time. A good example is the compact fluorescent light bulb ("CFL"). In the late 1980's, the cost of a CFL bulb was over $25. Today, a high quality CFL bulb can be purchased for less than $2.00.[6]
- The Company's avoided costs for generation capacity and energy can change dramatically over time, even over a period of two to three years. As a result, the cost effectiveness of energy efficiency measures and programs can change significantly.
- Energy savings potential estimates need to be updated to account for changes in Federal and State laws relating to energy efficiency standards for equipment and buildings.
- As time passes, the percent of households and businesses that have adopted high efficiency technologies and building practices increases, impacting savings potential.
- The Company's estimates of energy savings potential need to be updated to reflect the results of the Company's on-going impact evaluations of its programs.
- A potential study is relatively inexpensive compared to what the Company spends on supply-side studies and research. Potential studies can be conducted in approximately six months at a cost of a few hundred thousand dollars. Since the Commission's 2010 IRP Order adopted a policy recognizing energy efficiency as a priority resource, this is a small amount to spend to provide a detailed road map for this resource and to provide the focus for the Company's future energy efficiency programs.

[6] As of May 8, 2013, Walmart's web site advertises a package of 12 CFL bulbs (for replacing the lumens for an equivalent 75 watt incandescent bulb) for a price of $23.76 for 12 bulbs.

Q. DO YOU AGREE WITH THE COMPANY THAT ENERGY EFFICIENCY POTENTIAL STUDIES DO NOT CHANGE MUCH OVER TIME?

A. No. There are significant differences in the 2007 and 2012 studies performed by the Company. The avoided cost forecasts used in the two studies are very different. There are measures included in the 2012 study that are not included in the 2007 study. The annual kWh savings for many measures in the 2012 study are very different than what was used in the 2007 study. The total savings attributable to classes of measures are very different between the two studies. The 2007 study determined that the achievable savings potential over 10 years was 10 percent. The 2012 study determined that the achievable savings potential was 15 percent, 50 percent higher than the 2007 study.

Q. WHAT IS YOUR RECOMMENDATION REGARDING PREPARATION OF AN ENERGY EFFICIENCY POTENTIAL STUDY AS PART OF THE DEVELOPMENT OF THE COMPANY'S NEXT IRP FILING IN 2016?

A. Staff recommends that the Commission require the Company to prepare a new energy efficiency potential study as part of the development of its next IRP filing. This energy efficiency potential study is the critical foundation of the Company's demand-side plan that is included in the IRP. As noted in the Company's public disclosure responses to Staff Data Request set 3, questions 7, 15, 16, 17, 18, 22, 25 and 27, the results of the energy efficiency potential study provide the starting point for the available achievable potential savings for each energy efficiency measure included in the study. Without the

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June 26, 2013

Tom Ballinger, Director
Division of Engineering
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Dear Mr. Ballinger,

SACE wishes to thank Commission staff for holding an informal meeting on June 17th to discuss how to make the upcoming FEECA process more transparent and administratively efficient. In the spirit of that goal, we offer the following comments on the ideas and discussion that took place at the meeting to Commission staff and the parties that attended the meeting.

Quality Technical Potential Study

In 2009, Itron conducted the base technical potential study to determine the energy efficiency potential of the FEECA utilities. Based on the June 17th FEECA meeting, this study will be updated as part of the upcoming FEECA proceeding. SACE is concerned about the methodology that will be used to update this information. The concerns are twofold. First, we are concerned about what the source for the updated cost and deemed savings is; and second that the utilities will not update the cost and deemed savings for each measure using a uniform methodology. Both of these issues, if not appropriately addressed will result in an opaque and inaccurate representation of the technical potential for energy efficiency by FEECA utilities. We encourage the Commission staff to provide clear direction to the utilities about the sources for updating the cost and deemed savings for measures, and the methodology to do so; or request that the utilities hire a third party to update the entire catalog of measures to ensure it is done in a uniform fashion.

Additionally, the utility parties have provided a deadline of July 5th for SACE to submit any new measures for consideration in the technical potential study along with Florida-specific savings and cost data. SACE reviewed the measures from the 2009 energy efficiency potential study and compared them to TVA[1] and Georgia Power's[2] recent energy efficiency potential studies. There are many measures that appear to have been excluded from the 2009 Itron energy efficiency potential study that were included in the TVA and Georgia Power energy efficiency potential study. SACE has provided a list of these measures in Appendix 1, but will not be able to provide more detailed information beyond what is included in the TVA and Georgia Power potential

[1] Tennessee Valley Authority Potential Study, Final Report, December 21, 2011. Global Energy Partners, available at http://www.tva.gov/news/releases/energy_efficiency/GEP_Potential.pdf

[2] Achievable Energy-Efficiency Potentials Assessment, Submitted to Georgia Power Company by Nexant, January 31, 2012, available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=140174

studies. As these measures were included in energy efficiency potential studies that were completed in 2011 and 2012, it seems reasonable to assume that an update to the Florida utilities' energy efficiency potential study will also include these measures as part of a thorough analysis, and should not rely on stakeholders to provide this information to the companies. Finally, as SACE pointed out during the 2009 FEECA proceeding, there are a number of energy sectors that were excluded from the energy efficiency potential study. We have also identified these in Appendix 1, and trust that the utilities will include energy efficiency measures for these sectors in the 2013 energy efficiency potential study.

Transparency in the Economic and Achievable Potential Analysis

In the past, SACE has expressed its concern about Florida utilities using a two year measure payback as a proxy for free ridership. As we have mentioned many times, this methodology is not used by other utilities in the Southeast, and results in an incomplete picture of energy efficiency savings. Based on the informal FEECA meeting on June 17th, it is our understanding that staff has asked the utilities to provide the economic potential, including kWh savings, and RIM and TRC scores for all measures as part of their testimony in the next FEECA docket. If this is not correct, please notify us as soon as possible. While staff's request to the FEECA utilities for a sensitivity analysis of 1 year and 3 year paybacks mitigates the lack of transparency of the 2 year payback screen, we believe that there should be a sensitivity analysis without screening out any measures related to customer payback assumptions. Such an analysis will promote full transparency and will fully inform the Commission on the complete universe of measures at a utility's disposal to meet conservation goals.

Consistent CO^2 Sensitivities

The FEECA statute requires that the Commission to consider costs imposed by state and federal regulations on the emission of greenhouse gases.[3] The staff's suggestion that the base case sensitivity be a zero dollar amount is inconsistent with utility filings in other dockets that utilize sensitivities for CO^2 emission compliance. For example, DEF uses CO^2 sensitivities ranging from $20 to $82 dollar a ton in the year 2020 in this year's nuclear cost recovery clause docket.[4] Using a base case of zero in the FEECA docket unfairly undermines the value of efficiency measures in this docket. Fundamental fairness and consistency dictate that CO^2 sensitivities used for supply side resources as well as demand side resources be judged under the same standard.

DSM Financial Incentives

SACE supports the use of DSM financial incentives for meeting meaningful goals in a cost-efficient manner. Investor-owned utility directors and executive officers have a fiduciary duty to maximize shareholder value. Investor-owned utilities do not earn a rate of return on efficiency implementation in Florida. Moreover, efficiency measures delay or displace the need for new supply side generation on which utility shareholders earn a return. Therefore, there is a distinct regulatory disincentive for an investor-owned utility to deliver meaningful cost-efficient energy efficiency services unless they can provide value to its shareholders. Properly designed energy

[3] §366.82(3)(d), Fla. Stat.
[4] Direct Testimony of Chris Fallon, Docket No. 130009, (CMF-4) p. 11 of 18, May 1, 2013.

efficiency incentives can place demand side resources on a regulatory "level playing field" with supply side options.

We look forward to working with the Commission staff and other parties to ensure a fair, transparent, and administratively efficient FEECA proceeding.

Sincerely,

Natalie Mims, SACE Energy Efficiency Director

George Cavros, Attorney for SACE

Attachment 1: List of Measures and Sectors to be Included in 2013 Energy Efficiency Potential Study

1) Residential Measures
- Interior and exterior LEDs
- Interior and external halogen
- T-5, Super T-8
- Occupancy sensors
- Efficient ballasts and fixtures
- Attic Fan
- Ceiling Fan
- Whole house fan
- De-humidifer
- Room AC SEER 10.8 (energy star)
- AC SEER 21
- Central AC ductless mini split
- Heat pump ductless mini split
- Geothermal heat pump EER 14.1, 16, 18, 30
- Heat pump SEER 19
- Duct sealing (could be part of duct repair, don't know)
- Locate ducts in insulated space
- New construction insulation (foundation, wall sheathing, wall cavity)
- Storm and thermal doors
- Refrigerator, freezer, dishwasher high efficiency versions beyond energy star
- Compact freezer
- Compact refrigerator
- Stoves
- Programmable thermostats
- Room air cleaner
- Printer/fax/copier
- Pool heater
- Hot tub pumps and heaters
- Well pump
- Hot water saver
- Solar hot water with peak period lock out
- Refrigerator, freezer and room AC recycling
- Smart strip surge protection
- Energy Star Home
- Behavior changes from utility provided information

2) Commercial Measures
- Building commissioning (in the measure list there is refrigerator commissioning)
- T-5, super T-8
- LEDs

- HID lighting
- Delamping and reflectors
- Daylighting
- Dimmable ballasts
- Indoor lighting controls
- Task lighting
- Air cooled chillers
- Duct less mini split for rooftop AC
- Rooftop heat pump EER 9.3 -12
- Heat pump maintenance
- Rooftop AC EER 11.2, 12
- Chiller economizer
- Energy Management System
- Programmable thermostats
- Hotel guest room controls
- Plug load occupancy sensors
- Pool Pump timers
- Refrigerator recycling
- Refrigerator door gasket replacement
- High efficiency windows
- Hot water saver
- Hot water pipe wrap
- Hot water high efficiency circulation pump
- Icemaker
- Hot food container
- Ventilation hoods
- Steamers
- Griddle
- POS terminal
- Dishwasher
- Server
- Pool pump
- Pool heater
- Elevator motor
- Data center virtualization
- Clothes washers
- Clothes dryers
- Refrigerated vending machines

3) Industrial Measures

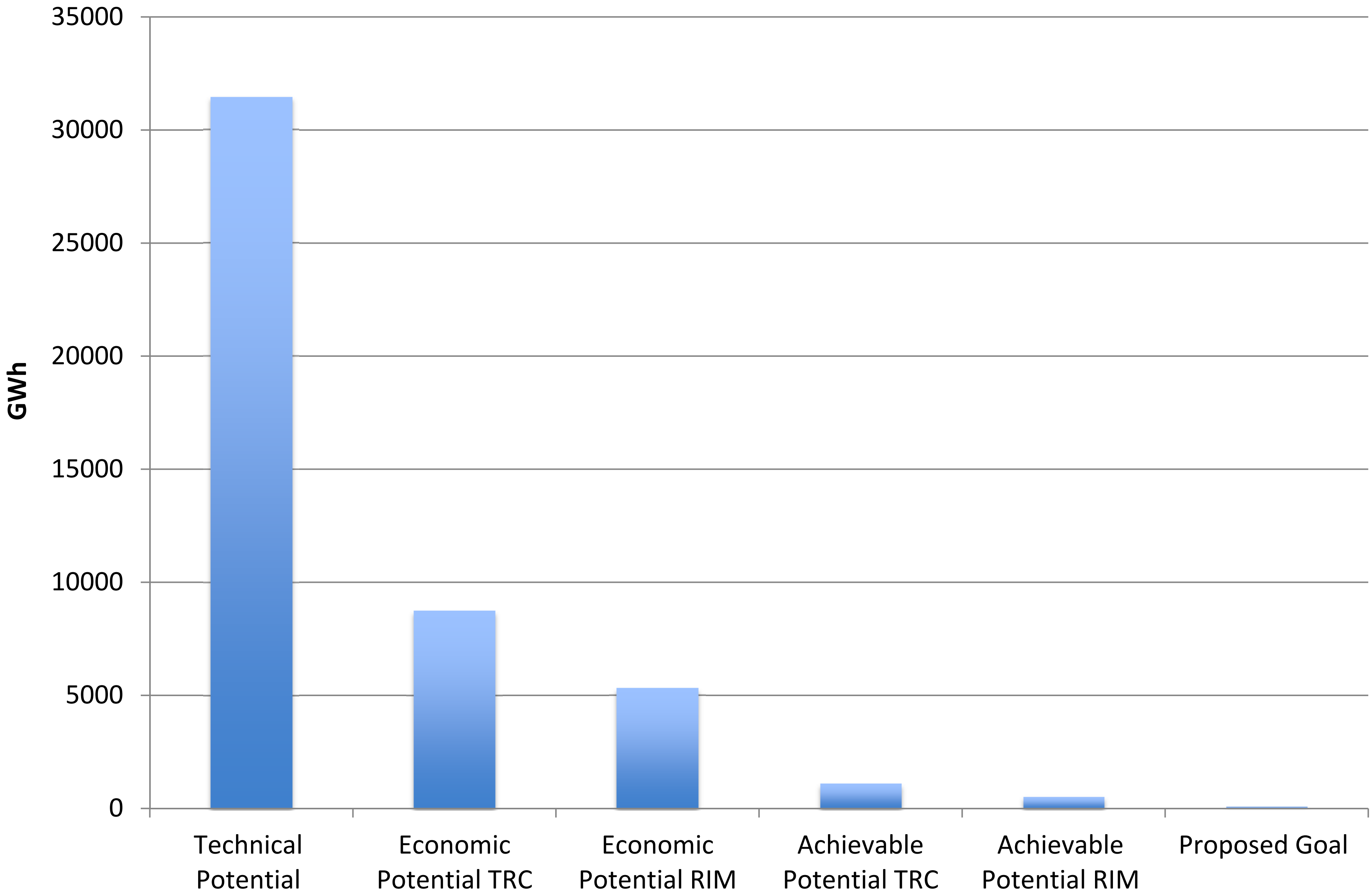
- Properly sized fans
- Synchronous fans
- HVAC improved controls
- HVAC Recommissioning

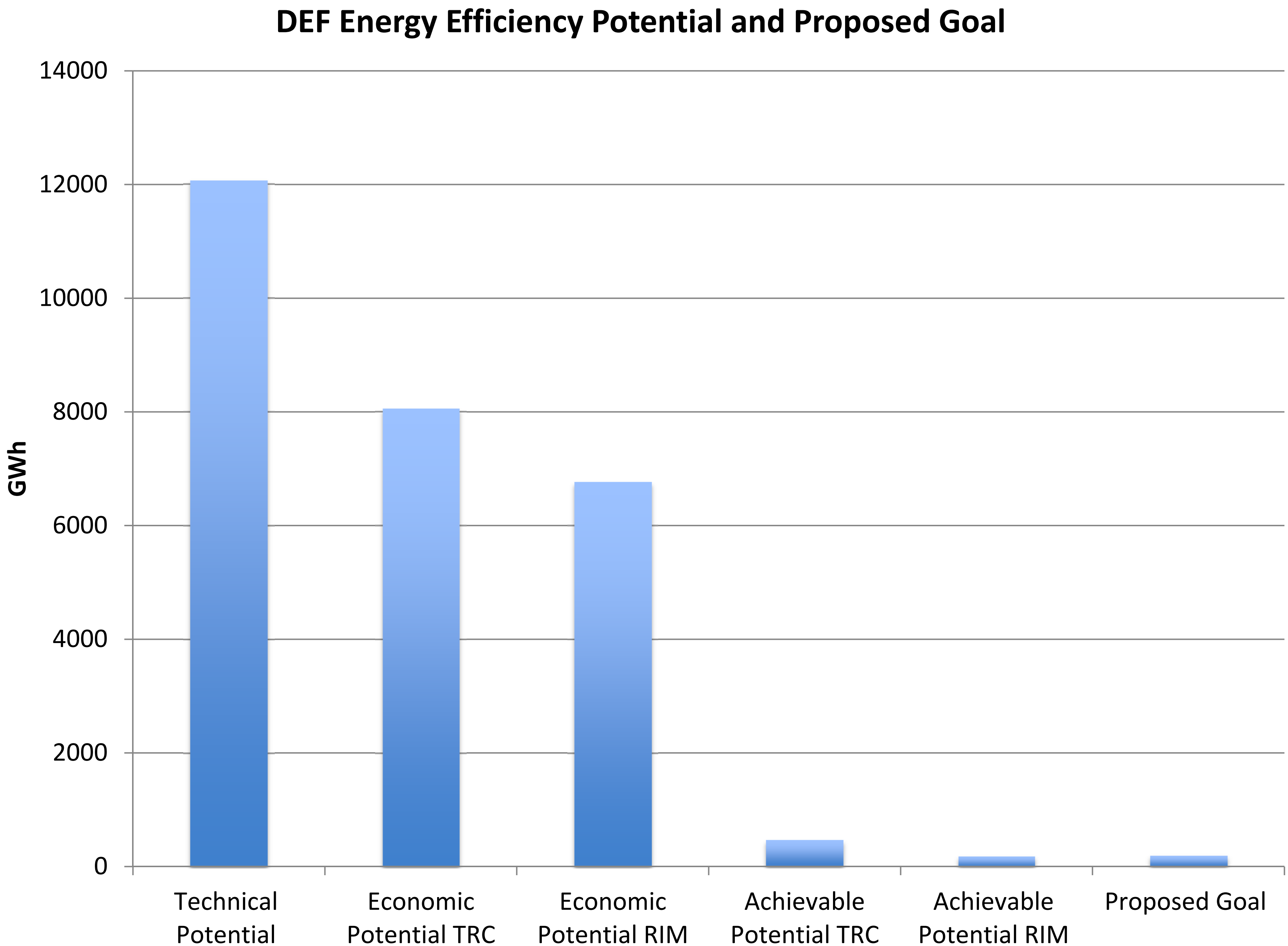
- Efficient lighting
- Lighting controls
- Plant Energy Management
- Transformers
- Motor management plan for air compressors and other motors

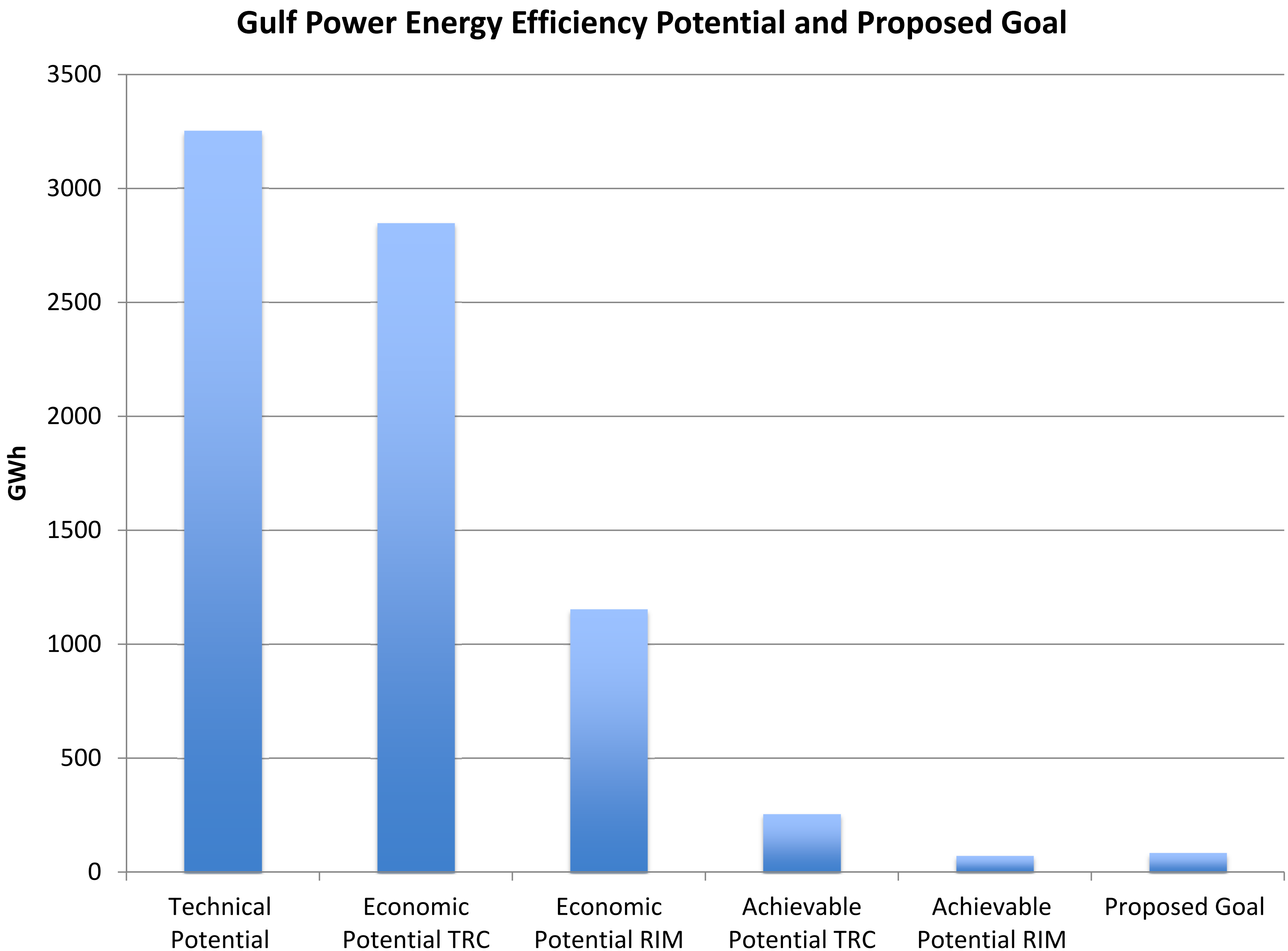
4) Sectors omitted from 2009 FEECA energy efficiency potential study

- Agriculture
- Transportation, communications and utilities
- Construction
- Outdoor lighting
- Street lighting

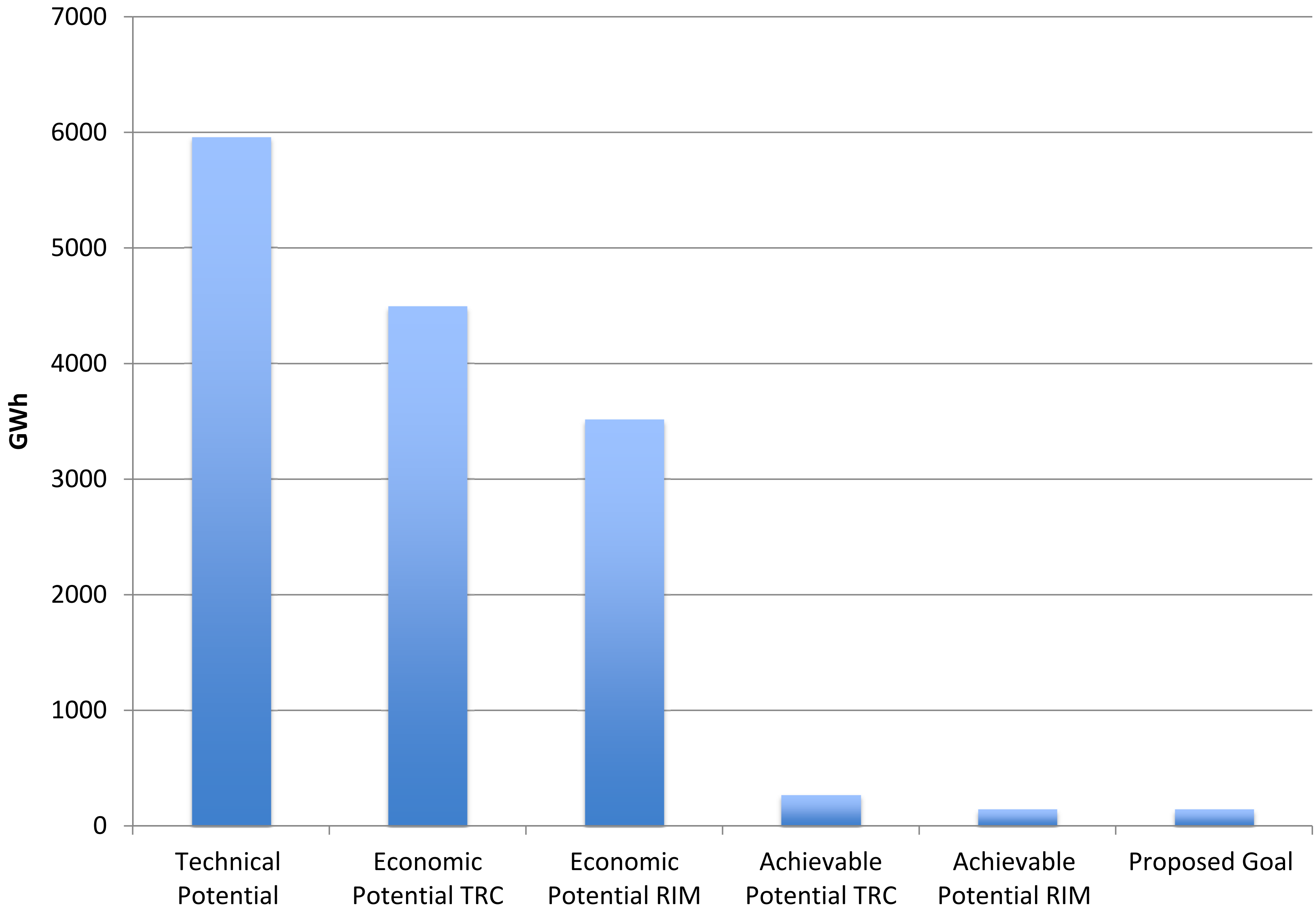
FPL Energy Efficiency Potential and Proposed Goal

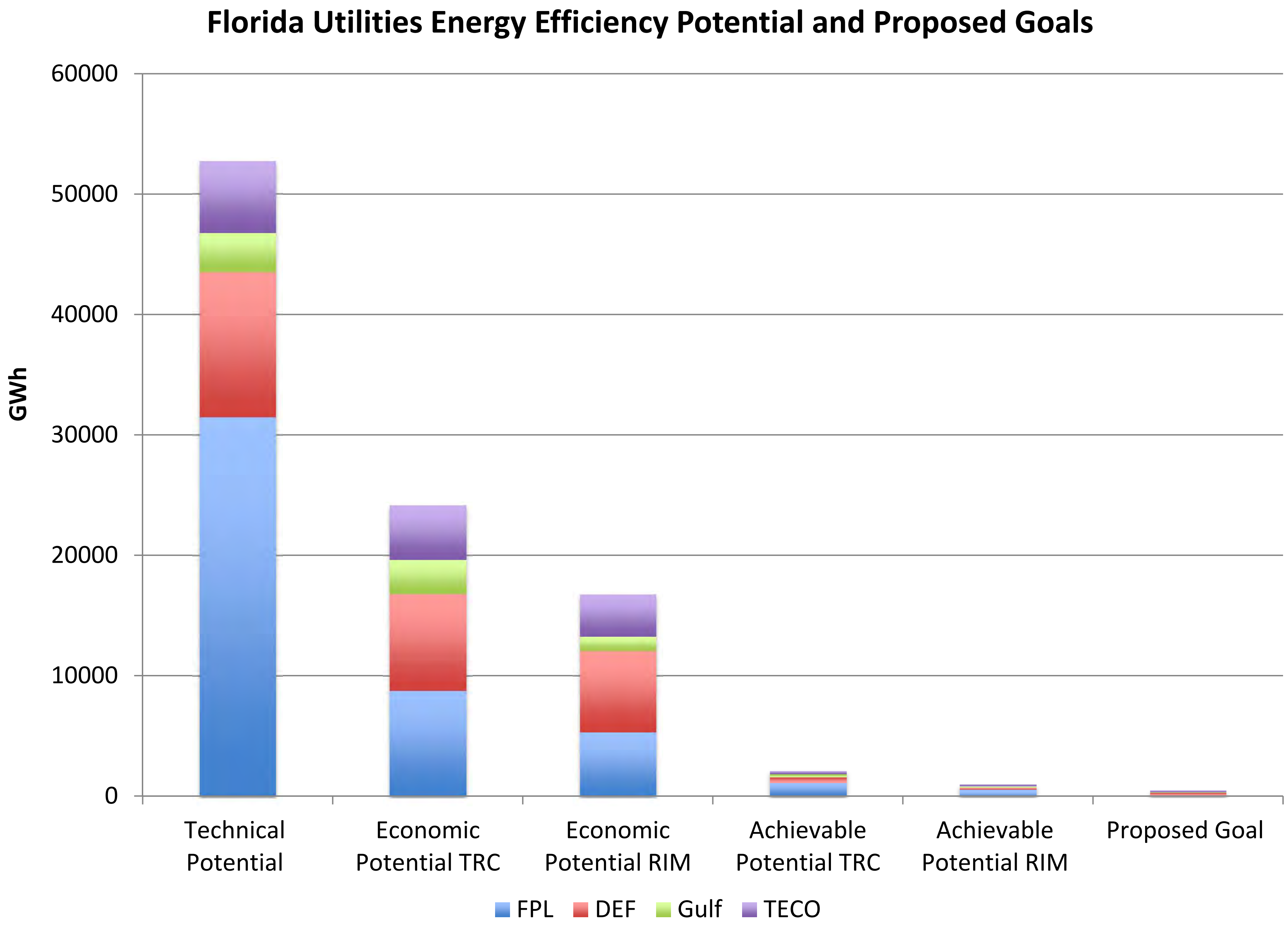



DEF Energy Efficiency Potential and Proposed Goal
14000
12000
10000
8000
6000
4000
2000
0
GWh
Technical Potential
Economic Potential TRC
Economic Potential RIM
Achievable Potential TRC
Achievable Potential RIM
Proposed Goal


Gulf Power Energy Efficiency Potential and Proposed Goal
GWh
3500
3000
2500
2000
1500
1000
500
0
Technical Potential
Economic Potential TRC
Economic Potential RIM
Achievable Potential TRC
Achievable Potential RIM
Proposed Goal

TECO Energy Efficiency Potential and Proposed Goal




Florida Utilities Energy Efficiency Potential and Proposed Goals
GWh
60000
50000
40000
30000
20000
10000
0
Technical Potential
Economic Potential TRC
Economic Potential RIM
Achievable Potential TRC
Achievable Potential RIM
Proposed Goal
FPL
DEF
Gulf
TECO

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric conservation goals (Florida Power & Light Company).	)	DOCKET NO. 130199-EI
In re: Commission review of numeric conservation goals (Duke Energy Florida, Inc.).	)	DOCKET NO. 130200-EI
In re: Commission review of numeric conservation goals (Tampa Electric Company).	)	DOCKET NO. 130201-EI
In re: Commission review of numeric conservation goals (Gulf Power Company).	)	DOCKET NO. 130202-EI

TESTIMONY OF KARL R. RÁBAGO ON BEHALF OF THE SOUTHERN ALLIANCE FOR CLEAN ENERGY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Karl R. Rábago. My business address is 2025 East 24th Avenue, Denver, Colorado.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the principal of Rábago Energy LLC, a Colorado limited liability company.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Southern Alliance for Clean Energy ("SACE").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I earned a B.B.A. in management (1977) from Texas A&M University, a J.D. with honors (1984) from the University of Texas School of Law, and LL.M. degrees in military law (1988) and environmental law (1990) from, respectively, the U.S. Army Judge Advocate General's School and Pace University School of Law. I served for more than twelve years as an officer in the U.S. Army, including in the Judge Advocate General's Corps and as an assistant professor of law at the United States Military Academy at West Point, New York. I have also worked for more than 20 years in the electricity industry and related fields. I have served as a Commissioner with the Texas Public Utility Commission (1992-1994) and as a Deputy Assistant Secretary for the Office of Utility Technologies with the U.S. Department of Energy (1995-1996). More recently, I have served as Director of Government and Regulatory Affairs for the AES Corporation (2006-2008) and as Vice President of Distributed Energy Services for Austin Energy, a large urban municipal electric utility in Texas. In 2012, I founded and became the principal of Rábago Energy LLC. I also currently serve as Chairman of the Board of Directors of the Center for Resource Solutions (1997-present) and as a member of the Board of Directors of the Interstate Renewable Energy Council (2012-present). My education and work experience is set forth in detail on my resume, attached as Exhibit KRR-1.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION (THE "COMMISSION")?

A. No. I have testified under oath before several state regulatory agencies, including the North Carolina Utilities Commission, the Virginia State Corporation Commission, the Georgia Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the District of Columbia Public Service Commission, and before Congress and state legislatures, including most recently the Minnesota State Senate and House of Representatives.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to make two key points regarding the solar photovoltaic ("solar PV") pilot programs administered by Florida Power & Light Company, Duke Energy Florida, Inc., Tampa Electric Company, and Gulf Power Company (the "Companies"). First, the Companies should substantially revise and continue their solar PV programs. Second, the Companies' solar programs should be revised to improve valuation techniques for solar PV in order to more accurately characterize solar PV cost effectiveness, and the Companies should be directed to improve their solar PV program structure and approach with a view to supporting the development of a self-sustaining solar PV market in Florida.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission disapprove the Companies' requests to cancel their solar PV programs in favor of a substantial revision to those programs. In particular, I recommend that:

- The Companies should be directed to develop, in conjunction with Commission staff and stakeholders, a Value of Solar Methodology similar to that now in place in Minnesota, and consistent with best practice guidance provided in the IREC "Regulator's Guidebook" relating to distributed solar valuation,
- The Companies should be further directed to use Value of Solar analysis in lieu of current cost-effectiveness tests to inform solar PV program structure, and
- The Companies should be directed to establish distributed solar PV programs that are focused not on compliance, but on supporting the emergence of a self-sustaining competitive market for distributed solar PV.

Q. WHAT MATERIALS DID YOU REVIEW IN PREPARING YOUR TESTIMONY?

A. I reviewed the original applications and supporting testimony filed by the Companies, as well as the Companies' responses to interrogatories and requests for production of documents submitted by SACE and Sierra Club.

Q. WHAT LEGAL AND POLICY PROVISIONS SUPPORT YOUR TESTIMONY, FINDINGS, AND RECOMMENDATIONS REGARDING IMPROVED ANALYSIS AND PROGRAM DESIGN FOR DISTRIBUTED SOLAR PV?

A. There is abundant support in Florida statutes and policy for advancement of clean renewable energy resources that reduce emissions and promote generation diversity. These include:

- Florida State Comprehensive Plan, Section 187.201, Florida Statutes (as amended 2008) – relating to improvement of air quality, reduction of emissions, promotion of alternative energy resources, promotion of solar energy technologies, promotion of low-carbon emitting power plants, and development of more secure energy resources.
- Florida Energy Efficiency Conservation Act (FEECA), Section 366.80, et seq., Florida Statutes – relating to legislative intent that the use of solar energy and other clean energy resources be encouraged; requiring Commission adoption of goals for demand-side renewable energy resources; requiring Commission consideration of costs and benefits to customers and the need for incentives; and requiring consideration of costs associated with regulation of greenhouse gas emissions.

Q. DOES FEDERAL POLICY ALSO IMPACT DISTRIBUTED SOLAR PV PROGRAMS?

A. Yes. In particular, I direct the Commission's attention to the recently reinstated U.S. EPA Cross-State Air Pollution Rule, which could provide opportunities to reduce regulatory risk and cost through increased reliance on distributed solar PV resources, and to forthcoming U.S. EPA regulations regulating greenhouse gas emissions from existing fossil fuel plants, which are expected to provide compliance flexibility mechanisms that favor distributed solar PV generation. I further note that the recently released National Climate Assessment that points out the serious risks facing Florida due to climate change resulting from greenhouse gas emissions.

IMPROVEMENTS TO THE COMPANIES' SOLAR PV PROGRAMS

Q. HAVE YOU REVIEWED THE COMPANIES' SOLAR PV PROGRAM

INFORMATION?

A. Yes, and based on that review, I have several recommendations for improving program design. My recommendations are informed by my own experience in program management as a utility executive, and by my familiarity with many other solar PV programs.

Q. WHAT ARE YOUR FINDINGS ON REVIEW OF THE COMPANIES' SOLAR PV PROGRAMS?

A. The Companies programs have resulted in valuable installations of distributed solar PV at homes, businesses, and schools. These systems will be generating clean, climate-proof, drought-proof, flat-priced electricity for decades to come. While the amount of distributed solar generation in Florida remains extremely small, the programs launched by the Commission hint at much greater potential for clean solar generation at or very near the point of consumption in Florida, to the benefit of ratepayers, the utilities, and society. However, the Companies' compliance-oriented approach to distributed solar PV severely constrained the opportunity reveal the benefits of solar rebate investments and to realize market transformation benefits in their service territories and therefore to maximize utility, ratepayer, and societal benefits that could have been obtained.

Q. WHAT DEFICIENCIES DO YOU FIND IN THE COMPANIES' SOLAR PV PILOT PROGRAMS?

A. My concerns are in two categories. First, I have concerns about the structure and operation of the solar PV pilot programs. The way in which the programs were conducted had significant negative impacts on the evaluation of the programs. Second, I have concerns about the metrics used to judge the cost-effectiveness of the Companies' solar PV pilot programs.

Q. WHAT ARE YOUR CONCERNS ABOUT SOLAR PV PROGRAM STRUCTURE AND ADMINISTRATION?

A. Most obviously, it is apparent that the Companies lack experience and determination to make distributed solar succeed, as demonstrated by the fact that these solar pilots had to be launched by Commission order as late as 2009, a time when many utilities in many less sunny states and nations were moving into mature and successful program structures. The numbers of customers taking advantage of the incentives demonstrates the pent-up demand for solar in Florida that existed in 2011 when programs started operating, and continues today.

Q. WHAT OTHER CONCERNS DO YOU HAVE?

A. The Companies reveal a mixed attitude to distributed solar PV. On the one hand, they declare distributed solar PV pilot programs as conclusively uneconomic for failure to pass DSM cost-effectiveness tests. Then they oppose any further efforts to support distributed solar PV deployment because, in the words of FPL witness Koch, "[t]he Solar Pilots have run for sufficient time to fully understand their performance and results, and they are scheduled to expire at the end of 2014." Witness Guthrie from DEF commented that in three years, installed price reductions did not meet expectations, but cited no efforts or explanation for that failure except that the Company now questions "if the rebates are truly incentivizing the market to reduce costs." Witness Guthrie further testifies that customer-owned solar has become "more viable and less expensive," and at the same time, the programs "fail the cost-effectiveness screens." On the other hand, witness Guthrie testifies, and I agree, that if the Commission decides to maintain the solar programs, new future programs should eliminate subsidization, leverage scale and scope to lower installed costs, account for and minimize integration costs, and gather and analyze meaningful data regarding solar deployment.

Q. CAN YOU DETAIL YOUR FINDINGS REGARDING THE COMPANIES' EVALUATION OF DISTRIBUTED SOLAR PV AND THE PILOT SOLAR

PROGRAMS?

A. This testimony addresses the programs and evaluations conducted by Florida Power & Light (FPL), Duke Energy Florida (DEF), Tampa Electric Company (TECO), and Gulf Power (Gulf). Several common themes emerge in the Companies' filings regarding the solar PV pilot programs and in their approach to distributed solar PV in general. These themes include:

- All of the Companies find that solar PV pilot programs were not cost-effective as evaluated. None considered any alternative approaches to evaluation of the programs.
- All of the Companies utilizes sophisticated avoided cost analysis in development of their resource plans and in screening alternative DSM programs. None applied this sophistication to the evaluation of the solar PV pilot programs or to the cost-effectiveness of distributed solar PV as a specific alternative resource.
- All of the Companies recognized the risk of fuel price volatility associated with increased reliance on natural gas; rather than integrate the avoidance of this risk into valuation of solar PV, the Companies limited their evaluation of fuel price risk to alternative price forecasts for entire resource plans.
- All of the Companies reported considering avoided generation, fuel, generation O&M, and transmission and distribution costs in evaluating alternative demand side resources. However, none of the Companies informed this analysis with the load-weighted and time differentiated value of solar PV generation. None of the Companies used Effective Load Carrying Capacity or other tools to fairly and fully assess the capacity credit that should be applied in valuing solar PV.
- All of the Companies reported that they do not develop specific cost estimates or detailed plans for transmission and distribution investments beyond a 10-year horizon, in some case as few as 5 years. As a result, they did not value transmission and

distribution cost avoidance during the entire 30+ years that a distributed solar PV system is likely to operate.

- None of the Companies reported assessing any value for the operational security and disaster-recovery benefits of distributed solar PV generation.
- None of the Companies assessed environmental regulatory risk beyond current compliance costs in valuing distributed solar PV as a specific technology option.
- All of the Companies reported that line losses at the transmission and distribution levels were correlated with load, but none of the Companies evaluated the value or cost-effectiveness of distributed solar PV in avoiding these load-weighted losses.
- None of the Companies integrated any location-specific analysis of the potential value of distributed solar PV into their evaluations.
- All of the Companies admitted that their solar PV pilot programs had enjoyed significant (from 25% to 38%) reductions in the installed cost of solar PV, and that their solar PV pilot programs had completely failed to contribute to those cost reductions.
- All of the Companies reported substantial popularity and rapid reservation of rebates in every program year of the solar PV pilots. All reported significant failure rates in converting reservations into installations. None reported any effort to regularize solar installation rates over the entire program year or to improve the completion rates for reservations.
- All of the Companies simultaneously cited the falling price of distributed solar as evidence of mature distributed solar markets and the failure of the programs to pass cost effectiveness tests.
- All of the Companies recommend termination of the funding for the solar PV pilots; none recommended improvements to the programs.

Q. WAS THERE ANY COMPANY-SPECIFIC INFORMATION THAT YOU WISH TO CITE IN PARTICULAR?

A. Yes. Though the quality and form of data provided in response to interrogatories and requests for production varied significantly, several noteworthy examples evidence a failure on the part of each Company to maximize the opportunity provided by the Commission's order to conduct pilot programs. In some cases, this evidence suggests efforts to ensure that distributed solar PV markets do not develop in Florida.

Q. WHAT DEF-SPECIFIC EVIDENCE DO YOU WANT TO NOTE?

A. DEF provided detailed information about solar PV technology assumptions. Many of these assumptions are inconsistent with broader market information. DEF relied on a 20-year measure life for solar PV even though virtually all module providers warrant their equipment for 25 years. DEF limits the value of the federal tax credit to 15% in spite of the fact that the credit is currently 30%. DEF assumes that residential solar costs $4.17/watt to install, even though prices are lower across Florida. DEF also includes marketing costs in its cost-effectiveness evaluations even though the programs require no marketing.

Q. WHAT GULF-SPECIFIC EVIDENCE DO YOU WANT TO NOTE?

A. Gulf reported that administrative expenses increased from 20% in 2011 to 30% in 2013 even as solar PV costs fell 38% during the same period. These excessive costs adversely impact cost-effectiveness. Gulf also reported that it spends ratepayer funds to purchase natural gas price hedges, but does not include this cost in evaluating the benefits of solar PV.

Q. WHAT FPL-SPECIFIC EVIDENCE DO YOU WANT TO NOTE?

A. FPL takes the position of assessing a penalty against distributed solar PV based on "avoiding fuel-efficient new generation," though the basis for this approach is not explained in testimony or responses.

Q. DO YOU AGREE WITH THE COMPANIES' ASSESSMENT THAT THE SOLAR PV PILOT PROGRAMS SHOULD BE TERMINATED?

A. The Companies' Solar PV Pilot Programs should not continue in their present form. I have strong concerns about leaving control and management of the solar PV programs in the hands of the Companies without significant modification, oversight, and stakeholder involvement.

Q. DO YOU AGREE WITH THE COMPANIES' CONCLUSIONS THAT SOLAR IS NOT COST-EFFECTIVE AND AS A RESULT, THE SOLAR PV PROGRAMS IMPOSE UNFAIR RATE IMPACTS ON NON-SOLAR CUSTOMERS?

A. No. The Companies' conclusions in this regard are unsupportable for two reasons. First, the solar PV programs were not properly structured to achieve cost-effectiveness or the development of a self-sustaining market for distributed solar. In the face of rapid and continuing declines in the price installed price of solar PV, a properly structured solar PV program could leverage these cost improvements, the growing customer popularity of distributed solar, efficiencies that will emerge from more mature market infrastructure, and more effective rebate and incentive strategies to support market development. Second, the solar PV programs use inadequate and inappropriate cost-effectiveness criteria when evaluating distributed solar as a resource. Improvements in valuation of the full range of costs and benefits associated with distributed solar PV would support a different conclusion regarding cost-effectiveness.

Q. DO YOU AGREE WITH FPL WITNESS KOCH THAT SOLAR PV PROGRAM PROPONENTS BEAR A BURDEN OF PRODUCTION OR PROOF IN ORDER TO JUSTIFY A COMMISSION ORDER FOR THE IMPROVEMENT AND CONTINUATION OF THE SOLAR PV INCENTIVE PROGRAMS?

A. No. In light of the extensive policy support provided in Florida Law for the clean renewable energy, in particular, solar energy, it is the Companies' obligation to conclusively establish that the solar PV programs should be terminated. In light of the problems that I have discussed, they have not met that burden.

Q. WHAT OVERRIDING OBJECTIVES SHOULD GUIDE THE STRUCTURE AND OPERATION OF A SOLAR PV PROGRAM?

A. In my view the primary goals for a strong solar PV program should be:

- The program and incentives should ultimately lead to a self-sustaining rooftop/small scale solar energy market in Florida.
- The program should provide fair compensation for solar energy value and additional financial incentives that are economically efficient, i.e., incentives that prompt customers to make solar energy investments they would not otherwise make, without being excessive.

Q. WHAT INDICATORS SHOULD THE COMPANIES TRACK IN MONITORING THEIR SOLAR PV PROGRAMS?

A. The Companies should focus not just on numbers of systems, dollars, kilowatts, and kilowatt hours. For a pilot program that should translate into a full program, it is the direction that the numbers are moving that is most important, and whether continued progress is being made toward program objectives designed to achieve program goals. Some of the key indicators of a sound solar program include:

- Progressive reduction in the incentives stimulating customer investment in solar PV.
- Progressive and systematic reductions in system and component costs.
- Progressive reduction in the fraction of system cost represented by incentives.
- Progressive increases in solar PV capacity per dollar of program budget.
- Progressive increases in the numbers of solar contractors and full-time, year-round employees.

Q. WHAT FACTORS SHOULD THE COMPANIES TRACK IN ORDER TO UNDERSTAND STATEWIDE AND COMPANY-SPECIFIC SOLAR PV MARKET CONDITIONS?

A. The Companies' program managers should track several factors on an ongoing basis that could impact local solar market conditions in order to reach a judgment about those market conditions so as to inform the setting of economically efficient solar incentive levels. Factors impacting emerging solar markets are local, regional, national, and even international, and include:

- Local and regional solar installer workloads
- Availability of skilled workforce
- Local and regional economic conditions
- Local customer awareness
- Local markets for solar financing
- Other local economic incentives
- Utility incentive programs in Florida, especially adjacent utilities
- Regulatory and legislative policy development in Florida, the Southeast, and the United States
- National solar module prices
- National solar incentive levels and status of programs
- National tax policy and incentives relating to solar energy
- International solar incentive programs (which impact global solar module prices)

In combination, these factors can impact customer demand for incentives and program participation. For example, when prices for modules drop quickly, customer demand for incentives can grow quickly. If such a trend is long-term in nature, adjustments to incentive levels may be warranted. In fact, recent reductions in installed solar costs as well as the availability of substantial federal tax incentives have been drivers of downward adjustments in rebates and incentives across the United States.

Q. WHAT OTHER RECOMMENDATIONS DO YOU HAVE FOR A STRONG SOLAR PV PROGRAM?

A. I have several other recommendations. These include:

- Good solar PV programs feature regular meetings of program staff with solar installation contractors and stakeholders, featuring two-way dialogue about market conditions, program performance, administrative requirements, and other issues. These meetings provide invaluable "ground-truthing" for solar program managers.
- Program managers should continually review the state of the art in solar promotion programs to stay abreast of innovations and opportunities for program improvements.
- While solar PV programs should be designed to provide predictability regarding incentives and program requirements, it is also appropriate to grant flexibility to program managers to respond to unexpected or sooner-than-expected changes in solar PV market conditions. When program adjustments are required they should not be a surprise to the Commission or stakeholders.
- Program managers should also be prepared for increases in the average size of installed systems as solar prices fall. Larger system sizes consume larger incentives per customer, and in a fixed budget environment, potentially reduce the number of systems receiving incentives. On the other hand, per-unit fixed and system costs decline with system size, allowing for more kilowatts per incentive dollar expended.
- Robust solar PV programs should account for repeat customers. Distributed solar is modular in nature, meaning customers can install a system one year, and expand the system in later years as demand or household budget grows. These system expansion investments can be a relatively low cost path to valuable incremental market growth.

THE COMPANIES SHOULD CONDUCT A COMPREHENSIVE VALUE OF SOLAR ANALYSIS

Q. WHAT IS THE BENEFIT OF COMPREHENSIVE VALUE OF SOLAR (VOS) ANALYSIS FOR SOLAR PV?

A. Full and updated evaluation of resource value improves the chance that a forward-looking resource or program plan will strike the economically efficient balance in crafting robust and least-cost plans in the most cost effective manner possible. If a renewable generation resource is under-valued by the Companies, it will be under-selected and under-utilized in its plans. In my view this is precisely the situation with the solar PV programs run by the Companies. The cost-effectiveness tests applied do not account for all the value of solar, and, as a result, the Companies reach a conclusion that their solar programs should be terminated. A full VOS analysis is necessary. It is not enough to say that one resource is "expensive" compared to another unless the benefits of the competing resources are also assessed and compared. The Companies' cost-effectiveness evaluations suffer from this flaw.

Q. HOW DO UTILITIES TYPICALLY ASSESS THE VALUE OF DISTRIBUTED SOLAR PV?

A. Distributed solar resources have historically not fared well in traditional utility ratemaking systems, which often have a financial bias toward large, capital-intensive projects owned by the utility. Historically, these utility-owned projects, if successful, tend to maximize profits at the expense of the lowest cost and highest value for customers. Historically utilized preferences tend to assign higher value to dispatchable generation options with low capacity cost, while undervaluing several increasingly valuable and important components, such as fuel price volatility, regulatory (especially environmental) risk, water supply and availability risk, transmission infrastructure requirements, and others. Traditional avoided cost methodologies, designed to set energy payments based on current costs, can reduce the value of low- or zero-risk resources and long run marginal cost and risk reductions.

Q. IS THIS APPROACH EVIDENT IN THE COMPANIES SOLAR PV PROGRAMS?

A. Yes. The Companies use and report the installed capacity cost of solar PV, but do not assess and characterize the full value of solar in providing energy, capacity, transmission and distribution, risk-reduction, and other benefits. It also appears that the Companies' do not assign full credit to solar PV generation that will accrue to the utility and all ratepayers over the full 30+ year useful life of installed systems. In addition, each of the Companies' assigns a "lost revenues" cost to solar PV that fails to account for all costs that the utilities avoid. This over-calculation of costs negatively impacts the cost-effectiveness assessment.

Q. DOES THIS TRADITIONAL PROCESS PROPERLY ADDRESS RENEWABLE RESOURCES?

A. No. This traditional process has not addressed renewable resources properly. More and different data about value is required.

Q. CAN YOU ELABORATE FURTHER?

A. Yes. It is important to understand the coincidence or overlap of solar production with hourly prices, which informs the energy value and capacity credit that should be recognized for this resource. Capacity credit informs the value for avoided capacity, avoided transmission and distribution investment, line losses, and other values. The Company should also recognize value for the greenhouse gas benefits of solar energy as well as the reduced risk of environmental regulation that solar energy provides—very real economic risks even in the absence of current control costs. Traditional calculations tend to ignore all manner of risk, including fuel price and environmental regulation risks. In response to SACE's efforts to adduce the various value factors considered by the Companies for renewable resources, it appears that in spite of a high availability of the raw data, few of these value factors are considered and even fewer are quantified.

Q. HOW HAS DISTRIBUTED SOLAR VALUATION EVOLVED?

A. As the U.S. Department of Energy reported to Congress in 2007,

"Calculating [distributed generation] benefits is complicated, and ultimately requires a complete dataset of site-specific operational characteristics and circumstances. This renders the possibility of utilizing a single, comprehensive analysis tool, model, or methodology to estimate national or regional benefits of [distributed generation] highly improbable. However, methodologies exist for accurately evaluating "local" costs and benefits (such as [distributed generation] to support a distribution feeder). It is also possible to develop comprehensive methods for aggregating local [distributed generation] costs and benefits for substations, local utility service areas, states, regional transmission organizations, and the Nation as a whole.[1]*"*

Over the past two decades, a number of local studies have been conducted to calculate the benefits of distributed solar. Today, VOS analysis rests on a solid foundation of data that, if applied, can significantly improve the Companies solar PV program structure and evaluation.

<u>VALUE OF SOLAR ANALYSIS</u>

Q. WHAT IS VALUE OF SOLAR (VOS) ANALYSIS?

A. VOS analysis identifies and characterizes the value attributes of solar energy generation by thoroughly characterizing and quantifying the costs avoided by solar generation. Numerous VOS studies published over the past decade share a common general approach and fairly common general structure. A representative list of these studies is described in greater detail in attached Exhibit KRR-2, a recent report from the Rocky Mountain Institute's eLab

[1] U.S. DOE, "The Potential Benefits of Distributed Generation and the Rate-Related Issues That May Impede Its Expansion: Report Pursuant to Section 1817 of the Energy Policy Act of 2005," June 2007.

Project entitled "A Review of Solar PV Benefit and Cost Studies.[2]" While results vary depending on methodologies, local energy markets and other factors, research consistently suggests that distributed solar energy has value that significantly exceeds the Companies' and utility ratepayers' costs associated with stimulating distributed solar energy development. That value should be, but is not, reflected in the Companies' evaluation of their solar PV programs and in their characterization of solar PV in planning. As a consequence, the Companies propose less solar development, zero goals, and even termination of distributed solar PV incentives. The Companies propose less solar PV support than would be economically efficient and miss a valuable opportunity to support the growth of a distributed solar market in Florida.

Q. WHAT ARE THE BASIC ELEMENTS OF DISTRIBUTED SOLAR VOS ANALYSIS?

A. VOS analysis is an expansion on a full avoided cost approach that adds a long term valuation perspective, including, as appropriate and quantifiable, social costs and benefits. There are two basic steps: first, benefits and costs are identified and grouped, then, second, the benefits are quantified. These steps are essentially the same as traditional ratemaking functions inherent in cost of service analysis. The focus is on the net value that distributed resources bring to utility and grid finances and operations.

Q. IS THE CALCULATION OF VOS MARKET DRIVEN?

A. Yes. VOS calculations are, at heart, avoided cost calculations that embrace a full range of costs avoided by distributed solar generation, including savings over the life of the solar generation system. So the source of the value of solar is in the market costs avoided and market benefits received. As explained earlier, solar valuation studies offer improved

[2] "A Review of Solar PV Benefit and Cost Studies," Rocky Mountain Institute eLab Report, April 2013. ("RMI eLab Report") Available at: http://www.rmi.org/Content/Files/eLab-DER_cost_value_Deck_130722.pdf.

market pricing signals over traditional avoided cost calculations, which ignore long-term risk, especially fuel price and environmental regulatory risk. My own experience with Austin Energy's VOS methodology is that the calculated value of solar better reflects market conditions and the value of solar investments than short-term avoided cost calculations and base rate calculations established in prior years based on historical test year costs.

Q. WHAT ARE THE BENEFITS AND COSTS STUDIED IN VOS ANALYSIS?

A. The benefits and costs are those that accrue to the utility and its ratepayers as a result of the satisfaction of the demand for electricity services from a distributed solar facility in lieu of the Companies' use of current and planned system resources to meet that demand. The value of solar to the Companies, as a renewable distributed generation resource, must be calculated in a very different manner from traditional capital- intensive, remote central station projects. A value of solar analysis also differs from other cost-effectiveness analyses conducted from a societal perspective in that customer investment and costs are typically omitted. At a high level, the costs and benefits to the Company and ratepayers associated with distributed solar energy generation systems include:

- Energy: The basic electrical energy created by the distributed solar system, plus a credit for line-loss savings that accrue because distributed solar displaced generation from remote, central station plants.
- Capacity: Also referred to as "demand." Capacity values capture the avoided capital investments in generation, transmission and distribution that flow from distributed solar generation units.
- Grid Support (Interconnected Operations Services): Often referred to as "ancillary services." These benefits include affirmative provision of services and avoidance of costs related to a range of services inherent in maintaining a reliable, functioning grid

network. This grid support or ancillary services include, at both the transmission and distribution level, reactive supply and voltage control, regulation and frequency response, energy and generator imbalance, scheduling, forecasting and system control and dispatch.

- Customer benefits: Customers accrue a number of benefits from hosting and operating distributed solar systems including reputational, community participation, bill management and stability, and efficiency support benefits. While some of these benefits do not accrue to the utility, some do, like reduced bad debt and delayed payment costs that accompany self-generation.
- Financial and security: These benefits generally reduce both the cost and risk associated with maintaining reliable electric service for customers, especially in the face or variable regulatory, economic, and grid security conditions. These benefits include utility fuel price volatility control, and costs associated with emergency customer power and outages, as well as more rapid and less costly recovery from outage events.
- Environment: Distributed solar creates benefits in reducing the supply portfolio costs associated with control of criteria pollutants, greenhouse gas emissions, water use, and land use. Where control regimes exist, these costs may be reflected in the cost of operating polluting resources. Distributed solar valuation goes beyond traditional avoided cost approaches in recognizing that these resources also affirmatively reduce financial risks associated with compliance with future control regimes.
- Social: Distributed solar also generates social benefits associated with net job growth benefits compared to "conventional" generation options, increased local tax revenues, reduced occupational safety costs (such as black lung insurance), and others.

Q. HOW ARE THESE BENEFITS AND COSTS QUANTIFIED?

A. I previously cited a Rocky Mountain Institute study that assessed several quantification studies. My recommendation is that the Companies should be directed to develop a quantification methodology and value of solar calculation in consultation with a broadly based group of stakeholders.

Q. HAVE ANY OF THE STUDIES QUANTIFIED THE VALUE OF SOLAR PV IN FLORIDA?

A. Though a strong body of research exists on this topic nationally, I have found no studies based on Florida data. The RMI eLab Report that I cited earlier and attached to this report characterizes more than a dozen "value of solar" and other studies addressing solar PV costs and benefits. Among the more prominent researchers cited was Richard Perez. Richard Perez led a team that published a study titled "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania.[3]" That study modeled the value of a 15% peak load penetration of distributed solar electric generation at seven locations in the region. The model addressed the following values:

- Fuel Cost Savings
- O&M Cost Savings
- Security Enhancement Value
- Long Term Societal Value
- Fuel Price Hedge Value
- Transmission and Distribution Capacity Value
- Market Price Reduction
- Environmental Value
- Economic Development Value
- Solar Penetration Costs

[3] "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania," Clean Power Research, November 2012. ("CPR NJ & PA Study 2012") Available at: http://mseia.net/site/wp-content/uploads/2012/05/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf

- Generation Capacity Value

The study found that the total value of distributed solar ranged from $0.256 to $0.318 per kWh. A copy of the paper is attached at Exhibit KRR-3 and is offered as an indicator of how a comprehensive distributed VOS study can be conducted. More recently, the State of Minnesota Department of Commerce developed, and the Minnesota Public Utilities Commission approved a value of solar calculation methodology.

Q. PLEASE DESCRIBE THE MINNESOTA DEPARTMENT OF COMMERCE'S VALUE OF SOLAR METHODOLOGY AND ITS RELEVANCE TO YOUR RECOMMENDATIONS.

A. In 2013, the State of Minnesota enacted a law that created an option for electric utilities to offer a Value of Solar tariff as an alternative to net metering. The Value of Solar rate aims to compensate solar generators fairly for the value of their output, and to create an opportunity for utilities to fully recover their costs of providing service to those customers. After a widely-praised stakeholder process that was transparent and engaged dozens of utilities, business and government representatives, advocates and concerned citizens, the Minnesota Department of Commerce developed a value of solar methodology (Minnesota Methodology)[4]. That methodology is intended to guide the development of any Value of Solar tariff proposals in Minnesota, and is attached at Exhibit KRR-4.

Q. WHAT ARE THE MAJOR FEATURES OF THE MINNESOTA METHODOLOGY?

A. Key aspects of the Minnesota methodology include:

- A standard solar photovoltaic rating convention
- Methods for creating an hourly solar production time-series, representing the aggregate

[4] Minnesota Value of Solar: Methodology, MN Department of Commerce Division of Energy Resources, Clean Power Research (Jan. 31, 2014), available at http://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf.

output of all solar systems in the service territory per unit capacity corresponding to the output of a solar resource on the margin

- Requirements for calculating the electricity losses of the transmission and distribution systems
- Methods for performing technical calculations for avoided energy, effective generation capacity and effective distribution capacity
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.)
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review

Q. WHY DO YOU DIRECT THE COMMISSION AND THE COMPANIES TO THE MINNESOTA METHODOLOGY?

A. The Minnesota Methodology stands in stark contrast to the methodologies used by the Companies in their applications. The Minnesota Methodology demonstrates the comprehensive, objectively verifiable approach that can be developed when a broad range of stakeholder and expert opinions are focused on the solar valuation issue. As explained in the Minnesota Methodology, if a value of solar is set correctly, it will account for the real value of photovoltaic generated electricity, and the utility and its ratepayers will be indifferent to whether the electricity is supplied from customer-owned photovoltaic resource or from comparable conventional means. This valuation eliminates cross-subsidization concerns if incorporated in a tariff, and used in resource planning, it can provide market signals for the adoption of technologies that could significantly enhance the value of solar electricity, such as smart inverters. A properly conducted resource plan should include accurate valuation of all resources options, including solar. The Minnesota Methodology represents a detailed and well-documented example that the Companies could use to guide their work in correcting the deficiencies of their current processes.

Q. CAN STUDY RESULTS FROM OTHER JURISDICTIONS BE APPLIED DIRECTLY TO THE COMPANIES AND UTILITY OPERATIONS IN FLORIDA?

A. These studies were not based on specific data from the Companies' service territory or from data for Florida. Given the diversity of the data sets from which the studies are drawn, and the relatively high importance of energy and local costs in the estimation, it is reasonable to conclude that the value delivered by distributed solar in the Companies' service territory will be significant and likely higher than the current retail price for electricity. Growing experience with VOS analysis yields insights as to best practice in distributed solar valuation. I recently co-authored a report published by the Interstate Renewable Energy Council (IREC) that sets out current best practice for distributed solar PV valuation.

Q. PLEASE DESCRIBE THE IREC REPORT ON SOLAR VALUATION AND ITS RELEVANCE TO YOUR RECOMMENDATIONS.

A. In October 2013, IREC published a paper authored by Jason Keyes and myself, entitled "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation" ("Guidebook").[5] The Guidebook, attached as Exhibit KRR-5, draws on many distributed solar valuation studies to recommend a framework for a methodology for performing a benefit/cost evaluation for distributed solar. The Guidebook's recommended approach differs greatly from the approaches taken by the Companies. Key principles underlying the methodology that my co-author and I recommended include reliance on data, transparency, reasonable evaluation of costs and benefits, and consistency in approach.

Q. WHAT DOES THE IREC GUIDEBOOK RECOMMEND REGARDING THE

[5] A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, Interstate Renewable Energy Council (Oct. 2013), available at http://www.irecusa.org/publications/.

SCOPING OF A BENEFITS/COSTS STUDY?

A. In the Guidebook we recommend that the Commission clarify a number of issues at the onset of a benefit/cost study, including:

- *What is the appropriate discount rate for evaluation of costs and benefits?*

  Studies typically use the utility weighted average cost of capital, though there is a strong argument for use of a risk-adjusted discount rate to reflect the performance characteristics of solar generation.

- *What is being considered – all solar generation or exports to the grid only?*

  Where net metering is being evaluated, it is appropriate to limit the evaluation to exported energy. However, for a two-part rate and full value of solar analysis, all generation should be evaluated.

- *Over what timeframe will the study examine the benefits and costs of solar resources?*

  The timeframe for analysis should reflect the useful life of solar resources, today typically 30 years, though there is a strong argument that a sensitivity evaluation should consider a useful life as long as 35 years.

- *What does utility load look like in the future?*

  Under traditional net metering arrangements, customer-sited distributed solar generation operates to reduce utility load. Under some structures, such as a feed-in tariff, distributed generation does not reduce load, but does contribute to utility energy and capacity requirements at or near the point of generation.

- *What level of market penetration for distributed solar generation is assumed in the future?*

  It is unreasonable to assume exponentially higher market penetration rates in the short term. Likewise, it is not reasonable to assume penetration rates that are artificially constrained. Sensitivity analysis can be useful to gauge the impacts of more reasonable penetration rates.

- *What models are used to provide analytical inputs?*

  Utility models such as Strategist are extremely useful in conducting integrated resource plan analysis, but often are constrained in their ability to model small-scale resources. Extrapolation of results to analyze these resources can induce errors. Full transparency and sensitivity analysis at varying scales of deployment, and with variation in other assumptions (such as the penetration rate of distributed storage technology) is essential to accurately model distributed solar generation.

- *What geographic boundaries are assumed in the analysis?*

  Solar resources may demonstrate improvements in availability due to geographic dispersion. Solar insolation values, which drive energy production, vary depending on location. These variations should be accounted for in study design.

- *What system boundaries are assumed?*

  Solar integration costs may vary the location where solar generation is cited. These factors extend beyond land and construction costs and should be accounted for in a study.

- *From whose perspective are benefits and costs measured?*

  I recommend that the Companies use a combined test that incorporates ratepayer impacts testing and societal cost testing.

- *Are benefits and costs estimated on an annualized or levelized basis?*

  A levelized cost analysis extending over the useful life of the solar resource is best for fully capturing the avoided costs and delivered benefits of solar generation.

Q. WHAT DATA SETS DOES THE GUIDEBOOK RECOMMEND TO CONDUCT A FULL BENEFITS/COSTS ANALYSIS FOR SOLAR GENERATION?

A. The Guidebook recommends that the utility obtain or develop the following data sets:

- The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the solar generation system.

- Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of solar generation.
- Hourly production profiles for distributed solar generators, including south-facing and west-facing arrays.
- Line losses based on hourly load data, so that marginal avoided line losses due to solar generation can be calculated.
- Both the initial capital cost and the fixed and variable O&M costs for the utility's marginal generation unit.
- Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth.
- Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of distributed solar generation, in order to capture the potential for avoiding or deferring circuit upgrades.

I believe that the Companies have assembled most, if not all, of this data in the course of ongoing resource planning and other activities. Where utility-specific data is not readily available, analysts may develop suitable estimation methods or use third-party data (such as PV-WATTS data for solar performance).

Q. WHAT CATEGORY OF BENEFITS FROM SOLAR GENERATION SHOULD BE ASSESSED?

A. Consistent with the Guidebook, I recommend that the following solar generation benefits be addressed by the Company in an analysis:

- Energy – Based on not running a gas-fired plant

- System Losses – Based on marginal losses
- Generation Capacity – Using Effective Load Carrying Capability or similar analysis
- Transmission and Distribution Capacity – Not limited to large planning increments
- Grid Support Services – Evaluation of ancillary services value
- Financial – Fuel price hedge
- Financial – Market Price Response
- Security – Stability and Resiliency
- Environment: Carbon & Other Factors – Residual (beyond compliance) benefits
- Social – Economic development

Q. WHAT COSTS SHOULD BE ASSESSED?

A. As discussed in the Guidebook, I believe it is appropriate to assess utility costs as well. These costs include direct utility costs and may include an assessment of lost revenues. I note that assumptions about administrative costs (such as billing costs) should reflect automated billing systems. Interconnection costs incurred solely by the customer should not be included. And finally, I reiterate that integration costs should be based on realistic assumptions about solar generation penetration rates.

Q. HOW DOES VOS RELATE TO INCENTIVE PAYMENTS MADE BY THE COMPANIES UNDER THEIR SOLAR PV PROGRAMS?

A. The calculated value of solar can serve as a benchmark indicator for payments a utility makes for third-party solar energy. As with the theory behind avoided cost calculation, VOS analysis quantifies the value equal to what it would cost either the utility or a third party to provide solar energy delivered to the point where the energy does its work. It establishes an economic "indifference price." The Companies, however, appears to conduct no value-based analysis to inform either incentive levels or cost-effectiveness evaluations.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE CALCULATION OF VOS AND

THE ANALYSIS OF SOLAR RESOURCES AS A FACTOR IN RETAIL RATES PAID BY RATEPAYERS IN GENERAL?

A. Because the VOS approach improves on the Companies' traditional avoided cost methodology, it indicates a compensation level that can be used to ensure net positive benefits to ratepayers. That is, once the value of solar is fully and accurately known, the Company can be assured that distributed solar enabled at a lower payment will generate excess value for the Company and its ratepayers. At volume, these cumulative excess benefits will exert downward pressure on rates, reflecting a value-to-price differential. The Company's practice today is not grounded in value analysis, but rather in strict regulatory compliance. Such practice provides no assurance of value in excess of cost. This represents a significant opportunity cost to the Company and its customers.

Q. DO SOLAR PROGRAM SUBSCRIPTION RATES INDICATE WHETHER THE INCENTIVE AND PAYMENT LEVEL REFLECTS THE VALUE OF SOLAR PV TO THE COMPANIES AND THEIR RATEPAYERS?

A. No. Program subscription rates indicate how investor-customers perceive payment levels under current market conditions. In some cases, the timing of program reservations can be a powerful indicator of poor program administration. Solar deployment markets will not mature to efficiency in feast/famine cycles. Releasing an entire year's worth of incentives in a short period of time will encourage rapid subscription, but as the Companies have all testified, rapid reservation does not necessary mean high completion rates or the development of more efficient markets.

Q. IN SUMMATION, WHAT SHOULD THE COMMISSION AND THE COMPANIES REASONABLY CONCLUDE BASED ON THE MANY PUBLISHED DISTRIBUTED VOS STUDIES?

A. From published VOS research, the Commission and the Companies can and should reasonably conclude that:

- Distributed solar systems in the Companies' service territories likely have value that will exceed the payment required to facilitate wider deployment of solar as a generation resource.
- Because distributed solar value exceeds the cost to facilitate deployment, increased deployment of distributed solar will put downward pressure on rates.
- Value of solar analysis coupled with greater market development can support and confirm the cost-effectiveness of solar PV, that is, the availability of distributed solar at costs that are less than value.

In sum, distributed solar value analysis enables the Commission and the Companies to benchmark the resource value of the distributed solar option and to conclude that the Companies should move forward with a revised solar PV program structure that advances the deployment of distributed solar in the Companies' service territories beyond the limits of previous programs, and, of course, current proposals.

VOS, AVOIDED COST, AND COST-EFFECTIVENESS TESTS

Q. EARLIER IN YOUR TESTIMONY, YOU DISCUSSED AVOIDED COST METHODOLOGY. CAN YOU DISTINGUISH BETWEEN VOS AND TRADITIONAL AVOIDED COST CALCULATIONS?

A. Yes. Avoided cost analysis differs from VOS analysis in two key ways. First, most avoided cost analysis is not a "full avoided cost" calculation. Second, traditional avoided cost analysis differs from more far-reaching, forward-looking analyses used to evaluate new resource additions. A major difference between the two approaches relates to risk. Not all resources bear the same risks. Risk is not well addressed even in full avoided cost methodologies. A resource that depends on long-term availability of fuel at an affordable price is very different from distributed solar, which has no fuel cost, now or in the future.

This risk of price volatility is not captured in avoided cost calculations or in cost-effectiveness tests currently utilized. Risk, therefore, is either ignored or undervalued in current evaluation methodologies.

Q. PLEASE EXPLAIN HOW RISK VALUATION IMPACTS RESOURCE VALUATION AND COST-EFFECTIVENESS EVALUATION.

A. Undervaluing fuel volatility risk and other risks means that resource options like distributed solar is seen to avoid less cost than it actually does. This results from adjustments made to traditional ratemaking and cost recovery decades ago. Utilities are increasing their dependence on generation run on fuels with volatile pricing patterns—natural gas, in particular. They use pass-through cost recovery mechanisms for fuel costs in fuel cost reconciliation charges or "fuel charges," as they are often called. Generally, regulations approved the addition of fuel costs recovery riders on customer bills, over and above basic rates for electricity to address potential regulatory lag issues arising from price volatility.

As a result, utility finances are largely immunized from the deleterious impacts of regulatory lag in fuel cost recovery, but also less sensitive to fuel price volatility than even their customers. The typical "peaker" approach to avoided cost calculations confirms this—it is a methodology that essentially gives no value to resources that reduce fuel price volatility and instead affirmatively favors resources with low capacity costs, even if the long-run fuel costs of the resource are extremely variable. By undervaluing distributed solar, this approach encourages a utility to procure or support solar at a sub-optimal levels in its planning, systematically rejecting resources that reduce portfolio exposure to fuel price volatility risk.

A similar undervaluation arises regarding security risk and vulnerability to disruptions due to natural and man-made events and risks associated with obtaining water at affordable prices, for example. Of course, greenhouse gas regulation and other environmental regulatory risks (such as that associated with coal ash pond spills) add additional risk. Economic efficiency is maximized by an analysis that quantifies the full future stream of benefits and costs avoided over the full operational life of distributed solar and expressly addresses the risk associated with all costs over the life of each resource option. There is significant value in a generation resource that has no fuel or water cost or environmental regulatory cost over its entire life—a value appears to be largely ignored in the Companies' planning process and, in particular, in the goal setting and solar PV program evaluation processes. Understanding risk reduction value of all types associated with increased deployment of solar PV is key to constructing an optimally diverse portfolio of resources and to evaluating program costs and benefits.

Q. ARE THERE FUTURE COSTS AND/OR BENEFITS THAT SHOULD BE INCLUDED IN EVALUATING THE VALUE OF DISTRIBUTED SOLAR, BUT WHICH ARE NOT FINITELY QUANTIFIABLE?

A. Some costs and benefits are not precisely quantifiable. There is an analytical risk in erroneous valuation. Undervaluing one "alternative" option is the same as overvaluing the incumbent or reference unit. Overvaluing an option might impose costs on ratepayers that could inflate rates. It is appropriate to reach a reasonable level of confidence about a value estimate before using it in resource evaluation decision. But, the field is hardly static. Avoided cost and VOS methodologies have improved over the past several decades. There are also some values that, while difficult to quantify, should be reviewed qualitatively as part of the process of resource plan development. For example, while the tax base and job creation benefits of distributed solar market penetration might not yet lend themselves to discrete quantification in a utility resource plan or explicit reflection in utility rates, job creation and other economic development benefits must be expressly reviewed in the planning exercises. Such factors often have a strong impact on market and regulatory risk.

Q. HOW WOULD FORWARD-LOOKING RESOURCE EVALUATION FURTHER IMPROVE THE EVALUATION OF ALTERNATIVES?

A. Avoided cost methodologies are an appropriate means for comparing the cost avoided when a single unit of energy from a Qualifying Facility is introduced into the grid on a year-by-year basis. Distributed solar systems, however, are long-lived, with high availability and low output degradation. This is why distributed solar programs should take a longer view than is taken with traditional avoided cost calculation. Levelized cost of energy calculations and production cost modeling exercises are explicitly focused on a resource's capability to meet the demand for energy over the life of the resource. They are not limited to traditional marginal cost calculations such as are used in setting avoided cost rates. The amount paid to stimulate the construction and operation of a new distributed system will likely yield thirty or more years of continued energy generation and benefit creation. The most common and appropriate way to account for this stream of benefits is to adjust a full avoided cost calculation by iterating it over the entire expected operating life of the system and then calculating a levelized present value of that stream of benefits.

Q. HOW DOES A LEVELIZED PRESENT VALUE OF A STREAM OF FULL AVOIDED COSTS CALCULATION POTENTIALLY IMPACT RATEPAYERS?

A. The approach of both conducting a full avoided cost calculation and then adjusting it for the forward looking stream of value puts evaluation of the resource alternative on a level evaluation playing field with other resources and with planned additions to the system. More importantly, it sets a benchmark for the price above which the utility and ratepayers would be adversely impacted, and below which both the utility and its ratepayers would benefit. It sets a fair level for testing for financial indifference. It is important to note that unlike utility-owned assets, distributed solar systems owned and operated by customers and third parties create no long term stranded cost risk for the utility. Performance or production payments at or below the full value of distributed solar are calculated to minimize such risk by only paying when energy is generated.

RECOMMENDATIONS

Q. PLEASE STATE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission disapprove the Companies' requests to cancel their solar PV programs and instead order a substantial revision to those programs. In particular, I recommend:

- The Companies should be directed to develop, in conjunction with Commission staff and stakeholders, a Value of Solar Methodology similar to that now in place in Minnesota and consistent with the best-practice recommendations in the Regulator's Guidebook on valuation of the benefits and costs of distributed solar generation.
- The Companies should be further directed to use Value of Solar analysis in lieu of current cost-effectiveness tests to inform solar PV program structure.
- The Companies should be directed to establish distributed solar PV programs that are focused not simply on minimal compliance, but on supporting the emergence of a self-sustaining competitive market for distributed solar PV. Staff and other stakeholders should have an explicit and formal role in this program development process.

Q. WHAT RECOMMENDATION DO YOU OFFER REGARDING COMMUNITY SOLAR PROGRAMS DISCUSSED BY THE COMPANIES?

A. I believe that community solar programs offer an important opportunity to make participation in the benefits of distributed solar an option for more customers and in more areas of a utility service territory. Community solar programs can be cost-effective, fair, and can help support the development of self-sustaining distributed solar markets. However, it is vitally important that these programs also be soundly designed and administered, and that cost-effectiveness analysis is supported by full VOS analysis. The

Interstate Renewable Energy Council has published a report entitled "Model Rules for Shared Renewable Energy Programs,[6]" attached at Exhibit KRR-6 that should be consulted prior to developing a proposal for community solar. While it is beyond the scope of this testimony to address the Companies' community solar programs in detail, I would note that the FPL proposal for a donation program for utility-owned solar projects in Docket No. 140070-EG is not a community solar program or a suitable alternative to customer-owned distributed solar generation. That proposal merely recycles a failed approach to solar PV development based on a charitable donation model.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[6] Model Rules for Shared Renewable Energy Programs, Interstate Renewable Energy Council (Jun. 2013), available at http://www.irecusa.org/regulatory-reform/shared-renewables/.

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Summary

Nationally recognized electricity industry leader and innovator. Experienced as a utility executive, public utility regulatory commissioner, research and development program manager, educator, business builder, federal executive, corporate sustainability leader, consultant, and advocate. Thought leader and practice expert in organizational transformation. Highly proficient in advising, managing and interacting with government agencies and committees, the media, citizen groups, and business associations. Successful track record of working with US Congress, state legislatures, governors, regulators, city councils, business leaders, researchers, academia, and community groups. National and international contacts through experience with Austin Energy, AES Corporation, US Department of Energy, Texas Public Utility Commission, Jicarilla Apache Tribal Utility Authority, Cargill Dow LLC (now NatureWorks, LLC), Rocky Mountain Institute, CH2M HILL, Houston Advanced Research Center, Environmental Defense Fund, and others. Expert in development of new energy markets in renewable energy, green power, and tradable credits, and in helping new market entrants shape new products and services. Skilled attorney, negotiator, and advisor with more than twenty years experience working with diverse stakeholder communities in electricity policy and regulation, emerging energy markets development, clean energy technology development, electric utility restructuring, smart grid development, and the implementation of sustainability principles. Extensive regulatory practice experience. Nationally recognized speaker on energy, environment and sustainable development matters. Managed staff as large as 250; responsible for operations of research facilities with staff in excess of 600. Developed and managed budgets in excess of $300 million. Law teaching experience at University of Houston Law Center and U.S. Military Academy at West Point. Trial experience as a Judge Advocate. Post doctorate degrees in environmental and military law. Military veteran.

Employment

RÁBAGO ENERGY LLC

Principal: July 2012--Present. Consulting practice dedicated to providing strategic advice and support to businesses and organizations in the clean and advanced energy sectors. Recognized national leader in development and implementation of award-winning “Value of Solar” alternative to traditional net metering. Services include distributed energy business, project, and product development; energy policy development and advocacy; renewable energy product, project, and market development; strategic and corporate sustainability planning; and government and regulatory affairs support. Additional activities:

- Chairman of the Board, Center for Resource Solutions (1997-present). CRS is a not-for-profit organization based at the Presidio in California. CRS developed and manages the Green-e Renewable Electricity Brand, a nationally and internationally recognized branding program for green power and green pricing products and programs. Past chair of the Green-e Governance Board (formerly the Green Power Board).
- Director, Interstate Renewable Energy Council (IREC) (2012-present). IREC focuses on issues impacting expanded renewable energy use such as rules that support renewable energy and distributed resources in a restructured market, connecting small-scale renewables to the utility grid, developing quality credentials that indicate a level of knowledge and skills competency for renewable energy professionals.
- Of Counsel, Osha Liang, LLP. Osha Liang is an intellectual property law firm with offices in Texas, California, France, and Japan.

AUSTIN ENERGY – THE CITY OF AUSTIN, TEXAS

Vice President, Distributed Energy Services: April 2009—June 2012. Executive in 8th largest public power electric utility serving more than one million people in central Texas. Responsible for management and oversight of energy efficiency, demand response, and conservation programs; low-income weatherization; distributed solar and other renewable energy technologies; green buildings program; key accounts relationships; electric vehicle infrastructure; and market research and product development. Executive sponsor of Austin Energy's participation in an innovative federally-funded smart grid demonstration project led by the Pecan Street Project. Led teams that successfully secured over $39 million in federal stimulus funds for energy efficiency, smart grid, and advanced electric transportation initiatives. Additional activities included:

- Director, Renewable Energy Markets Association. REMA is a trade association dedicated to maintaining and strengthening renewable energy markets in the United States.
- Membership on Pedernales Electric Cooperative Member Advisory Board. Invited by the Board of Directors to sit on first-ever board to provide formal input and guidance on energy efficiency and renewable energy issues for the nation's largest electric cooperative.

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008. Government and regulatory affairs manager for AES Wind Generation, one of the largest wind companies in the country. Manage a portfolio of regulatory and legislative initiatives to support wind energy market development in Texas, across the United States, and in many international markets. Active in national policy and the wind industry through work with the American Wind Energy Association as a participant on the organization's leadership council. Also served as Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC, a GE and AES venture committed to generating and marketing greenhouse gas credits to the U.S. voluntary market. Authored and implemented a standard of practice based on ISO 14064 and industry best practices. Commissioned the development of a suite of methodologies and tools for various greenhouse gas credit-producing technologies. Also served as Director, Global Regulatory Affairs, providing regulatory support and group management to AES's international electric utility operations on five continents. Additional activities:

- Director and past Chair, Jicarilla Apache Nation Utility Authority (1998 to 2008). Located in New Mexico, the JAUA is an independent utility developing profitable and autonomous utility services that provides natural gas, water utility services, low income housing, and energy planning for the Nation. Authored "First Steps" renewable energy and energy efficiency strategic plan.

HOUSTON ADVANCED RESEARCH CENTER

Group Director, Energy and Buildings Solutions: December 2003—May 2006. The Houston Advanced Research Center (HARC) is a mission-driven not-for-profit contract research organization based in The Woodlands, Texas. Responsible for developing, maintaining and expanding upon technology development, application, and commercialization support programmatic activities, including the Center for Fuel Cell Research and Applications, an industry-driven testing and evaluation center for near-commercial fuel cell generators; the Gulf Coast Combined Heat and Power Application Center, a state and federally funded initiative; and the High Performance Green Buildings Practice, a consulting and outreach initiative. Secured funding for major new initiative in carbon nanotechnology applications in the energy sector. Developed and launched new and integrated program activities relating to hydrogen energy technologies, combined heat and power, distributed energy resources, renewable energy, energy efficiency, green buildings, and regional clean energy development. Active participant in policy development and regulatory implementation in Texas, the Southwest, and national venues.

Frequently engaged with policy, regulatory, and market leaders in the region and internationally. Additional activities:

- President, Texas Renewable Energy Industries Association. As elected president of the statewide business association, leader and manager of successful efforts to secure and implement significant expansion of the state's renewable portfolio standard as well as other policy, regulatory, and market development activities.
- Director, Southwest Biofuels Initiative. Established the Initiative acts as an umbrella structure for a number of biofuels related projects, including emissions evaluation for a stationary biodiesel pilot project, feedstock development, and others.
- Member, Committee to Study the Environmental Impacts of Windpower, National Academies of Science National Research Council. The Committee was chartered by Congress and the Council on Environmental Quality to assess the impacts of wind power on the environment.
- Advisory Board Member, Environmental & Energy Law & Policy Journal, University of Houston Law Center.

CARGILL DOW LLC (NOW NATUREWORKS, LLC)

Sustainability Alliances Leader: April 2002—December 2003. Founded in 1997, NatureWorks, LLC is based in Minnetonka, Minnesota. Integrated sustainability principles into all aspects of a ground-breaking biobased polymer manufacturing venture. Responsible for maintaining, enhancing and building relationships with stakeholders in the worldwide sustainability community, as well as managing corporate and external sustainability initiatives. NatureWorks is the first company to offer its customers a family of polymers (polylactide – "PLA") derived entirely from annually renewable resources with the cost and performance necessary to compete with packaging materials and traditional fibers; now marketed under the brand name "Ingeo."

- Successfully completed Minnesota Management Institute at University of Minnesota Carlson School of Management, an alternative to an executive MBA program that surveyed fundamentals and new developments in finance, accounting, operations management, strategic planning, and human resource management.

ROCKY MOUNTAIN INSTITUTE

Managing Director/Principal: October 1999–April 2002. In two years, co-led the team and grew annual revenues from approximately $300,000 to more than $2 million in annual grant and consulting income. Co-authored "Small Is Profitable," a comprehensive analysis of the benefits of distributed energy resources. Worked to increase market opportunities for clean and distributed energy resources through consulting, research, and publication activities. Provided consulting and advisory services to help business and government clients achieve sustainability through application and incorporation of Natural Capitalism principles. Frequent appearance in media at international, national, regional and local levels. RMI is an independent, non-profit research and educational foundation. Joined the organization to develop the Natural Capitalism research and consulting practice at RMI.

- President of the Board, Texas Ratepayers Organization to Save Energy. Texas R.O.S.E. is a non-profit organization advocating low-income consumer issues and energy efficiency programs.
- Co-Founder and Chair of the Advisory Board, Renewable Energy Policy Project-Center for Renewable Energy and Sustainable Technology. REPP-CREST was a national non-profit research and internet services organization.

CH2M HILL

Vice President, Energy, Environment and Systems Group: July 1998–August 1999. Responsible for providing consulting services to a wide range of energy-related businesses and organizations, and for creating new business opportunities in the energy industry for an established engineering and consulting firm. Completed comprehensive electric utility restructuring studies for the states of Colorado and Alaska.

PLANERGY

Vice President, New Energy Markets: January 1998–July 1998. Responsible for developing and managing new business opportunities for the energy services market. Provided consulting and advisory services to utility and energy service companies.

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998. Managed renewable energy, energy efficiency, and electric utility restructuring programs for a not-for-profit environmental group with a staff of 160 and over 300,000 members. Led regulatory intervention activities in Texas and California. In Texas, played a key role in crafting Deliberative Polling processes. Initiated and managed nationwide collaborative activities aimed at increasing use of renewable energy and energy efficiency technologies in the electric utility industry, including the Green-e Certification Program, Power Scorecard, and others. Participated in national environmental and energy advocacy networks, including the Energy Advocates Network, the National Wind Coordinating Committee, the NCSL Advisory Committee on Energy, and the PV-COMPACT Coordinating Council. Frequently appeared before the Texas Legislature, Austin City Council, and regulatory commissions on electric restructuring issues.

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996. Manager of the Department's programs in renewable energy technologies and systems, electric energy systems, energy efficiency, and integrated resource planning. Supervised technology research, development and deployment activities in photovoltaics, wind energy, geothermal energy, solar thermal energy, biomass energy, high-temperature superconductivity, transmission and distribution, hydrogen, and electric and magnetic fields. Developed, coordinated, and advised on legislation, policy, and renewable energy technology development within the Department, among other agencies, and with Congress. Managed, coordinated, and developed international agreements for cooperative activities in renewable energy and utility sector policy, regulation, and market development between the Department and counterpart foreign national entities. Established and enhanced partnerships with stakeholder groups, including technology firms, electric utility companies, state and local governments, and associations. Supervised development and deployment support activities at national laboratories. Developed, advocated and managed a Congressional budget appropriation of approximately $300 million.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994. Appointed by Governor Ann W. Richards. Regulated electric and telephone utilities in Texas. Laid the groundwork for legislative and regulatory adoption of integrated resource planning, electric utility restructuring, and significantly increased use of renewable energy and energy efficiency resources. Appointed by Governor Richards to co-chair and organize the Texas Sustainable Energy Development Council. Served as Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation. Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT), a nationwide program to develop domestic markets for photovoltaics. Member, Southern States Energy Board Integrated Resource Planning Task Force. Member of the University of Houston Environmental Institute Board of Advisors.

LAW TEACHING

Associate Professor of Law: University of Houston Law Center, 1990–1992. Full time, tenure track member of faculty. Courses taught: Criminal Law, Environmental Law, Criminal Procedure, Environmental Crimes Seminar, Wildlife Protection Law. Provided *pro bono* legal services in administrative proceedings and filings at the Texas Public Utility Commission. Launched a student clinical effort that reviewed and made recommendations on utility energy efficiency program plans.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990. Member of the faculty in the Department of Law. Honorably discharged in August 1990, as Major in the Regular Army. Courses taught: Constitutional Law, Military Law, and Environmental Law Seminar. Greatly expanded the environmental law curriculum and laid foundation for the concentration program in law. While carrying a full time teaching load, earned a Master of Laws degree in Environmental Law. Established a program for subsequent environmental law professors to obtain an LL.M. prior to joining the faculty.**LITIGATION**

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987. Assigned to Trial Defense Service and Office of the Staff Judge Advocate. Prosecuted and defended over 150 felony courts-martial. As prosecutor, served as legal officer for two brigade-sized units (approximately 5,000 soldiers), advising commanders on appropriate judicial, non-judicial, separation, and other actions. Pioneered use of psychiatric and scientific testimony in administrative and judicial proceedings.

NON-LEGAL MILITARY SERVICE

Armored Cavalry Officer, 2d Squadron 9th Armored Cavalry, Fort Stewart, Georgia, May 1978–August 1981. Served as Logistics Staff Officer (S-4). Managed budget, supplies, fuel, ammunition, and other support for an Armored Cavalry Squadron. Served as Support Platoon Leader for the Squadron (logistical support), and as line Platoon Leader in an Armored Cavalry Troop. Graduate of Airborne and Ranger Schools. Special training in Air Mobilization Planning and Nuclear, Biological and Chemical Warfare.

Formal Education

LL.M., Environmental Law, Pace University School of Law, 1990: Curriculum designed to provide breadth and depth in study of theoretical and practical aspects of environmental law. Courses included: International and Comparative Environmental Law, Conservation Law, Land Use Law, Seminar in Electric Utility Regulation, Scientific and Technical Issues Affecting Environmental Law, Environmental Regulation of Real Estate, Hazardous Wastes Law. Individual research with Hudson Riverkeeper Fund, Garrison, New York.

LL.M., Military Law, U.S. Army Judge Advocate General's School, 1988: Curriculum designed to prepare Judge Advocates for senior level staff service. Courses included: Administrative Law, Defensive Federal Litigation, Government Information Practices, Advanced Federal Litigation, Federal Tort Claims Act Seminar, Legal Writing and Communications, Comparative International Law.

J.D. with Honors, University of Texas School of Law, 1984: Attended law school under the U.S. Army Funded Legal Education Program, a fully funded scholarship awarded to 25 or fewer officers each year. Served as Editor-in-Chief (1983–84); Articles Editor (1982–83); Member (1982) of the Review of Litigation. Moot Court, Mock Trial, Board of Advocates. Summer internship at Staff Judge Advocate's offices. Prosecuted first cases prior to entering law school.

B.B.A., Business Management, Texas A&M University, 1977: ROTC Scholarship (3–yr). Member: Corps of Cadets, Parson's Mounted Cavalry, Wings & Sabers Scholarship Society, Rudder's Rangers, Town Hall Society, Freshman Honor Society, Alpha Phi Omega service fraternity.

Selected Publications

“The Value of Solar Tariff: Net Metering 2.0,” The ICER Chronicle, Ed. 1, p. 46 [International Confederation of Energy Regulators] (December 2013)

“A Regulator’s Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation,” co-author, Interstate Renewable Energy Council (October 2013)

“The ‘Value of Solar’ Rate: Designing An Improved Residential Solar Tariff,” Solar Industry, Vol. 6, No. 1 (Feb. 2013)

“A Review of Barriers to Biofuels Market Development in the United States,” 2 Environmental & Energy Law & Policy Journal 179 (2008)

“A Strategy for Developing Stationary Biodiesel Generation,” Cumberland Law Review, Vol. 36, p.461 (2006)

“Evaluating Fuel Cell Performance through Industry Collaboration,” co-author, Fuel Cell Magazine (2005)

“Applications of Life Cycle Assessment to NatureWorks™ Polylactide (PLA) Production,” co-author, Polymer Degradation and Stability 80, 403-19 (2003)

“An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options,” contributing author, Prepared for the San Francisco Public Utilities Commission, Rocky Mountain Institute (2002)

“Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size,” co-author, Rocky Mountain Institute (2002)

“Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado,” with Thomas E. Feiler, Colorado Public Utilities Commission and Colorado Electricity Advisory Panel (April 1, 1999)

“Study of Electric Utility Restructuring in Alaska,” with Thomas E. Feiler, Legislative Joint Committee on electric Restructuring and the Alaska Public Utilities Commission (April 1, 1999)

“New Markets and New Opportunities: Competition in the Electric Industry Opens the Way for Renewables and Empowers Customers,” EEBA Excellence (Journal of the Energy Efficient Building Association) (Summer 1998)

“Building a Better Future: Why Public Support for Renewable Energy Makes Sense,” Spectrum: The Journal of State Government (Spring 1998)

“The Green-e Program: An Opportunity for Customers,” with Ryan Wiser and Jan Hamrin, Electricity Journal, Vol. 11, No. 1 (January/February 1998)

“Being Virtual: Beyond Restructuring and How We Get There,” Proceedings of the First Symposium on the Virtual Utility, Klewer Press (1997)

“Information Technology,” Public Utilities Fortnightly (March 15, 1996)

“Better Decisions with Better Information: The Promise of GIS,” with James P. Spiers, Public Utilities Fortnightly (November 1, 1993)

“The Regulatory Environment for Utility Energy Efficiency Programs,” Proceedings of the Meeting on the Efficient Use of Electric Energy, Inter-American Development Bank (May 1993)

“An Alternative Framework for Low-Income Electric Ratepayer Services,” with Danielle Jaussaud and Stephen Benenson, Proceedings of the Fourth National Conference on Integrated Resource Planning, National Association of Regulatory Utility Commissioners (September 1992)

“What Comes Out Must Go In: The Federal Non-Regulation of Cooling Water Intakes Under Section 316 of the Clean Water Act,” Harvard Environmental Law Review, Vol. 16, p. 429 (1992)

“Least Cost Electricity for Texas,” State Bar of Texas Environmental Law Journal, Vol. 22, p. 93 (1992)

“Environmental Costs of Electricity,” Pace University School of Law, Contributor–Impingement and Entrainment Impacts, Oceana Publications, Inc. (1990)

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A REVIEW OF SOLAR PV BENEFIT & COST STUDIES

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ABOUT THIS DOCUMENT

TABLE OF CONTENTS

OBJECTIVE AND ACKNOWLEDGEMENTS

The objective of this e-Lab discussion document is to assess what is known and unknown about the categorization, methodological best practices, and gaps around the benefits and costs of distributed photovoltaics (DPV), and to begin to establish a clear foundation from which additional work on benefit/cost assessments and pricing structure development can be built.

e-Lab members and advisors were invited to provide input on this report. The assessment greatly benefited from contributions by the following individuals: Stephen Frantz, Sacramento Municipal Utility District (SMUD); Mason Emnett, Federal Energy Regulatory Commission (FERC); Eran Mahrer, Solar Electric Power Association (SEPA); Sunil Cherian, Spirae; Karl Rabago, Rabago Energy; Tom Brill and Chris Yunker, San Diego Gas & Electric (SDG&E); and Steve Wolford, Sunverge.

This e-Lab work product was prepared by Rocky Mountain Institute to support e-Lab and industry-wide discussions about distributed energy resource valuation. e-Lab is a joint collaboration, convened by RMI, with participation from stakeholders across the electricity industry. e-Lab is not a consensus organization, and the views expressed in this document do not necessarily represent those of any individual e-Lab member or supporting organizations. Any errors are solely the responsibility of RMI.

WHAT IS e-LAB?

The Electricity Innovation Lab (e-Lab) brings together thought leaders and decision makers from across the U.S. electricity sector to address critical institutional, regulatory, business, economic, and technical barriers to the economic deployment of distributed resources.

In particular, e-Lab works to answer three key questions:

- How can we understand and effectively communicate the costs and benefits of distributed resources as part of the electricity system and create greater grid flexibility?
- How can we harmonize regulatory frameworks, pricing structures, and business models of utilities and distributed resource developers for greatest benefit to customers and society as a whole?
- How can we accelerate the pace of economic distributed resource adoption?

A multi-year program, e-Lab regularly convenes its members to identify, test, and spread practical solutions to the challenges inherent in these questions. e-Lab has three annual meetings, coupled with ongoing project work, all facilitated and supported by Rocky Mountain Institute. e-Lab meetings allow members to share learnings, best practices, and analysis results; collaborate around key issues or needs; and conduct deep-dives into research and analysis findings.

EXECUTIVE SUMMARY

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EXECUTIVE SUMMARY

THE NEED

- The addition of distributed energy resources (DERs) onto the grid creates new opportunities and challenges because of their unique siting, operational, and ownership characteristics compared to conventional centralized resources.
- Today, the increasingly rapid adoption of distributed solar photovoltaics (DPV) in particular is driving a heated debate about whether DPV creates benefits or imposes costs to stakeholders within the electricity system. But the wide variation in analysis approaches and quantitative tools used by different parties in different jurisdictions is inconsistent, confusing, and frequently lacks transparency.
- Without increased understanding of the benefits and costs of DERs, there is little ability to make effective tradeoffs between investments.

OBJECTIVE OF THIS DOCUMENT

- The objective of this e-Lab discussion document is to assess what is known and unknown about the categorization, methodological best practices, and gaps around the benefits and costs of DPV, and to begin to establish a clear foundation from which additional work on benefit/cost assessments and pricing structure design can be built.
- This discussion document reviews 15 DPV benefit/cost studies by utilities, national labs, and other organizations. Completed between 2005 and 2013, these studies reflect a significant range of estimated DPV value.

KEY INSIGHTS

- No study comprehensively evaluated the benefits and costs of DPV, although many acknowledge additional sources of benefit or cost and many agree on the broad categories of benefit and cost. There is broad recognition that some benefits and costs may be difficult or impossible to quantify, and some accrue to different stakeholders.
- There is a significant range of estimated value across studies, driven primarily by differences in local context, input assumptions, and methodological approaches.
    - **Local context**: Electricity system characteristics—generation mix, demand projections, investment plans, market structures—vary across utilities, states, and regions.
    - **Input assumptions**: Input assumptions—natural gas price forecasts, solar power production, power plant heat rates—can vary widely.
    - **Methodologies**: Methodological differences that most significantly affect results include (1) resolution of analysis and granularity of data, (2) assumed cost and benefit categories and stakeholder perspectives considered, and (3) approaches to calculating individual values.
- Because of these differences, comparing results across studies can be informative, but should be done with the understanding that results must be normalized for context, assumptions, or methodology.
- While detailed methodological differences abound, there is general agreement on overall approach to estimating energy value and some philosophical agreement on capacity value, although there remain key differences in capacity methodology. There is significantly less agreement on overall approach to estimating grid support services and currently unmonetized values including financial and security risk, environment, and social value.

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EXECUTIVE SUMMARY (CONT'D)

IMPLICATIONS

- Methods for identifying, assessing and quantifying the benefits and costs of distributed resources are advancing rapidly, but important gaps remain to be filled before this type of analysis can provide an adequate foundation for policymakers and regulators engaged in determining levels of incentives, fees, and pricing structures for DPV and other DERs.
- In any benefit/cost study, it is critical to be transparent about assumptions, perspectives, sources and methodologies so that studies can be more readily compared, best practices developed, and drivers of results understood.
- While it may not be feasible to quantify or assess sources of benefit and cost comprehensively, benefit/cost studies must explicitly decide if and how to account for each source of value and state which are included and which are not.
- While individual jurisdictions must adapt approaches based on their local context, standardization of categories, definitions, and methodologies should be possible to some degree and will help ensure accountability and verifiability of benefit and cost estimates that provide a foundation for policymaking.
- The most significant methodological gaps include:
    - **Distribution value:** The benefits or costs that DPV creates in the distribution system are inherently local, so accurately estimating value requires much more analytical granularity and therefore greater difficulty.
    - **Grid support services value:** There continues to be uncertainty around whether and how DPV can provide or require additional grid support services, but this could potentially become an increasingly important value.
    - **Financial, security, environmental, and social values:** These values are largely (though not comprehensively) unmonetized as part of the electricity system and some are very difficult to quantify.

LOOKING AHEAD

- Thus far, studies have made simplifying assumptions that implicitly assume historically low penetrations of DPV. As the penetration of DPV on the electric system increases, more sophisticated, granular analytical approaches will be needed and the total value is likely to change.
- Studies have largely focused on DPV by itself. But a confluence of factors is likely to drive increased adoption of the full spectrum of renewable and distributed resources, requiring a consideration of DPV's benefits and costs in the context of a changing system.
- With better recognition of the costs and benefits that all DERs can create, including PDV, pricing structures and business models can be better aligned, enabling greater economic deployment of DERs and lower overall system costs for ratepayers.

FRAMING THE NEED

01

- overview
- distributed energy resources
- structural misalignments
- structural misalignments in practice

FRAMING THE NEED

- A confluence of factors including rapidly falling solar prices, supportive policies and new approaches to finance are leading to a steadily increasing solar PV market.
  - In 2012, the US added 2 GW of solar PV to the nation's generation mix, of which approximately 50% were customer-sited solar, net-metered projects. [1]
  - Solar penetrations in certain regions are becoming significant. About 80% of customer-sited PV is concentrated in states with either ample solar resource and/ or especially solar-friendly policies: California, New Jersey, Arizona, Hawaii and Massachusetts. [2]
- The addition of DPV onto the grid creates new challenges and opportunities because of its unique siting, operational, and ownership characteristics compared to conventional centralized resources. The value of DPV is temporally, operationally and geographically specific and varies by distribution feeder, transmission line configuration, and composition of the generation fleet.
- Under today's regulatory and pricing structures, multiple misalignments along economic, social and technical dimensions are emerging. For example, pricing mechanisms are not in place to recognize or reward service that is being provided by either the utility or customer.
- Electricity sector stakeholders around the country are recognizing the importance of properly valuing DPV, the current lack of clarity around the costs and benefits that drive DPV's value or how to calculate it.
- To enable better technical integration and economic optimization, it is critical to better understand the services that DPV can provide, and the costs and benefits of those services as a foundation for more accurate pricing and market signals. As the penetration of DPV and other customer-sited resources increases, accurate pricing and market signals can help align stakeholder goals, minimize total system cost, and maximize total net value.

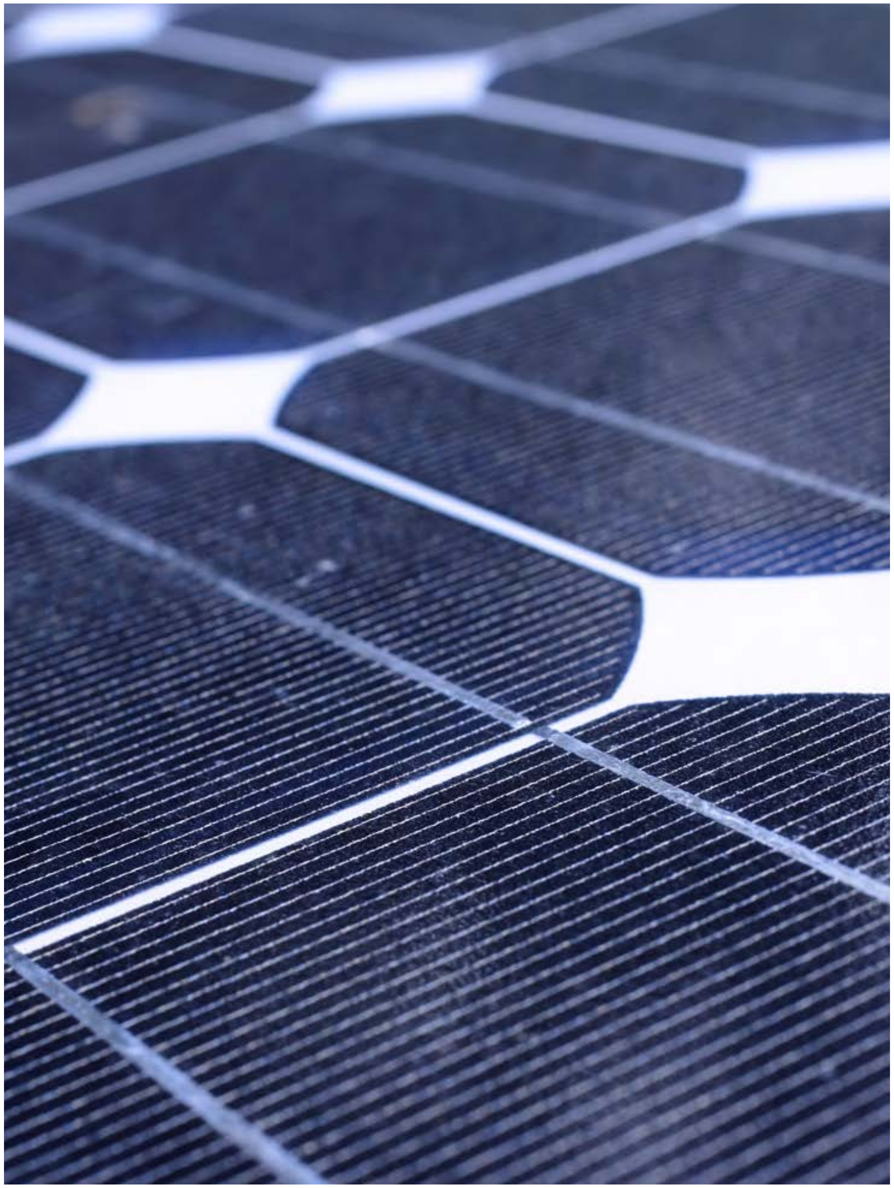


Photo courtesy of Shutterstock

1. Solar Electric Power Association. June 2013. *2012 SEPA Utility Solar Rankings,* Washington, DC.
2. Ibid.

DISTRIBUTED ENERGY RESOURCES (DERs)

DUE TO UNIQUE CHARACTERISTICS, DERs BEHAVE DIFFERENTLY FROM CONVENTIONAL RESOURCES—**THIS DISCUSSION DOCUMENT FOCUSES ON DISTRIBUTED PHOTOVOLTAICS (DPV)**

DISTRIBUTED ENERGY RESOURCES (DERs): demand- and supply-side resources that can be deployed throughout an electric distribution system to meet the energy and reliability needs of the customers served by that system. DERs can be installed on either the customer side or the utility side of the meter.

TYPES OF DERs:

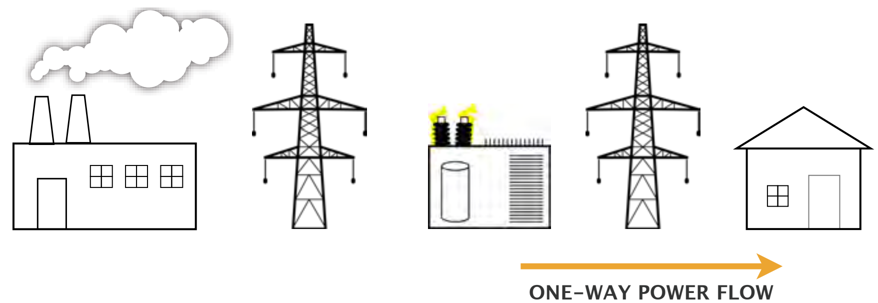
Efficiency
Technologies and behavioral changes that reduce the quantity of energy that customers need to meet all of their energy-related needs. The main type is:
- end-used efficiency

Distributed generation
Small, self-contained energy sources located near the final point of energy consumption. The main distributed generation sources are:
- Solar PV
- Combined heat & power
- Small-scale wind
- Others (i.e., fuel cells)

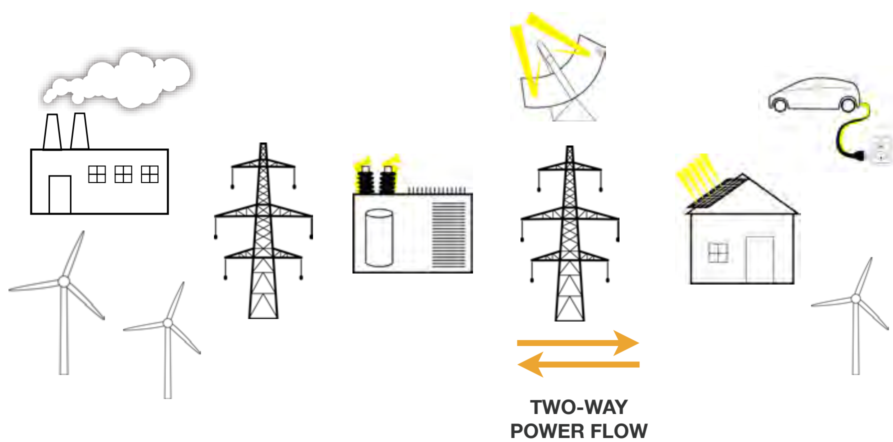
Distributed flexibility & storage
A collection of technologies that allows the overall system to use energy smarter and more efficiently by storing it when supply exceeds demand, and prioritizing need when demand exceeds supply. These technologies include:
- Demand response
- Electric vehicles
- Thermal storage
- Battery storage

Distributed intelligence
Technologies that combine sensory, communication, and control functions to support the electricity system, and magnify the value of DER system integration. Examples include:
- Smart inverters
- Home-area networks

CURRENT SYSTEM/VALUE CHAIN:



FUTURE SYSTEM/VALUE CONSTELLATION:



WHAT MAKES DERs UNIQUE:

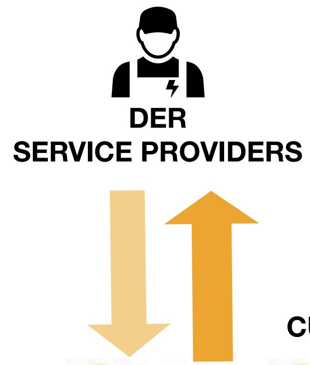
Siting
Smaller, more modular energy resources can be installed by disparate actors outside of the purview of centrally coordinated resource planning.

Operations
Energy resources on the distribution network operate outside of centrally controlled dispatching mechanisms that control the real-time balance of generation and demand.

Ownership
DERs can be financed, installed or owned by the customer or a third party, broadening the typical planning capability and resource integration approach.

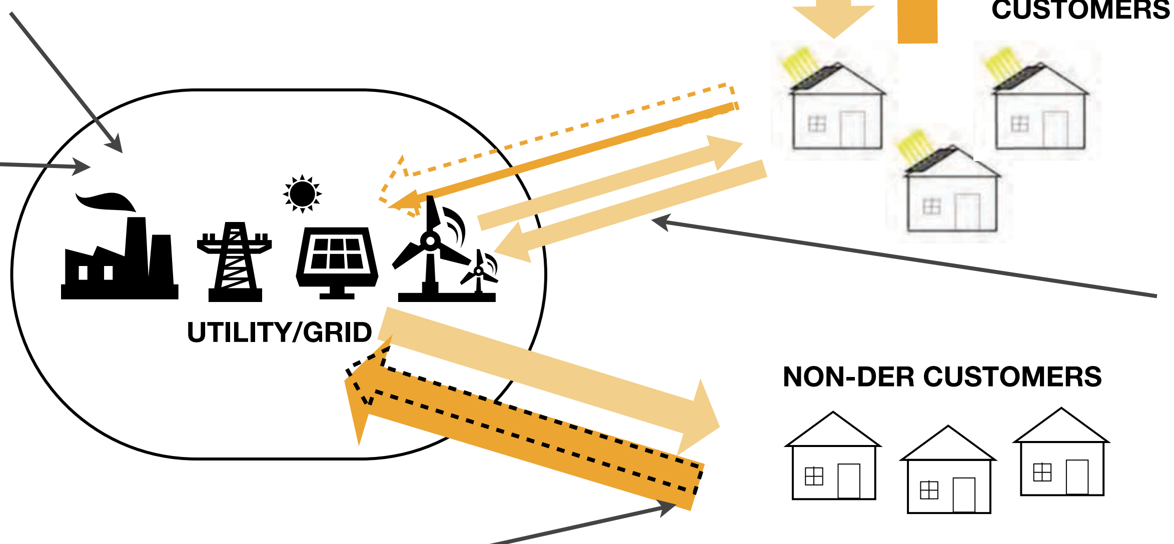
STRUCTURAL MISALIGNMENTS

TODAY, OPERATIONAL AND PRICING MECHANISMS DESIGNED FOR AN HISTORICALLY CENTRALIZED ELECTRICITY SYSTEM ARE NOT WELL-ADAPTED TO THE INTEGRATION OF DERS CAUSING FRICTION AND INEFFICIENCY



FLEXIBILITY & PREDICTABILITY

Providing reliable power requires grid flexibility and predictability. Power from some distributed renewables fluctuate with the weather, adding variability, and require smart integration to best shape their output to the grid. Legacy standards and rules can be restrictive.



BENEFIT AND COST RECOGNITION AND ALLOCATION

Mechanisms are not in place to transparently recognize or compensate service (be it monetized grid services like energy, capacity or balancing supply and demand, or less consistently monetized values, such as carbon emissions savings) provided by the utility or the customer. To the utility, revenue from DER customers may not match the cost to serve those customers. To the customer, bill savings or credit may not match the value provided.

LOCATION & TIME

Limited feedback loop to customers that the costs or benefit of any electricity resource, especially DERs, vary by location and time.

SOCIAL PRIORITIES

Society values the environmental and social benefits that DERs could provide, but those benefits are often externalized and unmonetized.

SOCIAL EQUITY

If costs are incurred by DER customers that are not paid for, those costs would be allocated to the rest of customers. Conversely, DER customers also provide provide benefits to other customers and to society.

$$ service

Adapted from RMI, Net Energy Metering, Zero Net Energy And The Distributed Energy Resource Future: Adapting Electric Utility Business Models For The 21st Century

000017

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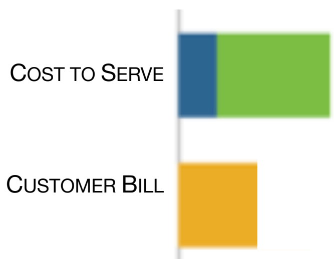
STRUCTURAL MISALIGNMENTS IN PRACTICE

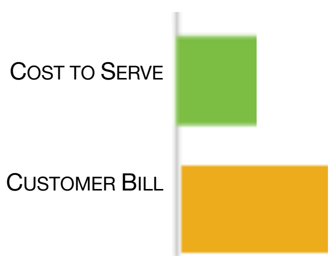
THESE STRUCTURAL MISALIGNMENTS ARE LEADING TO IMPORTANT QUESTIONS, DEBATE, AND CONFLICT

VALUE UNCERTAINTY...

What if a DPV customer does not pay for the full cost to serve their demand?



What if a DPV customer is not fully compensated for the service they provide?



...DRIVES HEADLINES...


MIDWEST ENERGY NEWS

HOME NEWS OPINION

Minnesota to ask: What is the value of solar power?

Posted on 06/10/2013 by Dan Haugen

Correction appended.

Utility customers who own solar panels are doing society a favor, helping to cut carbon emissions and ease transmission line congestion, among other benefits.

Or, they're power-grid freeloaders, lowering their own electric bills but sticking everyone else with a bigger ...

greentechsolar:

‹ PREV Soltec Revives CPV With New...

SOLAR: Markets & Policy

NEXT › Arizona's Biggest Utility Proposes...

Solar's Net Metering Fight in California Previews at Intersola...

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ENERGY 7/16/2013 @ 2:11PM

Escalating Fear Of Disintermediation Fuels Utility Backlash Against Distributed Energy

+ Comment Now + Follow Comments

Last week, the Arizona Public Service Company, the largest electric utility in Arizona, asked state utility regulators to raise electric rates for residential customers who install solar photovoltaic systems at their homes.

...RAISING KEY QUESTIONS

- What benefits can customers provide? Is the ability of customers to provide benefits contingent on anything?
- What costs are incurred to support DER customer needs?
- What are the best practice methodologies to assess benefits and costs?
- How should externalized and unmonetized values, such as environmental and social values, be recognized?
- How can benefits and costs be more effectively allocated and priced?

000018

SETTING THE STAGE

02

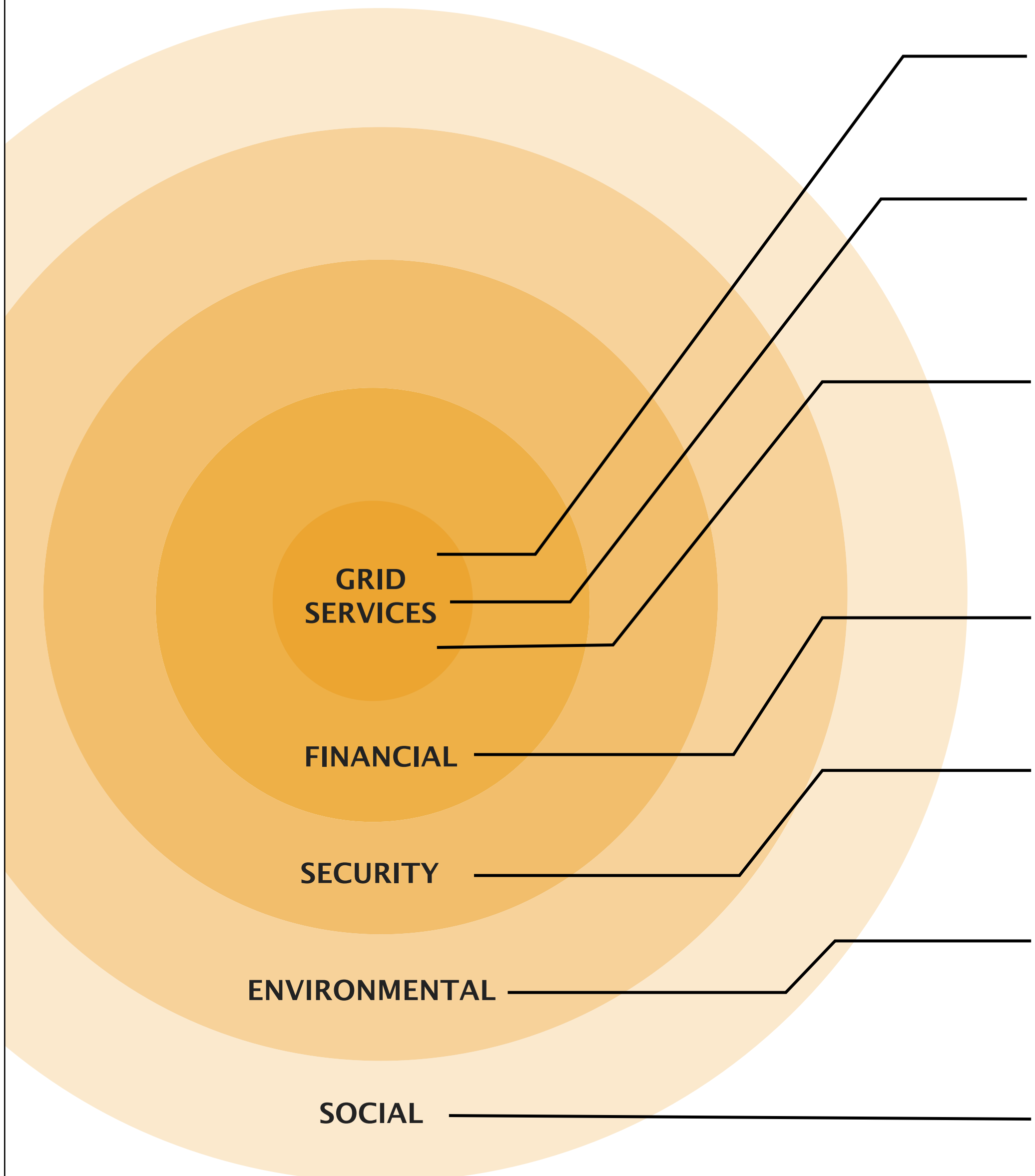
defining value
categories of value
stakeholder implications

SETTING THE STAGE

- When considering the total value of DPV or any electricity resource, it is critical to consider the types of value, the stakeholder perspective and the flow of benefits and costs–that is, who incurs the costs and who receives the benefits (or avoids the costs).
- For the purposes of this report, value is defined as net value, i.e. benefits minus costs. Depending upon the size of the benefit and the size of the cost, value can be positive or negative.
- A variety of categories of benefits or costs of DPV have been considered or acknowledged in evaluating the value of DPV. Broadly, these categories are: energy, system losses, capacity (generation, transmission and distribution), grid support services, financial risk, security risk, environmental and social.
- These categories of costs and benefits differ significantly by the degree to which they are readily quantifiable or there is a generally accepted methodology for doing so. For example, there is general agreement on overall approach to estimating energy value and some philosophical agreement on capacity value, although there remain key differences in capacity methodology. There is significantly less agreement on overall approach to estimating grid support services and currently unmonetized values including financial and security risk, environment, and social value.
- Equally important, the qualification of whether a factor is a cost or benefit also differs depending upon the perspective of the stakeholder. Similar to the basic framing of testing cost effectiveness for energy efficiency, the primary stakeholders in calculating the value of DPV are: the participant, or in this case, the solar customer; the utility; other customers (also referred to as ratepayers); and society (taxpayers are a subset of society).

BENEFIT & COST CATEGORIES

For the purposes of this report, **value is defined as net value, i.e. benefits minus costs.** Depending upon the size of the benefit and the size of the cost, value can be positive or negative. A variety of categories of benefits or costs of DPV have been considered or acknowledged in evaluating the value of DPV. Broadly, these categories are:



ENERGY
- energy
- energy losses

CAPACITY
- generation capacity
- transmission & distribution capacity
- DPV installed capacity

GRID SUPPORT SERVICES
- reactive supply & voltage control
- regulation & frequency response
- energy & generator imbalance
- synchronized & supplemental operating reserves
- scheduling, forecasting, and system control & dispatch

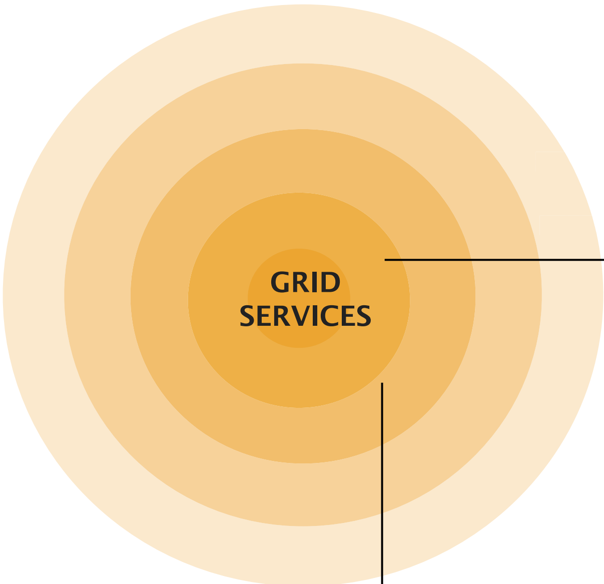
FINANCIAL RISK
- fuel price hedge
- market price response

SECURITY RISK
- reliability & resilience

ENVIRONMENTAL
- carbon emissions
- criteria air pollutants (SOx, NOx, PM10)
- water
- land

SOCIAL
- Economic development (jobs and tax revenues)

BENEFIT & COST CATEGORIES DEFINED



ENERGY

Energy value of DPV is positive when the solar energy generated displaces the need to produce energy from another resource at a net savings. There are two primary components:

- **Avoided Energy** - The cost and amount of energy that would have otherwise been generated to meet customer needs, largely driven by the variable costs of the marginal resource that is displaced. In addition to the coincidence of solar generation with demand and generation, key drivers of avoided energy cost include (1) fuel price forecast, (2) variable operation & maintenance costs, and (3) heat rate.

- **Energy Losses** - The value of the additional energy generated by central plants that would otherwise be lost due to inherent inefficiencies (electrical resistance) in delivering energy to the customer via the transmission and distribution system. Since DPV generates energy at or near the customer, that additional energy is not lost. Losses act as a magnifier of value for capacity and environmental benefits, since avoided energy losses result in lower required capacity and lower emissions.

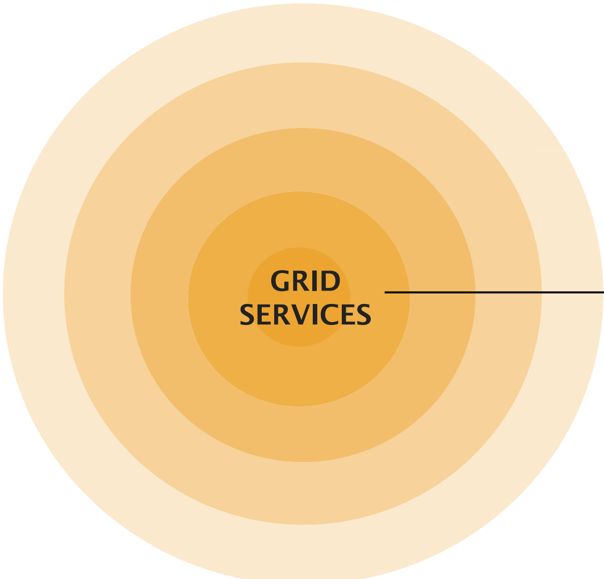
CAPACITY

Capacity value of DPV is positive when the addition of DPV defers or avoids more investment in generation, transmission, and distribution assets than it incurs. There are two drivers primary components:

- **Generation Capacity** - The cost of the amount of central generation capacity that can be deferred of avoided due to DPV. Key drivers of value include (1) DPV's effective capacity and (2) system capacity needs.

- **Transmission & Distribution Capacity** - The value of the net change in T&D infrastructure investment due to DPV. Benefits occur when DPV is able to meet rising demand locally, relieving capacity constraints upstream and deferring or avoiding T&D upgrades. Costs occur when additional T&D investment is needed to support the addition of DPV.

BENEFIT & COST CATEGORIES DEFINED



GRID SUPPORT SERVICES

Grid support value of DPV is positive when the net amount and cost of grid support services required to balance supply and demand is decreased than would otherwise have been required. Grid support services, which encompass more narrowly defined ancillary services (AS), are those services required to enable the reliable operation of interconnected electric grid systems. Grid support services include:

- **Reactive supply and voltage control**—Using generating facilities to supply reactive power and voltage control.
- **Frequency regulation**—Control equipment and extra generating capacity necessary to (1) maintain frequency by following the moment-to-moment variations in control area load (supplying power to meet any difference in actual and scheduled generation), and (2) to respond automatically to frequency deviations in their networks. While the services provided by Regulation Service and Frequency Response Service are different, they are complementary services made available using the same equipment and are offered as part of one service.
- **Energy imbalance**—This service supplies any hourly net mismatch between scheduled energy supply and the actual load served.
- **Operating reserves**—Spinning reserve is provided by generating units that are on-line and loaded at less than maximum output, and should be located near the load (typically in the same control area). They are available to serve load immediately in an unexpected contingency. Supplemental reserve is generating capacity used to respond to contingency situations that is not available instantaneously, but rather within a short period, and should be located near the load (typically in the same control area).
- **Scheduling/forecasting**—Interchange schedule confirmation and implementation with other control areas, and actions to ensure operational security during the transaction.

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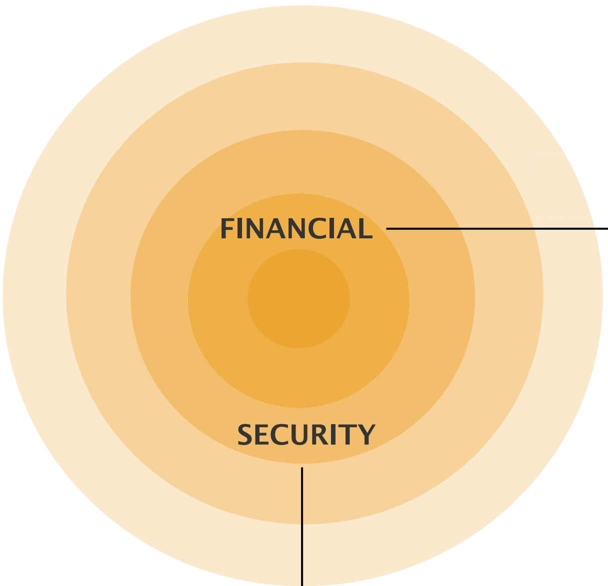
CATEGORIES DEFINED



FINANCIAL RISK

Financial value of DPV is positive when financial risk or overall market price is reduced due to the addition of DPV. There are two components of financial value:

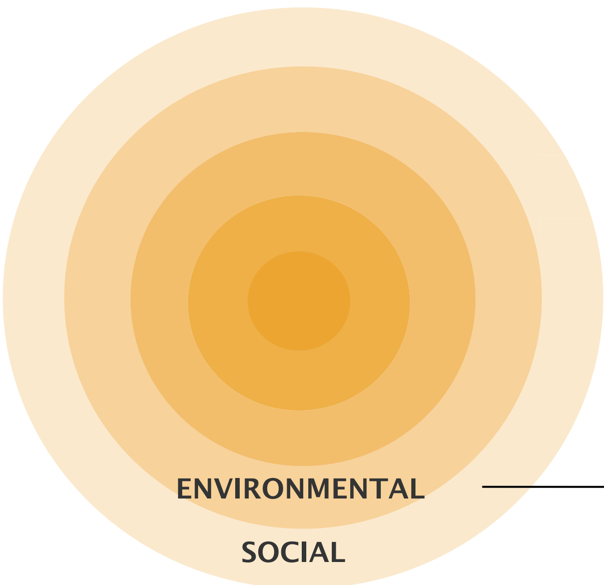
- **Fuel Price Hedge** - The cost that a utility would otherwise incur to guarantee that a portion of electricity supply-costs are fixed.

- **Market Price Response** - The price impact as a result of DPV's reducing demand for centrally-supplied electricity and the fuel power those generators, thereby lowering electricity prices and potentially commodity prices.

SECURITY RISK

Security value of DPV is positive when grid **reliability and resiliency** are increased by (1) reducing outages by reducing congestion along the T&D network, (2) reducing large-scale outages by increasing the diversity of the electricity system's generation portfolio with smaller generators that are geographically dispersed, and (3) providing back-up power sources available during outages through the combination of PV, control technologies, inverters and storage.

CATEGORIES DEFINED



ENVIRONMENTAL

Environmental value of DPV is positive when DPV results in the reduction of environmental or health impacts that would otherwise have been created. Key drivers include primarily the environmental impacts of the marginal resource being displaced. There are four components of environmental value:

- **Carbon** - The value from reducing carbon emissions is driven the emission intensity of displaced marginal resource and the price of emissions.
- **Criteria Air Pollutants** - The value from reducing criteria air pollutant emissions—NOX, SO2, and particulate matter—is driven by the cost of abatement technologies, the market value of pollutant reductions, and/or the cost of human health damages.
- **Water** - The value from reducing water use is driven by the differing water consumption patterns associated with different generation technologies, and can be measured by the price paid for water in competing sectors.
- **Land** - The value associated with land is driven by the difference in the land footprint required for energy generation and any change in property value driven by the addition of DPV.

SOCIAL

Social value of DPV is positive when DPV results in a net increase in jobs and local economic development. Key drivers include the number of jobs created or displaced, as measured by a job multiplier, as well as the value of each job, as measured by average salary and/or tax revenue.

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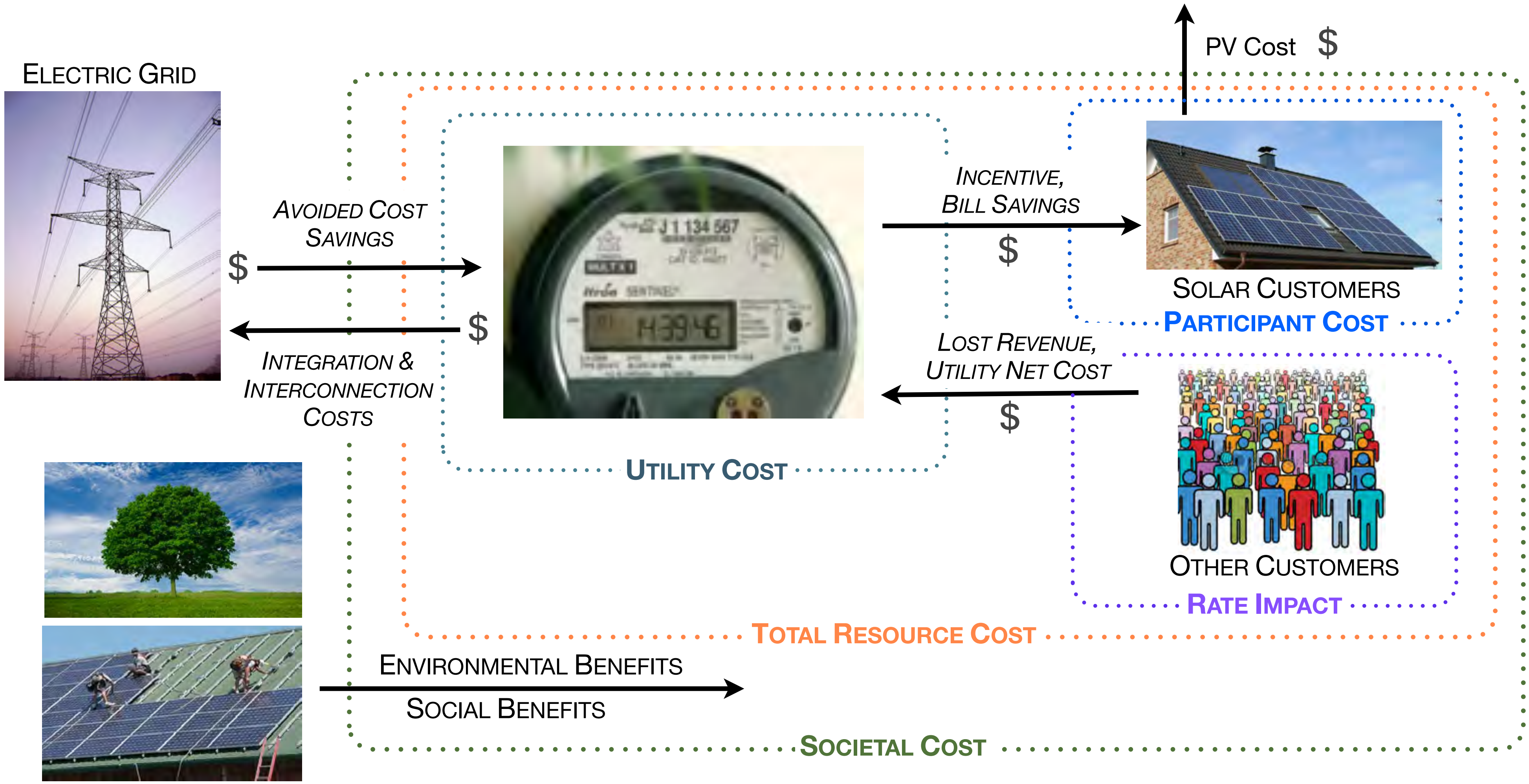
FLOW OF BENEFITS AND COSTS

BENEFITS AND COSTS ACCRUE TO DIFFERENT STAKEHOLDERS IN THE SYSTEM

The California Standard Practice Manual established the general standard for evaluating the flow of benefits and costs among stakeholders.



Photos courtesy of Shutterstock

STAKEHOLDER PERSPECTIVES

stakeholder perspective		factors affecting value
PV CUSTOMER 	"I want to have a predictable return on my investment, and I want to be compensated for benefits I provide."	Benefits include the reduction in the customer's utility bill, any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received. Costs include cost of the equipment and materials purchased (inc. tax & installation), ongoing O&M, removal costs, and the customer's time in arranging the installation.
OTHER CUSTOMERS 	"I want reliable power at lowest cost."	Benefits include reduction in transmission, distribution, and generation, capacity costs; energy costs and grid support services. Costs include administrative costs, rebates/ incentives, and decreased utility revenue that is offset by increased rates.
UTILITY 	"I want to serve my customers reliably and safely at the lowest cost, provide shareholder value and meet regulatory requirements."	Benefits include reduction in transmission, distribution, and generation, capacity costs; energy costs and grid support services. Costs include administrative costs, rebates/ incentives, and decreased revenue.
SOCIETY 	"We want improved air/water quality as well as an improved economy."	The sum of the benefits and costs to all stakeholder, plus any additional benefits or costs that accrue to society at large rather than any individual stakeholder.

Photos courtesy of Shutterstock

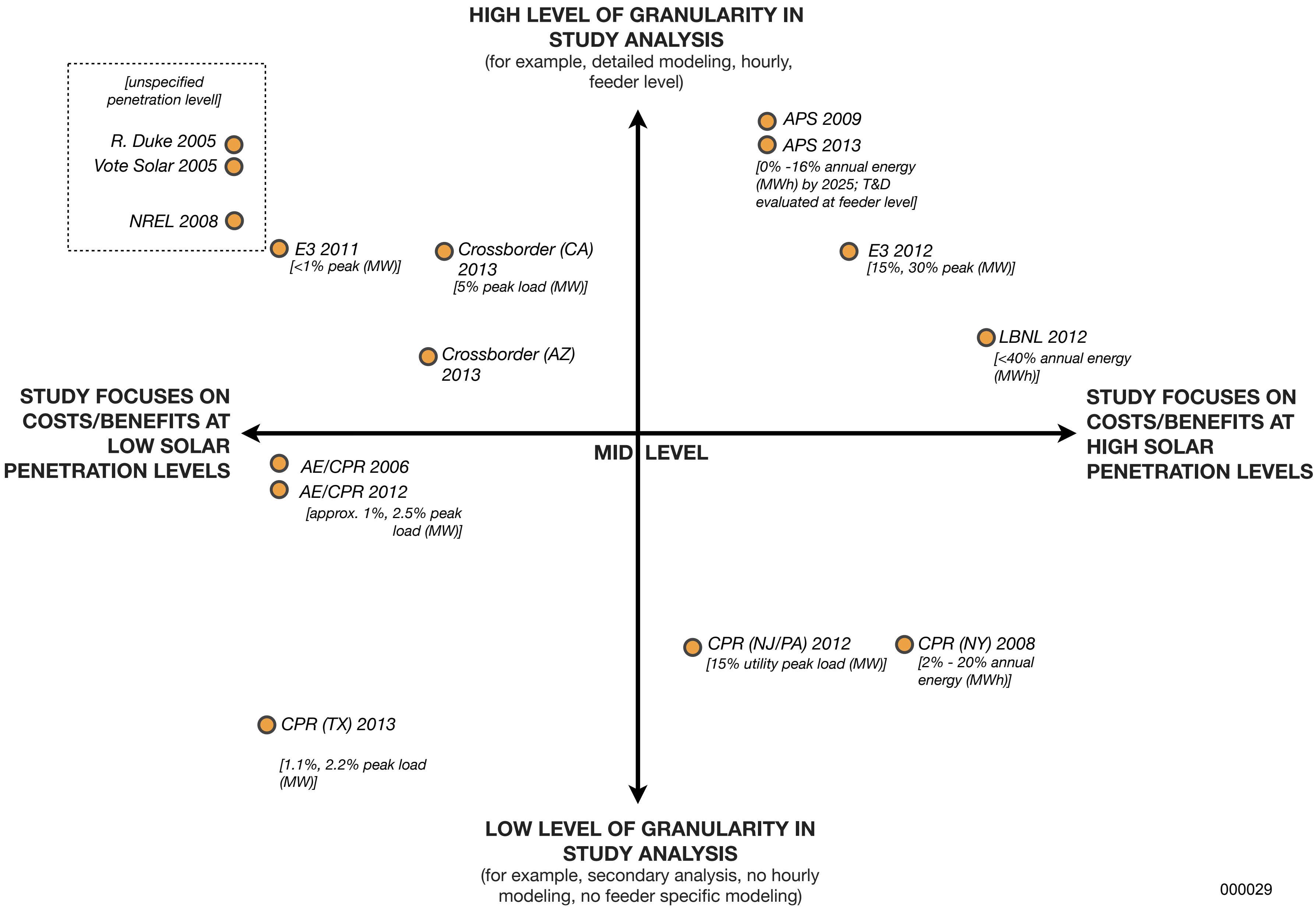
ANALYSIS FINDINGS

analysis overview
summary of benefits and costs
detail: categories of benefit and cost

03

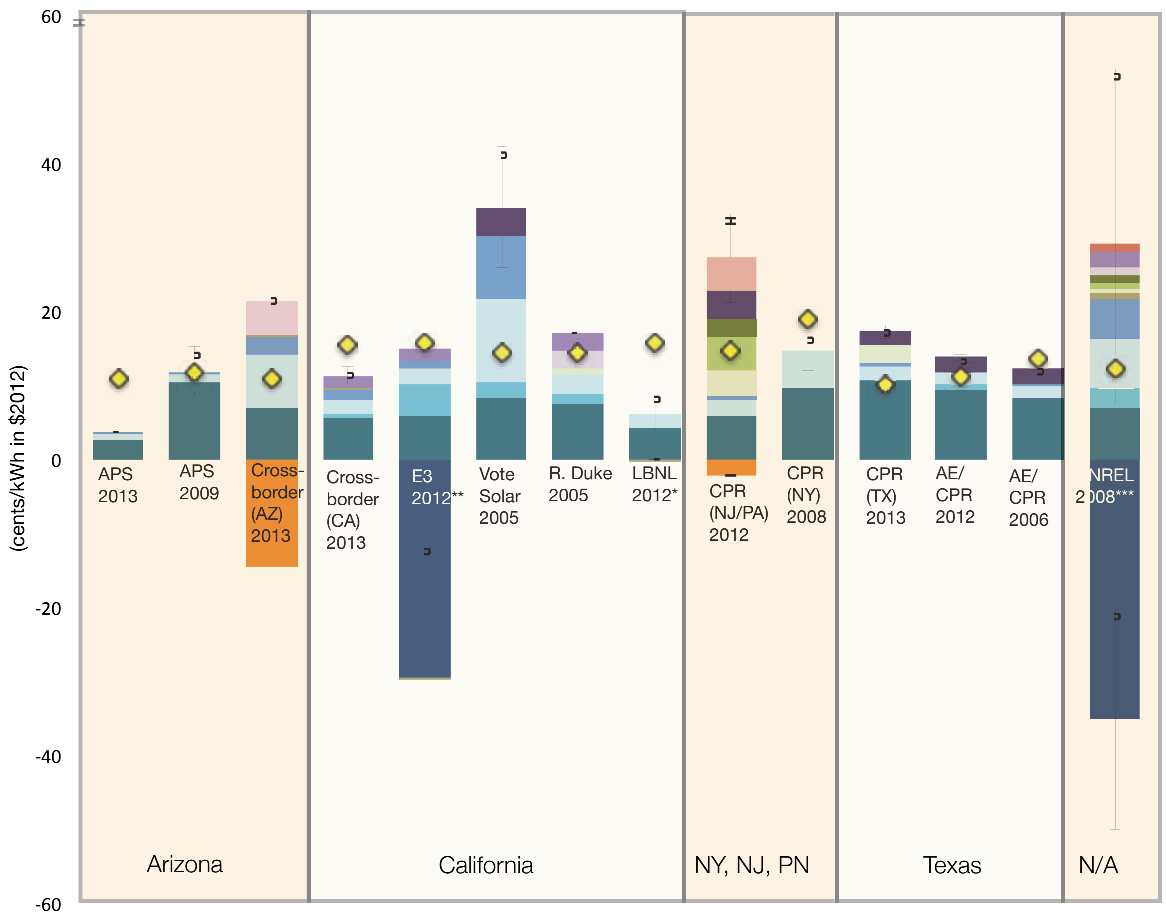
ANALYSIS OVERVIEW

THIS ANALYSIS INCLUDES 15 STUDIES, REFLECTING DIVERSE DPV PENETRATION LEVELS AND ANALYTICAL GRANULARITY



SUMMARY OF DPV BENEFITS AND COSTS

BENEFITS AND COSTS OF DISTRIBUTED PV BY STUDY



Monetized

- Energy
- Losses
- Gen Capacity
- T&D Capacity
- DPV Technology
- Grid Support Services
- Solar Penetration Cost

Inconsistently Unmonetized

- Financial: Fuel Price Hedge
- Financial: Mkt Price Response
- Security Risk
- Env: Carbon
- Env: Criteria Air Pollutants
- Env: Unspecified
- Social
- Avoided Renewables
- Customer Services

Average Local Retail Rate****
(in year of study per EIA)

INSIGHTS

- No study comprehensively evaluated the benefits and costs of DPV, although many acknowledge additional sources of benefit or cost and many agree on the broad categories of benefit and cost.
- There is a significant range of estimated value across studies, driven primarily by differences in local context, input assumptions, and methodological approaches.
- Because of these differences, comparing results across studies can be informative, but should be done with the understanding that results must be normalized for context, assumptions, or methodology.
- While detailed methodological differences abound, there is some agreement on overall approach to estimating energy and capacity value. There is significantly less agreement on overall approach to estimating grid support services and currently unmonetized values including financial and security risk, environment, and social value.

* The LBNL study only gives the net value for ancillary services
** E3's DPV technology cost includes LCOE + interconnection cost
*** The Navigant study is a meta-analysis, not a research study
****Average retail rate is included for reference; it is not necessarily appropriate to compare the average retail rate to total benefits presented without also reflecting costs (i.e., net value) and any material differences within rate designs (i.e., not average).

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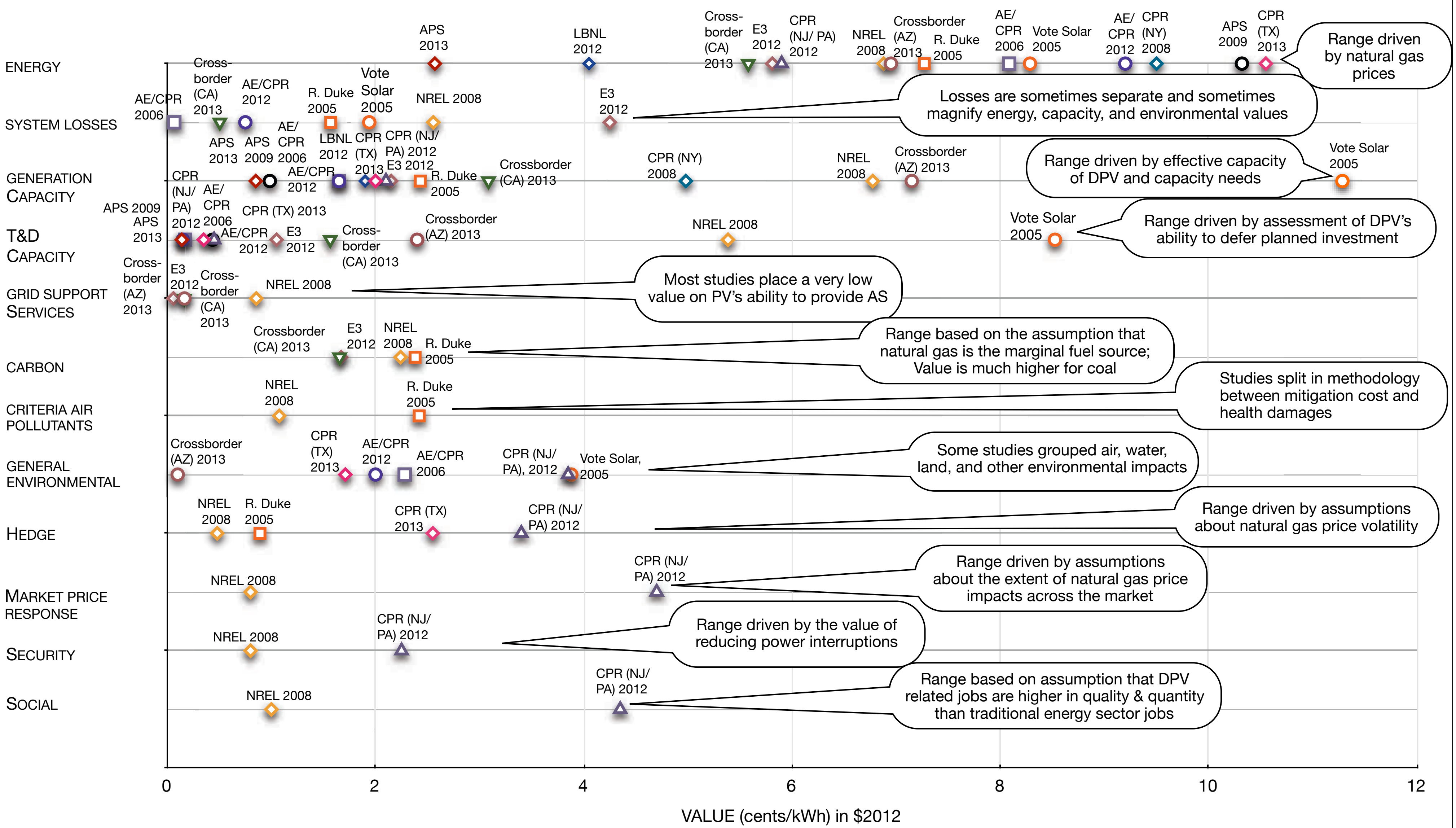
BENEFIT ESTIMATES

RANGE IN BENEFIT ESTIMATES ACROSS STUDIES DRIVEN BY VARIATION IN SYSTEM CONTEXT, INPUT ASSUMPTIONS, AND METHODOLOGIES

PUBLISHED AVERAGE BENEFIT ESTIMATES*

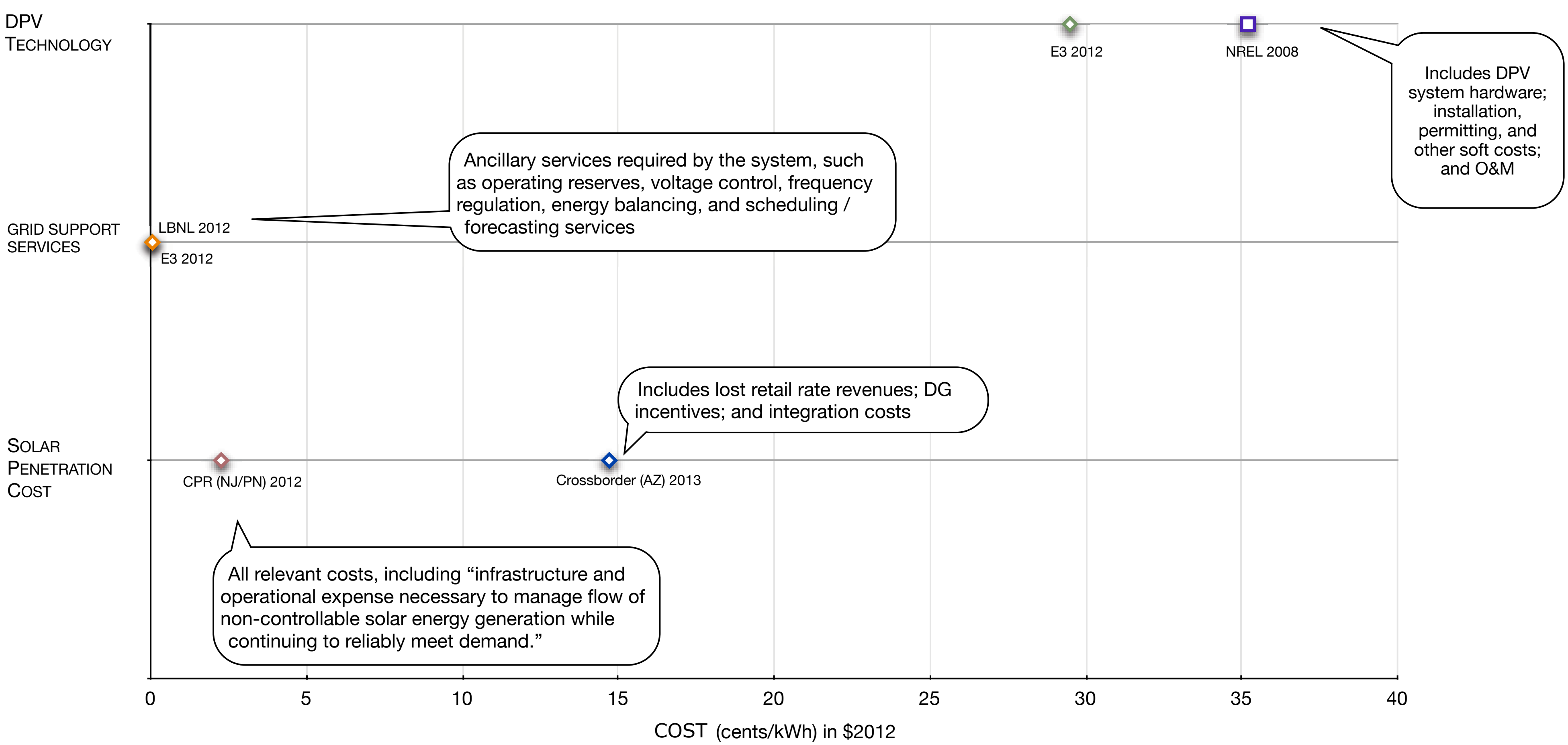


*For the full range of values observed see the individual methodology slides.

COST ESTIMATES

COSTS ASSOCIATED WITH INCREASED DPV DEPLOYMENT ARE NOT ADEQUATELY ASSESSED

PUBLISHED AVERAGE COST VALUES FOR REVIEWED SOURCES



Other studies (for example E3 2011) include costs, but results are not presented individually in the studies and so not included in the chart above. Costs generally include costs of program rebates or incentives paid by the utility, program administration costs, lost revenue to the utility, stranded assets, and costs and inefficiencies associated with throttling down existing plants.

ENERGY

VALUE OVERVIEW

Energy value is created when DPV generates energy (kWh) that displaces the need to produce energy from another resource. There are two components of energy value: the amount of energy that would have been generated equal to the DPV generation, and the additional energy that would have been generated but lost in delivery due to inherent inefficiencies in the transmission and distribution system.

APPROACH OVERVIEW

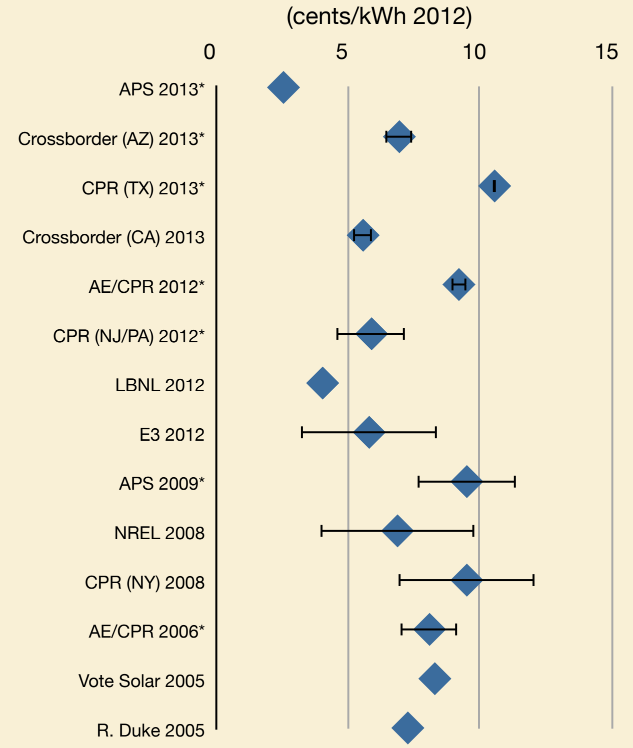
There is broad agreement on the general approach to calculating energy value, although numerous differences in methodological details. Energy is frequently the most significant source of benefit.

- Energy value is the avoided cost of the marginal resource, generally assumed to be natural gas.
- Key assumptions generally include fuel price forecast, operating & maintenance costs, and heat rate, and depending on the study, can include line losses and a carbon price.

WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Market structure** - Some ISOs and states value capacity and energy separately, whereas some ISOs only have energy markets but no capacity markets. ISOs with only energy markets may reflect capacity value in the energy price.
  - **Marginal resource** - Regions with ISOs may calculate the marginal price based on wholesale market prices, rather than on the cost of the marginal power plant; different resources may be on the margin in different regions or with different solar penetrations.
- **Input Assumptions:**
  - **Fuel price forecast** - Since gas is usually on the margin, most studies focus on gas prices. Studies most often base natural gas prices on the NYMEX forward market and then extrapolate to some future date (varied approaches to this extrapolation), but some take a different approach to forecasting, for example, based on Energy Information Administration projections.
  - **Power plant efficiency** - The efficiency of the marginal resource significantly impacts energy value; studies show a wide range of assumed natural gas plant heat rates.
  - **Variable operating & maintenance costs** - While there is some difference in values assumed by studies, variable O&M costs are generally low.
  - **Carbon price** - Some studies include an estimated carbon price in energy value, others account for it separately, and others do not include it at all.
- **Methodologies:**
  - **Study window** - Some studies (for example, APS 2013) calculate energy value in a sample year, whereas others (for example, Crossborder (AZ) 2013) calculate energy value as a levelized cost over 20 years.
  - **Level of granularity/what's on the margin** - Studies take one of three general approaches: (1) DPV displaces energy from a gas plant, generally a combined cycle, (2) DPV displaces energy from one type of plant (generally a combined cycle) off-peak and a different type of plant (generally a combustion turbine) on-peak, (3) DPV displaces the resource on the margin during every hour of the year, based on a dispatch analysis.

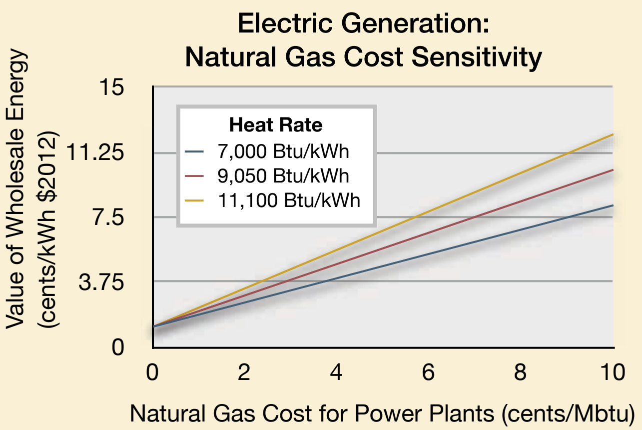
BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



* = value includes losses

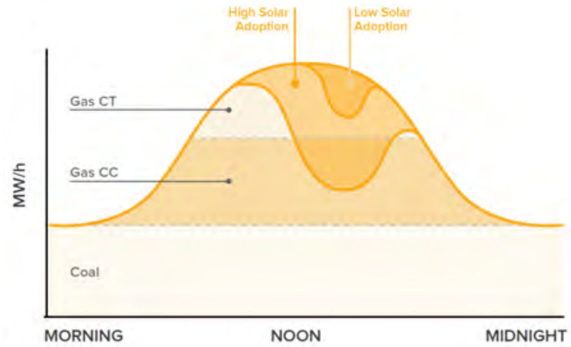
ENERGY (CONT'D)

SENSITIVITIES TO MAIN DRIVERS



INSIGHTS & IMPLICATIONS

- Accurately defining the marginal resource that DPV displaces requires an increasingly sophisticated approach as DPV penetration increases.



What DPV displaces depends on the dispatch order of other resources, when the solar is generated, and how much is generated.

More accurate, more complex

Marginal Resource Characterization	Pros	Cons
Single power plant assumed to be on the margin (typically gas CC)	Simple; often sufficiently accurate at low solar penetrations	Not necessarily accurate at higher penetrations or in all jurisdictions
Plant on the margin on-peak/plant on the margin off-peak	More accurately captures differences in energy value reflected in merit-order dispatch	Not necessarily accurate at higher penetrations or in all jurisdictions
Hourly dispatch or market assessment to determine marginal resource in every hour	Most accurate, especially with increasing penetration	More complex analysis required; solar shape and load shape must be from same years

- Taking a more granular approach to determining energy value also requires a more detailed characterization of DPV's generation profile. It's also critical to use solar and load profiles from the same year(s), to accurately reflect weather drivers and therefore generation and demand correlation.

- In cases where DPV is displacing natural gas, the NYMEX natural gas forward market is a reasonable basis for a natural gas price forecast, adjusted appropriately for delivery to the region in question. It is not apparent from studies reviewed what the most effective method is for escalating prices beyond the year in which the NYMEX market ends.

LOOKING FORWARD

As renewable and distributed resource (not just DPV) penetration increases, those resources will start to impact the underlying load shape differently, requiring more granular analysis to determine energy value.

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SYSTEM LOSSES

VALUE OVERVIEW

Energy losses are the value of the additional energy generated by central plants that is lost due to inherent inefficiencies (electrical resistance) in delivering energy to the customer via the transmission and distribution system. Since DPV generates energy at or near the customer, that additional energy is not lost. Energy losses can also act as a magnifier of value for capacity and environmental benefits, since avoided energy losses result in lower required capacity and lower emissions.

APPROACH OVERVIEW

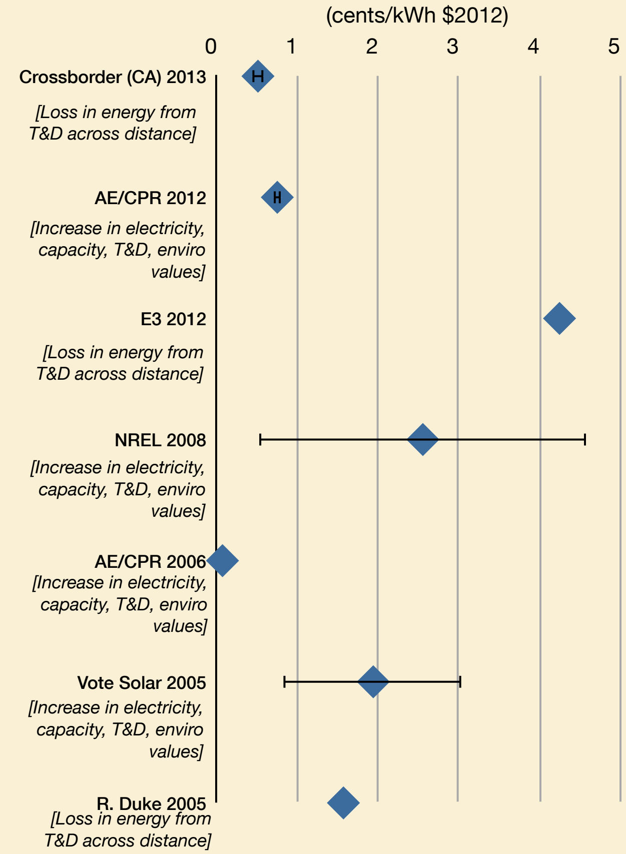
Losses are generally recognized as a value, although there is significant variation around what type of losses are included and how they are assessed. Losses usually represent a small but not insignificant source of value, although some studies report comparatively high values.

- Energy lost in delivery magnify the value of other benefits, including capacity and environment.
- Calculate loss factor(s) (amount of loss per unit of energy delivered) based on modeled or observed data.

WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Congestion** - Because energy losses are proportional to the inverse of current squared, the higher the utilization of the transmission & distribution system, the greater the energy losses.
  - **Solar characterization**—The timing, quantity, and geographic location of DPV, and therefore its coincidence with delivery system utilization, impacts losses.
- **Input Assumptions:**
  - **Loss factors** - Some studies apply loss factors based on actual observation, others develop theoretical loss factors based on system modeling. Further, some utility systems have higher losses than others.
- **Methodologies:**
  - **Types of losses recognized** - Most studies recognize energy losses, some recognize capacity losses, and a few recognize environmental losses.
  - **Adder vs. stand-alone value** - There is no common approach to whether losses are represented as stand-alone values (for example, NREL 2008 and E3 2012) or as adders to energy, capacity, and environmental value (for example, Crossborder (AZ) 2013 and APS 2013), complicating comparison across studies.
  - **Level of time and geographic granularity** - Some studies apply an average loss factor to all energy generated by DPV, others apply peak/off-peak factors, and others conduct hourly analysis. Some studies also reflect geographically-varying losses.

SYSTEM LOSSES BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



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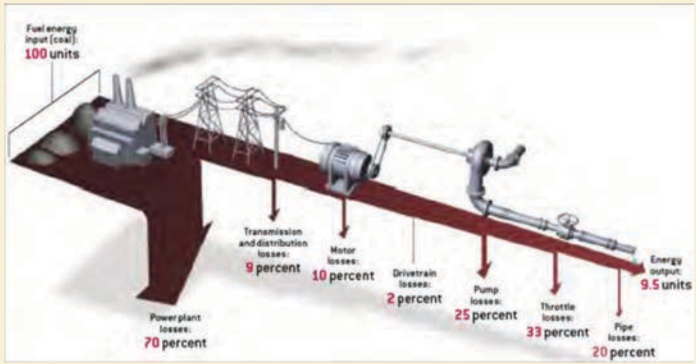
LOSSES (CONT'D)

WHAT ARE LOSSES?

Some energy generated at a power plant is lost as it travels through the transmission and distribution system to the customer. As shown in the graphic below, more than 90% of primary energy input into a power plant is lost before it reaches the end use, or stated in reverse, for every one unit of energy saved or generated close to where it is needed, 10 units of primary energy are saved.



For the purposes of this discussion document, relevant losses are those driven by inherent inefficiencies (electrical resistance) in the transmission and distribution system, not those in the power plant or customer equipment. Energy losses are proportional to the square of current, and associated capacity benefit is proportional to the square of reduced load.

INSIGHTS & IMPLICATIONS

- All relevant system losses—energy, capacity, and environment—should be assessed.
- Because losses are driven by the square of current, losses are significantly higher during peak periods. Therefore, when calculating losses, it's critical to reflect marginal losses, not just average losses.
- Whether or not losses are ultimately represented as an adder to an underlying value or as a stand-alone value, they are generally calculated separately. Studies should distinguish these values from the underlying value for transparency and to drive consistency of methodology.

LOOKING FORWARD

Losses will change over time as the loading on transmission and distribution lines changes due to a combination of changing customer demand and DPV generation.

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GENERATION CAPACITY

VALUE OVERVIEW

Generation capacity value is the amount of central generation capacity that can be deferred of avoided due to DPV. Key drivers of value include (1) DPV's dependable capacity and (2) system capacity needs.

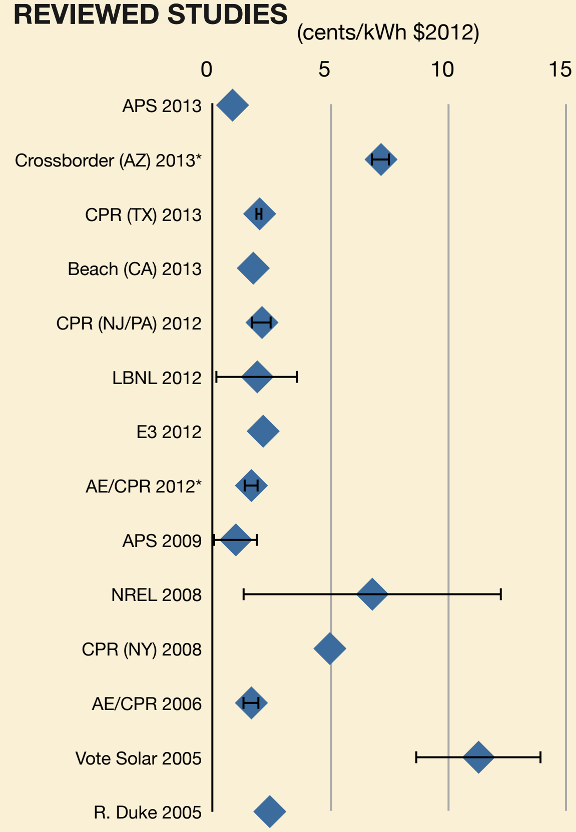
APPROACH OVERVIEW

Generation capacity value is the avoided cost of the marginal capacity resource, most frequently assumed to be a gas combustion turbine, and based on a calculation of DPV dependable capacity, most commonly based on effective load carrying capability (ELCC).

WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Load growth/generation capacity investment plan** - The ability to avoid or defer generation capacity depends on underlying load growth and how much additional capacity will be needed, when.
  - **Solar characterization** - The timing, quantity, and geographic location of DPV, and therefore its coincidence with system peak, impacts DPV's dependable capacity (see methodology below).
  - **Market structure** - Some ISOs and states value capacity and energy separately, whereas some ISOs only have energy markets but no capacity markets. ISOs with only energy markets may reflect capacity value as part of the energy price. For California, E3 2012 calculates capacity value based on "net capacity cost"—the annual fixed cost of the marginal unit minus the gross margins captured in the energy and ancillary service market.
- **Input Assumptions:**
  - **Marginal resource** - Most studies assume that a gas combustion turbine, or occasionally a gas combined cycle, is the generation capacity resource that could be deferred. What this resource is and its associated capital and fixed O&M costs are a primary determinant of capacity value.
- **Methodologies:**
  - **Formulation of dependable capacity** - There is broad agreement that DPV's dependable capacity is most accurately determined using an effective load carrying capability (ELCC) approach, which measures the amount of additional load that can be met with the same level of reliability after adding DPV. There is some variation across studies in ELCC results, likely driven by a combination of underlying solar resource profile and ELCC calculation methodology. The approach to dependable capacity is sometimes different when considering T&D capacity.
  - **Minimum DPV required to defer capacity** - Some studies (for example, Crossborder (AZ) 2013) credit every unit of dependable DPV capacity with capacity value, whereas others (for example, APS 2009) require a certain minimum amount of solar be installed to defer an actual planned resource before capacity value is credited.
  - **Inclusion of losses** - Some studies include capacity losses as an adder to capacity value rather than as a stand-alone benefit.

GENERATION CAPACITY BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



* = value takes into account loss savings

GENERATION CAPACITY (CONT'D)

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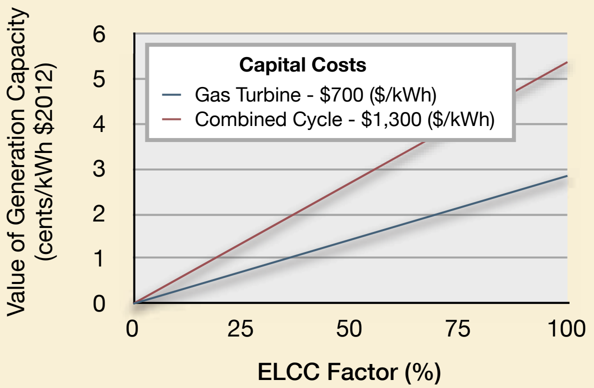
KEY DRIVERS OF VALUE AND MAIN ASSUMPTIONS

Sensitivity of Generation Capacity Value to the ELCC Factor

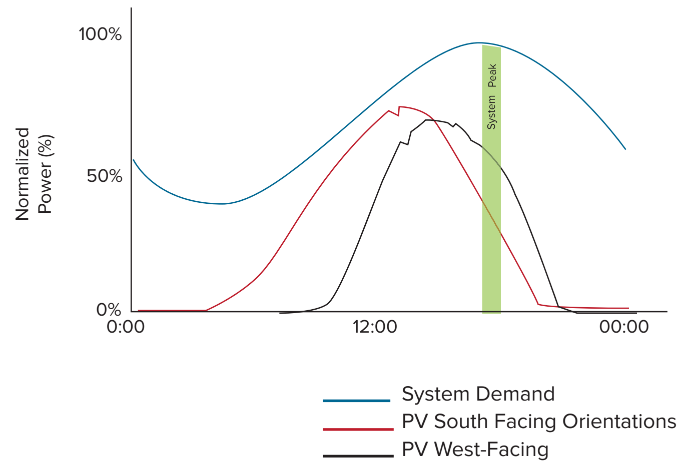


ASSUMPTIONS:

Capacity Factor: 20%
Discount Rate: 5%
Plant Lifetime: 25 years

INSIGHTS & IMPLICATIONS

- Generation capacity value is highly dependent on the correlation of DPV generation to load, so it's critical to accurately assess that correlation using an ELCC approach, as all studies reviewed do. Hoewver, varying results indicate possible different formulations of ELCC.



While ELCC assesses DPV's contribution to reliability throughout the year, generation capacity value will generally be higher if DPV output is more coincident with peak.

- The value also depends on whether new capacity is needed on the system, and therefore whether DPV defers new capacity. It's important to assess what capacity would have been needed without any additional, expected, or planned DPV.

- Generation capacity value is likely to change significantly as more DPV, and more renewable and distributed resources of all kinds are added to the system. Some amount of DPV can displace the most costly resources in the capacity stack, but increasing amounts of DPV could begin to displace less costly resources. Similarly, the underlying load shape, and therefore even the concept of a peak could begin to shift.

LOOKING FORWARD

Generation capacity is one of the values most likely to change, most quickly, with increasing DPV penetration. Key reasons for this are (1) increasing DPV penetration could have the effect of pushing the peak to later in the day, when DPV generation is lower, and (2) increasing DPV penetration will displace expensive peaking resources, but once those resources are displaced, the cost of the next resource may be lower. Beyond DPV, it's important to note that a shift towards more renewables could change the underlying concept of a daily or seasonal peak.

TRANSMISSION & DISTRIBUTION CAPACITY

VALUE OVERVIEW

The transmission and distribution (T&D) capacity value is a measure of the net change in T&D infrastructure as a result of the addition of DPV. Benefits occur when DPV is able to meet rising demand locally, relieving capacity constraints upstream and deferring or avoiding transmission or distribution upgrades. Costs are incurred when additional transmission or distribution investment are necessary to support the addition of DPV, which could occur when the amount of solar energy exceeds the demand in the local area and increases needed line capacity.

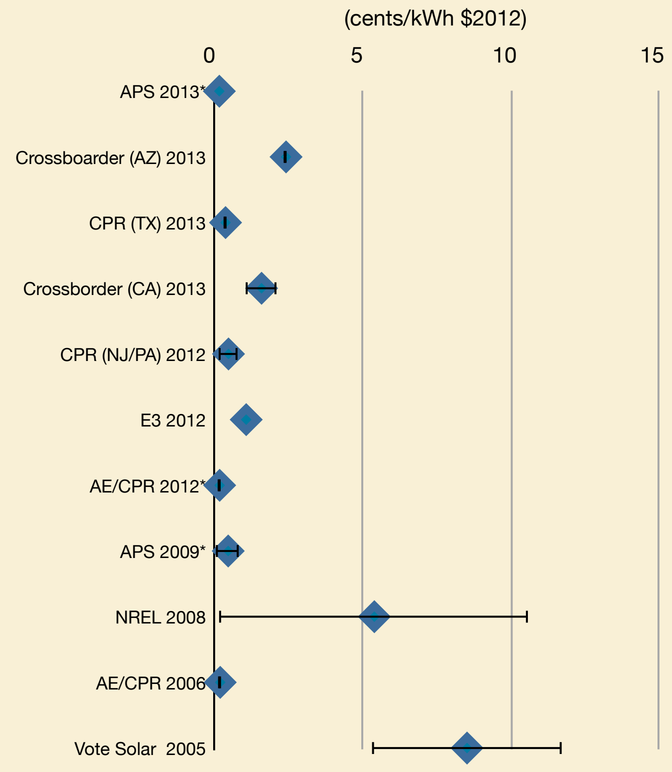
APPROACH OVERVIEW

The net value of deferring or avoiding T&D investments is driven by rate of load growth, DPV configuration and energy production, peak coincidence and dependable capacity. Given the site specific nature of T&D, especially distribution, there can be significant range in the calculated value of DPV. Historically low penetrations of DPV has meant that studies have primarily focused on analyzing the ability of DPV to defer transmission or distribution upgrades and have not focused on potential costs, which would likely not arise until greater levels of penetration. Studies typically determine the T&D capacity value based on the capital costs of planned expansion projects in the region of interest. However, the granularity of analysis differs.

WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Locational characteristics -** Transmission and distribution infrastructure projects are inherently site-specific and their age, service life, and use can vary significantly. Thus, the need, size and cost of upgrades, replacement or expansion correspondingly vary.
  - **Projected load growth** - Expected rate of demand growth affects the need, scale and cost of T&D upgrades and the ability of DPV to defer or offset anticipated T&D expansions. The rate of growth of DPV would need to keep pace with the growth in demand, both by order of magnitude and speed.
  - **PV temporal coincidence with system and/ or local demand** - The timing of energy production from DPV and its coincidence with system peaks (transmission) and local peaks (distribution) drive the ability of DPV to contribute as dependable capacity that could defer or displace a transmission or distribution capacity upgrade.
  - **The length of time the investment is deferred** -The length of time that T&D can be deferred by the installation of PV varies by the rate of load growth, the assumed dependable capacity of the PV, and PV's correlation with peak. The cost of capital saved will increase with the length of deferment.
- **Input Assumptions:**
  - **T or D investment plan characteristics -** Depending upon data available and depth of analysis, studies vary by the level of granularity in which T&D investment plans were assessed–project by project or broader generalizations across service territories.
- **Methodologies:**
  - **Accrual of capacity value to DPV** - One of the most significant methodological differences is whether DPV has incremental T&D capacity value the face of "lumpy" T&D investments. (see implications and insights).
  - **Losses -** Some studies include the magnified benefit of deferred T&D capacity due to avoided losses within the calculation of T&D value, while others itemize line losses separately.

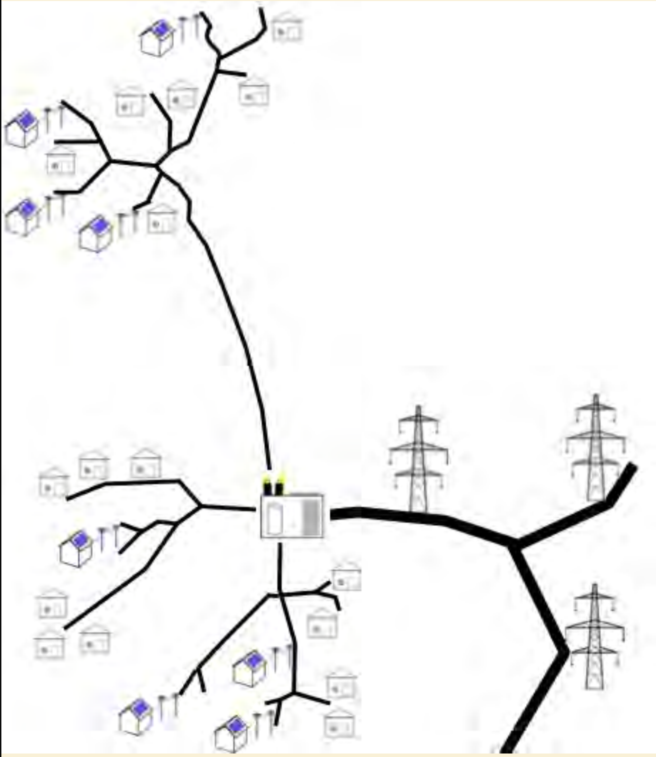
T&D CAPACITY BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



* = value includes losses

TRANSMISSION & DISTRIBUTION CAPACITY

TRANSMISSION & DISTRIBUTION SYSTEM



INSIGHTS & IMPLICATIONS

- Strategically targeted DPV deployment can relieve T&D capacity constraints by providing power close to demand and potentially defer capacity investments, but dispersed deployment has been found to provide less benefit. Thus, the ability to access DPV's T&D deferral value will require proactive distribution planning that incorporates distributed energy resources, such as DPV, into the evaluation.

- The values of T&D are often grouped together, but they are unique when considering the potential costs and benefits that result from DPV.
  - While the ability to defer or avoid transmission is still locational dependent, it is less so than distribution. Transmission aggregates disparate distribution areas and the effects of additional DPV at the distribution level typically require less granular data and analysis.
  - The distribution system requires more geographically specific data that reflects the site specific characteristics such as local hourly PV production and correlation with local load.

- There are significantly differing approaches on the ability of DPV to accrue T&D capacity deferment or avoidance value that require resolution:
  - How should DPV's capacity deferral value be estimated in the face of "lumpy" T&D investments? While APS 2009 and APS 2013 posit that a minimum amount of solar must be installed to defer capacity before credit is warranted, Crossborder (AZ) 2013 credits every unit of reliable capacity with capacity value.
  - What standard should be applied to estimate PV's ability to defer a specific distribution expansion project? While most studies use ELCC to determine effective capacity, APS 2009 and APS 2013 use the level at which there is a 90% confidence of that amount of generation.

LOOKING FORWARD

Any distributed resources, not just DPV, that can be installed near the end user to reduce use of, and congestion along, the T&D network could potentially provide T&D value. This includes technologies that allow energy to be used more efficiently or at different times, reducing the quantity of electricity traveling through the T&D network (especially during peak hours).

GRID SUPPORT SERVICES

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VALUE OVERVIEW

Grid support services, also commonly referred to as ancillary services (AS) in wholesale energy markets, are required to enable the reliable operation of interconnected electric grid systems, including operating reserves, reactive supply and voltage control; frequency regulation; energy imbalance; and scheduling.

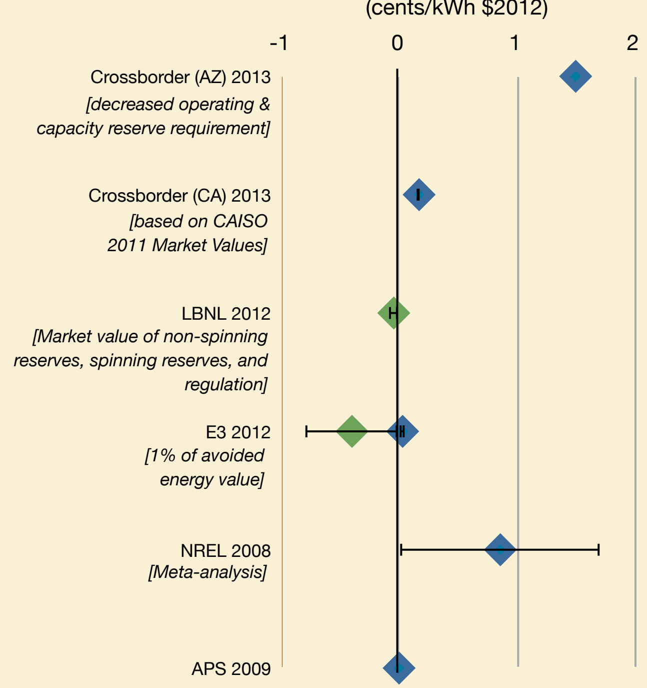
APPROACH OVERVIEW

There is significant variation across studies on the impact DPV will have on the addition or reduction in the need of grid support services and the associated cost or benefit. Most studies focus on the cost DPV could incur in requiring additional grid support services, while a minority evaluate the value DPV could provide by reducing load and required reserves or the AS that DPV could provide when coupled with other technologies. While methodologies are inconsistent, the approaches generally focus on methods for calculating changes in necessary operating reserves, and less precision or rules of thumb are applied to the remainder of AS, such as voltage regulation. Operating reserves are typically estimated by determining the reliable capacity for which PV can be counted on to provide capacity when demanded over the year.

WHY AND HOW VALUES DIFFER

- **System Context:**
    - **Reliability standards and market rules** - The standards and rules for reliability that govern the requirements for grid support services and reserve margins differ. These standards directly impact the potential net value of adding DPV to the system.
    - **Availability of ancillary services market** - Where wholesale electricity markets exist, the estimated value is correlated to the market prices of AS.
    - **PV temporal coincidence with system and/ or local demand** - The timing of energy production from DPV and it's coincidence with system peaks differs locationally.
    - **Penetration of PV** - As PV penetrations increase, the value of its reliable capacity decreases and, under standard reliability planning approaches, would increase the amount of system reserves necessary to maintain reliable operations.
    - **System generation mix -** The performance characteristics of the existing generation mix, including the generators ability to respond quickly by increasing or decreasing production, can significantly change the supply value of ancillary services and the value.
- **Methodologies:**
    - **Reliable or dependable capacity of PV** - The degree that DPV can be depended to provide capacity when demanded has a direct effect on the amount of operating reserves that the rest of the system must supply. The higher the "dependable capacity," the less operating reserves necessary.
    - **Correlating reduced load with reduced ancillary service needs** - Crossborder (AZ) 2013 calculated a net benefit of PDV based on 1) load reduction & reduced operating reserve requirements; 2) peak demand reduction and utility capacity requirements.
    - **Potential of PV to provide grid support with technology coupling** - While the primary focus across studies was the impact DPV would have on the need for additional AS, NREL 2008 & AE/CPR 2006 both noted that PV could provide voltage regulation with smart inverters were installed.

GRID SUPPORT SERVICES BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



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GRID SUPPORT SERVICES

Grid Support Services	The potential for PV to provide grid support services (with technology modifications)
REACTIVE SUPPLY AND VOLTAGE CONTROL	**(+/-)** PV with an advanced inverter can inject/consume VARs, adjusting to control voltage
FREQUENCY REGULATION	**(+/-)** Advanced inverters can adjust output frequency; standard inverters may
ENERGY IMBALANCE	**(+/-)** If PV output < expected, imbalance service is required. Advanced inverters could adjust output to provide imbalance
OPERATING RESERVES	**(-)** Depending on weather, controllability, standalone PV may introduce additional forecast error
SCHEDULING / FORECASTING	**(-)** The variability of the solar resource requires additional forecasting to reduce uncertainty

INSIGHTS & IMPLICATIONS

- As with large scale renewable integration, there is still controversy over determining the net change in "ancillary services due to variable generation and much more controversy regarding how to allocate those costs between specific generators or loads." (LBNL 2012)
- Areas with wholesale AS markets enable easier quantification of the provision of AS services. Regions without markets have less standard methodologies for quantifying the value of AS services.
- One of the most significant differences in reviewed methodological approaches is whether the necessary amount of operating reserves, as specified by required reserve margin, decreases by DPV's capacity value (as determined by ELCC, for example). Crossborder (CA) 2013, E3 2012 and Vote Solar 2005 note that the addition of DPV reduces load served by central generation, thus allowing utilities to reduce procured reserves. Additional analysis is needed to determine whether the required level of reserves should be adjusted in the face of a changing system.
- Studies varied in their assessments of grid support services. APS, 2009 did not expect DPV would contribute significantly to spinning or operating reserves, but predicted regulation reserves could be affected at high penetration levels.

LOOKING FORWARD

Increasing levels of distributed energy resources and variable renewable generation will begin to shift both the need for grid support services as well as the types of assets that can and need to provide them. The ability of DPV to provide grid support requires technology modifications or additions, such as advanced inverters or storage, which incur additional costs. However, it is likely that the net value proposition will increase as technology costs decrease and the opportunity (or requirements) to provide these services increase with penetration.

FINANCIAL: FUEL PRICE HEDGE

VALUE OVERVIEW

DPV produces roughly constant-cost power compared to fossil fuel generation, which is tied to potentially volatile fuel prices. DPV can provide a "hedge" against it, reducing risk exposure to utilities and customers.

APPROACH OVERVIEW

More than half the studies reviewed acknowledge DPV's fuel price hedge benefit, although fewer quantify it and those that do take different, although conceptually similar, approaches.

- In future years when natural gas futures market prices are available, using those NYMEX prices to develop a natural gas price forecast should include the value of volatility.
- In future years beyond when natural gas futures market prices are available, estimate natural gas price and volatility value separately. Differing approaches include:
  - Escalating NYMEX prices at a constant rate, under the assumption that doing so would continue to reflect hedge value (Crossborder (AZ) 2013); or
  - Estimating volatility hedge value separately as the value or an option/swap, or as the actual price adder the utility is incurring now to hedge gas prices (CPR (NJ/PA 2012), NREL 2008).

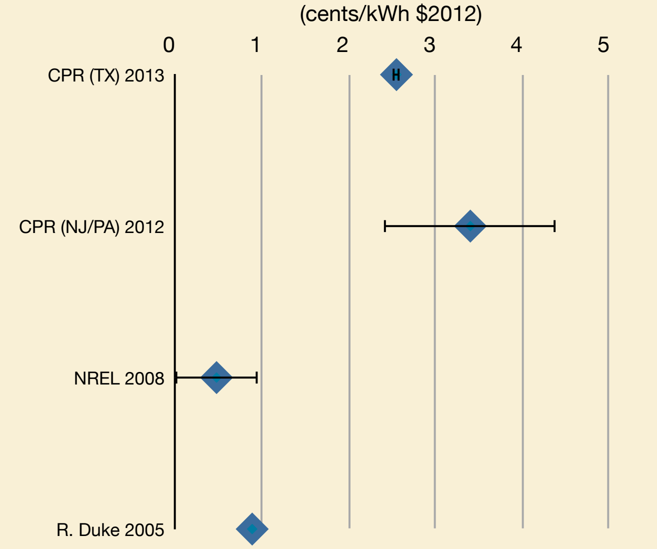
WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Marginal resource** - What resource is on the margin, and therefore how much fuel is displaced varies.
  - **Exposure to fuel price volatility** - Most utilities already hedge some portion of their natural gas purchases for some period of time in the future.
- **Methodologies:**
  - **Approach to estimating value** - While most studies agree that NYMEX futures prices are an adequate reflection of volatility, there is no largely agreed upon approach to estimating volatility beyond when those prices are available.

INSIGHTS & IMPLICATIONS

- NYMEX futures market prices are an adequate reflection of volatility in the years in which it operates.
- Beyond that, volatility should be estimated, although there is no obvious best practice. Further work is required to develop an approach that accurately measures hedge value.

FUEL PRICE HEDGE BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



FINANCIAL: MARKET PRICE RESPONSE

VALUE OVERVIEW

The addition of DPV, especially at higher penetrations, can affect the market price of electricity in a particular market or service territory. These market price effects span energy and capacity values in the short term and long term, all of which are interrelated. Benefits can occur as DPV provides electricity close to demand, reducing the demand for centrally-supplied electricity and the fuel powering those generators, thereby lowering electricity prices and potentially fuel commodity prices. A related benefit is derived from the effect of DPV's contribution at higher penetrations to reshape the load profile that central generators need to meet. Depending upon the correlation of DPV production and load, the peak demand could be reduced and the marginal generator could be more efficient and less costly, reducing total electricity cost. However, these benefits could potentially be reduced in the longer term as energy prices decline, which could result in higher demand. Additionally, depressed prices in the energy market could have a feedback effect by raising capacity prices.

APPROACH OVERVIEW

While several studies evaluate a market price response of DPV, distinct approaches were employed by E3 2012, CPR (NJ/PN) 2012, and NREL 2008.

WHY AND HOW VALUES DIFFER

- **Methodologies:**
  - **Considering market price effects of DPV in the context of other renewable technologies** - E3 2012 incorporated market price effect in its high penetration case by adjusting downward the marginal value of energy that DPV would displace. However, for the purposes of the study, E3 2012 did not add this as a benefit to the avoided cost because they "assume the market price effect would also occur with alternative approaches to meeting [CA's] RPS."
  - **Incorporating capacity effects** - E3 2012 represented a potential feedback effect between the energy and capacity by assuming an energy market calibration factor. That is, it assumes that, in the long run, the CCGT's energy market revenues plus the capacity payment equal the fixed and variable costs of the CCGT. Therefore, a CCGT would collect more revenue through the capacity and energy markets than is needed to cover its costs, and a decrease in energy costs would result in a relative increase in capacity costs.
  - CPR (NJ/PA) 2012 incorporates market price effect "by reducing demand during the high priced hours [resulting in] a cost savings realized by all consumers." They note "that further investigation of the methods may be warranted in light of two arguments...that the methodology does address induced increase in demand due to price reductions, and that it only addresses short-run effects (ignoring the impact on capacity markets)."

INSIGHTS & IMPLICATIONS

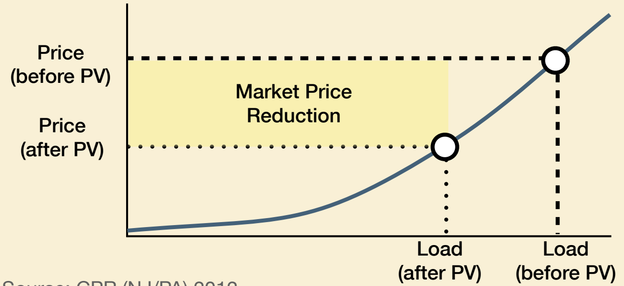
- The market price reduction value only assesses the initial market reaction of reduced price, not subsequent market dynamics (e.g. increased demand in response to price reductions, or the impact on the capacity market), which has to be studied and considered, especially in light of higher penetrations of DPV.

LOOKING FORWARD

Technologies powered by risk-free fuel sources (such as wind) and technologies that increase the efficiency of energy use and decrease consumption would also have similar effects.

MARKET PRICE RESPONSE BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES

MARKET PRICE VS. LOAD



Source: CPR (NJ/PA) 2012

SECURITY: RELIABILITY AND RESILIENCY

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VALUE OVERVIEW

The grid security value that DPV could provide is attributable to three primary factors, the last of which would require coupling DPV with other technologies to achieve the benefit:

1. The potential to reduce outages by reducing congestion along the T&D network. Power outages and rolling blackouts are more likely when demand is high and the T&D system is stressed.
2. The ability to reduce large-scale outages by increasing the diversity of the electricity system's generation portfolio with smaller generators that are geographically dispersed.
3. The benefit to customers to provide back-up power sources available during outages through the combination of PV, control technologies, inverters and storage.

APPROACH OVERVIEW

While there is general agreement across studies that integrating DPV near the point of use will decrease stress on the broader T&D system, most studies do not calculate a benefit due to the difficulty of quantification. CPR 2012 and 2011 did represent the value as the value of avoided outages based on the total cost of power outages to the U.S. each year, and the perceived ability of DPV to decrease the incidence of outages.

INSIGHTS & IMPLICATIONS

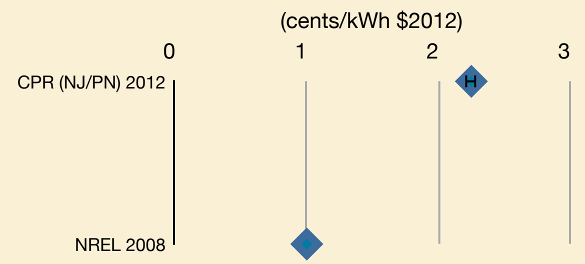
- The value of increased reliability is significant, but there is a need to quantify and demonstrate how much value can be provided by DPV. Rules-of-thumb assumptions and calculations for security impacts require significant analysis and review.

- Opportunities to leverage combinations of distributed technologies to increase customer reliability are starting to be tested. The value of DPV in increasing suppling power during outages can only be realized if DPV is coupled with storage and equipped with the capability to island itself from the grid during a power outage, which come at additional capital cost.

LOOKING FORWARD

Any distributed resources that can be installed near the end user to reduce use of, and congestion along, the T&D network could potentially reduce transmission stress. This includes technologies that allow energy to be used more efficiently or at different times, reducing the quantity of electricity traveling through the T&D network (especially during peak hours). Any distributed technologies with the capability to be islanded from the grid could also play a role.

RELIABILITY AND RESILIENCY BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES



Disruption Value Range by Sector
(cents/kWh $2012)

Sector	Min	Max
Residential	0.028	0.41
Commercial	11.77	14.40
Industrial	0.4	1.99

Source: The National Research Council, 2010

ENVIRONMENT: CARBON

VALUE OVERVIEW

The benefits of reducing carbon emissions include (1) reducing future compliance costs, carbon taxes, or other fees, and (2) mitigating the heath and ecosystem damages potentially caused by climate change.

APPROACH OVERVIEW

By and large, studies that addressed carbon focused on the compliance costs or fees associated with future carbon emissions, and conclude that carbon reduction can increase DPV's value by more than two cents per kilowatt-hour, depending heavily on the price placed on carbon. While there is some agreement that carbon reduction provides value and on the general formulation of carbon value, there are widely varying assumptions, and not all studies include carbon value.

Carbon reduction benefit is the amount of carbon displaced times the price of reducing a ton of carbon. The amount of carbon displaced is directly linked to the amount of energy displaced, when it is displaced, and the carbon intensity of the resource being displaced.

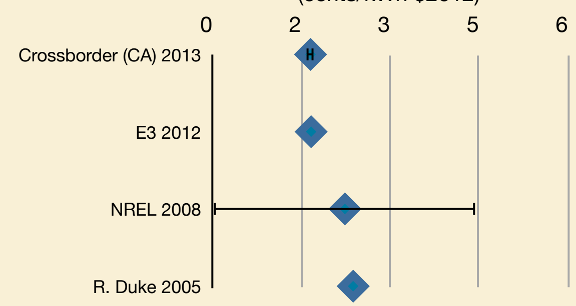
WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Marginal resource** - Different resources may be on the margin in different regions or with different solar penetrations. Carbon reduction is significantly different if energy is displaced from coal, gas combined cycles, or gas combustion turbines.
- **Input Assumptions:**
  - **Value of carbon reduction** - Studies have widely varying assumptions about the price or carbon. Some studies base price on reported prices in European markets, others on forecasts based on policy expectations, others on a combination. The increased uncertainty around U.S. Federal carbon legislation has made price estimates more difficult.
  - **Heat rates of marginal resources** - The assumed efficiency of the marginal power plant is directly correlated to amount of carbon displaced by DPV.
- **Methodologies:**
  - **Adder vs. stand-alone value** - There is no common approach to whether carbon is represented as a stand-alone value (for example, NREL 2008 and E3 2012) or as an adder to energy value (for example, APS 2013).
  - **Level of granularity/what's on the margin** - Just as with energy (which is directly linked to carbon reduction), studies take one of three general approaches: (1) DPV displaces energy from a gas plant, generally a combined cycle, (2) DPV displaces energy from one type of plant (generally a combined cycle) off-peak and a different type of plant (generally a combustion turbine) on-peak, (3) DPV displaces whatever resource is on the margin during every hour of the year, based on a dispatch analysis.

BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES

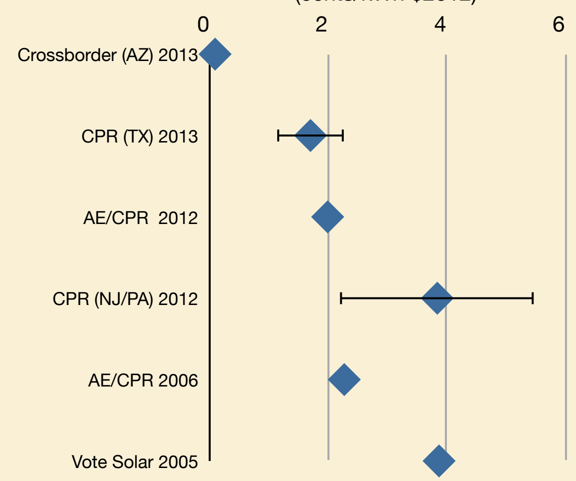
Range of Benefits and Costs from Studies that Evaluate Carbon Separately

(cents/kWh $2012)



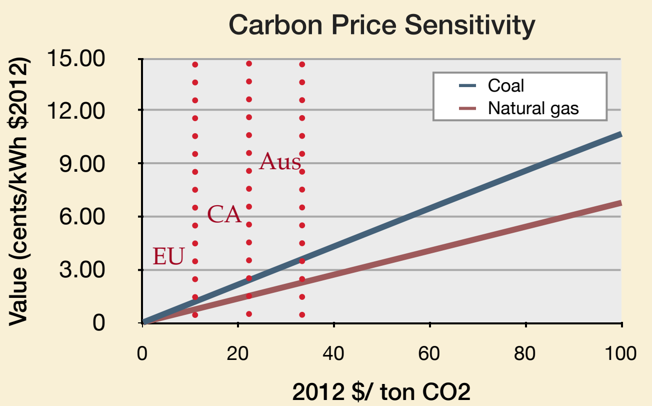
Range of Benefits and Costs from Studies that Group All Environmental Values

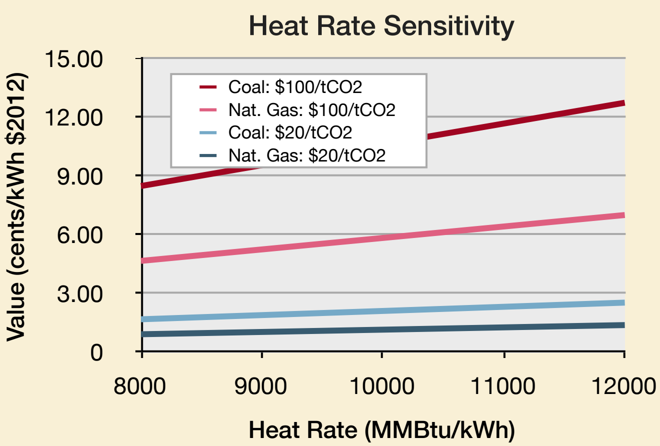
(cents/kWh $2012)



ENVIRONMENT: CARBON (CONT'D)

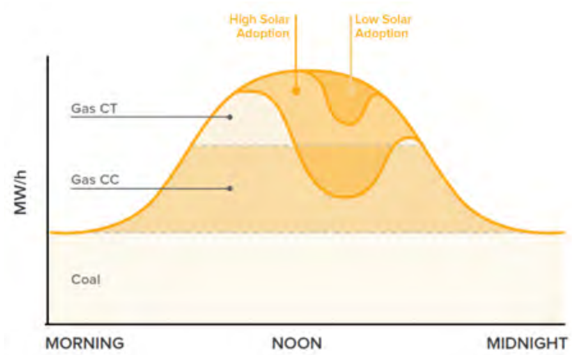
KEY DRIVERS OF VALUE AND MAIN ASSUMPTIONS





INSIGHTS & IMPLICATIONS

- Just as with energy value, carbon value depends heavily on what the marginal resource is that is being displaced. The same determination of the marginal resource should be used to drive both energy and carbon values.



How much carbon DPV displaces depends on the dispatch order of other resources, when the solar is generated, and how much is generated.

- While there is little agreement on what the $/ton price of carbon is or should be, it is likely non-zero.

LOOKING FORWARD

While there has been no Federal action on climate over the last few years, leading to greater uncertainty about potential future prices, many states and utilities continue to value carbon as a reflection of assumed benefit. There appears to be increasing likelihood that the US Environmental Protection Agency will take action to limit emissions from coal plants, potentially providing a more concrete indicator of price.

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ENVIRONMENT: OTHER FACTORS

In addition to carbon, DPV has several other environmental benefits (or potentially costs) that, while commonly acknowledged, are included in only a few of the studies reviewed here. That said, there is a significant body of thought for each outside the realm of DPV cost/benefit valuation.

CRITERIA AIR POLLUTANTS

SUMMARY: Criteria air pollutants (NOX, SO_2, and particulate matter) released from the burning of fossil fuels can produce both health and ecosystem damages. The economic cost of these pollutants is generally estimated as:

1. The compliance costs of reducing pollutant emissions from power plants, or the added compliance costs to further decrease emissions beyond some baseline standard; and/or

2. The estimated cost of damages, such as medical expenses for asthma patients or the value of mortality risk, which attempts to measure willingness to pay for a small reduction in risk of dying due to air pollution.

VALUE: Crossborder (AZ) 2013 estimated the value of criteria air pollutant reductions, based on APS's Integrated Resource Plan, as \$0.365/MWh, and NREL 2008 as \$0.2-14/MWh (2012\$). CPR (NJ/PA) 2012 and AE/CPR 2012 also acknowledged criteria air pollutants, but estimate cost based on a combined environmental value.

RESOURCES:

Epstein, P., Buonocore, J., Eckerle, K. et al., *Full Cost Accounting for the Life Cycle of Coal*, 2011.

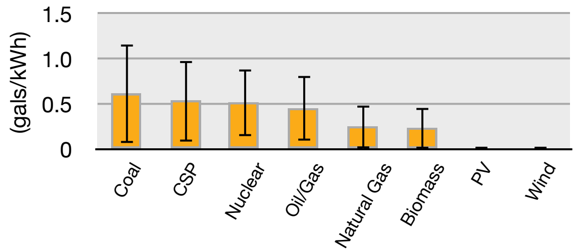
Muller, N., Mendelsohn, R., Nordhaus, W., *Environmental Accounting for Pollution in the US Economy.* American Economic Review 101, Aug. 2011. pp. 1649 - 1675.

National Research Council. *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use,* 2010.

WATER

SUMMARY: Coal and natural gas power plants withdraw and consume water primarily for cooling. Approaches to valuing reduced water usage have focused on the cost or value of water in competing sectors, potentially including municipal, agricultural, and environmental/recreational uses.

WATER CONSUMPTION BY TECHNOLOGY



Source: Fthenakis

VALUE: The only study reviewed that explicitly values water reduction is Crossborder (AZ) 2013, which estimates a \$1.084/MWh value based on APS's IRP.

RESOURCES:

Tellinghulsen, S., *Every Drop Counts.* Western Resources Advocates, Jan. 2011.

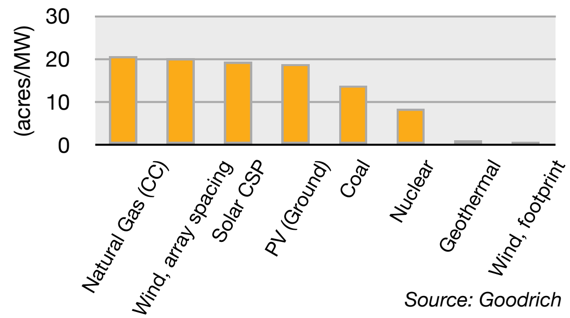
Fthenakis, V., Hyungl, C., *Life-cycle Use of Water in U.S. Electricity Generation.* Renewable and Sustainable Energy Review 14, Sept. 2010. pp.2039-2048.

LAND

SUMMARY: DPV can impact land in three ways:

1. Change in property value with the addition of DPV;
2. Land requirement; or
3. Ecosystem impacts.

LIFE-CYCLE LAND USE BY TECHNOLOGY



Source: Goodrich

VALUE: None of the studies reviewed explicitly estimate land impacts.

RESOURCES:

Goodrich et al. Residential, Commercial, and Utility Scale Photovoltaic (V) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities. NREL. February 2012. Pages 14, 23—28

SOCIAL: ECONOMIC DEVELOPMENT

VALUE OVERVIEW

The assumed social value from DPV is based on any job and economic growth benefits that DPV brings to the economy, including jobs and higher tax revenue. The value of economic development depends on number of jobs created or displaced, as measured by a job multiplier, as well as the value of each job, as measured by average salary and/or tax revenue.

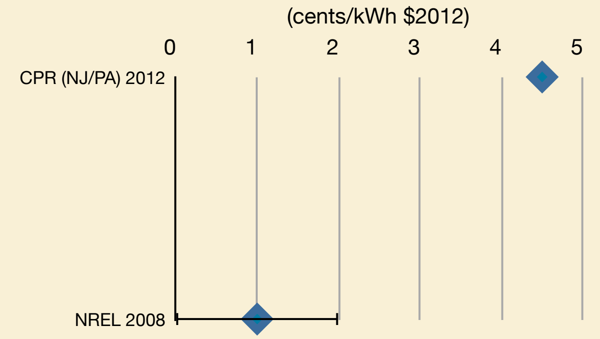
APPROACH OVERVIEW

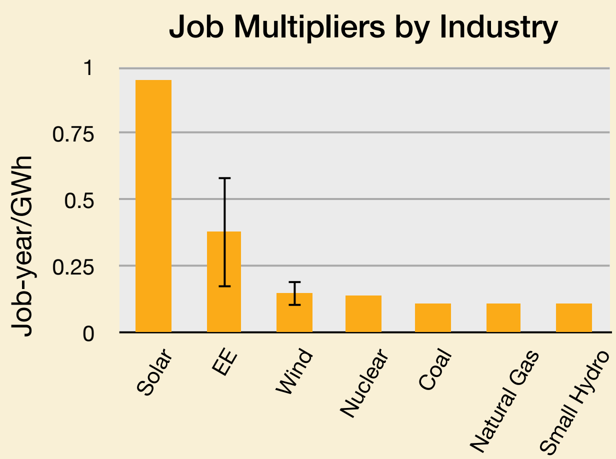
Very few studies reviewed quantify employment and tax revenue value, although a number of them acknowledge the value. *CPR (NJ/PN) 2012* calculated job impact based on enhanced tax revenues associated with the net job creating for solar vs conventional power resources. The 2011 study included increased tax revenue, decreased unemployment, and increased confidence for business development economic growth benefits, but only quantified the tax revenue benefit.

IMPLICATIONS AND INSIGHTS

- There is significant variability in the range of job multipliers.
- Many of the jobs created from PV, particularly those associated with installation, are local, so there can be value to society and local communities from growth in quantity and quality of jobs available. The locations where jobs are created are likely not the same as where jobs are lost. While there could be a net benefit to society, some regions could bear a net cost from the transition in the job market.
- While employment and tax revenues have not generally been quantified in studies reviewed, E3 2011 recommends an input-output modeling approach as an adequate representation of this value.

ECONOMIC DEVELOPMENT BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES





Sources: Wei, 2010

RESOURCES:

Wei, M., Patadia, S., and Kammen, D., Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Energy Industry Generate in the US? Energy Policy 38, 2010. pp. 919-931.

Brookings Institute, Sizing the Clean Economy: A National and Regional Green Jobs Assessment, 2011.

STUDY OVERVIEWS

04

Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

RW BECK FOR ARIZONA PUBLIC SERVICE, 2009

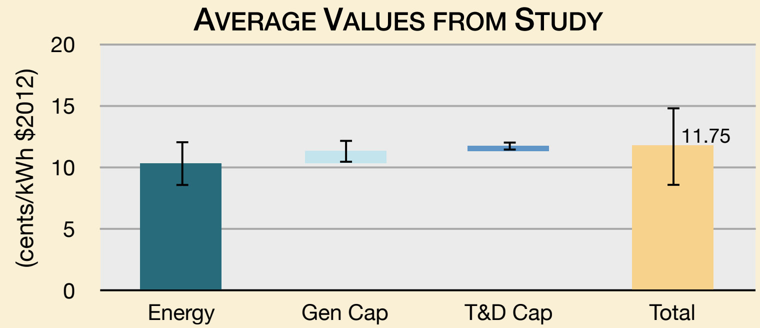
DISTRIBUTED RENEWABLE ENERGY OPERATING IMPACTS & VALUATION STUDY

System Characteristics	
STUDY OBJECTIVE	To determine the potential value of DPV for Arizona Public Service, and to understand the likely operating impacts.
GEOGRAPHIC FOCUS	Arizona Public Service territory
SYSTEM CONTEXT	Vertically integrated IOU, 15% RPS by 2025 with 30% distributed resource carveout
LEVEL OF SOLAR ANALYZED	0.2-16% by 2025 (by energy)
STAKEHOLDER PERSPECTIVE	Utility
GRANULARITY OF ANALYSIS	Feeder level, hourly, measures incremental value in 2010, 2015, and 2025
TOOLS USED	• ABB's Feeder-All • EPRI's Distribution System Simulator • PROMOD

Highlights

- The study approach combined system modeling, empirical testing, and information review, and represents one of the more technically rigorous approaches of reviewed studies.
- A key methodological assumption in the study is that generation, transmission, and distribution capacity value can only be given to DPV when it actually defers or avoids a planned investment. The implications are that a certain minimum amount of DPV must be installed in a certain time period (and in a certain location for distribution capacity) to create value.
- The study determines that total value decreases over time, primarily driven by decreasing capacity value. Increasing levels of DPV effectively pushes the system peak to later hours.
- The study acknowledged but did not quantify a number of other values including job creation, a more sustainable environment, carbon reduction, and increased worker productivity.

OVERVIEW OF VALUE CATEGORIES



**this chart represents the present value of 2025 incremental value, not a levelized cost*

Energy = Energy provides the largest source of value to the APS system. Value is calculated based on a PROMOD hourly commitment and dispatch simulation. DPV reduces fuel, purchased power requirements, line losses, and fixed O&M. The natural gas price forecast is based on NYMEX forward prices with adjustment for delivery to APS's system.

Generation capacity = There is little, but some, generation capacity value. Generation capacity value does not differ based on the geographic location of solar, but generation capacity investments are "lumpy", so a significant amount of solar is needed to displace it.

Capacity value includes benefits from reduced losses. Capacity value is determined by comparing DPV's dependable capacity (determined as the ELCC) to APS's generation investment plan.

T&D capacity = There is very little distribution capacity value, and what value exists comes from targeting specific feeders. Solar generation peaks earlier in the day than the system's peak load, DPV only has value if it is on a feeder that is facing an overloaded condition, and DPV's dependable capacity diminishes as solar penetration increases. Distribution value includes capacity, extension of service life, reduction in equipment sizing, and system performance issues.

There is little, but some, transmission capacity value since value does not differ based on the geographic location of solar, but transmission investments are "lumpy", so a significant amount of solar is needed to displaced it. Transmission value includes capacity and potential detrimental impacts to transient stability and spinning resources (i.e., ancillary services).

T&D capacity value includes benefits from reduced losses, modeled with a combination of hourly system-wide and feeder-specific modeling. T&D capacity value is determined by comparing DPV's dependable capacity to APS's T&D investment plan. For T&D, as compared to generation, dependable capacity is determined as the level of solar output that will occur with 90% confidence during the daily five hours of peak during summer months.

SAIC for Arizona Public Service, 2013
2013 Updated Solar PV Value Report

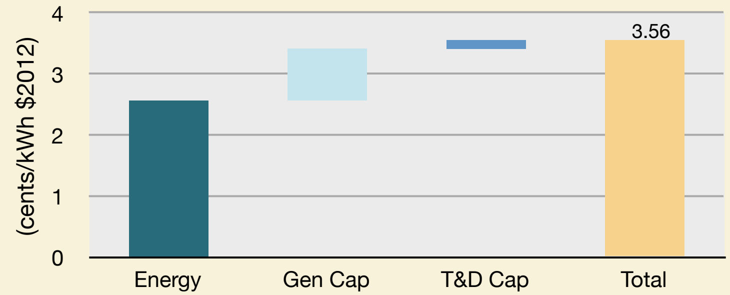
Study Characteristics	
STUDY OBJECTIVE	To update the valuation of future DPV systems in the Arizona Public Service (APS) territory installed after 2012.
GEOGRAPHIC FOCUS	Arizona Public Service territory
SYSTEM CONTEXT	Vertically integrated IOU, 15% RPS by 2025 with 30% distributed resource carve out, peak extends past sunset
LEVEL OF SOLAR ANALYZED	4.5-16% by 2025 (by energy)
STAKEHOLDER PERSPECTIVE	Ratepayers
GRANULARITY OF ANALYSIS	Feeder level, hourly, measures incremental value in 2015, 2020, and 2025
TOOLS USED	• NREL's SAM 2.0 • EPRI's DSS Distribution Feeder Model • PROMOD

Highlights

- DPV provides less value than in APS's 2009 study, due to changing power market and system conditions. Energy generation and wholesale purchase costs have decreased due to lower natural gas prices. Expected CO2 costs are significantly lower due to decreased likelihood of Federal legislation. Load forecasts are lower, meaning reduced generation, distribution and transmission capacity requirements.
- The study notes the potential for increased value (primarily in T&D capacity) if DPV can be geographically targeted in sufficient quantities. However, it notes that actual deployment since the 2009 study does not show significant clustering or targeting.
- Like the 2009 study, capacity value is assumed to be based on DPV's ability to defer planned investments, rather than assuming every installed unit of DPV defers capacity.

OVERVIEW OF VALUE CATEGORIES

Average Values from Study



**this chart represents the present value of 2025 incremental value, not a levelized cost*

Energy = Energy provides the largest source of value to the APS system. Value is calculated based on a PROMOD hourly commitment and dispatch simulation. DPV reduces fuel, purchased power requirements, line losses, and fixed O&M. The natural gas price forecast is based on NYMEX forward prices with adjustment for delivery to APS's system. Energy losses are included as part of energy value, and unlike the 2009 report, are based on a recorded average energy loss.

Generation capacity = Generation capacity value is highly dependent on DPV's dependable capacity during peak. Generation capacity value is based on PROMOD simulations, and results in the deferral of combustion turbines. Benefits from avoided energy losses are included as part of capacity value, and unlike the 2009 report, are based on a recorded peak demand loss. Like the 2009 study, generation capacity value is based on an ELCC calculation.

T&D capacity = The study concludes that there are an insufficient number of feeders that can defer capacity upgrades based on non-targeted solar PV installations to determine measurable capacity savings. Distribution capacity savings can only be realized if distributed solar systems are installed at adequate penetration levels and located on specific feeders to relieve congestion or delay specific projects, but solar adoption has been geographically dispersed. Distribution value includes reduced losses, capacity, extended service life, and reduced equipment sizing.

Transmission capacity value is highly dependent on DPV's dependable capacity during peak. No transmission projects can be deferred more than one year, and none past the target years. As with the 2009 study, DPV dependable capacity for the purposes of T&D benefits is calculated based on a 90% confidence of generation during peak summer hours. Benefits from avoided energy losses are included.

CROSSBORDER ENERGY, 2013

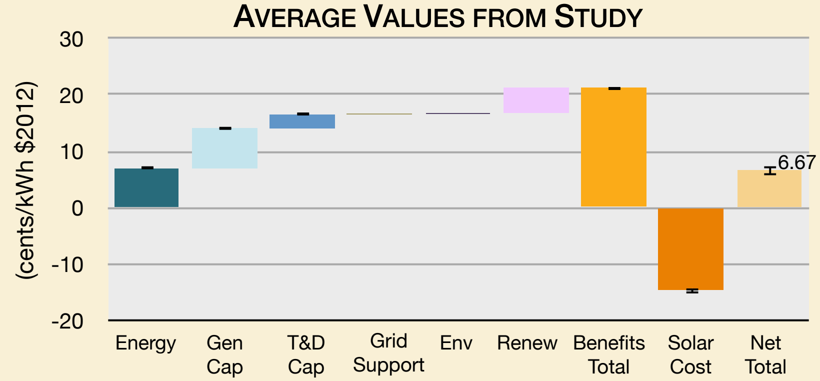
THE BENEFITS AND COSTS OF SOLAR DISTRIBUTED GENERATION FOR ARIZONA PUBLIC SERVICE

System Characteristics	
STUDY OBJECTIVE	To determine how demand-side solar will impact APS's ratepayers; a response to the APS 2013 study.
GEOGRAPHIC FOCUS	Arizona Public Service territory
SYSTEM CONTEXT	Vertically integrated IOU, 15% RPS by 2025
LEVEL OF SOLAR ANALYZED	DPV likely to be installed between 2013-2015; estimated here to be approximately 1.5%
STAKEHOLDER PERSPECTIVE	Ratepayers
GRANULARITY OF ANALYSIS	Derived from APS 2013
TOOLS USED	• Secondary analysis based on SAIC and APS detailed modeling

Highlights

- The benefits of DPV on the APS system exceed the cost by more than 50%. Key methodological differences between this study and the APS 2009 and 2013 studies include:
  - Determining value levelized over 20 years, as compared to incremental value in test years.
  - Crediting capacity value to every unit of solar DG installed, rather than requiring solar DG to be installed in "lumpy" increments.
  - Using ELCC to determine dependable capacity for generation, transmission, and distribution capacity values, as compared to using ELCC for generation capacity and a 90% confidence during peak summer hours for T&D capacity.
  - Focusing on solar installed over next few years years, rather than examining whether there is diminishing value with increasing penetration.
- The study notes that DPV must be considered in the context of efficiency and demand response—together they defer generation, transmission, and distribution capacity until 2017.

OVERVIEW OF VALUE CATEGORIES



Energy = Avoided energy costs are the most significant source of value. APS's long-term marginal resource is assumed to be a combustion turbine in peak months and a combined cycle in off-peak months, and avoided energy is based on these resources. The natural gas price forecast is based on NYMEX forward market gas prices, and the study determines that it adequately captures the fuel price hedge benefit. Key assumptions: $15/ton carbon adder, 12.1% line losses included in the energy value.

Generation capacity = Generation capacity value is calculated as DPV dependable capacity (based on DPV's near-term ELCC from APS's 2012 IRP) times the fixed costs of a gas combustion turbine. Every installed unit of DPV receives that capacity value, based on the assumption that, when coupled with efficiency and demand response, capacity would have otherwise been needed before APS's planned investment.

T&D capacity = T&D capacity value is calculated as DPV dependable capacity (ELCC) times APS's reported costs of T&D investments. Like generation capacity, every installed unit is credited with T&D capacity, with the assumption that 50% of distribution feeders can see deferral benefit. The study notes that APS could take a proactive approach to targeting DPV deployment, thereby increasing distribution value.

Grid Support (Ancillary services) = DPV in effect reduces load and therefore reduces the need for ancillary services that would otherwise be required, including spinning, non-spinning, and capacity reserves.

Environment = DPV effectively reduces load and therefore reduces environmental impacts that would otherwise be incurred. Lower load means reduced criteria air pollutant emissions and lower water use (carbon is included as an adder to energy value).

Renewable Value = DPV helps APS meet its Renewable Energy Standard, thereby lowering APS's compliance costs.

Solar Cost = Since the study takes a utility perspective, costs included are lost retail rate revenues, incentive payments, and integration costs.

E3 FOR CALIFORNIA PUBLIC UTILITIES COMMISSION, 2011
CALIFORNIA SOLAR INITIATIVE COST-EFFECTIVENESS EVALUATION

System Characteristics	
STUDY OBJECTIVE	"To perform a cost-effectiveness evaluation of the California Solar Initiative (CSI) in accordance with the CSI Program Evaluation Plan."
GEOGRAPHIC FOCUS	California
SYSTEM CONTEXT	Study: CSI program, retail net metering CA: 33% RPS, ISO market
LEVEL OF SOLAR ANALYZED	1,940 MW program goal (<1% of 2016 peak load)
STAKEHOLDER PERSPECTIVE	Participants (DPV customers), Ratepayers, Program Administrator, Total Resource, Society
GRANULARITY OF ANALYSIS	Hourly
TOOLS/APPROACH USED	• E3 avoided cost model (2011)

Highlights

- The study concludes that DPV is not expected to be cost-effective from a total resource or rate impact perspective during the study period, but that participant economics will not hinder CSI adoption goals. Program incentives support participant economics in the short-run, but DPV is expected to be cost-effective for many residential customers without program incentives by 2017. The study suggests that the value of non-economic benefits of DPV should be explored to determine if and how they provide value to California.

- The study focuses seven benefits including energy, line losses, generation capacity, T&D capacity, emissions, ancillary services, and avoided RPS purchases. It focuses on costs including net energy metering bill credits, rebates/incentives, utility interconnection, costs of the DG system, net metering costs, and program administration.

- The study assesses hourly avoided costs in each of California's 16 climate zones to reflect varying costs in those zones, and calculates benefits and costs as 20-year levelized values. It uses E3's avoided cost model.

OVERVIEW OF VALUE CATEGORIES

This study assesses overall cost-effectiveness based on five cost tests (participant cost test, ratepayer impact measure, program administrator cost, total resource cost, and societal cost) as defined in the California Standard Practices Manual, and presents total rather than itemized results. Therefore, individual results are not shown here in a chart.

Energy = Hourly wholesale value of energy measured at the point of wholesale energy transaction. Natural gas price is based on NYMEX forward market and then on a long-run forecast of natural gas prices.

Losses = Losses between the delivery location and the point of wholesale energy transaction. Losses scale with energy value, and reflect changing losses at peak periods.

Generation capacity = Value of avoiding new generation capacity (assumed to be a gas combustion turbine) to meet system peak loads, including additional capacity avoided due to decrease energy losses. DPV receives the full value of avoided capacity after the resource balance year. Value is less in the short-run (before the resource balance year) because of CAISO's substantial planning reserve margin.

T&D capacity = Value of deferring T&D capacity to meet peak loads.

Grid support services (ancillary services) = Value based on historical ancillary services market prices, scaled with the price of natural gas. Individual ancillary services included are regulation up, regulation down, spinning reserves, and non-spinning reserves, and value is based on how a load reduction affects the procurement of each AS.

Avoided RPS = Value is the incremental avoided cost of purchasing renewable resources to meet California's RPS.

Environmental = Value of CO_2 reduction, with $/ton price based on a meta-analysis of forecasts. Unpriced externalities (primarily health effects) were valued at $0.01-0.03/kWh based on secondary sources.

Social = The study acknowledges that customers who install DPV may also install more energy efficiency, but does not attempt to quantify that value. The study also acknowledges potential benefits associated with employment and tax revenues and suggests that an input-output model would be an appropriate approach, although these benefits are not quantified in this study.

ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3), 2012

TECHNICAL POTENTIAL FOR LOCAL DISTRIBUTED PHOTOVOLTAICS IN CALIFORNIA

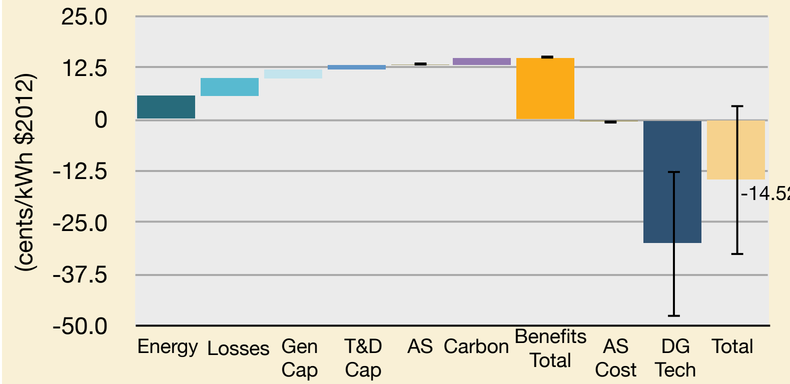
STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To estimate the technical potential of local DPV in California, and the associated costs and benefits.
GEOGRAPHIC FOCUS	California
SYSTEM CONTEXT	California's 3 investor-owned utilities (IOU): PG&E, SDG&E, SCE
SOLAR PENETRATION LEVEL ANALYZED	15% of system peak load
STAKEHOLDER PERSPECTIVES	Total resource cost (TRC)
GRANULARITY OF ANALYSIS	1,800 substations
TOOLS USED	E3 Avoided Cost Calculator

Highlights

- Local DPV is defined as PV sized such that its output will be consumed by load on the feeder or substation where it is interconnected. Specifically, the generation cannot backflow from the distribution system onto the transmission system.
- The process for identifying sites included using GIS data to identify sites surrounding each of approximately 1,800 substations in PG&E, SDG&E and SCE. The study compared hourly load that the individual substation level to potential PV generation at the same location.
- Cost of local distributed PV increases significantly with Investment Tax Credit (ITC) expiration in 2017.
- When PV is procured on a least net cost basis, opportunities may exist to locate in areas with high avoided costs. In 2012, a least net cost procurement approach results in net costs that are approximately $65 million lower assuming avoided transmission and distribution costs can be realized. These benefits carry through to 2016 for the most part, but disappear by 2020, when all potential has been realized regardless of cost.

OVERVIEW OF VALUE CATEGORIES

AVERAGE VALUES FROM STUDY



Energy savings (Generation Energy) = Estimate of hourly wholesale value of energy adjusted for losses between the point of wholesale transaction and delivery. Annual forecast based on market forwards that transition to annual average market price needed to cover the fixed and operating costs of a new CCGT, less net revenue from day-ahead energy, ancillary service, and capacity markets. Hourly forecast derived based on historical hourly day-ahead market price shapes are from CAISO's MRTU system.

Losses (Line Losses) = The loss in energy from transmission and distribution across distance.

Generation capacity = In the long-run (after the resource balance year), generation capacity value is based on the fixed cost of a new CT less expected revenues from real-time energy and ancillary services markets. Prior to resource balance, value is based on a resource adequacy value.

T&D capacity = Value is based on the "present worth" approach to calculate deferment value, incorporating investment plans as reported by utilities.

Grid support services = Value based on the value of avoided reserves, scaling with energy.

Environmental benefits = Value of CO_2 emissions, based on an estimate of the marginal resource and a meta-analysis of forecasted carbon prices.

*E3's components of electricity avoided costs include generation energy, line losses, system capacity, ancillary services, T&D capacity, environment.

CROSSBORDER ENERGY FOR VOTE SOLAR INITIATIVE, 2013
EVALUATING THE BENEFITS AND COSTS OF NET ENERGY METERING IN CALIFORNIA

System Characteristics	
STUDY OBJECTIVE	"To explore recent claims from California's investor-owner utilities that the state's NEM policy causes substantial cost shifts between energy customers with Solar PV systems and non-solar customers, particularly in residential market."
GEOGRAPHIC FOCUS	California
SYSTEM CONTEXT	33% RPS, retail net metering, increasing solar penetration, ISO market
LEVEL OF SOLAR ANALYZED	Up to 5% of peak (by capacity)
STAKEHOLDER PERSPECTIVE	Other customers (ratepayers)
GRANULARITY OF ANALYSIS	Hourly, by climate zone
TOOLS USED	• E3 avoided cost model (2011), PVWatts

Highlights

- The study concludes that "on average over the residential markets of the state's three big IOUs, NEM does not impose costs on non-participating ratepayers, and instead creates a small net benefit." This conclusion is driven by "recent significant changes that the CPUC has adopted in IOUs' residential rate designs" plus "recognition that [DPV]...avoid other purchases or renewable power, resulting in a significant improvement in the economics of NEM compared to the CPUC's 2009 E3 NEM Study."

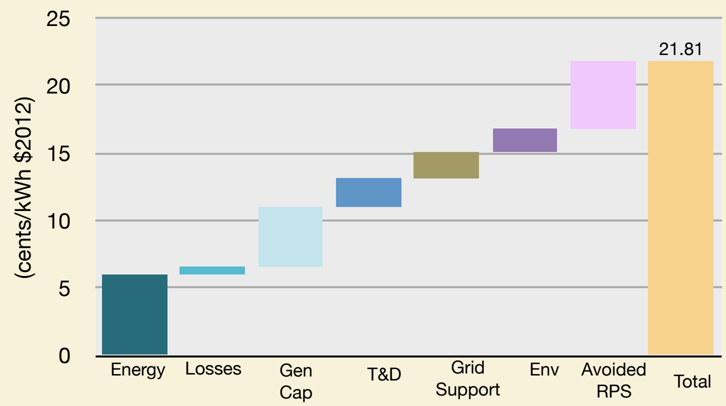
- The study focused on seven benefits: avoided energy, avoided generation capacity, reduced cost for ancillary services, lower line losses, reduced T&D investments, lower costs for the utility's purchase of other renewable generation, and avoided emissions. The study's analysis reflects costs to other customers (ratepayers) from "bill credits that the utility provides to solar customers as compensation for NEM exports, plus any incremental utility costs to meter and bill NEM customers." These costs are not quantified and levelized individually in the report, so they are not reflected in the chart to the right.

- The study bases its DPV value assessment on E3's avoided cost model and approach. It updates key assumptions including natural gas price forecast, greenhouse gas allowance prices, and ancillary services revenues, and excludes the resource balance year approach (the year in which avoided costs change from short-run to long-run). The study views the resource balance year as inconsistent with the modular, short lead-time nature of DPV.

- The study only considered the value of the exports to the grid under the utility's net metering program.

OVERVIEW OF VALUE CATEGORIES

AVERAGE VALUES FROM STUDY



Energy = Wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery. Crossborder adjusted natural gas price forecast and greenhouse gas price forecast.

Losses = The loss in energy from transmission and distribution across distance.

Grid support services (ancillary services) = The marginal cost of providing system operations and reserves for electricity grid reliability. Crossborder updated assumed ancillary services revenues.

Environment = The cost of carbon dioxide emissions associated with the marginal generating resource.

Generation capacity = The cost of building new generation capacity to meet system peak loads. Crossborder does not use E3's "resource balance year" approach, which means that generation capacity value is based on long-run avoided capacity costs.

T&D capacity = The costs of expanding transmission and distribution capacity to meet peak loads.

Avoided RPS = The avoided net cost of procuring renewable resources to meet an RPS Portfolio that is a percentage of total retail sales due to a reduction in retail loads.

VOTE SOLAR INITIATIVE, 2005

QUANTIFYING THE BENEFITS OF SOLAR POWER FOR CALIFORNIA

eLab
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

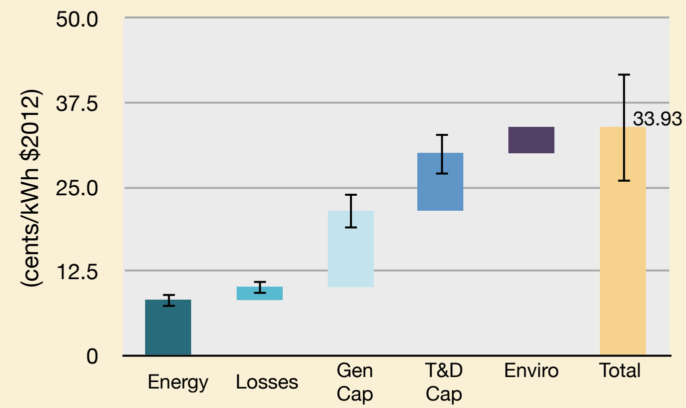
STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To provide a quantitative analysis of key benefits of solar energy for California.
GEOGRAPHIC FOCUS	California
SYSTEM CONTEXT	California's 3 investor-owned utilities (IOU): PG&E, SDG&E, SCE
SOLAR PENETRATION LEVEL ANALYZED	Unspecified
STAKEHOLDER PERSPECTIVES	Utility, ratepayer, participant, society
GRANULARITY OF ANALYSIS	Average ELCC assumed to be 50% from range of 36%-70% derived from NREL study[1]
TOOLS USED	Spreadsheet analysis

Highlights

- The value of on-peak solar energy in 2005 ranged from $0.23 - 0.35 /kWh.
- The analysis looks at avoided costs under two alternative scenarios for the year 2005. The two scenarios vary the cost of developing new power plants and the price of natural gas.
  - Scenario 1 assumed new peaking generation will be built by the electric utility at a cost of capital of 9.5% with cost recovery over a 20 year period; the price of natural gas is based on the 2005 summer market price (average gas price)
  - Scenario 2 assumed new peaking generation will be built by a merchant power plant developer at a cost of capital of 15% with cost recovery over a 10 year period; the price of natural gas is based on the average gas price in California for the period of May 2000 through June 2001 (high gas price – 24% higher)
- While numerous unquantifiable benefits were noted, five benefits were quantified:
  - 1. deferral of investments in new peaking power capacity
  - 2. avoided purchase of natural gas used to produce electricity
  - 3. avoided emissions of CO2 and NOx that impact global climate and local air quality
  - 4. reduction in transmission and distribution system power losses
  - 5. deferral of transmission and distribution investments that would be needed to meet growing loads.
- The study assumed that, "in California, natural gas is the fuel used by power plants on the margin both for peak demand periods and non-peak periods. Therefore it is reasonable to assume the solar electric facilities will displace the burning of natural gas in all hours that they produce electricity."

OVERVIEW OF VALUE CATEGORIES

AVERAGE VALUES FROM STUDY



Energy (Avoided Fuel and Variable O&M) = Natural gas fuel price multiplied by assumed heat rate of peaking power plant (9360 MMBTU/kWh). Assumed value of consumables such as water and ammonia to be approximately 0.5 cents/kWh. For non-peak, average heat rates of existing fleet of natural gas plants were used for each electric utility's service area. Those heat rates are as follows: PG&E: 8740 MMBTU/kWh, SCE - 9690 MMBTU/kWh, SDG&E – 9720 MMBTU/kWh.

Losses (Line Losses) = Solar assumed to be delivered at secondary voltage. The summer peak and the summer shoulder loss factors are used to calculate the additional benefit derived from solar power systems because of their location at load.

Generation capacity = Cost of installing a simple cycle gas turbine peaking plant multiplied by DPV's ELCC and a capital recovery factor, converted into costs per kilowatt hour by expected hours of on-peak operation.

T&D capacity = One study area was selected for each utility to calculate the value of solar electricity in avoiding T&D upgrades. to simplify the analysis the need for T&D upgrades was assumed to be driven by growth in demand during 5% of the hours in a year. The 50% ELCC was used used in calculating the value of avoided T&D upgrades.

Environmental benefits = Assumed to be the avoided air emissions, carbon dioxide and NOx, created from marginal generator (natural gas). CO2 = $100/ton; NOx = $.014/kWh

1 "Solar Resource-Utility Load-Matching Assessment," Richard Perez, National Renewable Energy Laboratory, 1994

RICHARD DUKE, ENERGY POLICY, 2005

ACCELERATING RESIDENTIAL PV EXPANSION: DEMAND ANALYSIS FOR COMPETITIVE ELECTRICITY MARKETS

Study Characteristics	
STUDY OBJECTIVE	To quantify the potential market for grid-connected, residential PV electricity integrated into new houses built in the US.
GEOGRAPHIC FOCUS	California and Illinois
SYSTEM CONTEXT	California: 33% RPS, mostly gas generation; Illinois: mostly coal generation
LEVEL OF SOLAR ANALYZED	not stated; assumed low
STAKEHOLDER PERSPECTIVE	System
GRANULARITY OF ANALYSIS	High level, largely based on secondary analysis
TOOLS USED	• n/a

Highlights

- Total value varies significantly between the two regions studied largely driven by what the off-peak marginal resource is (gas vs coal). Coal has significantly higher air pollution costs, although lower fuel costs.
- The study notes that true value varies dramatically with local conditions, so precise calculations at a high-level analysis level are impossible. As such, transmission and distribution impacts were acknowledged but not included.

OVERVIEW OF VALUE CATEGORIES

AVERAGE VALUES FROM STUDY

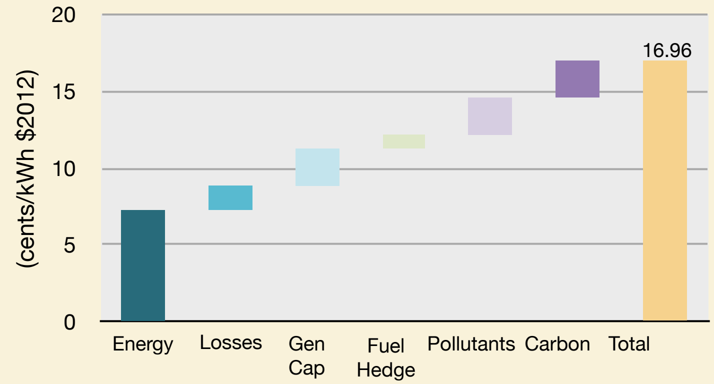


Chart data only reflects California assessment for comparison

Energy = Energy value is based on the marginal resource on-peak (gas combustion turbine) and off-peak (inefficient gas in California, and coal in Illinois). Fuel prices are based on Energy Information Administration projections, and levelized.

Losses = Energy losses are assumed to be 7-8% off-peak, and up to twice that on-peak. Losses are only included as energy losses.

Generation capacity = Generation capacity value is based on the assumption that the marginal resource is always a gas combustion turbine. Dependable capacity is based on an ELCC estimate from secondary sources.

Financial (Fuel price hedge) = Hedge value is estimated based on the market value to utilities of a fixed natural gas price for up to 10 years based on market swap data. The hedge is assumed to be additive since EIA gas prices were used rather than NYMEX futures market.

Environment (criteria air pollutants, carbon) = Criteria air pollutant reduction value is based on avoided costs of health impacts, estimated by secondary sources. Carbon value is the price of carbon (estimated based on European market projections) times the amount of carbon displaced.

LAWRENCE BERKELEY NATIONAL LAB, 2012

CHANGES IN THE ECONOMIC VALUE OF VARIABLE GENERATION AT HIGH PENETRATION LEVELS: A PILOT CASE STUDY OF CALIFORNIA

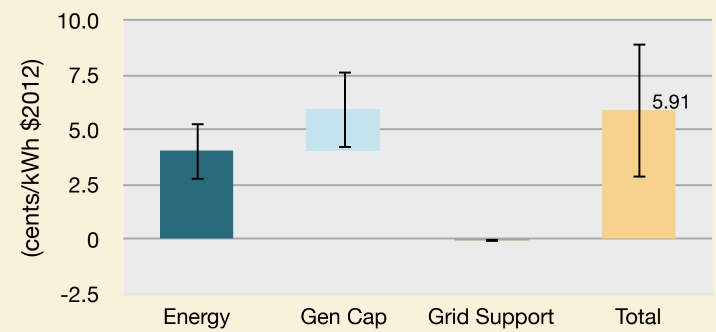
Study Characteristics	
STUDY OBJECTIVE	To quantify the change in value for a subset of economic benefits (energy, capacity, ancillary services, DA forecasting error) that results from using renewable generation technologies (wind, PV, CSP, & Thermal Energy Storage) at different penetration levels.
GEOGRAPHIC FOCUS	Loosely based on California
SYSTEM CONTEXT	33% RPS, ISO market
LEVEL OF SOLAR ANALYZED	Up to 40% (by energy)
STAKEHOLDER PERSPECTIVE	System
GRANULARITY OF ANALYSIS	Long-run investment decisions and short-term dispatch and operations
TOOLS USED	• Customized model

Highlights

- The marginal economic value of solar exceeds the value of flat block power at low penetration levels, largely attributable to generation capacity value and solar coincidence with peak.
- The marginal value of DPV drops considerably as the penetration of solar increases, initially, driven by a decrease in capacity value with increasing solar generation. At the highest renewable penetrations considered, there is also a decrease in energy value as PV displaces lower cost resources.
- The study notes that it is critical to use an analysis framework that addresses long-term investment decisions as well as short-term dispatch and operational constraints.
- Several costs and impacts are not considered in the study, including environmental impacts, transmission and distribution costs or benefits, effects related to the lumpiness and irreversibility of investment decisions, uncertainty in future fuel and investment capital costs, and DPV's capital cost.

OVERVIEW OF VALUE CATEGORIES

AVERAGE VALUES FROM STUDY



Energy = Energy value decreases at high penetrations because the marginal resource that DPV displaces changes as the system moves down the dispatch stack to a lower cost generator. Energy value is based on the short-run profit earned in non-scarcity hours (those hours where market prices are under $500/MWh), and generally displaces energy from a gas combined cycle. Fuel costs are based on Energy Information Administration projections.

Generation capacity = Generation capacity value is based on the portion of short-run profit earned during hours with scarcity prices (those hours where market price equals or exceeds $500/MWh). Dependable DPV capacity is based on an implied capacity credit as a result of the model's investment decisions, rather than a detailed reliability or ELCC analysis.

Grid Support (Ancillary Services) = Ancillary services value is the net earnings from selling ancillary services in the market as well as paying for increased ancillary services due to increased short-term variability and uncertainty.

Clean Power Research, 2012

The Value of Distributed Solar Electric Generation To New Jersey and Pennsylvania

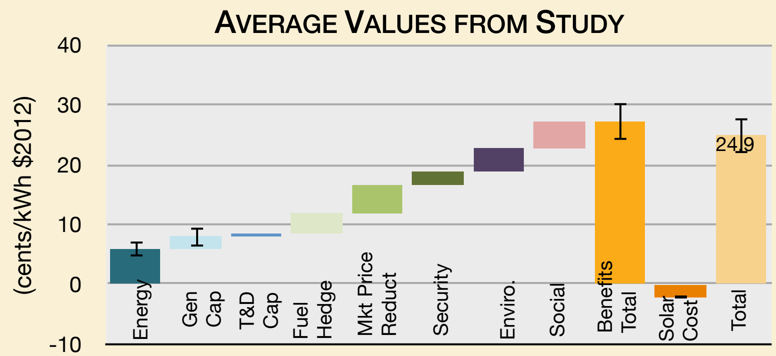
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

Study Characteristics	
Study Objective	To quantify the cost and value components provided to utilities, ratepayers, and taxpayers by grid-connected, distributed PV in Pennsylvania and New Jersey.
Geographic Focus	7 cities across PA and NJ
System Context	PJM ISO
Solar Penetration Level Analyzed	15% of system peak load, totaling 7 GW across the 7 utility hubs
Stakeholder Perspectives	Utility, ratepayers, taxpayer
Granularity of Analysis	Locational Marginal Price node
Tools Used	Clean Power Research's Distributed PV Value Calculator; Solar Anywhere, 2012

Highlights

- The study evaluated 10 benefits and 1 cost. Evaluated benefits included: Fuel cost savings, O&M cost savings, security enhancement, long term societal benefit, fuel price hedge, generation capacity, T&D capacity, market price reduction, environmental benefit, economic development benefit. The cost evaluated was the solar penetration cost.
- The analysis represents the value of PV for a "fleet" of PV systems, evaluated in 4 orientations, each at 7 locations (Pittsburgh, PA; Harrisburg, PA; Scranton, PA; Philadelphia, PA; Jamesburg, NJ; Newark, NJ; and Atlantic City, NJ), spanning 6 utility service territories, each differing by: cost of capital, hourly loads, T&D loss factors, distribution expansion costs, and growth rate.
- The total value ranged from $256 to $318/MWh. Of this, the highest value components were the Market Price Reduction (avg $55/MWh) and the Economic Development Value (avg $44/MWh).
- The moderate generation capacity value is driven by a moderate match between DPV output and utility system load. The effective capacity ranges from 28% to 45% of rated output (in line with the assigned PJM value of 38% for solar resources).
- Loss savings were not treated as a stand-alone benefit under the convention used in this methodology. Rather, the effect of loss savings is included separately for each value component.

OVERVIEW OF VALUE CATEGORIES



Energy savings (Fuel cost savings + O&M Cost Savings) = PV output plus loss savings times marginal energy cost, summed all hrs of the year, discounted over PV life (30 years). Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (assumed to be a combined cycle gas turbine). Assumed natural gas price forecast: NYMEX futures years 0-12; NYMEX futures price for year 12 x 2.33% escalation factor. Escalation rate assumed to be rate of wellhead price escalation from 1981-2011.

Generation capacity = Capital cost of displace generation times PV's effective load carrying capability (ELCC), taking into account loss savings.

T&D capacity = Expected long-term T&D system capacity upgrade cost, divided by load growth, times financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load. In this study, T&D values were based on utility-wide average loads, which may obscure higher value areas.

Fuel price hedge value = Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. The value is directly related to the utility's cost of capital.

Market Price Reduction = Value to customers of the reduced cost of wholesale energy as a result of PV installation decreasing the demand for wholesale energy. Quantified through an analysis of the supply curve and reduction in demand, and the accompanying new market clearing price.

Security (Security Enhancement Value) = Annual cost of power outages in the U.S. times the percent (5%) that are high-demand stress type that can be effectively mitigated by distributed PV at a capacity penetration of 15%.

Social (Economic Development Value) = Value of tax revenues associated with net job creation for solar vs conventional power generation. PV hard and soft cost /kW times portion of each attributed to local jobs, divided by annual PV system energy produced, minus CCGT cost/kW times portion attributed to local jobs divided by annual energy produced. Levelized over the 30 year lifetime of PV system, adjusted for lost utility jobs, multiplied by tax rate of a $75K salary, multiplied by indirect job multiplier.

Environmental benefits = Environmental cost of a displaced conventional generation technology times the portion of this technology in the energy generation mix, repeated and summed for each conventional generation sources displaced by PV. Environmental cost for each generation source based on costs of GHG, SOx / NOx emissions, mining degradations, ground-water contamination, toxic releases and wastes. etc...as calculated in several environmental health studies. 000060

CLEAN POWER RESEARCH & SOLAR SAN ANTONIO, 2013

THE VALUE OF DISTRIBUTED SOLAR ELECTRIC GENERATION TO SAN ANTONIO

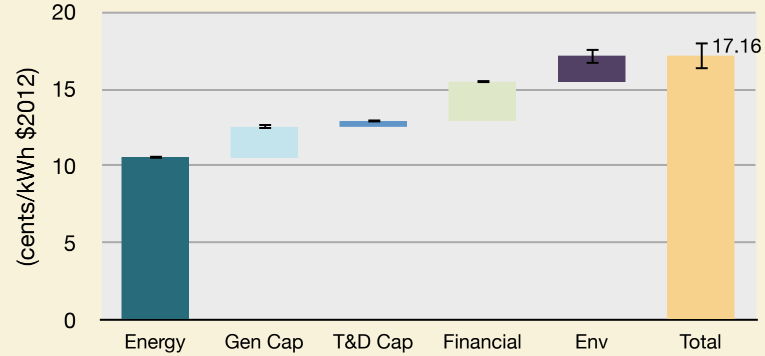
System Characteristics	
STUDY OBJECTIVE	To quantify the value provided by grid-connected, distributed PV in San Antonio from a utility perspective.
GEOGRAPHIC FOCUS	CPS Energy territory
SYSTEM CONTEXT	Municipal utility
LEVEL OF SOLAR ANALYZED	1.1-2.2% of peak load (by capacity)
STAKEHOLDER PERSPECTIVE	Utility
GRANULARITY OF ANALYSIS	Single marginal resource assumed, ELCC approach
TOOLS USED	• SolarAnywhere • PVSimulator • DGValuator

Highlights

- The study concludes that DPV provides significant value to CPS Energy, primarily driven by energy, generation capacity deferment, and fuel price hedge value. The study is based solely on publicly-available data; it notes that results would be more representative with actual financial and operating data. Value is a levelized over 30 years.
- The study notes that value likely decreases with increasing penetration, although higher penetration levels needed to estimate this decrease were not analyzed.
- The study acknowledged but did not quantify a number of other values including climate change mitigation, environmental mitigation, and economic development.

OVERVIEW OF VALUE CATEGORIES

AVERAGE VALUES FROM STUDY



Energy = The study shows high energy value compared to other studies, driven by using EIA's "advanced gas turbine" with a high heat rate as the marginal resource. The natural gas price forecast is based on NYMEX forward market gas prices, then escalated at a constant rate. Energy losses are included in energy value, and are calculated on an hourly marginal basis.

Generation capacity = Generation capacity value is DPV's dependable capacity times the fixed costs of an "advanced gas turbine", assumed to be the marginal resource. Dependable capacity based on ELCC; the reported ELCC is significantly higher than other studies. Every installed unit of DPV is given generation capacity value.

T&D capacity = The study takes a two step approach: first, an economic screening to determine expansion plan costs and load growth expectations by geographic area, and second, to assess the correlation of DPV and load in the most promising locations.

Financial (Fuel price hedge) = The study estimates hedge value as a combination of two financial instruments, risk-free zero-coupon bonds and a set of natural gas futures contracts, to represent the avoided cost of reducing fuel price volatility risk.

Environmental = The study quantified environmental value, as shown in the chart above, but did not include it in its final assessment of benefit since the study was from the utility perspective.

AUSTIN ENERGY & CLEAN POWER RESEARCH, 2006

THE VALUE OF DISTRIBUTED PHOTOVOLTAICS IN AUSTIN ENERGY AND THE CITY OF AUSTIN

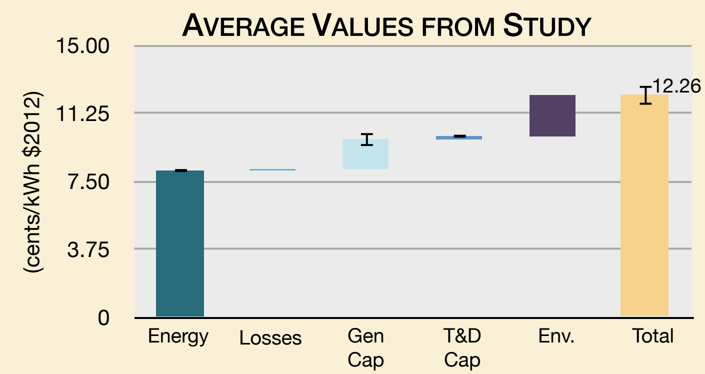
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To quantify the comprehensive value of DPV to Austin Energy (AE) in 2006 and document methodologies to assist AE in performing analysis as conditions change and apply to other technologies
GEOGRAPHIC FOCUS	Austin, TX
SYSTEM CONTEXT	Municipal utility
SOLAR PENETRATION LEVEL ANALYZED	2%* system peak load
STAKEHOLDER PERSPECTIVES	Utility, ratepayer, participant, society
GRANULARITY OF ANALYSIS	PV capacity value (ELCC) calculated system wide; Distribution expansion
TOOLS USED	CPR internal analysis; satellite solar data; PVFORM 4.0 for solar simulation; AE's load flow analysis for T&D losses

Highlights

- The study evaluated 7 benefits–energy production, line losses, generation capacity, T&D capacity, reactive power control (*grid support*), environment, natural gas price hedge (*financial*), and disaster recovery (*security*).
- The analysis assumed a 15 MW system in 7 PV system orientations, including 5 fixed and 2 single-axis.
- Avoided energy costs are the most significant source of value (about two-thirds of the total value), which is highly sensitive to the price of natural gas.
- Distribution capacity deferral value was relatively minimal. AE personnel estimated that 15% of the distribution capacity expansion plans have the potential to be deferred after the first ten years (assuming growth rates remain constant). Therefore, the study assumed that currently budgeted distribution projects were not deferrable, but the addition of PV could possibly defer distribution projects in the 11th year of the study period.
- Two studied values were excluded from the final results:
  - While reactive power benefits was estimated, the value ($0-$20/kW) was assumed not to justify the cost of the inverter that would be required to access the benefit. (The estimated cost was not included.)
  - The value of disaster recovery could be significant but more work is needed before this value can be explicitly captured.

OVERVIEW OF VALUE CATEGORIES



Energy = PV output plus loss savings times marginal energy cost. Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (typically, a combined cycle gas turbine).

Losses = Computed differently depending upon benefit category. For all categories, loss savings are calculated hourly on the margin.

Generation capacity = Cost of capacity times PV's effective load carrying capability (ELCC), taking into account loss savings.

Financial (Fuel price hedge value) = Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. Fuel price hedge value is included in the energy value.

T&D capacity = Expected long-term T&D system capacity upgrade cost, divided by load growth, times financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load.

Environmental benefits = PV output times REC price—the incremental cost of offsetting a unit of conventional generation.

*ELCC was evaluated from 0%-20%; however, the ELCC estimate for 2% penetration was used in final value.

AUSTIN ENERGY & CLEAN POWER RESEARCH, 2012
DESIGNING AUSTIN ENERGY'S SOLAR TARIFF USING A DISTRIBUTED PV CALCULATOR

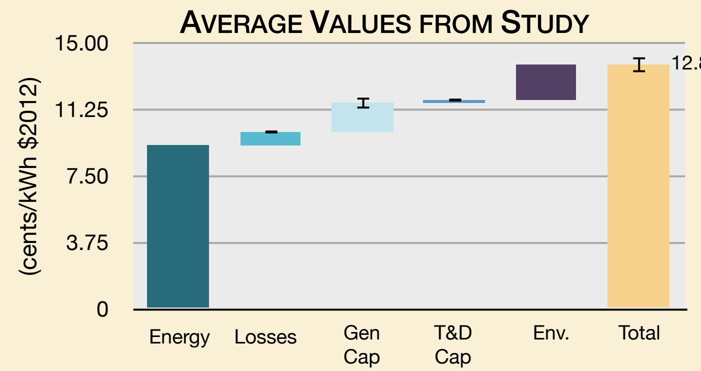
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

STUDY CHARACTERISTICS	
STUDY OBJECTIVE	To design a residential solar tariff based on the value of solar energy generated from DPV systems to Austin Energy
GEOGRAPHIC FOCUS	Austin, TX
SYSTEM CONTEXT	Municipal utility with access to ISO (ERCOT)
SOLAR PENETRATION LEVEL ANALYZED	Assumed to be 2012 levels of penetration (5 MW)[1]<0.5% penetration by energy[2]
STAKEHOLDER PERSPECTIVES	Utility
GRANULARITY OF ANALYSIS	Assumed to replicate granularity of AE/CPR 2006 study
TOOLS USED	Clean Power Research's Distributed PV Value Calculator; Solar Anywhere, 2012

Highlights

- The study focused on 6 benefits–energy, generation capacity, fuel price hedge value (included in energy savings), T&D capacity, and environmental benefits–which represent "a 'break-even' value...at which the utility is economically neutral to whether it supplies such a unit of energy or obtains it from the customer." The approach, which builds on the 2006 CPR study, is "an avoided cost calculation at heart, but improves on [an avoided cost calculation]... by calculating a unique, annually adjusted value for distributed solar energy."
- The fixed, south-facing PV system with a 30-degree tilt, the most common configuration and orientation in AE's service territory of approximately 1,500 DPV systems, was used as the reference system.
- As with the AE/CPR 2006 study, avoided energy costs are the most significant source of value, which is very sensitive to natural gas price assumptions.
- The levelized value of solar was calculated to total $12.8/kWh.
- Two separate calculation approaches were used to estimate the near term and long term value, combined to represent the "total benefits of DPV to Austin Energy" over the life time of a DPV system.
  - For the the near term (2 years) value of DPV energy, A PV output weighted nodal price was used to try to capture the relatively good correlation between PV output and electricity demand (and high price) that is not captured in the average nodal price.
  - To value the DPV energy produced during the mid and long term–through the rest of the 30-year assumed life of solar PV systems–the typical value calculator methodology was used.

OVERVIEW OF VALUE CATEGORIES



Energy = PV output plus loss savings times marginal energy cost. Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (typically, a combined cycle gas turbine).

Losses = Computed differently depending upon benefit category. For all categories, loss savings are calculated hourly on the margin.

Generation capacity = Cost of capacity times PV's effective load carrying capability (ELCC), taking into account loss savings.

Fuel price hedge value = Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. Fuel price hedge value is included in the energy value.

T&D capacity = Expected long-term T&D system capacity upgrade cost, divided by load growth, times financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load.

Environmental benefits = PV output times Renewable Energy Credit (REC) price—the incremental cost of offsetting a unit of conventional generation.

1 http://www.austinenergy.com/About%20Us/Newsroom/Reports/solarGoalsUpdate.pdf
2 http://www.austinenergy.com/About%20Us/Newsroom/Reports/2012AnnualPerformanceReportDRAFT.pdf

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NAVIGANT CONSULTING FOR NREL, 2008
PHOTOVOLTAICS VALUE ANALYSIS

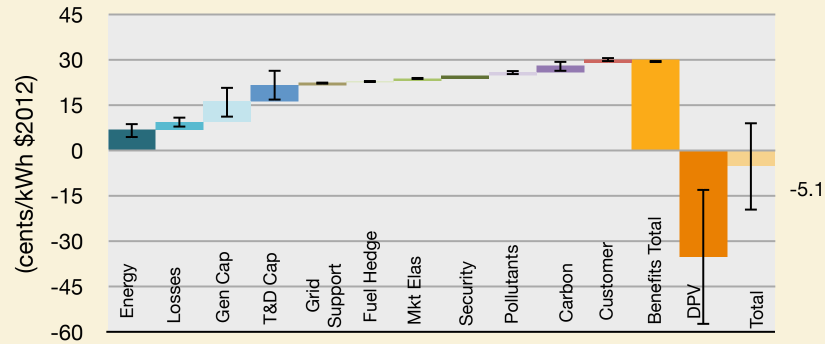
Study Characteristics	
STUDY OBJECTIVE	To summarize and describe the methodologies and range of values for the costs and values of 19 services provided or needed by DPV from existing studies.
GEOGRAPHIC FOCUS	Studies reviewed reflected varying geographies; case studies from TX, CA, MN, WI, MD, NY, MA, and WA
SYSTEM CONTEXT	n/a
LEVEL OF SOLAR ANALYZED	n/a
STAKEHOLDER PERSPECTIVE	Participating customers, utilities, ratepayers, society
GRANULARITY OF ANALYSIS	n/a
TOOLS USED	• Custom-designed Excel tool to compare results and sensitivities

Highlights

- There are 19 key values of distributed PV, but the study concludes that only 6 have significant benefits (energy, generation capacity, T&D costs, GHG emissions, criteria air pollutant emissions, and implicit value of PV).
- Deployment location and solar output profile are the most significant drivers of DPV value.
- Several values require additional R&D to establish a standardized quantification methodology.
- Value can be proactively increased.

OVERVIEW OF VALUE CATEGORIES

AVERAGE VALUES FROM STUDY



Energy = Energy value is fuel cost times the heat rate plus operating and maintenance costs for the marginal power plant, generally assumed to be natural gas.

Losses = Avoided loss value is the amount of loss associated with energy, generation capacity, T&D capacity, and environmental impact, times the cost of that loss.

Generation capacity = Generation capacity value is the capital cost of the marginal power plant times the dependable capacity (ELCC) of DPV.

T&D capacity = T&D capacity value is T&D investment plan costs times the value of money times the dependable capacity, divided by load growth, levelized.

Grid support services (Ancillary Services) = Ancillary services include VAR support, load following, operating reserves, and dispatch and scheduling. PV is unlikely to be able to provide all of these.

Financial (Fuel price hedge, Market price response) = Hedge value is the cost to guarantee a portion of electricity costs are fixed. Reduced demand for electricity decreases the price of electricity for all customers and creates a customer surplus.

Security = Customer reliability in the form of increased outage support can be realized, but only when DPV is coupled with storage.

Environment (Criteria air pollutants, Carbon) = Value is either the market value of penalties or costs, or the value of avoided health costs and shortened lifetimes. Carbon value is the emission intensity of the marginal resource times the value of emissions.

Customer = Value to customer of having green option, as indicate by their willingness to pay.

DPV cost = Costs include capital cost of equipment plus fixed operating and maintenance costs.

SOURCES

05

Lab
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STUDIES REVIEWED IN ANALYSIS

Study	Funded / Commissioned by	Prepared by
SAIC. 2013 Updated Solar PV Value Report. Arizona Public Service. May, 2013.	Arizona Public Service	SAIC (company that took over R.W. Beck)
Beach, R., McGuire, P., The Benefits and Costs of Solar Distributed Generation for Arizona Public Service. Crossborder Energy May, 2013.		Crossborder Energy
Norris, B., Jones, N. *The Value of Distributed Solar Electric Generation to San Antonio.* Clean Power Research & Solar San Antonio, March 2013.	DOE Sunshot Initiative	Clean Power Research & Solar San Antonio
Beach, R., McGuire, P., *Evaluating the Benefits and Costs of Net Energy Metering for Residential Customers in California.* Crossborder Energy, Jan. 2013.	Vote Solar Initiative	Crossborder Energy
Rabago, K., Norris, B., Hoff, T., *Designing Austin Energy's Solar Tariff Using A Distributed PV Calculator.* Clean Power Research & Austin Energy, 2012.	Austin Energy	Clean Power Research & Solar San Antonio
Perez, R., Norris, B., Hoff, T., *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania.* Clean Power Research, 2012.	The Mid-Atlantic Solar Energy Industries Association, & The Pennsylvania Solar Energy Industries Association	Clean Power Research
Mills, A., Wiser, R., *Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California*. Lawrence Berkeley National Laboratory, June 2012.	DOE office of Energy Efficiency and Renewable Energy and Office of Electricity Delivery and Energy Reliability	Lawrence Berkeley National Laboratory
Energy and Environmental Economics, Inc. Technical Potential for Local Distributed Photovoltaics in California, Preliminary Assessment. March 2012.	California Public Utilities Commission	Energy and Environmental Economics, Inc. (E3)
Energy and Environmental Economics, Inc.California Solar Initiative Cost-Effectiveness Evaluation. April 2011.	California Public Utilities Commission	Energy and Environmental Economics, Inc. (E3)
R.W. Beck, Arizona Public Service, *Distributed Renewable Energy Operating Impacts and Valuation Study.* Jan. 2009.	Arizona Public Service	R.W. Beck, Inc with Energized Solutions, LLC, Phasor Energy Company, Inc, & Summit Blue Consulting, LLC
Perez, R., Hoff, T., Energy and Capacity Valuation of Photovoltaic Power Generation in New York. Clean Power Research, March 2008.	Solar Alliance and the New York Solar Energy Industry Association	
Contreras, J.L., Frantzis, L., Blazewicz, S., Pinault, D., Sawyer, H., *Photovoltaics Value Analysis.* Navigant Consulting, Feb, 2008.	National Renewable Energy Laboratory	Navigant Consulting, Inc.
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The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania

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Thomas E. Hoff

November 2012

Prepared for:

Mid-Atlantic Solar Energy Industries Association

&

Pennsylvania Solar Energy Industries Association

Prepared by:

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Executive Summary

This report presents an analysis of value provided by grid-connected, distributed PV in Pennsylvania and New Jersey. The analysis does not provide policy recommendations except to suggest that each benefit must be understood from the perspective of the beneficiary (utility, ratepayer, or taxpayer).

The study quantified ten value components and one cost component, summarized in Table ES- 1. These components represent the benefits (and costs) that accrue to the utilities, ratepayers, and taxpayers in accepting solar onto the grid. The methodologies for quantifying these values are described further in Appendix 2.

Table ES- 1. Value component definitions.

Value Component	Basis
Fuel Cost Savings	Cost of natural gas fuel that would have to be purchased for a gas turbine (CCGT) plant operating on the margin to meet electric loads and T&D losses.
O&M Cost Savings	Operations and maintenance costs for the CCGT plant.
Security Enhancement Value	Avoided economic impacts of outages associated due to grid reliability of distributed generation.
Long Term Societal Value	Potential value (defined by all other components) if the life of PV is 40 years instead of the assumed 30 years.
Fuel Price Hedge Value	Cost to eliminate natural gas fuel price uncertainty.
Generation Capacity Value	Cost to build CCGT generation capacity.
T&D Capacity Value	Financial savings resulting from deferring T&D capacity additions.
Market Price Reduction	Wholesale market costs incurred by all ratepayers associated with a shift in demand.
Environmental Value	Future cost of mitigating environmental impacts of coal, natural gas, nuclear, and other generation.
Economic Development Value	Enhanced tax revenues associated with net job creation for solar versus conventional power generation.
(Solar Penetration Cost)	Additional cost incurred to accept variable solar generation onto the grid.

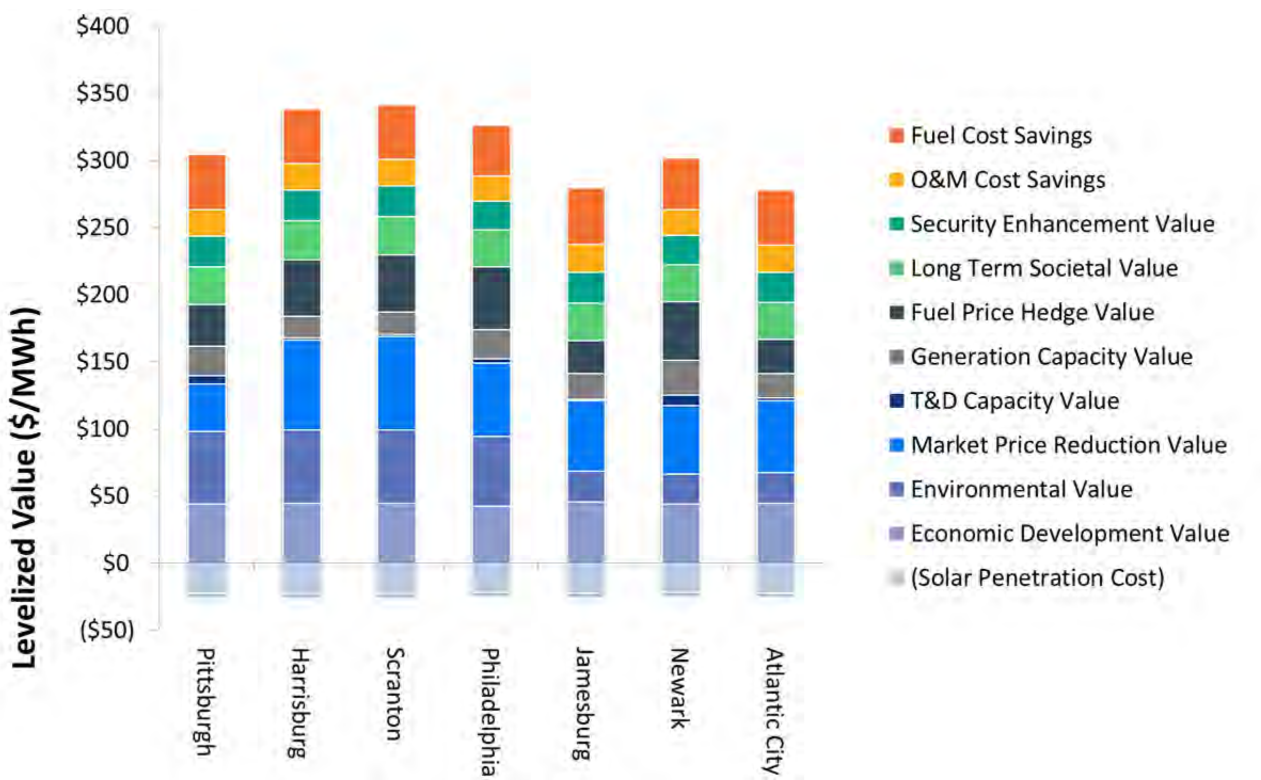
The analysis represents the value of PV for a “fleet” of PV systems (that is, a large set of systems generating into the grid). Four different fleet configurations (e.g., fixed, south-facing, 30-degree tilt angle) were evaluated at each of seven locations (Pittsburgh, PA; Harrisburg, PA; Scranton, PA;

Philadelphia, PA; Jamesburg, NJ; Newark, NJ; and Atlantic City, NJ). These locations represent a diversity of geographic and economic assumptions across six utility service territories (Duquesne Light Co., PPL Utilities Corp, PECO Utilities Corp, Jersey Central P&L, PSE&G, and Atlantic Electric).

The analysis represented a moderate assumption of penetration: PV was to provide 15% of peak electric load for each study location (higher penetration levels result in lower value per MWh). PV was modeled using SolarAnywhere®, a solar resource data set that provides time- and location-correlated PV output with loads. Load data and market pricing was taken from PJM for the six zones, and utility economic inputs were derived from FERC submittals. Additional input data was taken from the EIA and the Bureau of Labor Statistics (producer price indices).

Levelized value results for the seven locations are shown in Figure ES- 1 and Table ES- 2. Detailed results for all scenarios are included in Appendix 3.

Figure ES- 1. Levelized value ($/MWh), by location (South-30).



The following observations and conclusions may be made:

- **Total Value**. The total value ranges from $256 per MWh to $318 per MWh. Of this, the highest value components are the Market Price Reduction (averaging $55 per MWh) and the Economic Development Value (averaging $44 per MWh).
- **Market Price Reduction**. The two locations of highest total value (Harrisburg and Scranton) are noted for their high Market Price Reduction value. This may be the result of a good match between LMP and PV output. By reducing demand during the high priced hours, a cost savings is realized by all consumers. Further investigation of the methods may be warranted in light of two arguments put forth by Felder [32]: that the methodology does address induced increase in demand due to price reductions, and that it only addresses short-run effects (ignoring the impact on capacity markets).
- **Environmental Value**. The state energy mix is a differentiator of environmental value. Pennsylvania (with a large component of coal-fired generation in its mix) leads to higher environmental value in locations in that state relative to New Jersey.
- **T&D Capacity Value**. T&D capacity value is low for all scenarios, with the average value of only $3 per MWh. This may be explained by the conservative method taken for calculating the effective T&D capacity.
- **Fuel Price Hedge**. The cost of eliminating future fuel purchases—through the use of financial hedging instruments—is directly related to the utility's cost of capital. This may be seen by comparing the hedge value in Jamesburg and Atlantic City. At a utility discount rate of 5.68%, Jersey Central Power & Light (the utility serving Jamesburg) has the lowest calculated cost of capital among the six utilities included in the study. In contrast, PSE&G (the utility serving Newark) has a calculated discount rate of 8.46%, the highest among the utilities. This is reflected in the relative hedge values of $24 per MWh for Jamesburg and $44 per MWh for Newark, nearly twice the value.
- **Generation Capacity Value**. There is a moderate match between PV output and utility system load. The effective capacity ranges from 28% to 45% of rated output, and this is in line with the assigned PJM value of 38% for solar resources.

Table ES- 2. Levelized Value of Solar ($/MWh), by Location.

	Pittsburgh	Harrisburg	Scranton	Philadelphia	Jamesburg	Newark	Atlantic City
Energy							
Fuel Cost Savings	$41	$41	$41	$38	$42	$39	$41
O&M Cost Savings	$20	$20	$20	$18	$21	$19	$20
Total Energy Value	$61	$60	$60	$56	$63	$58	$61
Strategic							
Security Enhancement Value	$23	$23	$23	$22	$23	$22	$22
Long Term Societal Value	$28	$29	$29	$27	$28	$28	$28
Total Strategic Value	$51	$52	$52	$49	$51	$50	$50
Other							
Fuel Price Hedge Value	$31	$42	$42	$47	$24	$44	$25
Generation Capacity Value	$22	$16	$17	$22	$19	$26	$18
T&D Capacity Value	$6	$1	$1	$3	$1	$8	$2
Market Price Reduction Value	$35	$67	$69	$54	$52	$51	$54
Environmental Value	$54	$55	$55	$52	$23	$22	$23
Economic Development Value	$44	$45	$45	$42	$45	$44	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($22)	($23)	($22)	($22)
Total Other Value	$170	$203	$206	$199	$143	$173	$144
Total Value	**$282**	**$315**	**$318**	**$304**	**$257**	**$280**	**$256**

Contents

Introduction: The Value of PV

This report attempts to quantify the value of distributed solar electricity in Pennsylvania and New Jersey. It uses methodologies and analytical tools that have been developed over several years. The framework supposes that PV is located in the distribution system. PV that is located close to the loads provides the highest value per unit of energy to the utility because line losses are avoided, thereby increasing the value of solar relative to centrally-located resources.

The value of PV may be considered the aggregate of several components, each estimated separately, described below. The methods used to calculate value are described in more detail in the Appendices.

Fuel Cost Savings

Distributed PV generation offsets the cost of power generation. Each kWh generated by PV results in one less unit of energy that the utility needs to purchase or generate. In addition, distributed PV reduces system losses so that the cost of the wholesale generation that would have been lost must also be considered.

Under this study, the value is defined as the cost of natural gas fuel that would otherwise have to be purchased to operate a gas turbine (CCGT) plant and meet electric loads and T&D losses. The study presumes that the energy delivered by PV displaces energy at this plant.

Whether the utility receives the fuel cost savings directly by avoiding fuel purchases, or indirectly by reducing wholesale power purchases, the method of calculating the value is the same.

O&M Cost Savings

Under the same mechanism described for Fuel Cost Savings, the utility realizes a savings in O&M costs due to decreased use of the CCGT plant. The cost savings are assumed to be proportional to the energy avoided, including loss savings.

Security Enhancement Value

The delivery of distributed PV energy correlated with load results in an improvement in overall system reliability. By reducing the risk of power outages and rolling blackouts, economic losses are reduced.

Long Term Societal Value

The study period is taken as 30 years (the nominal life of PV systems), and the calculation of value components includes the benefits provided over this study period. However, it is possible that the life can be longer than 30 years, in which case the full value would not be accounted for. This "long term societal value" is the potential extended benefit of all value components over a 10 year period beyond the study period. In other words, if the assumed life were 40 years instead of 30, the increase in total value is the long term societal value.

Fuel Price Hedge Value

PV generation is insensitive to the volatility of natural gas or other fuel prices, and therefore provides a hedge against price fluctuation. This is quantified by calculating the cost of a risk mitigation investment that would provide price certainty for future fuel purchases.

Generation Capacity Value

In addition to the fuel and O&M cost savings, the total cost of power generation includes capital cost. To the extent that PV displaces the need for generation capacity, it would be valued as the capital cost of displaced generation. The key to valuing this component is to determine the effective load carrying capability (ELCC) of the PV fleet, and this is accomplished through an analysis of hourly PV output relative to overall utility load.

T&D Capacity Value

In addition to capital cost savings for generation, PV potentially provides utilities with capital cost savings on T&D infrastructure. In this case, PV is not assumed to displace capital costs but rather defer the need. This is because local loads continue to grow and eventually necessitate the T&D capital investment. Therefore, the cost savings realized by distributed PV is merely the cost of capital saved in the intervening period between PV installation and the time at which loads again reach the level of effective PV capacity.

Market Price Reduction

PV generation reduces the amount of load on the utility systems, and therefor reduces the amount of energy purchased on the wholesale market. The demand curve shifts to the left, and the market clearing price is reduced. Thus, the presence of PV not only displaces the need for energy, but also reduces the cost of wholesale energy to all consumers. This value is quantified through an analysis of the supply curve and the reduction in demand.

Environmental Value

One of the primary motives for PV and other renewable energy sources is to reduce the environmental impact of power generation. Environmental benefits covered in this analysis represent future savings for mitigating environmental damage (sulfur dioxide emissions, water contamination, soil erosion, etc.).

Economic Development Value

Distributed PV provides local jobs (e.g., installers) at higher rates than conventional generation. These jobs, in turn, translate to tax revenue benefits to all taxpayers.

Solar Penetration Cost

In addition to the value provided by PV, there are costs that must be factored in as necessary to accept variable solar generation onto the grid. Infrastructural and operational expenses will be incurred to manage the flow of non-dispatchable PV resources. These costs are included as a negative value.

Value Perspective

The value of solar accrues either to the electric utility or to society (ratepayers and taxpayers), depending upon component. For example, PV reduces the amount of wholesale energy needed to serve load, resulting in savings to the utility. On the other hand, environmental mitigation costs accrue to society.

Approach

Locations

Seven locations were selected to provide broad geographical and utility coverage in the two states of interest (see Table 1). Four locations were selected in Pennsylvania representing three utilities[1] and three locations were selected in New Jersey, each served by a separate utility.

Table 1. Study location summary.

		Location	Utility	2011 Utility Peak Load (MW)	PV Fleet Capacity (MW)
PA	1	Pittsburgh	Duquesne Light Co.	3,164	475
PA	2	Scranton	PPL Utilities Corp.	7,527	1,129
PA	3	Harrisburg	PPL Utilities Corp.	7,527	1,129
PA	4	Philadelphia	PECO Energy Co.	8,984	1,348
NJ	5	Jamesburg	Jersey Central P&L	6,604	991
NJ	6	Newark	PSE&G	10,933	1,640
NJ	7	Atlantic City	Atlantic City Electric	2,956	443

These locations represent a diversity of input assumptions:

- The locations span two states: PA and NJ. These states differ in generation mix (percentage of coal, gas, nuclear, etc.), and this is reflected in different environmental cost assumptions (see Appendix 2).
- The locations differ in solar resource.

[1] Scranton and Harrisburg are both served by PPL Utilities.

- The locations represent six different utility service territories. Each of these utilities differ by cost of capital, hourly loads, T&D loss factors, distribution expansion costs, and growth rate.

Penetration Level

Fleet capacity was set to 15% of the utility peak load. This assumption was intended to represent a moderate long-term penetration level.

The value of solar per MWh decreases with increasing penetration for several reasons:

- The match between PV output and loads is reduced. As more PV is added to the resource mix, the peak shifts to non-solar hours, thereby limiting the ability of PV to support the peak.
- Line losses are related to the square of the load. Consequently, the greatest marginal savings provided by PV is achieved with small amounts of PV. By adding larger and larger quantities of PV, the loss savings continue to be gained, but at decreasing rates.
- Similarly, the market prices are non-linear, and PV is most effective in causing market price reduction with small PV capacity.

Based on the above considerations, this study is intended to represent a moderate level of long-term PV penetration. With penetration levels less than 15%, the value of solar would be expected to be higher than the results obtained in this study.

Peak loads for each utility were obtained from hourly load data corresponding to PJM load zones, and these were used to set the fleet capacity as shown in the table.

Fleet Configurations

Four PV system configurations were included in the study:

- South-30 (south-facing, 30-degree tilt, fixed)
- Horizontal (fixed)
- West-30 (west facing, 30-degree tilt, fixed)
- 1-Axis (tracking at 30-degree tilt)

These were selected in order to capture possible variations in value due to the different production profiles. For example, West-facing systems are sometimes found to be the best match with utility loads and have the potential to provide more capacity benefits. On the other hand, tracking systems deliver more energy per unit of rated output, so they have the potential to offer more energy benefits (e.g., fuel cost savings).

Scenarios and Fleet Modeling

Value was determined for each of 28 scenarios (four fleet configurations at each of seven locations). For modeling purposes, fleets were described by latitude and longitude coordinates, AC rating, a module derate factor (90%), inverter efficiency (95%) and other loss factor (90%). These factors were consistent across all scenarios.

Fleets were modeled for all hours of 2011 using SolarAnywhere® satellite-derived irradiance data and simulation model with a 10 km x 10 km pixel resolution. [2] Under this procedure, the fleet output for each scenario is location- and time-correlated with hourly PJM zonal loads.

[2] http://www.solaranywhere.com.

Results

Utility Analysis

Utility analysis results are shown in Table 2, obtained from an analysis of FERC filings and PJM hourly data using methods developed previously for NYSERDA.[3] These include:

- Utility discount rate
- Utility system loss data
- Distribution expansion costs (present value)
- Distribution load growth rate
- Distribution loss data

Note that actual utility costs are used in this analysis because they are the basis of value. For this reason, the utility cost of capital is required (e.g., an "assumed" or "common" value cannot be used). The results may therefore differ, in part, due to differences in utility discount rate.

PV Technical Analysis

A summary of fleet technical performance results is presented in Table 3. Annual energy production is the modeled output for 2011. Capacity factor is the annual energy production relative to a baseload plant operating at 100% availability with the same rated output. Generation capacity is Effective Load Carrying Capability (ELCC) expressed as a percentage of rated capacity. T&D Capacity is a measure of the direct annual peak-load reduction provided by the PV system expressed as a percentage of rated capacity.

[3] Norris and Hoff, "PV Valuation Tool," Final Report (DRAFT), NYSERDA, May 2012.

Table 2. Utility analysis results.

		Pittsburgh	Scranton	Harrisburg	Philadelphia	Jamesburg	Newark	Atlantic City
Utility		Duquesne Light Co.	PPL Utilities Corp.	PPL Utilities Corp.	PECO Energy Co.	Jersey Central P&L	PSE&G	Atlantic City Electric
UtilityID		DUQ	PPL	PPL	PECO	JCPL	PSEG	AECO
UTILITY DATA								
Economic Factors								
Discount Rate	percent per year	6.63%	8.08%	8.08%	9.00%	5.68%	8.46%	5.88%
Utility System								
Load Loss Condition	MW	1,757	4,786	4,786	4,958	2,893	5,435	1,369
Avg. Losses (at Condition)	percent	5.84%	6.55%	6.55%	4.23%	6.35%	4.86%	5.61%
Distribution								
Distribution Expansion Cost	$ PW	$485,009,880	$423,994,174	$423,994,174	$722,046,118	$446,914,440	$573,820,751	$288,330,547
Distribution Expansion Cost Escalation	percent per year	3.89%	3.89%	3.89%	3.89%	3.89%	3.89%	3.89%
Distribution Load Growth Rate	MW per year	30.9	98.3	98.3	110.7	93.4	91.4	39.5
Load Loss Condition	MW	1,757	4,786	4,786	4,958	2,893	5,435	1,369
Avg. Losses (at Condition)	percent	5.84%	6.55%	6.55%	4.23%	6.35%	4.86%	5.61%

Table 3. Technical results, by location (South-30).

	Pittsburgh	Harrisburg	Scranton	Philadelphia	Jamesburg	Newark	Atlantic City
Fleet Capacity (MWac)	475	1129	1129	1348	991	1640	443
Annual Energy Production (MWh)	716,621	1,809,443	1,698,897	2,339,424	1,675,189	2,677,626	827,924
Capacity Factor (%)	17%	18%	17%	20%	19%	19%	21%
Generation Capacity (% of Fleet Capacity)	41%	28%	28%	38%	45%	45%	46%
T&D Capacity (% of Fleet Capaccity)	31%	14%	14%	21%	29%	56%	36%

Value Analysis

Figure 1 shows the value results in levelized dollars per MWh generated. Figure 2 shows the data in dollars per kW installed. This data is also presented in tabular form in Table 4 and Table 5. Detailed results for individual locations are shown in Appendix 3.

The total value ranges from $256 per MWh to $318 per MWh. Of this, the highest value components are the Market Price Reduction (averaging $55 per MWh) and the Economic Development Value (averaging $44 per MWh).

The differences between Table 4 and Table 5 are due to differences in the cost of capital between the utilities. For example, Atlantic City has the highest value per installed kW, but Atlantic City Electric has one of the lowest calculated discount rates (Table 2). Therefore, when this value is levelized over the 30 year study period, it represents a relatively low value.

Other observations:

- **Market Price Reduction**. The two locations of highest total value (Harrisburg and Scranton) are noted for their high Market Price Reduction value. This may be the result of a good match between LMP and PV output. By reducing demand during the high priced hours, a cost savings is realized by all consumers. Further investigation of the methods may be warranted in light of two arguments put forth by Felder [32]: that the methodology does address induced increase in demand due to price reductions, and that it only addresses short-run effects (ignoring the impact on capacity markets).
- **Environmental Value**. The state energy mix is a differentiator of environmental value. Pennsylvania (with a large component of coal-fired generation in its mix) leads to higher environmental value in locations in that state relative to New Jersey. As described in Appendix 2, the PA generation mix is dominated by coal (48%) compared to NJ (10%).
- **T&D Capacity Value**. T&D capacity value is low for all scenarios, with the average value of only $3 per MWh. This may be explained by the conservative method taken for calculating the effective T&D capacity.
- **Fuel Price Hedge**. The cost of eliminating future fuel purchases—through the use of financial hedging instruments—is directly related to the utility's cost of capital. This may be seen by comparing the hedge value in Jamesburg and Atlantic City. At a rate of 5.68%, Jersey Central Power & Light (the utility serving Jamesburg) has the lowest calculated cost of capital among the

six utilities included in the study. In contrast, PSE&G (the utility serving Newark) has a calculated discount rate of 8.46%, the highest among the utilities. This is reflected in the relative hedge values of $24 per MWh for Jamesburg and $44 per MWh for Newark, nearly twice the value.

Figure 1. Levelized value ($/MWh), by location (South-30).

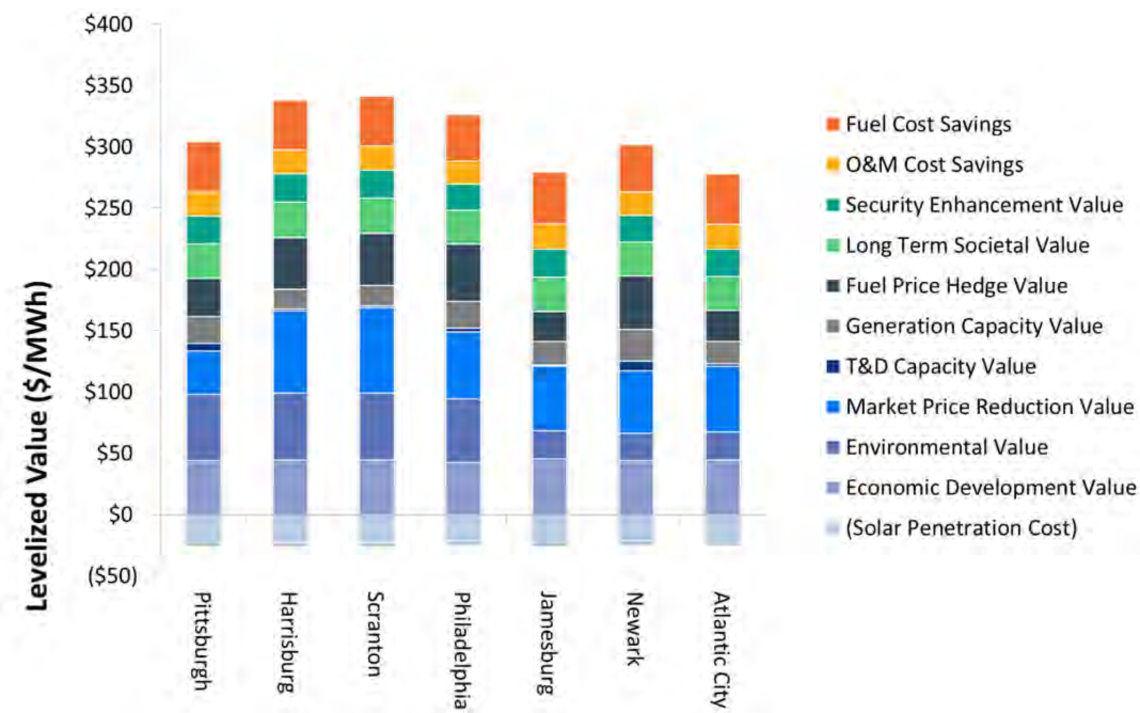


Figure 2. Value ($/kW), by location (South-30).

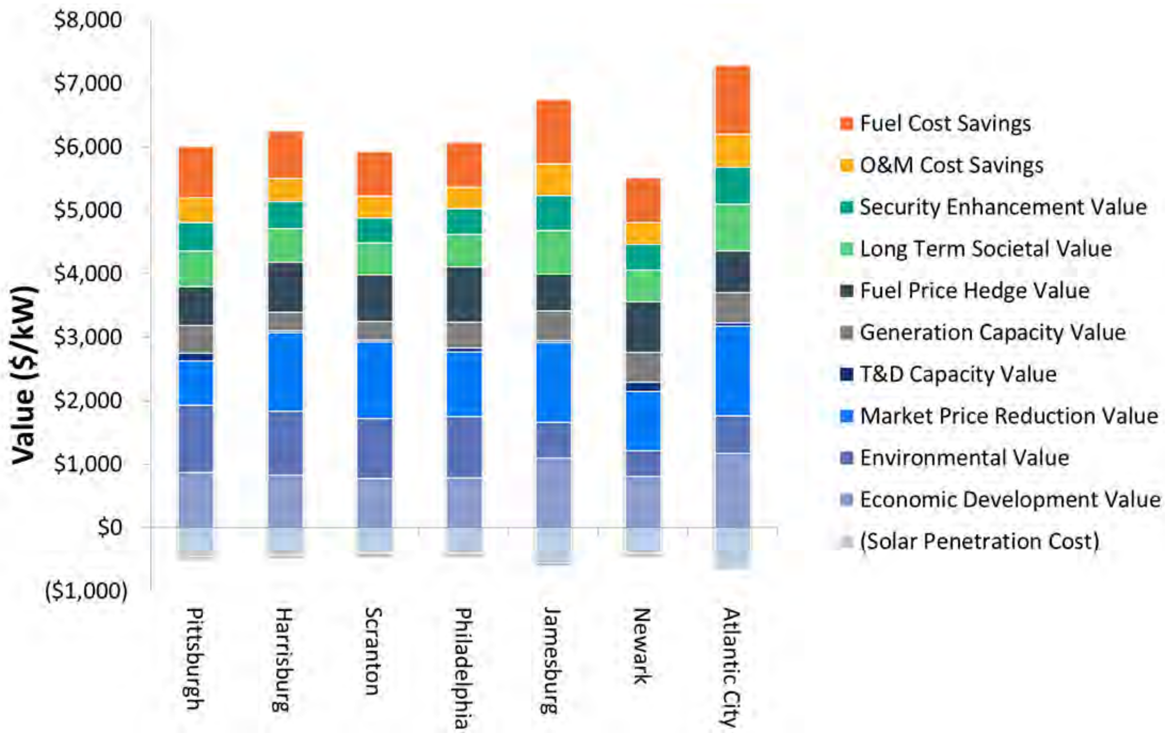


Table 4. Value (levelized $/MWh), by location (South-30).

	Pittsburgh	Harrisburg	Scranton	Philadelphia	Jamesburg	Newark	Atlantic City
Energy							
Fuel Cost Savings	$41	$41	$41	$38	$42	$39	$41
O&M Cost Savings	$20	$20	$20	$18	$21	$19	$20
Total Energy Value	$61	$60	$60	$56	$63	$58	$61
Strategic							
Security Enhancement Value	$23	$23	$23	$22	$23	$22	$22
Long Term Societal Value	$28	$29	$29	$27	$28	$28	$28
Total Strategic Value	$51	$52	$52	$49	$51	$50	$50
Other							
Fuel Price Hedge Value	$31	$42	$42	$47	$24	$44	$25
Generation Capacity Value	$22	$16	$17	$22	$19	$26	$18
T&D Capacity Value	$6	$1	$1	$3	$1	$8	$2
Market Price Reduction Value	$35	$67	$69	$54	$52	$51	$54
Environmental Value	$54	$55	$55	$52	$23	$22	$23
Economic Development Value	$44	$45	$45	$42	$45	$44	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($22)	($23)	($22)	($22)
Total Other Value	$170	$203	$206	$199	$143	$173	$144
Total Value	**$282**	**$315**	**$318**	**$304**	**$257**	**$280**	**$256**

Table 5. Value ($/kW), by location (South-30).

	Pittsburgh	Harrisburg	Scranton	Philadelphia	Jamesburg	Newark	Atlantic City
Energy							
Fuel Cost Savings	$813	$751	$706	$706	$1,020	$709	$1,081
O&M Cost Savings	$396	$366	$344	$344	$497	$345	$527
Total Energy Value	$1,209	$1,117	$1,050	$1,049	$1,517	$1,054	$1,609
Strategic							
Security Enhancement Value	$446	$424	$398	$405	$549	$403	$584
Long Term Societal Value	$557	$530	$498	$507	$686	$504	$730
Total Strategic Value	$1,003	$954	$896	$912	$1,234	$907	$1,314
Other							
Fuel Price Hedge Value	$613	$786	$738	$876	$586	$798	$662
Generation Capacity Value	$432	$297	$290	$401	$468	$470	$478
T&D Capacity Value	$127	$24	$24	$65	$23	$147	$49
Market Price Reduction Value	$696	$1,241	$1,206	$1,013	$1,266	$927	$1,412
Environmental Value	$1,064	$1,011	$950	$967	$560	$411	$596
Economic Development Value	$870	$827	$777	$790	$1,097	$806	$1,168
(Solar Penetration Cost)	($446)	($424)	($398)	($405)	($549)	($403)	($584)
Total Other Value	$3,355	$3,761	$3,586	$3,706	$3,451	$3,156	$3,781
Total Value	**$5,568**	**$5,832**	**$5,532**	**$5,667**	**$6,202**	**$5,117**	**$6,704**

Future Work

In the course of conducting this study, several observations were made that suggest further refinement to these results should be considered:

- The market price reduction estimated as part of the present study will have to be ascertained as PV develops and penetrates the NJ and PA grids. In particular, the impact of PV-induced price reduction on load growth, hence feedback secondary load-growth induced market price increase as suggested by Felder [32] should be quantified. In addition, the feedback of market price reduction on capacity markets will have to be investigated.

- In this study 15% PV capacity penetration was assumed-- amounting to a total PV capacity of 7GW across the seven considered utility hubs. Since both integration cost increases and capacity value diminishes with penetration, it will be worthwhile to investigate other penetration scenarios. This may be particularly useful for PA where the penetration is smaller than NJ. In addition, it may be useful to see the scenarios with penetration above 15%. For these cases, it would be pertinent to establish the cost of displacing (nuclear) baseload generation with solar generation[4] since this question is often brought to the forefront by environmentally-concerned constituents in densely populated areas of NJ and PA.

- Other sensitivities may be important to assess as well. Sensitivities to fuel price assumptions, discount rates, and other factors could be investigated further. In particular the choice made here to use documented utility-specific discount rates and its impact on the per MWh levelized results[5] could be quantified and compared to an assumption using a common discount rate representative of average regional business practice.

- The T&D values derived for the present analysis are based on utility-wide average loads. Because this value is dependent upon the considered distribution system's characteristics – in particular load growth, customer mix and equipment age – the T&D value may vary considerably from one distribution feeder to another. It would therefore be advisable to take this study one step further and systematically identify the highest value areas. This will require the collaboration of the servicing utilities to provide relevant subsystem data.

[4] Considering integration solutions including storage, wind/PV synergy and gas generation backup.
[5] Note that the per kW value results are much less dependent upon the discount rate

Appendix 1: Detailed Assumptions

Input assumptions that are common across all of the scenarios are shown in Table 6.

Table 6. Input assumptions and units common to all scenarios.

INPUT ASSUMPTIONS		
PV Characteristics		
PV Degradation	0.50%	per year
PV System Life	30	years
Generation Factors		
Gen Capacity Cost	$1,045	per kW
Gen Heat Rate (First Year)	7050	BTU/kWh
Gen Plant Degradation	0.00%	per year
Gen O&M Cost (First Year)	$12.44	per MWh
Gen O&M Cost Escalation	3.38%	per year
Garver Percentage	5.00%	Pct of Ann Peak
NG Wholesale Market Factors		
End of Term NG Futures Price Escalation	2.33%	per year

PV degradation is assumed to be 0.50% per year indicating that the output of the system will degrade over time. This is a conservative assumption (PV degradation is likely to be less than 0.5% per year). Studies often ignore degradation altogether because the effect is small, but it is included here for completeness.

The study period is taken as 30 years, corresponding to typical PV lifetime assumptions.

PV is assumed to displace power generated from peaking plants fueled by natural gas. Gas turbine capital, O&M, heat rate, and escalation values are taken from the EIA.[6] Plant degradation is assumed to be zero.

[6] Updated Capital Cost Estimates for Electricity Generation Plants, U.S. Energy Information Administration, November 2010, available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf. Taken from Table 1, page 7. Costs are escalated to 2012 dollars.

Costs for generation O&M are assumed to escalate at 3.38%, calculated from the change in Producer Price Index (PPI) for the "Turbine and power transmission equipment manufacturing" industry[7] over the period 2004 to 2011.

Natural gas prices used in the fuel price savings value calculation are obtained from the NYMEX futures prices. These prices, however, are only available for the first 12 years. Ideally, one would have 30 years of futures prices. As a proxy for this value, it is assumed that escalation after year 12 is constant based on historically long term prices to cover the entire 30 years of the PV service life (years 13 to 30). The EIA published natural gas wellhead prices from 1922 to the present.[8] It is assumed that the price of the NG futures escalates at the same rate as the wellhead prices.[9] A 30-year time horizon is selected with 1981 gas prices at $1.98 per thousand cubic feet and 2011 prices at $3.95. This results in a natural gas escalation rate of 2.33%.

[7] PPI data is downloadable from the Bureau industry index selected was taken as the most representative of power generation O&M. BLS does publish an index for "Electric power generation" but this is assumed.

[8] US Natural Gas Prices (Annual), EIA, release date 2/29/2012, available at http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

[9] The exact number could be determined by obtaining over-the-counter NG forward prices.

Appendix 2: Methodologies

Overview

The methodologies used in the present project drew upon studies performed by CPR for other states and utilities. In these studies, the key value components provided by PV were determined by CPR, using utility-provided data and other economic data.

The ability to determine value on a site-specific basis is essential to these studies. For example, the T&D Capacity Value component depends upon the ability of PV to reduce peak loads on the circuits. An analysis of this value, then, requires:

Hour by hour loads on distribution circuits of interest.

- Hourly expected PV outputs corresponding to the location of these circuits and expected PV system designs.
- Local distribution expansion plan costs and load growth projections.

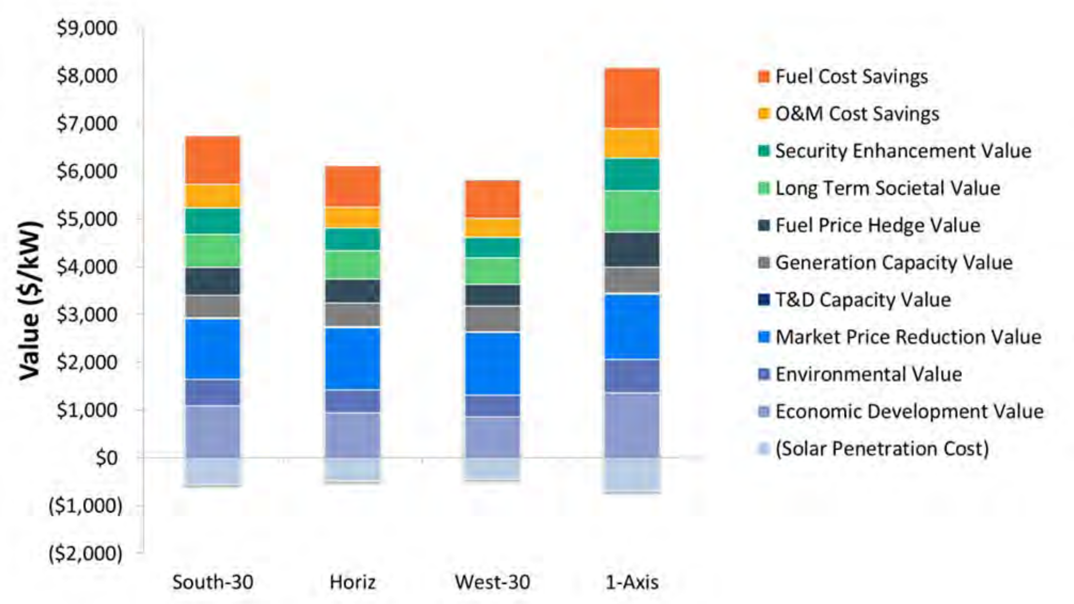
Units of Results

The discounting convention assumed throughout the report is that energy-related values occur at the end of each year and that capacity-related values occur immediately (i.e., no discounting is required).[10]

The Present Value results are converted to per unit value (Present Value $/kW) by dividing by the size of the PV system (kW). An example of this conversion is illustrated in Figure 3 for results from a previous study. The y-axis presents the per unit value and the x-axis presents seven different PV system configurations. The figure illustrates how value components can be significantly affected by PV system configuration. For example, the tracking systems, by virtue of their enhanced energy production capability, provide greater generation benefits.

[10] The effect of this will be most apparent in that the summations of cash flows start with the year equal to 1 rather than 0.

Figure 3. Sample results.



The present value results per unit of capacity ($/kW) are converted to levelized value results per unit of energy ($/MWh) by dividing present value results by the total annual energy produced by the PV system and then multiplying by an economic factor.

PV Production and Loss Savings

PV System Output

An accurate PV value analysis begins with a detailed estimate of PV system output. Some of the energy-based value components may only require the total amount of energy produced per year. Other value components, however, such as the energy loss savings and the capacity-based value components, require hourly PV system output in order to determine the technical match between PV system output and the load. As a result, the PV value analysis requires time-, location-, and configuration-specific PV system output data.

For example, suppose that a utility wants to determine the value of a 1 MW fixed PV system oriented at a 30° tilt facing in the southwest direction located at distribution feeder “A”. Detailed PV output data that is time- and location-specific is required over some historical period, such as from Jan. 1, 2001 to Dec. 31, 2010.

Methodology

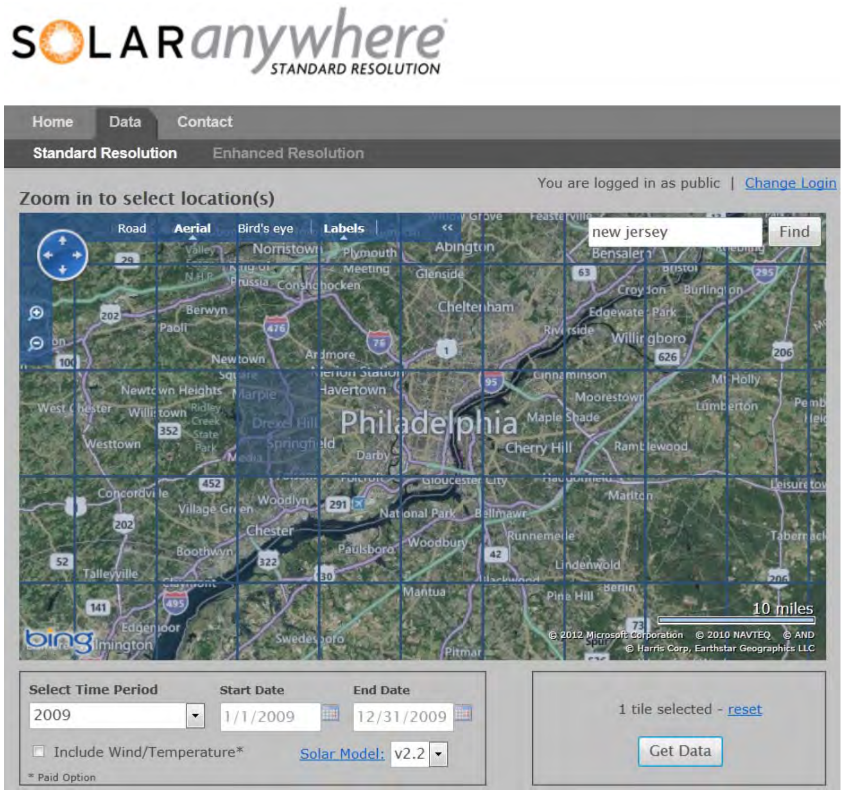
It would be tempting to use a representative year data source such as NREL's Typical Meteorological Year (TMY) data for purposes of performing a PV value analysis. While these data may be representative of long-term conditions, they are, by definition, not time-correlated with actual distribution line loading on an hourly basis and are therefore not usable in hourly side-by-side comparisons of PV and load. Peak substation loads measured, say, during a mid-August five-day heat wave must be analyzed alongside PV data that reflect the same five-day conditions. Consequently, a technical analysis based on anything other than time- and location-correlated solar data may give incorrect results.

CPR's SolarAnywhere® and PVSimulator™ software services will be employed under this project to create time-correlated PV output data. SolarAnywhere is a solar resource database containing almost 14 years of time- and location-specific, hourly insolation data throughout the continental U.S. and Hawaii. PVSimulator, available in the SolarAnywhere Toolkit, is a PV system modeling service that uses this hourly resource data and user-defined physical system attributes in order to simulate configuration-specific PV system output.

The SolarAnywhere data grid web interface is available at www.SolarAnywhere.com (Figure 4). The structure of the data allows the user to perform a detailed technical assessment of the match between PV system output and load data (even down to a specific feeder). Together, these two tools enable the evaluation of the technical match between PV system output and loads for any PV system size and orientation.

Previous PV value analyses were generally limited to a small number of possible PV system configurations due to the difficulty in obtaining time- and location-specific solar resource data. This new value analysis software service, however, will integrate seamlessly with SolarAnywhere and PVSimulator. This will allow users to readily select any PV system configuration. This will allow for the evaluation of a comprehensive set of scenarios with essentially no additional study cost.

Figure 4. SolarAnywhere data selection map.



Loss Savings

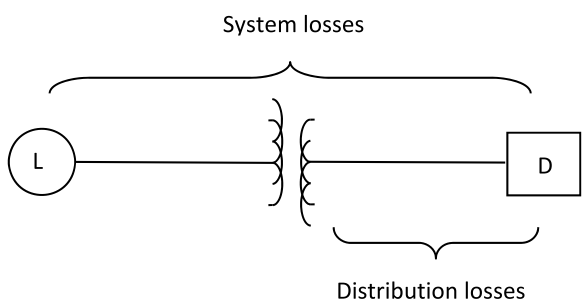
<u>Introduction</u>

Distributed resources reduce system losses because they produce power in the same location that the power is consumed, bypassing the T&D system and avoiding the associated losses.

Loss savings are not treated as a stand-alone benefit under the convention used in this methodology. Rather, the effect of loss savings is included separately for each value component. For example, in the section that covers the calculation of Energy Value, the quantity of energy saved by the utility includes both the energy produced by PV and the amount that would have been lost due to heating in the wires if the load were served from a remote source. The total energy that would have been procured by the utility equals the PV energy plus avoided line losses. Loss savings can be considered a sort of “adder” for each benefit component.

This section describes the methodology for calculating loss savings for each hour. The results of these calculations are then used in subsequent sections. As illustrated in Figure 5, it will be important to note that, while the methodology describes the calculation of an hourly loss result, there are actually two different loss calculations that must be performed: “system” losses, representing the losses incurred on both the transmission and distribution systems (between generation load, L, and end-use demand, D), and “distribution” losses, representing losses specific to distribution system alone.

Figure 5. System losses versus distribution losses.



The two losses are calculated using the same equation, but they are each applicable in different situations. For example, “Energy Value” represents a benefit originating at the point of central generation, so that the total system losses should be included. On the other hand, “T&D Capacity Value” represents a benefit as measured at a distribution substation. Therefore, only the losses saved on the distribution system should be considered.

The selection of “system” versus “distribution” losses is discussed separately for each subsequent benefit section.

Methodology

One approach analysts have used to incorporate losses is to adjust energy- and capacity-related benefits based on the *average* system losses. This approach has been shown to be deficient because it fails to capture the true reduction in losses on a marginal basis. In particular, the approach underestimates the reduction in losses due to a peaking resource like PV. Results from earlier studies demonstrated that loss savings calculations may be off by more than a factor of two if not performed correctly [6].

For this reason, the present methodology will incorporate a calculation of loss savings on a marginal basis, taking into account the status of the utility grid when the losses occur. Clean Power Research has previously developed methodologies based on the assumption that the distributed PV resource is small relative to the load (e.g., [6], [9]). CPR has recently completed new research that expands this methodology so that loss savings can now be determined for any level of PV penetration.

Fuel Cost Savings and O&M Cost Savings

Introduction

Fuel Cost Savings and O&M Cost Savings are the benefits that utility participants derive from using distributed PV generation to offset wholesale energy purchases or reduce generation costs. Each kWh generated by PV results in one less unit of energy that the utility needs to purchase or generate. In addition, distributed PV reduces system losses so that the cost of the wholesale generation that would have been lost must also be considered. The capacity value of generation is treated in a separate section.

Methodology

These values can be calculated by multiplying PV system output times the cost of the generation on the margin for each hour, summing for all hours over the year, and then discounting the results for each year over the life of the PV system.

There are two approaches to obtaining the marginal cost data. One approach is to obtain the marginal costs based on historical or projected market prices. The second approach is to obtain the marginal costs based on the cost of operating a representative generator that is on the margin.

Initially, it may be appealing to take the approach of using market prices. There are, however, several difficulties with this approach. One difficulty is that these tend to be hourly prices and thus require hourly PV system output data in order to calculate the economic value. This difficulty can be addressed by using historical prices and historical PV system output to evaluate what results would have been in the past and then escalating the results for future projections. A more serious difficulty is that, while hourly market prices could be projected for a few years into the future, the analysis needs to be performed over a much longer time period (typically 30 years). It is difficult to accurately project hourly market prices 30 years into the future.

A more robust approach is to explicitly specify the marginal generator and then to calculate the cost of the generation from this unit. This is often a Combined Cycle Gas Turbine (CCGT) powered using natural gas (e.g., [6]). This approach includes the assumption that PV output always displaces energy from the same marginal unit. Given the uncertainties and complications in market price projections, the second approach is taken.

Fuel Cost Savings and O&M Cost Savings equals the sum of the discounted fuel cost savings and the discounted O&M cost savings.

Security Enhancement Value

Because solar generation is closely correlated with load in much of the US, including New Jersey and Pennsylvania [26], 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 effective capacity value of PV accrues to the ratepayer (see above) both at the transmission and distribution levels. It is thus possible to argue that the reserve margins required by regulators would account for this new capacity, hence that no increased outage risk reduction capability would occur beyond the pre-PV conditions. This is the reason this value item above is not included as one of the directly quantifiable attributes of PV.

On the other hand there is ample evidence that during heat wave-driven extreme conditions, the availability of PV is higher than suggested by the effective capacity (reflecting of all conditions) -- e.g., see [27], [28], on the subject of major western and eastern outages, and [29] on the subject of localized rolling blackouts. In addition, unlike conventional centralized generation injecting electricity (capacity) at specific points on the grid, PV acts as a load modulator that provides immediate stress relief throughout the grid where stress exists due to high-demand conditions. It is therefore possible to argue that, all conditions remaining the same in terms of reserve margins, a load-side dispersed PV resource would mitigate issues leading to high-demand-driven localized and regional outages.

Losses resulting from power outages are generally not a utility's (ratepayers') 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, 5%, are of the high-demand stress type that can be effectively mitigated by dispersed solar generation at a capacity penetration of 15%,[11] it is straightforward to calculate, as shown below, that, nationally, the value of each kWh generated by such a dispersed solar base would be of the order of $20/MWh to the taxpayer.

The US generating capacity is roughly equal to 1000 GW. At 15% capacity penetration, taking a national average of 1500 kWh (slightly higher nationwide than PA and NJ) generated per year per installed kW, PV would generate 225,000 GWh/year. By reducing the risk of outage by 5%, the value of this energy would thus be worth $5 billion, amounting to $20 per PV-generated MWh.

This national value of $20 per MWh was taken for the present study because the underlying estimate of cost was available on a national basis. In reality, there would be state-level differences from this estimate, but these are not available.

Long Term Societal Value

This item is an attempt to place a present-value $/MWh on the generally well accepted argument that solar energy is a good investment for our children and grandchildren's well-being. Considering:

1. The rapid growth of large new world economies and the finite reserves of conventional fuels now powering the world economies, it is likely that fuel prices will continue to rise exponentially fast for the long term beyond the 30-year business life cycle considered here.
2. The known very slow degradation of the leading (silicon) PV technology, many PV systems installed today will continue to generate power at costs unaffected by the world fuel markets after their guaranteed lifetimes of 25-30 years

One approach to quantify this type of long-view attribute has been to apply a very low societal discount rate (e.g., 2% or less, see [25]) to mitigate the fact that the present-day importance of long-term expenses/benefits is essentially ignored in business as usual practice. This is because discount rates are

[11] Much less than that would have prevented the 2003 NE blackout. See [30].

used to quantify the present worth of future events and that, and therefore, long-term risks and attributes are largely irrelevant to current decision making.

Here a less controversial approach is proposed by arguing that, on average, PV installation will deliver, on average, a minimum of 10 extra years of essentially free energy production beyond the life cycle considered in this study.

The present value of these extra 10 years, all other assumptions on fuel cost escalation, inflation, discount rate, PV output degradation, etc. remaining the same, amounts to ~ $25/MWh for all the cities/PJM hubs considered in this study.

Fuel Price Hedge Value

Introduction

Solar-based generation is insensitive to the volatility of fuel prices while fossil-based generation is directly tied to fuel prices. Solar generation, therefore, offers a “hedge” against fuel price volatility. One way this has been accounted for is to quantify the value of PV’s hedge against fluctuating natural gas prices [6].

Methodology

The key to calculating the Fuel Price Hedge Value is to effectively convert the fossil-based generation investment from one that has substantial fuel price uncertainty to one that has no fuel price uncertainty. This can be accomplished by entering into a binding commitment to purchase a lifetime’s worth of fuel to be delivered as needed. The utility could set aside the entire fuel cost obligation up front, investing it in risk-fee securities to be drawn from each year as required to meet the obligation. The approach uses two financial instruments: risk-free, zero-coupon bonds[12] and a set of natural gas futures contracts.

Consider how this might work. Suppose that the CCGT operator wants to lock in a fixed price contract for a sufficient quantity of natural gas to operate the plant for one month, one year in the future. First, the operator would determine how much natural gas will be needed. If E units of electricity are to be generated and the heat rate of the plant is H, $E * H$ BTUs of natural gas will be needed. Second, if the corresponding futures price of this natural gas is $P^{NG\ Futures}$ (in $ per BTU), then the operator will need $E *$

[12] A zero coupon bond does not make any periodic interest payments.

$H * P^{NG\ Futures}$ dollars to purchase the natural gas one year from now. Third, the operator needs to set the money aside in a risk-free investment, typically a risk-free bond (rate-of-return of $r^{risk\text{-}free}$ percent) to guarantee that the money will be available when it is needed one year from now. Therefore, the operator would immediately enter into a futures contract and purchase $E * H * P^{NG\ Futures} / (1+ r^{risk\text{-}free})$ dollars worth of risk-free, zero-coupon bonds in order to guarantee with certainty that the financial commitment (to purchase the fuel at the contract price at the specified time) will be satisfied.[13]

This calculation is repeated over the life of the plant to calculate the Fuel Price Hedge value.

Generation Capacity Value

Introduction

Generation Capacity Value is the benefit from added capacity provided to the generation system by distributed PV. Two different approaches can be taken to evaluating the Generation Capacity Value component. One approach is to obtain the marginal costs based on market prices. The second approach is to estimate the marginal costs based on the cost of operating a representative generator that is on the margin, typically a Combined Cycle Gas Turbine (CCGT) powered by natural gas.

Methodology

The second approach is taken here for purposes of simplicity. Future version of the software service may add a market price option.

Once the cost data for the fully-dispatchable CCGT are obtained, the match between PV system output and utility loads needs to be determined in order to determine the effective value of the non-dispatchable PV resource. CPR developed a methodology to calculate the effective capacity of a PV system to the utility generation system (see [10] and [11]) and Perez advanced this method and called it the Effective Load Carrying Capability (ELCC) [12]. The ELCC method has been identified by the utility industry as one of the preferable methods to evaluate PV capacity [13] and has been applied to a variety of places, including New York City [14].

The ELCC is a statistical measure of effective capacity. The ELCC of a generating unit in a utility grid is defined as the load increase (MW) that the system can carry while maintaining the designated reliability

[13] $[E * H * P^{NG\ Futures} / (1+ r^{risk\text{-}free})] * (1+ r^{risk\text{-}free}) = E * H * P^{NG\ Futures}$

criteria (e.g., constant loss of load probability). The ELCC is obtained by analyzing a statistically significant time series of the unit's output and of the utility's power requirements.

Generation Capacity Value equals the capital cost ($/MW) of the displaced generation unit times the effective capacity provided by the PV.

T&D Capacity Value

Introduction

The benefit that can be most affected by the PV system's location is the T&D Capacity Value. The T&D Capacity Value depends on the existence of location-specific projected expansion plan costs to ensure reliability over the coming years as the loads grow. Capacity-constrained areas where loads are expected to reach critical limits present more favorable locations for PV to the extent that PV will relieve the constraints, providing more value to the utility than those areas where capacity is not constrained.

Distributed PV generation reduces the burden on the distribution system. It appears as a "negative load" during the daylight hours from the perspective of the distribution operator. Distributed PV may be considered equivalent to distribution capacity from the perspective of the distribution planner, provided that PV generation occurs at the time of the local distribution peak.

Distributed PV capacity located in an area of growing loads allows a utility planner to defer capital investments in distribution equipment such as substations and lines. The value is determined by the avoided cost of money due to the capital deferral.

Methodology

It has been demonstrated that the T&D Capacity Value can be quantified in a two-step process. The first step is to perform an economic screening of all areas to determine the expansion plan costs and load growth rates for each planning area. The second step is to perform a technical load-matching analysis for the most promising locations [18].

Market Price Reduction Value

Two cost savings occur when distributed PV generation is deployed in a market that is structured where the last unit of generation sets the price for all generation and the price is an increasing function of load. First, there is the direct savings that occur due to a reduction in load. This is the same as the value of energy provided at the market price of power. Second, there is the indirect value of market price reduction. Distributed generation reduces market demand and this results in lower prices to all those purchasing power from the market. This section outlines how to calculate the market savings value.

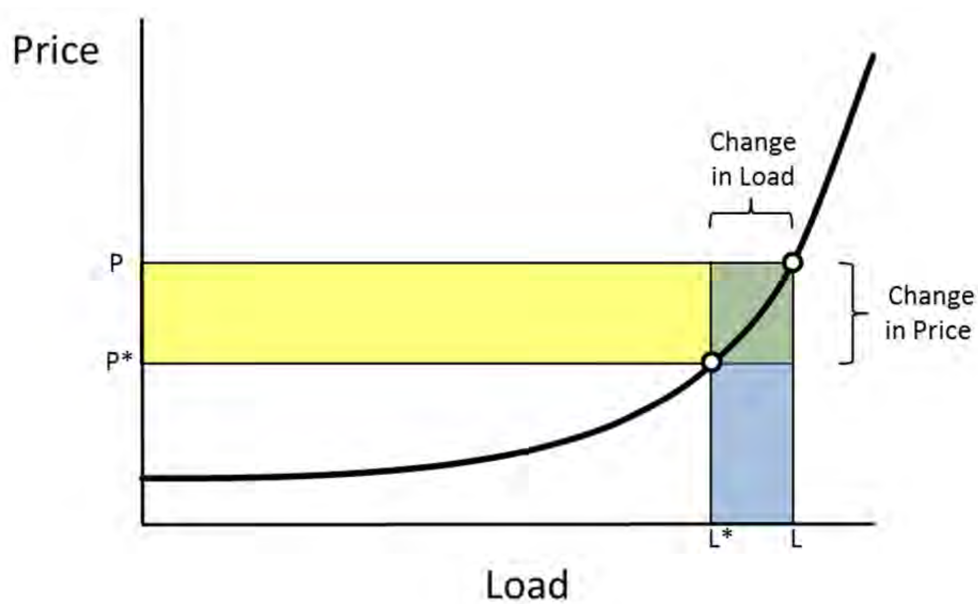
Cost Savings

As illustrated in Figure 6, the total market expenditures at any given point in time are based on the current price of power (P) and the current load (L). The rate of expenditure equals P L. Total market expenditures after PV is deployed equals the new price (P*) times the new load (L*), or P*L*. Cost savings equal the difference between the total before and after expenditures.

$$Cost\ Savings = P\ L - P^{*}L^{*} \qquad \textbf{(1)}$$

The figure illustrates that the cost savings occur because there is both a change in load and a change in price.

Figure 6. Illustration of price changes that occur in market as result of load changes.



Equation (1) can be expanded by adding $-P^{*}L + P^{*}L$ and then rearranging the result.

$$Cost\ Savings \quad = P\ L + (-P^{*}L + P^{*}L) - P^{*}L^{*} \qquad (2)$$

$$= (P - P^*)L + P^*(L - L^*)$$

$$= \left[\left(\frac{P - P^*}{L - L^*}\right) L + P^*\right](L - L^*)$$

Let $\Delta L = L - L^*$ and $\Delta P = P - P^*$ and substitute into Equation (2). The result is that

$$Cost\ Savings = \left[P + \frac{\Delta P}{\Delta L} L - \Delta P\right] \Delta L \qquad \textbf{(3)}$$

Per unit cost savings is obtained by dividing Equation (3) by ΔL.

$$Per\ Unit\ Cost\ Savings = \overbrace{P}^{Direct\ Savings} + \overbrace{\frac{\Delta P}{\Delta L} L - \Delta P}^{Market\ Price\ Reduction\ Value} \qquad \textbf{(4)}$$

Discussion

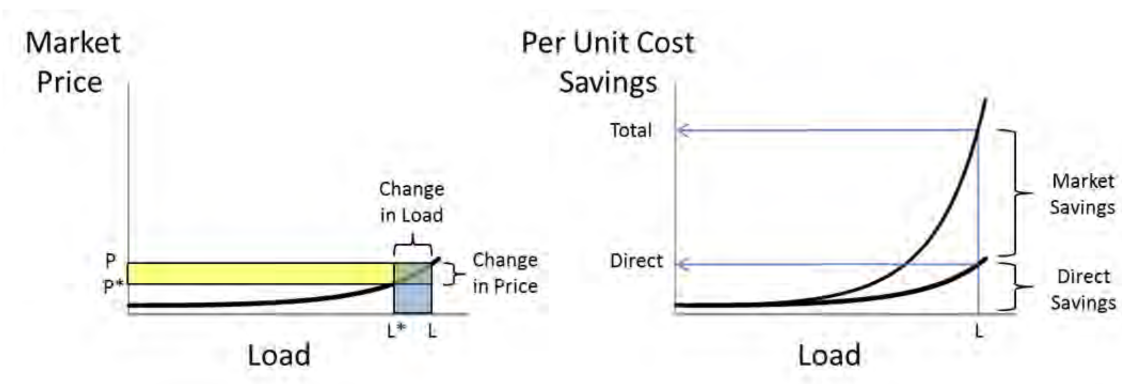
Equation (4) suggests that there are two cost savings components: direct savings and market price suppression. The direct savings equal the existing market price of power. The market price reduction value is the savings that the entire market realizes as a result of the load reduction. These savings depends on the change in load, change in price, and existing load. It is important to note that the change in load and the existing load can be measured directly while the change in price cannot be measured directly. This means that the change in price must be modeled (rather than measured).

It is useful to provide an interpretation of the market price reduction component and illustrate the potential magnitude. The market price reduction component in Equation (4) has two terms. The first term is the slope of the price curve (i.e., it is the derivative as the change in load goes to zero) times the existing load. This is the positive benefit that the whole market obtains due to price reductions. The second term is the reduced price associated with the direct savings.

The left side of Figure 7 presents the same information as in Figure 6, but zooms out on the y-axis scale of the chart. The first term corresponds to the yellow area. The second term corresponds to the overlapping areas of the change in price and change in load effects.

The market price curve can be translated to a cost savings curve. The right side of Figure 7 presents the per unit cost savings based on the information from the market price curve (i.e., the left side of the figure). The lower black line is the price vs. load curve. The upper line adds the market price suppression component to the direct savings component. It assumes that there is the same load reduction for all loads as in the left side of the figure. The figure illustrates that no market price suppression exist when the load is low but the market price suppression exceed the direct cost savings when the load is high. The saving is dependent upon the shape of the price curve and the size of the load reduction.

Figure 7. Direct + market price reduction vs. load (assuming constant load reduction).



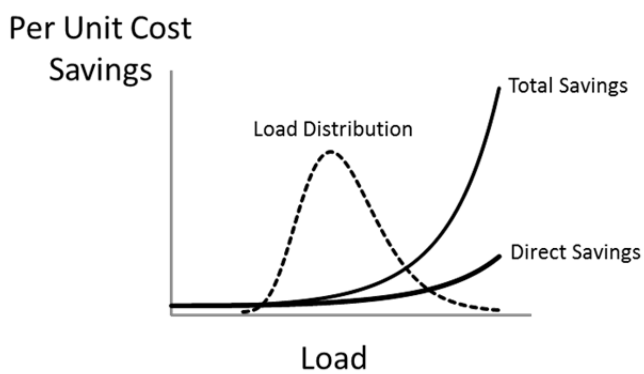
<u>Total Value</u>

The previous sections calculated the cost savings at a specific instant in time. The total cost savings is calculated by summing this result overall all periods in time. The per unit cost savings is calculated by dividing by the total energy. (Note that it is assumed that each unit of time represents 1 unit). The result is that:

$$Per\ Unit\ Cost\ Savings = \frac{Total\ Cost\ Savings}{Total\ Energy} = \frac{\sum_{t=1}^{T}\left[P_t + \frac{\Delta P_t}{\Delta L_t} L_t - \Delta P_t\right]\Delta L_t}{\sum_{t=1}^{T}\Delta L_t} \quad (5)$$

This result can be viewed graphically as the probability distribution of the load times the associate cost savings curves when there is a constant load reduction. Multiply the load distribution by the total per unit savings to obtain the weighted average per unit cost savings.

Figure 8. Apply load distribution to calculate total savings over time.



Application

As discussed above, all of the parameters required to perform this calculation can be measured directly except for the change in price. Thus, it is crucial to determine how to estimate the change in price.

This is implemented in four steps:

1. Obtain LMP price data and develop a model that reflects this data.
2. Use the LMP price model and Equation (4) to calculate the price suppression benefit. Note that this depends upon the size of the change in load.
3. Obtain time-correlated PV system output and determine the distribution of this output relative to the load.
4. Multiply the PV output distribution times the price suppression benefit to calculate the weighted-average benefit.

Historical LMP and time- and location-correlated PV output data are required to perform the analysis. LMPs are obtained from the market and the PV output data are obtained by simulating time- and location-specific PV output using SolarAnywhere.

Figure 9 illustrates how to perform the calculations using measured prices and simulated PV output for PPL in June 2012. The left side of the figure illustrates that the historical LMPs (black circles) are used to develop a price model (solid black line). The center of the figure illustrates how the price model is used with Equation (4) is used to calculate the price suppression benefit for every load level. Since this benefit depends upon the size of the change in the load, the figure presents a range. The solid blue line is the benefit for a very small PV output. The dashed blue line corresponds to the benefit for a 1,000 MW PV output. The right side of the figure (red line) presents the distribution of the PV energy relative to the load (i.e., the amount of PV energy produced at each load level, so higher values correspond to more frequent weighting). The weighted-average price suppression benefit is calculated by multiply the PV output distribution times the price suppression benefit. Note that in practice, the actual calculation is performed for each hour of the analysis since the price suppression benefit is a function of both the load and the PV output.

Figure 9. Illustration of how to calculate benefit using measured data for June 2011.

Step 1:	Step 2:	Step 3:
Develop price model based on measured LMP data	Calculate price reduction benefit (depends on output)	Develop PV output distribution

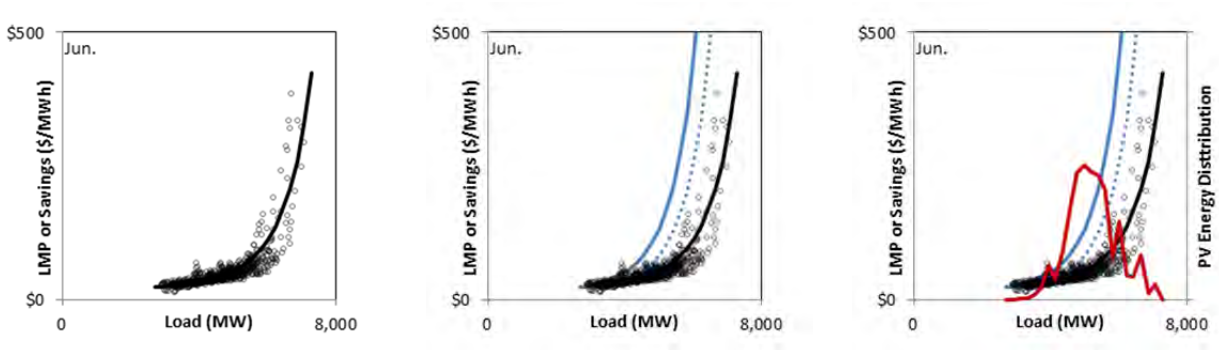
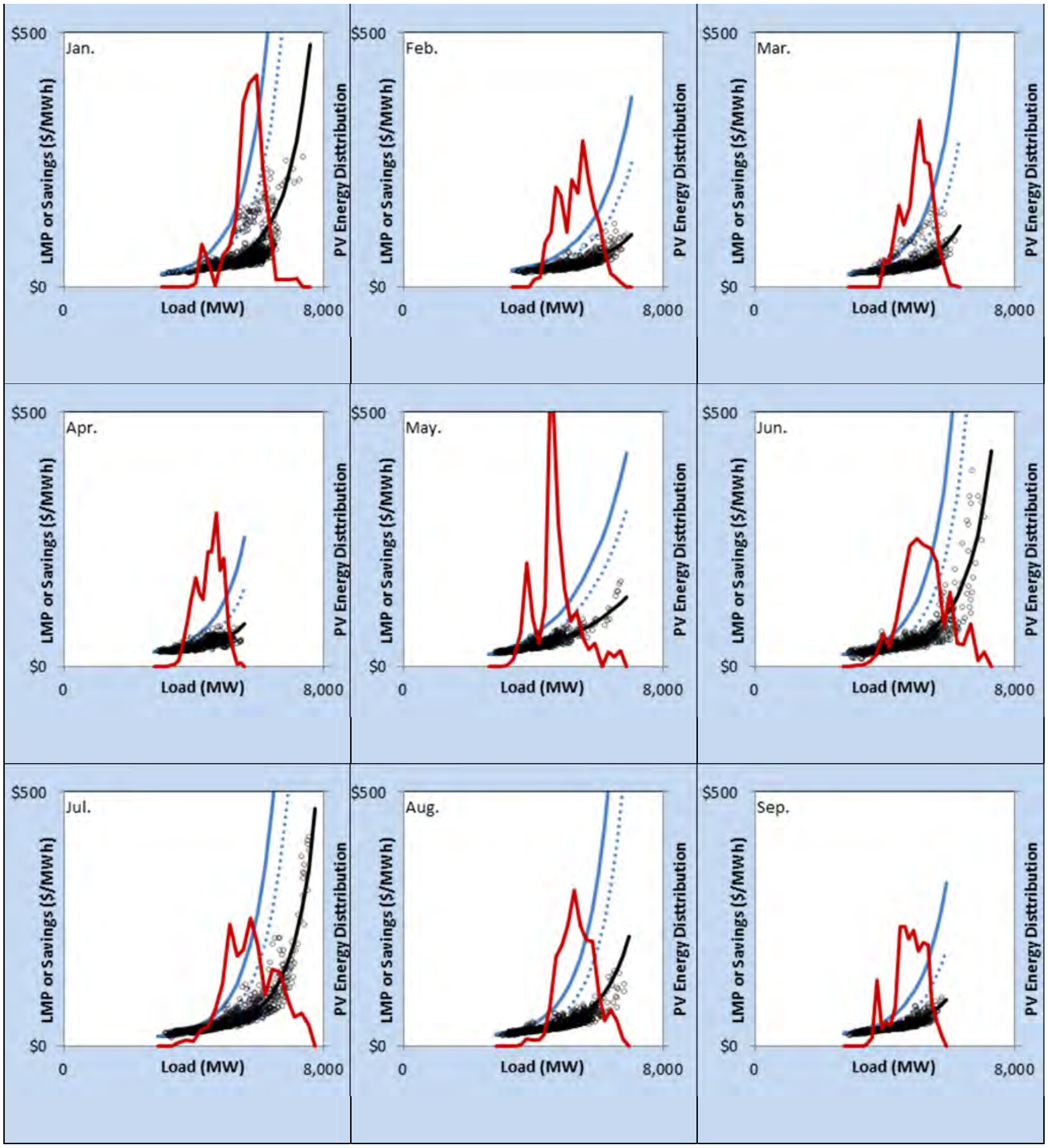
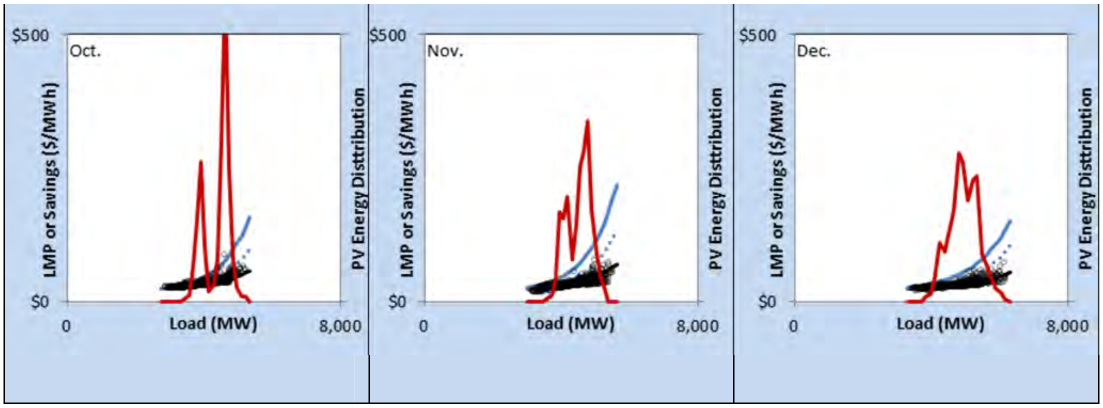


Figure 10 presents the results for the three steps for each month in 2011.

Figure 10. Measured and modeled LMPs (black circles and lines), price suppression benefit (solid blue for small output and dashed blue for 1,000 MW of output) and PV output distribution (PPL 2011).





Results

As illustrated in Table 7 the price reduction benefits are more than double the direct savings for a 100 MW of PV and slightly exceed the direct saving for 1,000 MW PV, for a combined value ranging from $127/MWh to $180/MWh.

Table 7. Market savings illustration.

	100 MW	1,000 MW
Direct Savings	$58	$58
Market Price Reduction	$122	$69
Total	$180	$127

A comparison of direct market savings and energy savings as calculated in this study is shown in Table 8. Fuel cost savings and O&M cost savings are combined because they represent the same costs that are included in market price. Direct savings were calculated for each hour as P·ΔL, summed for the year, and escalated at the same rate each year as natural gas futures beyond the 12 year limit.

Table 8. Direct market savings comparison (Newark, South-30).

	Value ($/kW)	Value ($/MWh)
Fuel Cost Savings	$709	38.8
O&M Cost Savings	$345	18.9
Total Energy Savings	**$1,054**	**57.7**
Direct Market Savings	**$1,470**	**80.4**

The results show that direct market savings are 39% above the energy savings. This discrepancy reflects the fact that the two quantities, while representing the same value components, use entirely different approaches. Fuel cost savings are derived from natural gas futures, discounted at the utility discount rate, and applied against an assumed CCGT heat rate. Direct market savings are based on hourly PJM zonal prices for 2011.

The energy savings achieved by the utility is based on avoided market purchases. However, historical market prices are not necessarily an indicator of future years, especially for 30 years into the future. For this reason, the energy savings methodology used in this analysis is more closely tied to the fundamentals of the cost: fuel and O&M costs that must be recovered by the marketplace for generation to be sustainable in the long run.

Zonal Price Model

To calculate the market price reduction in equation (4), a zonal price model was developed as follows. A function F() may be defined whose value is proportional to market clearing price using the form:

$$F(Load) = Ae^{BxLoad^{C}+D}$$

where coefficients A, B, C, and D are evaluated for each utility and for each month using hourly PJM zonal market price data, amounting to a total of 84 individual models.

P is the zonal wholesale clearing price, and P* is given by:

$$\frac{P^*}{P} = \frac{F(Load - FleetPower - LossSavings)}{F(Load)}$$

The market price reduction (in $/MWh) is calculated using the relevant term in Equation (4) and multiplying by the change in load, including loss savings.

Environmental Value

Introduction

It is well established that the environmental impact of PV is considerably smaller than that of fossil-based generation since PV is able to displace pollution associated with drilling/mining, and power plant emissions [15].

Methodology

There are two general approaches to quantifying the Environmental Value of PV: a regulatory cost-based approach and an environmental/health cost-based approach.

The regulatory cost-based approach values the Environmental Value of PV based on the price of Renewable Energy Credits (RECs) or Solar Renewable Energy Credits (SRECs) that would otherwise have to be purchased to satisfy state Renewable Portfolio Standards (RPS). These costs are a preliminary legislative attempt to quantify external costs. They represent actual business costs faced by utilities in certain states.

An environmental/health cost-based approach quantifies the societal costs resulting from fossil generation. 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., that are all present or postponed costs to society. Several exhaustive studies have estimated the environmental/health cost of energy generated by fossil-based generation [16], [17]. The results from environmental/health cost-based approach often vary widely and can be controversial.

The environmental/health cost-based approach was used for this study.

The environmental footprint of solar generation is considerably smaller than that of the fossil fuel technologies generating most of our electricity (e.g., [19]). 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 in New Jersey and Pennsylvania 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 real and quantifiable however: depending on the current generation mix, 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 (i.e., the taxpayers).

The environmental value, EV, of each kWh produced by PV (i.e., not produced by another conventional source) is given by:

$$EV = \sum_{i=0}^{n} x_i \, EC_i$$

Where EC_i is the environmental cost of the displaced conventional generation technology and x_i is the proportion of this technology in the current energy mix.

Several exhaustive studies emanating from such diverse sources as the nuclear industry or the medical community ([20], [21]) estimate the environmental/health cost of 1 MWh generated by coal at $90-250, while a [non-shale[14]] natural gas MWh has an environmental cost of $30-60.

Considering New Jersey and Pennsylvania's electrical generation mixes (Table 9) and assuming that (1) nuclear energy is not displaced by PV at the assumed penetration level[15] and (2) that all natural gas is conventional, the environmental value of each MWh displaced by PV, hence the taxpayer benefit, is estimated at $48 to $129 in Pennsylvania and $20 to $48 in New Jersey.

We retained a value near the lower range of these estimates for the present analysis.

[14] Shale gas environmental footprint is likely higher both in terms of environment degradation and GHG emissions.

[15] The study therefore ascribes no environmental value related to nuclear generation. Scenarios can certainly be designed in which nuclear generation would be displaced, in which case the environmental cost of nuclear generation would have to be considered. This is a complex and controversial subject that reflects the probability of catastrophic accidents and the environmental footprint of the existing uranium cycle. The fact that the environmental liability is assumed to be zero under the present study may therefore be considered a conservative case.

Table 9. Environmental input calculation.

	Generation Mix		Prorated Environmental Cost ($/MWh)		
Pennsylvania	48%	Coal	43.2	to	120.0
	15%	Natural Gas	4.5	to	9.0
	34%	Nuclear	0.0	to	0.0
	3%	Other	0.0	to	0.0
	Environmental Value for PA		47.7	to	129.0
New Jersey	10%	Coal	9.0	to	25.0
	38%	Natural Gas	11.4	to	22.8
	50%	Nuclear	0.0	to	0.0
	2%	Other	0.0	to	0.0
	Environmental Value for NJ		20.4	to	47.8

Economic Development Value

The German and Ontario experiences as well as the experience in New Jersey, where fast PV growth is occurring, show that solar energy sustains more jobs per unit of energy generated than conventional energy ([21], [22]). 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.

In this report, only tax revenue enhancement from the jobs created as a measure of PV-induced economic development value is considered. This metric provides a tangible low estimate of solar energy's likely larger multifaceted economic development value. In Pennsylvania and New Jersey, this low estimate amounts to respectively $39 and $40 per MWh, even under the very conservative, but thus far realistic, assumption that 80% of the PV manufacturing jobs would be either out-of-state or foreign (see methodology section, below).

Methodology

In a previous (New York) study [24], net PV-related job creation numbers were used directly based upon Ontario and Germany's historical numbers. However this assumption does not reflects the rapid changes of the PV industry towards lower prices. In this study a first principle approach is applied based upon the difference between the installed cost of PV and conventional generation: in essence this approach quantifies the fact that part of the price premium paid for PV vs. conventional generation returns to the local economy in the form of jobs hence tax.

Therefore, assuming that:

- Turnkey PV costs $3,000 per kW vs. $1,000 per kW for combine cycle gas turbines (CCGT)
- Turnkey PV cost is composed of 1/3 technology (modules & inverter/controls) and 2/3 structure and installation and soft costs.
- 20% of the turnkey PV technology cost and 90% of the other costs are traceable to local jobs, while 50% of the CCGT are assumed to be local jobs, thus:
    - The local jobs-traceable amount spent on PV is equal to: $\left(\frac{0.2}{3}+\frac{0.9\times2}{3}\right)\times 3000 = \$1{,}990/kW$
    - And the local jobs-traceable amount spent on CCGT is equal to: $0.5 \times 1000 = \$500/kW$
- PV systems in NJ and PA have a capacity factor of ~ 16%, producing ~ 1,400 kWh per year per kW_{AC} and CCGT have an assumed capacity factor of 50%, producing 4,380 kWh per year, therefore
    - The local jobs-traceable amount spent per PV kWh in year one is: 1,900/1,400 = $1.42
    - The local jobs-traceable amount spent per CCGT kWh in year one is: 500/4,380 = $0.114
- The net local jobs-traceable between PV and CCGT is thus equal to 1.42-0.11 = $1.30
- Assuming that the life span of both PV and CCGT is 30 years, and using a levelizing factor of 8%, the net local jobs-traceable amount per generated PV kWh over its lifetime amounts to: $1.30 \times \frac{0.08\times1.08^{30}}{1.08^{29}} = \$0.116/\text{kWh}$
- Assuming that locally-traceable O&M costs per kWh for PV are equal to the locally-traceable O&M costs for CCGT, [16] but also assuming that because PV-related T&D benefits displace a commensurate amount of utility jobs assumed to be equal to this benefit (~0.5 cents per kWh), the net lifetime locally-traceable PV-CCGT difference is equal to 0.116-0.005 = $0.111/kWh
- Finally assuming that each PV job is worth $75K/year after standard deductions – hence has a combined State and Federal income tax rate of 22.29% in PA and 22.67% in NJ[17] -- and that each

[16] This includes only a fraction of the fuel costs – the other fraction being imported from out-of-state.

[17] For the considered solar job income level, the effective state rate = 3.07% in PA and 3.54% in NJ and the effective federal rate = 19.83%. The increased federal tax collection is counted as an increase for New Jersey's

new job has an indirect job multiplier of 1.6,[18] it can be argued that each PV MWh represents a net new-job related tax collection increase for NJ equal to a levelized value of $\$111/\mathrm{MWh} \times 0.2267 \times 1.6 = \$40/\mathrm{MWh}$, and a tax collection increase for PA equal to $\$111/\mathrm{MWh} \times 0.2229 \times 1.6 = \$39/\mathrm{MWh}$.

Solar Penetration 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 to the utility and to its ratepayers. 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. [31] showed that in much of the US, this cost is negligible at low penetration and remains manageable for a solar capacity penetration of 30%. For utilities representative of the demand pattern and solar load synergies found in Pennsylvania, this penetration cost has been found to range from 0 to 5 cents per kWh when PV penetration ranges from 0% to 30% in capacity. Up to this level of penetration, the infrastructural and operational expense would consist of localized load management, [user-sited] storage and/or backup.[19] At the 15% level of penetration considered in this study, the cost of penetration can be estimated from the Perez et al. study[18] at \$10-20/MWh.

taxpayer, because it can be reasonably argued that federal taxes are (1) redistributed fairly to the states and (2) that federal expense benefit all states equally.

[18] 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

[19] At the higher penetration levels the two approaches to consider would be regional (or continental) interconnection upgrade and smart coupling with natural gas generation and wind power generation – the cost of these approaches has not been quantified as part of this study.

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Appendix 3: Detailed Results

Pittsburgh

Table A4- 1. Technical results, Pittsburgh.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	475	475	475	475
Annual Energy Production (MWh)	716,621	631,434	595,373	892,905
Capacity Factor (%)	17%	15%	14%	21%
Generation Capacity (% of Fleet Capacity)	41%	43%	45%	48%
T&D Capacity (% of Fleet Capaccity)	31%	32%	32%	32%

Table A4- 2. Value ($/kW), Pittsburgh.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$813	$719	$678	$1,011
O&M Cost Savings	$396	$350	$331	$493
Total Energy Value	$1,209	$1,069	$1,009	$1,503
Strategic				
Security Enhancement Value	$446	$394	$372	$554
Long Term Societal Value	$557	$493	$465	$693
Total Strategic Value	$1,003	$887	$837	$1,247
Other				
Fuel Price Hedge Value	$613	$542	$512	$763
Generation Capacity Value	$432	$446	$468	$505
T&D Capacity Value	$127	$127	$130	$129
Market Price Reduction Value	$696	$718	$715	$740
Environmental Value	$1,064	$940	$888	$1,322
Economic Development Value	$870	$769	$726	$1,081
(Solar Penetration Cost)	($446)	($394)	($372)	($554)
Total Other Value	$3,355	$3,149	$3,067	$3,987
Total Value	**$5,568**	**$5,105**	**$4,913**	**$6,737**

Table A4- 3. Levelized Value ($/MWh), Pittsburgh.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$41	$41	$41	$41
O&M Cost Savings	$20	$20	$20	$20
Total Energy Value	$61	$61	$62	$61
Strategic				
Security Enhancement Value	$23	$23	$23	$23
Long Term Societal Value	$28	$28	$28	$28
Total Strategic Value	$51	$51	$51	$51
Other				
Fuel Price Hedge Value	$31	$31	$31	$31
Generation Capacity Value	$22	$26	$29	$21
T&D Capacity Value	$6	$7	$8	$5
Market Price Reduction Value	$35	$41	$44	$30
Environmental Value	$54	$54	$54	$54
Economic Development Value	$44	$44	$44	$44
(Solar Penetration Cost)	($23)	($23)	($23)	($23)
Total Other Value	$170	$181	$187	$162
Total Value	**$282**	**$293**	**$300**	**$274**

Figure A4- 1. Value ($/kW), Pittsburgh.

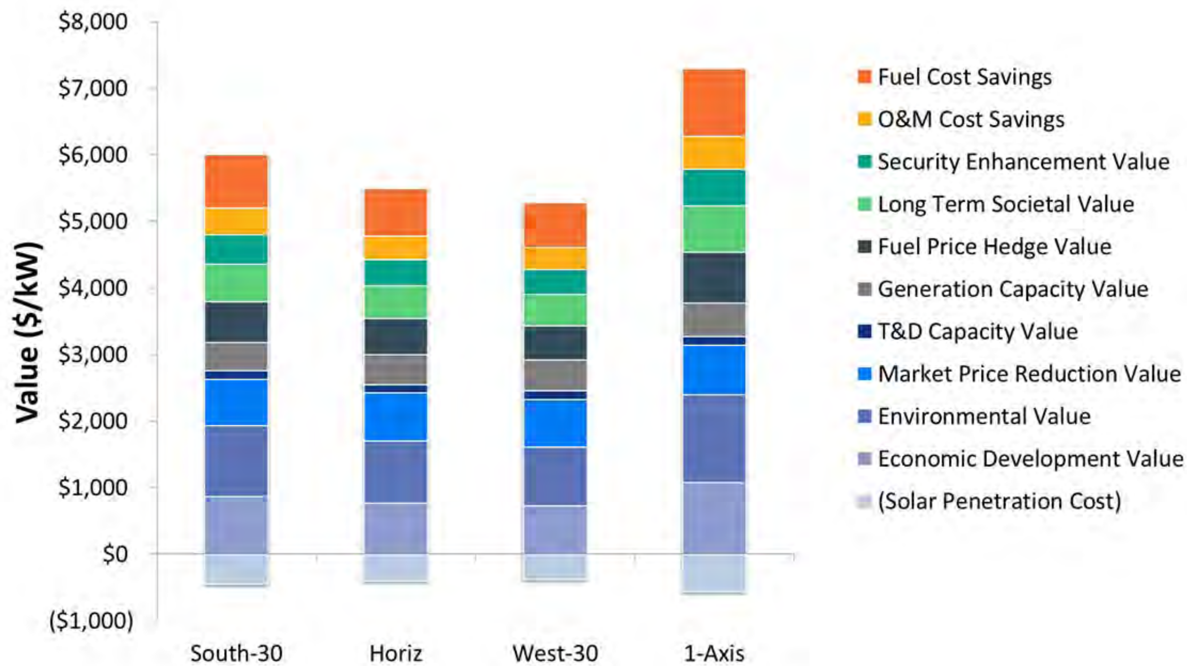
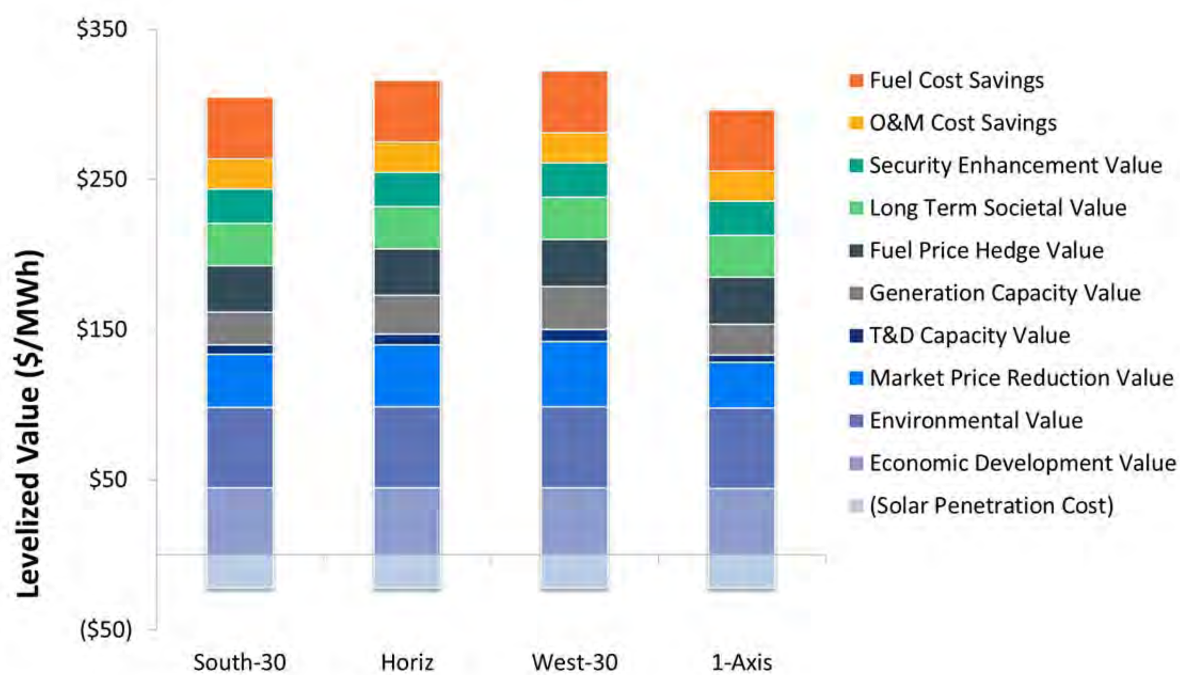


Figure A4- 2. Levelized Value ($/MWh), Pittsburgh.



Harrisburg[20]

Table A4- 4. Technical results, Harrisburg.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	1129	1129	1129	1129
Annual Energy Production (MWh)	1,809,443	1,565,940	1,461,448	2,274,554
Capacity Factor (%)	18%	16%	15%	23%
Generation Capacity (% of Fleet Capacity)	28%	27%	26%	32%
T&D Capacity (% of Fleet Capaccity)	14%	14%	14%	14%

Table A4- 5. Value results ($/kW), Harrisburg.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$751	$652	$608	$942
O&M Cost Savings	$366	$318	$296	$459
Total Energy Value	$1,117	$969	$904	$1,401
Strategic				
Security Enhancement Value	$424	$368	$343	$532
Long Term Societal Value	$530	$460	$429	$665
Total Strategic Value	$954	$827	$772	$1,196
Other				
Fuel Price Hedge Value	$786	$682	$636	$985
Generation Capacity Value	$297	$287	$274	$336
T&D Capacity Value	$24	$24	$24	$24
Market Price Reduction Value	$1,241	$1,224	$1,171	$1,335
Environmental Value	$1,011	$877	$819	$1,268
Economic Development Value	$827	$717	$669	$1,037
(Solar Penetration Cost)	($424)	($368)	($343)	($532)
Total Other Value	$3,761	$3,444	$3,249	$4,454
Total Value	**$5,832**	**$5,240**	**$4,925**	**$7,051**

[20] Scranton and Harrisburg constitute two examples of a 15% penetration within PPL territory. Strictly speaking this does not amount to a 30% penetration, but two examples of 15% grid penetration where resource would be deployed in either location, illustrating how results are influenced by the location choice, everything else (utility and economic assumptions) being equal.

Table A4- 6. Levelized Value results ($/MWh), Harrisburg.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$41	$41	$41	$40
O&M Cost Savings	$20	$20	$20	$20
Total Energy Value	$60	$61	$60	$60
Strategic				
Security Enhancement Value	$23	$23	$23	$23
Long Term Societal Value	$29	$29	$29	$29
Total Strategic Value	$52	$52	$52	$51
Other				
Fuel Price Hedge Value	$42	$43	$43	$42
Generation Capacity Value	$16	$18	$18	$14
T&D Capacity Value	$1	$1	$2	$1
Market Price Reduction Value	$67	$76	$78	$57
Environmental Value	$55	$55	$55	$55
Economic Development Value	$45	$45	$45	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($23)
Total Other Value	$203	$215	$217	$191
Total Value	**$315**	**$327**	**$330**	**$303**

Figure A4- 3. Value ($/kW), Harrisburg.

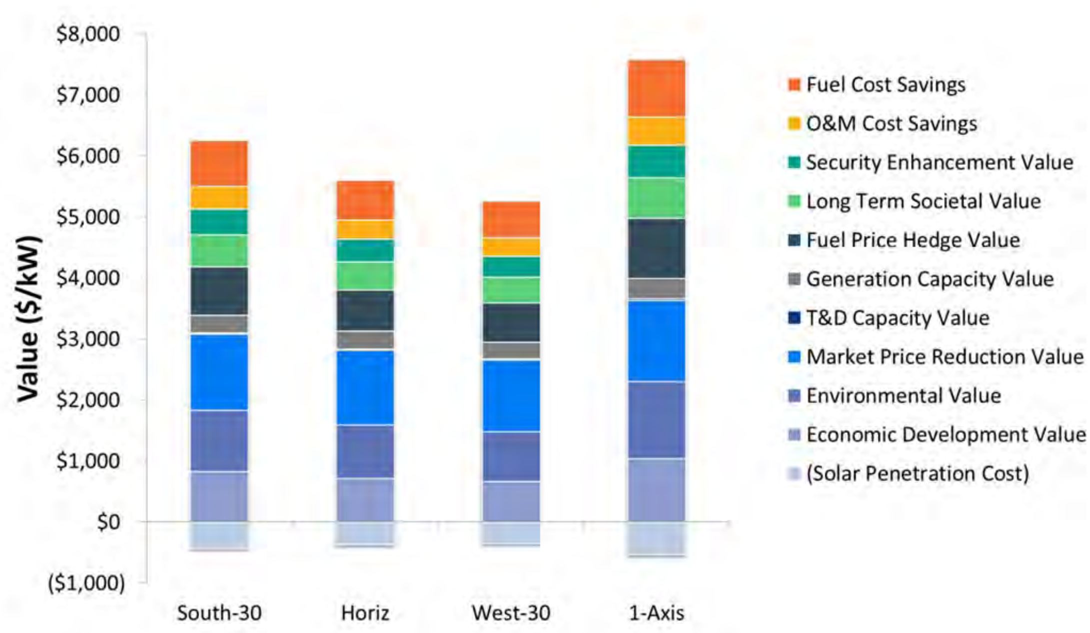
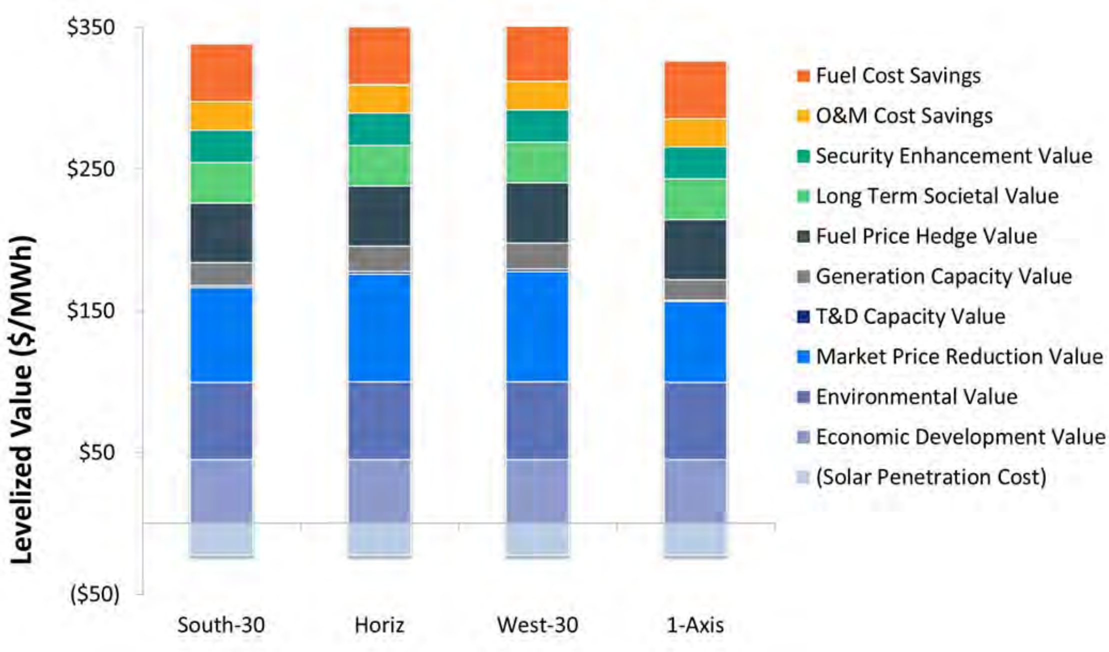


Figure A4- 4. Levelized Value ($/MWh), Harrisburg.



Scranton

Table A4- 7. Technical results, Scranton.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	1129	1129	1129	1129
Annual Energy Production (MWh)	1,698,897	1,479,261	1,386,699	2,123,833
Capacity Factor (%)	17%	15%	14%	21%
Generation Capacity (% of Fleet Capacity)	28%	27%	26%	32%
T&D Capacity (% of Fleet Capaccity)	14%	14%	14%	14%

Table A4- 8. Value ($/kW), Scranton.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$706	$616	$577	$880
O&M Cost Savings	$344	$300	$281	$429
Total Energy Value	$1,050	$916	$859	$1,309
Strategic				
Security Enhancement Value	$398	$348	$326	$497
Long Term Societal Value	$498	$435	$407	$621
Total Strategic Value	$896	$782	$733	$1,118
Other				
Fuel Price Hedge Value	$738	$644	$604	$921
Generation Capacity Value	$290	$283	$276	$336
T&D Capacity Value	$24	$24	$24	$24
Market Price Reduction Value	$1,206	$1,193	$1,157	$1,311
Environmental Value	$950	$829	$777	$1,185
Economic Development Value	$777	$678	$636	$969
(Solar Penetration Cost)	($398)	($348)	($326)	($497)
Total Other Value	$3,586	$3,303	$3,148	$4,249
Total Value	**$5,532**	**$5,001**	**$4,740**	**$6,676**

Table A4- 9. Levelized Value ($/MWh), Scranton.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$41	$41	$41	$41
O&M Cost Savings	$20	$20	$20	$20
Total Energy Value	$60	$61	$61	$60
Strategic				
Security Enhancement Value	$23	$23	$23	$23
Long Term Societal Value	$29	$29	$29	$29
Total Strategic Value	$52	$52	$52	$51
Other				
Fuel Price Hedge Value	$42	$43	$43	$42
Generation Capacity Value	$17	$19	$19	$15
T&D Capacity Value	$1	$2	$2	$1
Market Price Reduction Value	$69	$79	$82	$60
Environmental Value	$55	$55	$55	$55
Economic Development Value	$45	$45	$45	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($23)
Total Other Value	$206	$218	$222	$196
Total Value	**$318**	**$331**	**$334**	**$307**

Figure A4- 5. Value ($/kW), Scranton.

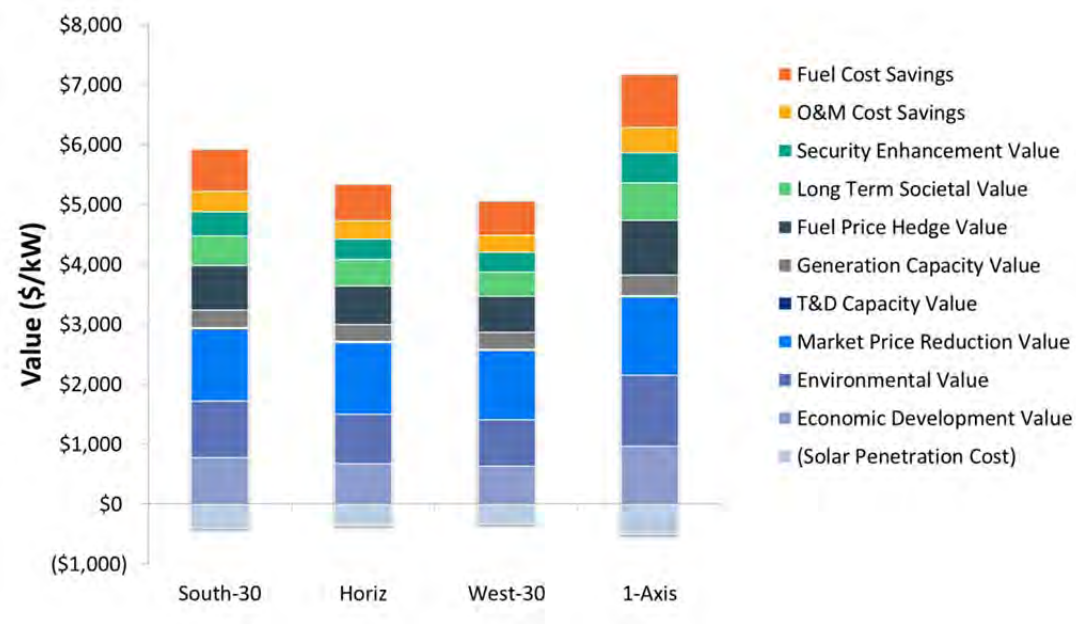
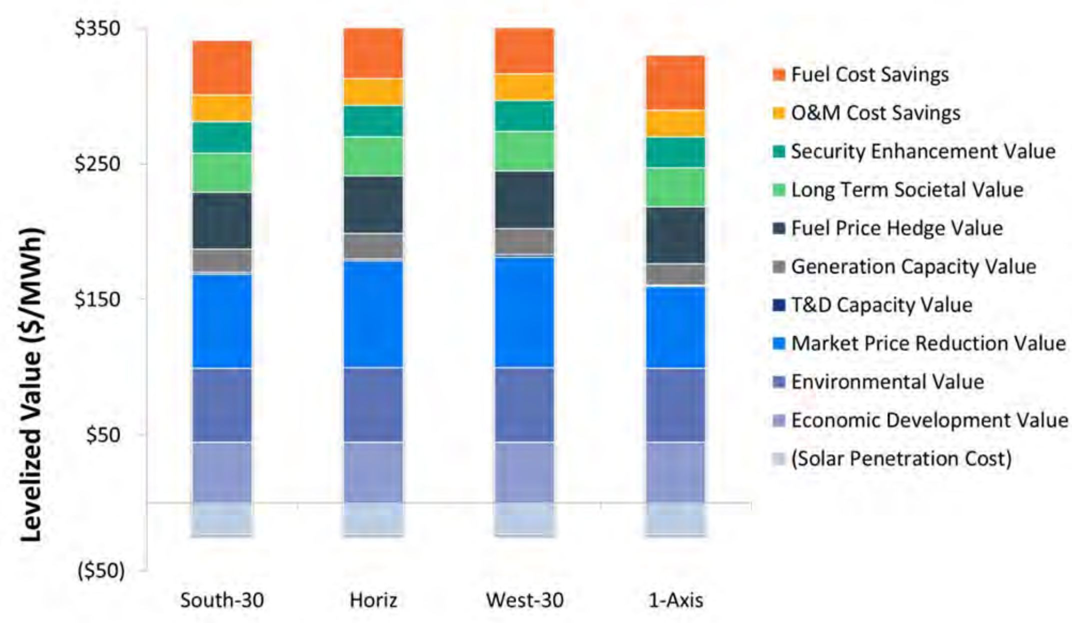


Figure A4- 6. Levelized Value ($/MWh), Scranton.



Philadelphia

Table A4- 10. Technical results, Philadelphia.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	1348	1348	1348	1348
Annual Energy Production (MWh)	2,339,424	1,991,109	1,847,394	2,943,101
Capacity Factor (%)	20%	17%	16%	25%
Generation Capacity (% of Fleet Capacity)	38%	40%	43%	46%
T&D Capacity (% of Fleet Capaccity)	21%	21%	21%	21%

Table A4- 11. Value results ($/kW), Philadelphia.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$706	$602	$559	$886
O&M Cost Savings	$344	$294	$273	$432
Total Energy Value	$1,049	$896	$832	$1,318
Strategic				
Security Enhancement Value	$405	$346	$321	$509
Long Term Societal Value	$507	$432	$402	$636
Total Strategic Value	$912	$778	$723	$1,145
Other				
Fuel Price Hedge Value	$876	$747	$694	$1,100
Generation Capacity Value	$401	$418	$452	$483
T&D Capacity Value	$65	$65	$65	$65
Market Price Reduction Value	$1,013	$1,027	$1,018	$1,103
Environmental Value	$967	$825	$766	$1,214
Economic Development Value	$790	$675	$626	$993
(Solar Penetration Cost)	($405)	($346)	($321)	($509)
Total Other Value	$3,706	$3,412	$3,300	$4,449
Total Value	**$5,667**	**$5,086**	**$4,855**	**$6,912**

Table A4- 12. Levelized Value results ($/MWh), Philadelphia.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$38	$38	$38	$38
O&M Cost Savings	$18	$19	$19	$18
Total Energy Value	$56	$57	$57	$56
Strategic				
Security Enhancement Value	$22	$22	$22	$22
Long Term Societal Value	$27	$27	$27	$27
Total Strategic Value	$49	$49	$49	$49
Other				
Fuel Price Hedge Value	$47	$47	$47	$47
Generation Capacity Value	$22	$26	$31	$21
T&D Capacity Value	$3	$4	$4	$3
Market Price Reduction Value	$54	$65	$69	$47
Environmental Value	$52	$52	$52	$52
Economic Development Value	$42	$43	$43	$42
(Solar Penetration Cost)	($22)	($22)	($22)	($22)
Total Other Value	$199	$215	$224	$190
Total Value	**$304**	**$321**	**$330**	**$295**

Figure A4- 7. Value ($/kW), Philadelphia.

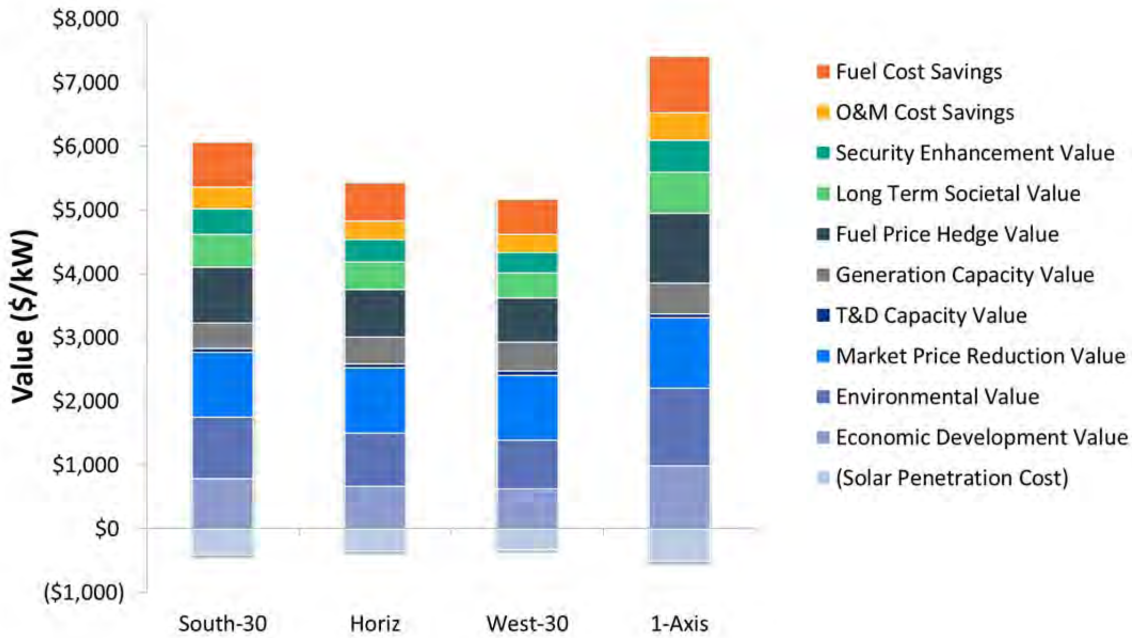
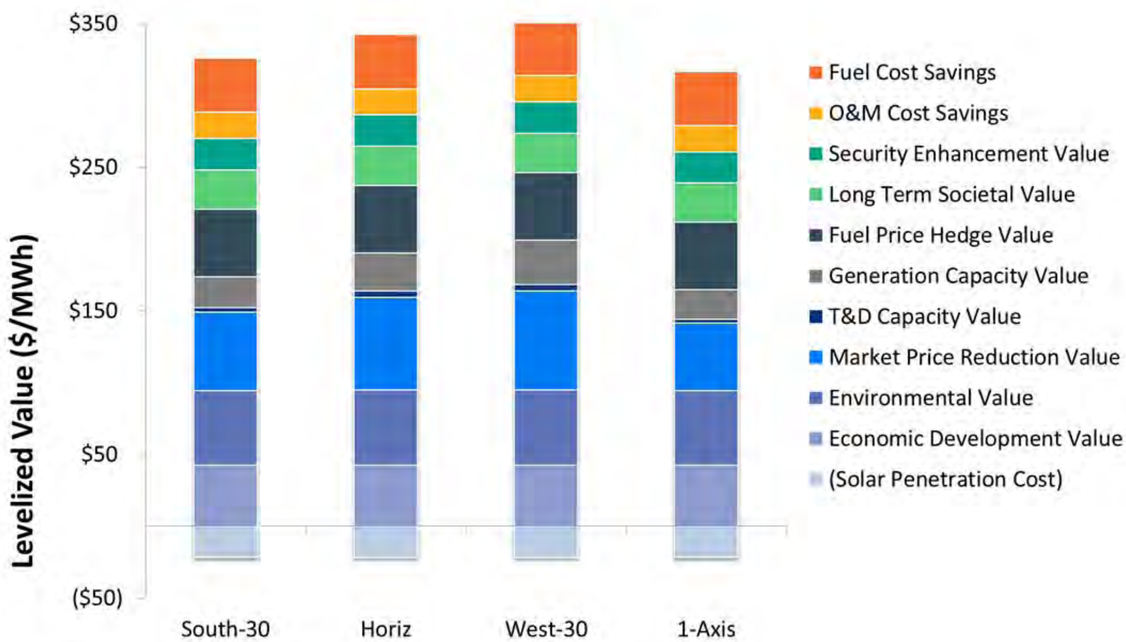


Figure A4- 8. Levelized Value ($/MWh), Philadelphia.



Jamesburg

Table A4- 13. Technical results, Jamesburg.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	991	991	991	991
Annual Energy Production (MWh)	1,675,189	1,431,899	1,315,032	2,102,499
Capacity Factor (%)	19%	16%	15%	24%
Generation Capacity (% of Fleet Capacity)	45%	47%	51%	52%
T&D Capacity (% of Fleet Capaccity)	29%	31%	29%	26%

Table A4- 14. Value results ($/kW), Jamesburg.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$1,020	$878	$808	$1,276
O&M Cost Savings	$497	$428	$394	$622
Total Energy Value	$1,517	$1,306	$1,203	$1,898
Strategic				
Security Enhancement Value	$549	$472	$435	$686
Long Term Societal Value	$686	$590	$544	$858
Total Strategic Value	$1,234	$1,062	$978	$1,544
Other				
Fuel Price Hedge Value	$586	$504	$465	$733
Generation Capacity Value	$468	$496	$531	$546
T&D Capacity Value	$23	$25	$23	$21
Market Price Reduction Value	$1,266	$1,306	$1,315	$1,363
Environmental Value	$560	$482	$444	$700
Economic Development Value	$1,097	$944	$870	$1,373
(Solar Penetration Cost)	($549)	($472)	($435)	($686)
Total Other Value	$3,451	$3,285	$3,212	$4,050
Total Value	**$6,202**	**$5,653**	**$5,393**	**$7,492**

Table A4- 15. Levelized Value results ($/MWh), Jamesburg.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$42	$42	$43	$42
O&M Cost Savings	$21	$21	$21	$21
Total Energy Value	$63	$63	$63	$63
Strategic				
Security Enhancement Value	$23	$23	$23	$23
Long Term Societal Value	$28	$29	$29	$28
Total Strategic Value	$51	$51	$52	$51
Other				
Fuel Price Hedge Value	$24	$24	$24	$24
Generation Capacity Value	$19	$24	$28	$18
T&D Capacity Value	$1	$1	$1	$1
Market Price Reduction Value	$52	$63	$69	$45
Environmental Value	$23	$23	$23	$23
Economic Development Value	$45	$46	$46	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($23)
Total Other Value	$143	$159	$169	$134
Total Value	**$257**	**$274**	**$284**	**$247**

Figure A4- 9. Value ($/kW), Jamesburg.

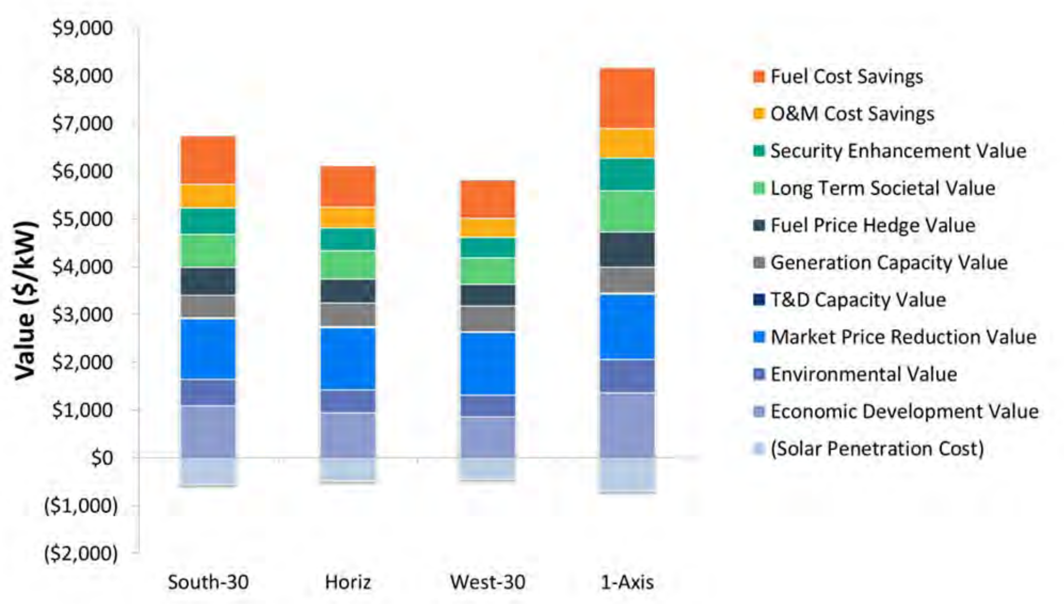
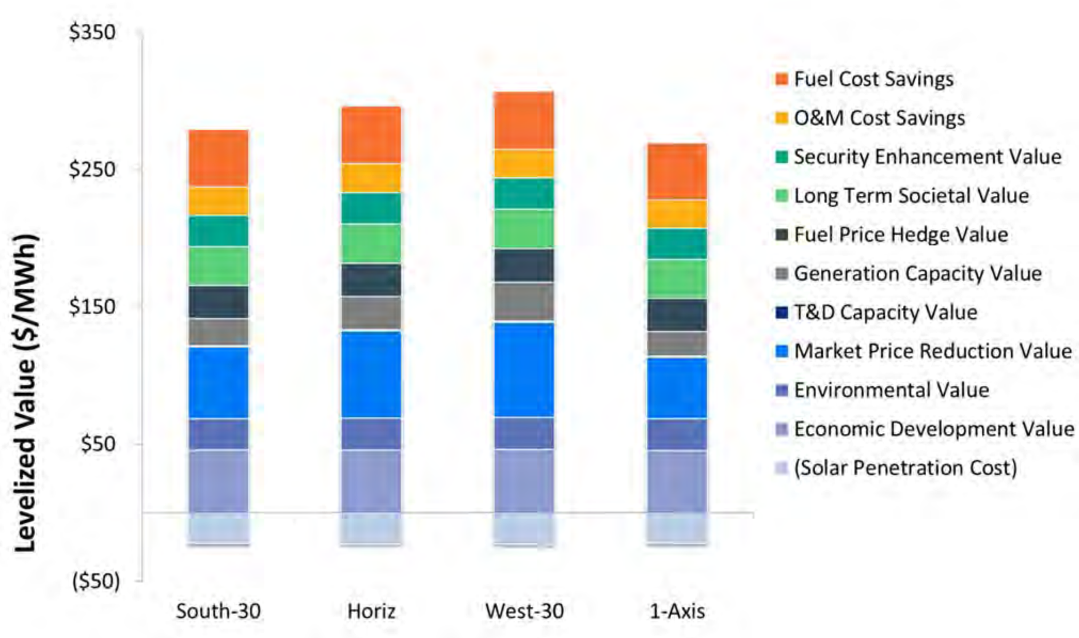


Figure A4- 10. Levelized Value ($/MWh), Jamesburg.



Newark

Table A4- 16. Technical results, Newark.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	1640	1640	1640	1640
Annual Energy Production (MWh)	2,677,626	2,303,173	2,118,149	3,350,313
Capacity Factor (%)	19%	16%	15%	23%
Generation Capacity (% of Fleet Capacity)	45%	47%	51%	54%
T&D Capacity (% of Fleet Capaccity)	56%	57%	57%	57%

Table A4- 17. Value results ($/kW), Newark.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$709	$612	$564	$885
O&M Cost Savings	$345	$298	$275	$431
Total Energy Value	$1,054	$911	$839	$1,317
Strategic				
Security Enhancement Value	$403	$348	$321	$503
Long Term Societal Value	$504	$435	$401	$629
Total Strategic Value	$907	$783	$721	$1,132
Other				
Fuel Price Hedge Value	$798	$689	$635	$996
Generation Capacity Value	$470	$489	$534	$568
T&D Capacity Value	$147	$151	$151	$151
Market Price Reduction Value	$927	$959	$958	$989
Environmental Value	$411	$355	$327	$513
Economic Development Value	$806	$696	$641	$1,007
(Solar Penetration Cost)	($403)	($348)	($321)	($503)
Total Other Value	$3,156	$2,991	$2,926	$3,721
Total Value	**$5,117**	**$4,685**	**$4,486**	**$6,170**

Table A4- 18. Levelized Value results ($/MWh), Newark.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$39	$39	$39	$39
O&M Cost Savings	$19	$19	$19	$19
Total Energy Value	$58	$58	$58	$58
Strategic				
Security Enhancement Value	$22	$22	$22	$22
Long Term Societal Value	$28	$28	$28	$28
Total Strategic Value	$50	$50	$50	$50
Other				
Fuel Price Hedge Value	$44	$44	$44	$44
Generation Capacity Value	$26	$31	$37	$25
T&D Capacity Value	$8	$10	$10	$7
Market Price Reduction Value	$51	$61	$66	$43
Environmental Value	$22	$23	$23	$22
Economic Development Value	$44	$44	$44	$44
(Solar Penetration Cost)	($22)	($22)	($22)	($22)
Total Other Value	$173	$190	$202	$163
Total Value	**$280**	**$298**	**$310**	**$270**

Figure A4- 11. Value ($/kW), Newark.

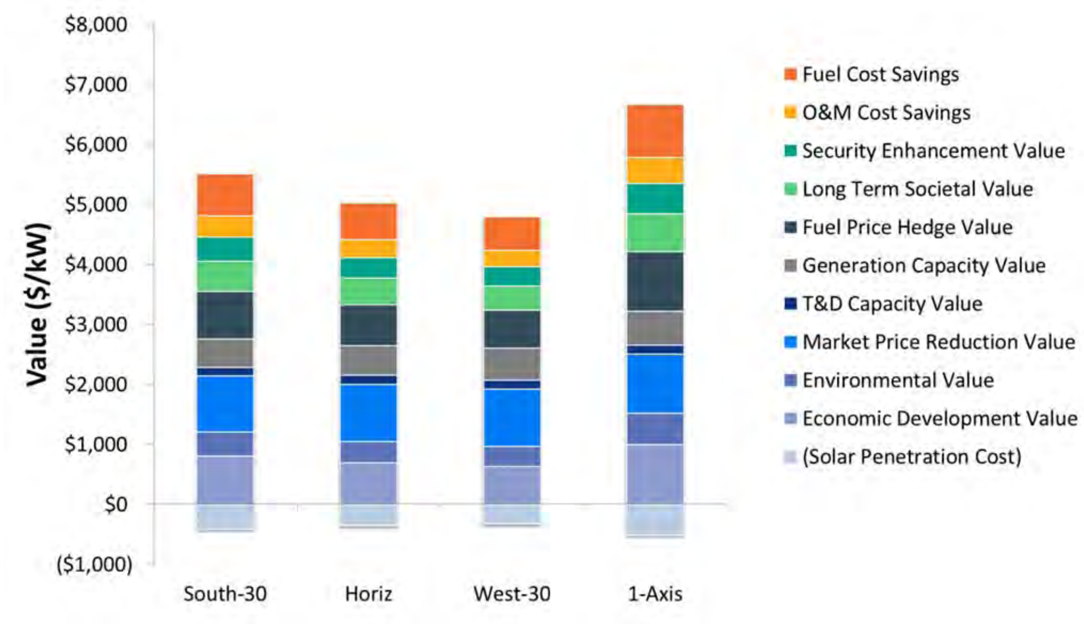
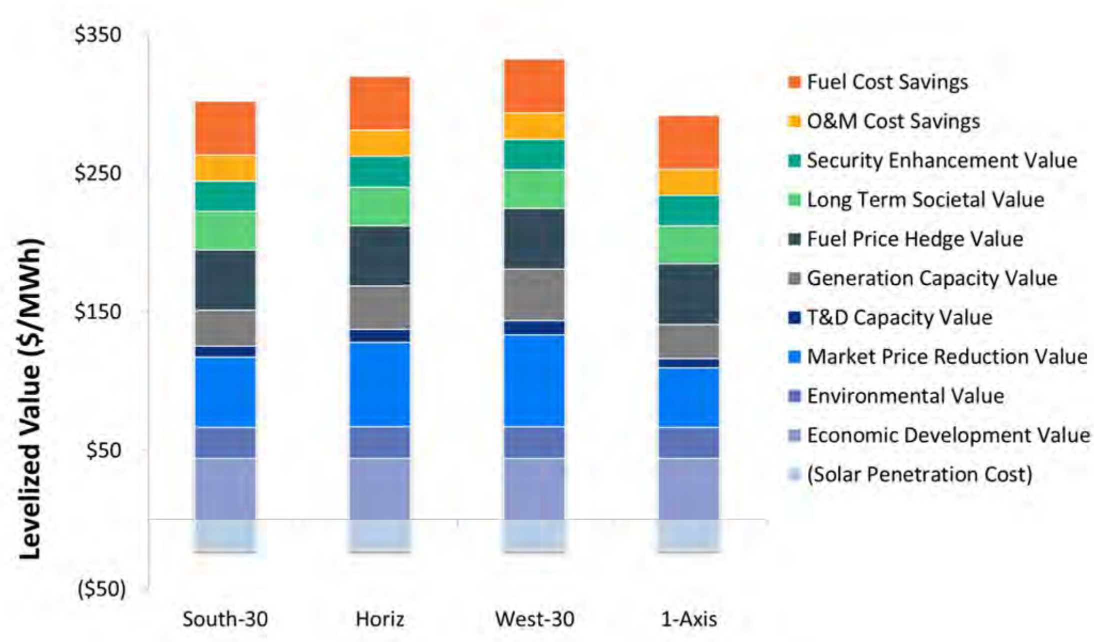


Figure A4- 12. Levelized Value ($/MWh), Newark.



Atlantic City

Table A4- 19. Technical results, Atlantic City.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	443	443	443	443
Annual Energy Production (MWh)	827,924	705,374	654,811	1,039,217
Capacity Factor (%)	21%	18%	17%	27%
Generation Capacity (% of Fleet Capacity)	46%	48%	54%	57%
T&D Capacity (% of Fleet Capaccity)	36%	37%	38%	36%

Table A4- 20. Value results ($/kW), Atlantic City.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$1,081	$927	$863	$1,354
O&M Cost Savings	$527	$452	$421	$660
Total Energy Value	$1,609	$1,380	$1,283	$2,015
Strategic				
Security Enhancement Value	$584	$501	$466	$732
Long Term Societal Value	$730	$626	$582	$914
Total Strategic Value	$1,314	$1,127	$1,048	$1,646
Other				
Fuel Price Hedge Value	$662	$567	$528	$828
Generation Capacity Value	$478	$503	$569	$600
T&D Capacity Value	$49	$51	$52	$49
Market Price Reduction Value	$1,412	$1,485	$1,508	$1,503
Environmental Value	$596	$511	$475	$746
Economic Development Value	$1,168	$1,002	$932	$1,463
(Solar Penetration Cost)	($584)	($501)	($466)	($732)
Total Other Value	$3,781	$3,618	$3,598	$4,458
Total Value	**$6,704**	**$6,125**	**$5,929**	**$8,119**

Table A4- 21. Levelized Value results ($/MWh), Atlantic City.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$41	$42	$42	$41
O&M Cost Savings	$20	$20	$20	$20
Total Energy Value	$61	$62	$62	$61
Strategic				
Security Enhancement Value	$22	$22	$22	$22
Long Term Societal Value	$28	$28	$28	$28
Total Strategic Value	$50	$50	$51	$50
Other				
Fuel Price Hedge Value	$25	$25	$25	$25
Generation Capacity Value	$18	$23	$27	$18
T&D Capacity Value	$2	$2	$2	$1
Market Price Reduction Value	$54	$66	$73	$46
Environmental Value	$23	$23	$23	$23
Economic Development Value	$45	$45	$45	$44
(Solar Penetration Cost)	($22)	($22)	($22)	($22)
Total Other Value	$144	$162	$174	$135
Total Value	**$256**	**$274**	**$286**	**$247**

Figure A4- 13. Value ($/kW), Atlantic City.

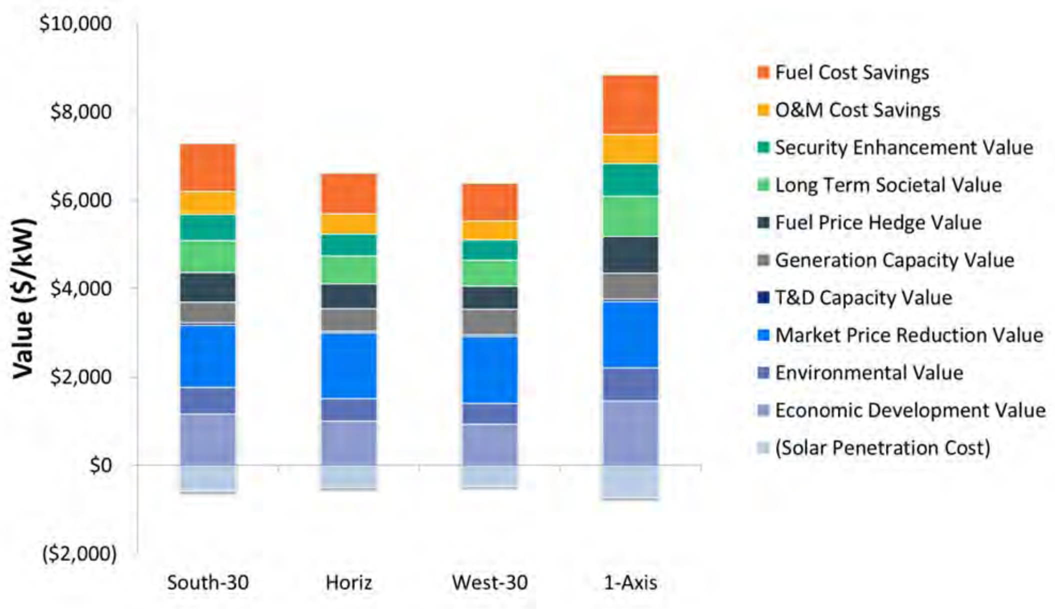
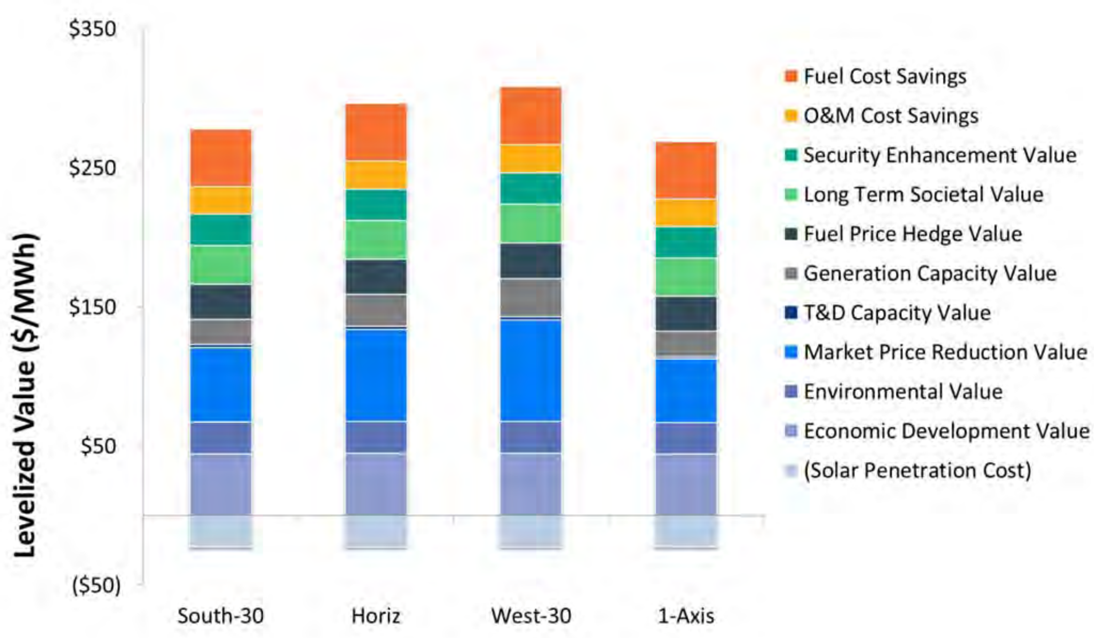


Figure A4- 14. Levelized Value ($/MWh), Atlantic City.



Minnesota Value of Solar: Methodology

Prepared for

Minnesota Department of Commerce,

Division of Energy Resources

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Legal Notice from Clean Power Research

Executive Summary

Minnesota passed legislation[1] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS tariff. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The 2013 legislation specifically mandated that the VOS legislation take into account the following values of distributed PV: energy and its delivery; generation capacity; transmission capacity; transmission and distribution line losses; and environmental value. The legislation also mandated a method of implementation, whereby solar customers will be billed for their gross electricity consumption under their applicable tariff, and will receive a VOS credit for their gross solar electricity production.

The present document provides the methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input, and guidance from Commerce. It includes a detailed example calculation for each step of the calculation.

Key aspects of the methodology include:

- A standard PV rating convention
- Methods for creating an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit capacity corresponding to the output of a PV resource on the margin
- Requirements for calculating the electricity losses of the transmission and distribution systems
- Methods for performing technical calculations for avoided energy, effective generation capacity and effective distribution capacity
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.)
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review

Application of the methodology results in the creation of two tables: the VOS Data Table (a table of utility-specific input assumptions) and the VOS Calculation Table (a table of utility-specific total value of

[1] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

solar). Together these two tables ensure stakeholder transparency and facilitate stakeholder understanding.

The VOS Calculation Table is illustrated in Figure ES-1. The table shows each value component and how the gross value of each component is converted into a distributed solar value. The process uses a component-specific load match factor (where applicable) and a component-specific Loss Savings Factor. The values are then summed to yield the 25-year levelized value.

Figure ES-1. VOS Calculation Table: economic value, load match, loss savings and distributed PV value.

25 Year Levelized Value	Gross Value ($/kWh)	×	Load Match Factor (%)	× (1 +	Loss Savings Factor (%)	)	=	Distributed PV Value ($/kWh)
Avoided Fuel Cost	GV1				LSF-Energy			V1
Avoided Plant O&M - Fixed	GV2				LSF-Energy			V2
Avoided Plant O&M - Variable	GV3				LSF-Energy			V3
Avoided Gen Capacity Cost	GV4		ELCC		LSF-ELCC			V4
Avoided Reserve Capacity Cost	GV5		ELCC		LSF-ELCC			V5
Avoided Trans. Capacity Cost	GV6		ELCC		LSF-ELCC			V6
Avoided Dist. Capacity Cost	GV7		PLR		LSF-PLR			V7
Avoided Environmental Cost	GV8				LSF-Energy			V8
Avoided Voltage Control Cost								
Solar Integration Cost								
								Value of Solar

As a final step, the methodology calls for the conversion of the 25-year levelized value to an equivalent inflation-adjusted credit. The utility would then use the first year value as the credit for solar customers, and would adjust each year using the latest Consumer Price Index (CPI) data.

Contents

Introduction

Background

Minnesota passed legislation[2] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS rate. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The present document provides the VOS methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input and guidance from Commerce.

Purpose

The State of Minnesota has identified a VOS tariff as a potential replacement for the existing Net Energy Metering (NEM) policy that currently regulates the compensation of home and business owners for electricity production from PV systems. As such, the adopted VOS legislation is not an incentive for distributed PV, nor is it intended to eliminate or prevent current or future incentive programs.

While NEM effectively values PV-generated electricity at the customer retail rate, a VOS tariff seeks to quantify the value of distributed PV electricity. If the VOS is set correctly, it will account for the real value of the PV-generated electricity, and the utility and its ratepayers would be indifferent to whether the electricity is supplied from customer-owned PV or from comparable conventional means. Thus, a VOS tariff eliminates the NEM cross-subsidization concerns. Furthermore, a well-constructed VOS tariff could provide market signals for the adoption of technologies that significantly enhance the value of electricity from PV, such as advanced inverters that can assist the grid with voltage regulation.

VOS Calculation Table Overview

The VOS is the sum of several distinct value components, each calculated separately using procedures defined in this methodology. As illustrated in Figure 1, the calculation includes a gross component value, a component-dependent load-match factor (as applicable for capacity related values) and a component-dependent Loss Savings Factor.

[2] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

For example, the avoided fuel cost does not have a load match factor because it is not dependent upon performance at the highest hours (fuel costs are avoided during all PV operating hours). Avoided fuel cost does have a Loss Savings Factor, however, accounting for loss savings in both transmission and distribution systems. On the other hand, the Avoided Distribution Capacity Cost has an important Load Match Factor (shown as Peak Load Reduction, or 'PLR') and a Loss Savings Factor that only accounts for distribution (not transmission) loss savings.

Gross Values, Distributed PV Values, and the summed VOS shown in Figure 1 are all 25-year levelized values denominated in dollars per kWh.

Figure 1. Illustration of the VOS Calculation Table

25 Year Levelized Value	Gross Value ($/kWh)	×	Load Match Factor (%)	×	(1 +	Loss Savings Factor (%)	)	=	Distributed PV Value ($/kWh)
Avoided Fuel Cost	GV1					LSF-Energy			V1
Avoided Plant O&M - Fixed	GV2					LSF-Energy			V2
Avoided Plant O&M - Variable	GV3					LSF-Energy			V3
Avoided Gen Capacity Cost	GV4		ELCC			LSF-ELCC			V4
Avoided Reserve Capacity Cost	GV5		ELCC			LSF-ELCC			V5
Avoided Trans. Capacity Cost	GV6		ELCC			LSF-ELCC			V6
Avoided Dist. Capacity Cost	GV7		PLR			LSF-PLR			V7
Avoided Environmental Cost	GV8					LSF-Energy			V8
Avoided Voltage Control Cost									
Solar Integration Cost									
									Value of Solar

VOS Rate Implementation

Separation of Usage and Production

Minnesota's VOS legislation mandates that, if a VOS tariff is approved, solar customers will be billed for all usage under their existing applicable tariff, and will receive a VOS credit for their gross solar energy production. Separating usage (charges) from production (credits) simplifies the rate process for several reasons:

- Customers will be billed for all usage. Energy derived from the PV systems will not be used to offset ("net") usage prior to calculating charges. This will ensure that utility infrastructure costs will be recovered by the utilities as designed in the applicable retail tariff.
- The utility will provide all energy consumed by the customer. Standby charges for customers with on-site PV systems are not permitted under a VOS rate.
- The rates for usage can be adjusted in future ratemaking.

VOS Components

The definition and selection of VOS components were based on the following considerations:

- Components corresponding to minimum statutory requirements are included. These account for the "value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value."
- Non-required components were selected only if they were based on known and measurable evidence of the cost or benefit of solar operation to the utility.
- Environmental costs are included as a required component, and are based on existing Minnesota and EPA externality costs.
- Avoided fuel costs are based on long-term risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel, as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.
- Credit for systems installed at high value locations (identified in the legislation as an option) is included as an option for the utility. It is not a separate VOS component but rather is implemented using a location-specific distribution capacity value (the component most affected by location). This is addressed in the Distribution Capacity Cost section.
- Voltage control and solar integration (a cost) are kept as "placeholder" components for future years. Methodologies are not provided, but these components may be developed for the future. Voltage control benefits are anticipated but will first require implementation of recent changes to national interconnection standards. Solar integration costs are expected to be small, but possibly measureable. Further research will be required on this topic.

Table 1 presents the VOS components selected by Commerce and the cost basis for each component. Table 2 presents the VOS components that were considered but not selected by Commerce. Selections were made based on requirements and guidance in the enabling statute, and were informed by stakeholder comments (including those from Minnesota utilities; local and national solar and environmental organizations; local solar manufacturers and installers; and private parties) and workshop discussions. Stakeholders participated in four public workshops and provided comments through workshop panels, workshop Q&A sessions and written comments.

Table 1. VOS components included in methodology.

Value Component	Basis	Legislative Guidance	Notes
Avoided Fuel Cost	Energy market costs (portion attributed to fuel)	Required (energy)	Includes cost of long-term price risk
Avoided Plant O&M Cost	Energy market costs (portion attributed to O&M)	Required (energy)	
Avoided Generation Capacity Cost	Capital cost of generation to meet peak load	Required (capacity)	
Avoided Reserve Capacity Cost	Capital cost of generation to meet planning margins and ensure reliability	Required (capacity)	
Avoided Transmission Capacity Cost	Capital cost of transmission	Required (transmission capacity)	
Avoided Distribution Capacity Cost	Capital cost of distribution	Required (delivery)	
Avoided Environmental Cost	Externality costs	Required (environmental)	
Voltage Control	Cost to regulate distribution (future inverter designs)		Future (TBD)
Integration Cost[3]	Added cost to regulate system frequency with variable solar		Future (TBD)

[3] This is not a value, but a cost. It would reduce the VOS rate if included.

Table 2. VOS components not included in methodology.

Value Component	Basis	Legislative Guidance	Notes
Credit for Local Manufacturing/ Assembly	Local tax revenue tied to net solar jobs	Optional (identified in legislation)	
Market Price Reduction	Cost of wholesale power reduced in response to reduction in demand		
Disaster Recovery	Cost to restore local economy (requires energy storage and islanding inverters)		

Solar Penetration

Solar penetration refers to the total installed capacity of PV on the grid, generally expressed as a percentage of the grid's total load. The level of solar penetration on the grid is important because it affects the calculation of the Effective Load Carrying Capability (ELCC) and Peak Load Reduction (PLR) load-match factors (described later).

In the methodology, the near-term level of PV penetration is used. This is done so that the capacity-related value components will reflect the near-term level of PV penetration on the grid. However, the change in PV penetration level will be accounted for in the annual adjustment to the VOS. To the extent that PV penetration increases, future VOS rates will reflect higher PV penetration levels.

Marginal Fuel

This methodology assumes that PV displaces natural gas during PV operating hours. This is consistent with current and projected MISO market experience. During some hours of the year, other fuels (such as coal) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the calculated VOS tariff. However, if future analysis indicates that the assumption is not warranted, then the methodology may be modified accordingly. For example, by changing the methodology to include displacement of coal production, avoided fuel costs may decrease and avoided environmental costs may increase.

Economic Analysis Period

In evaluating the value of a distributed PV resource, the economic analysis period is set at 25 years, the assumed useful service life of the PV system[4]. The methodology includes PV degradation effects as described later.

Annual VOS Tariff Update

Each year, a new VOS tariff would be calculated using current data, and the new resulting VOS rate would be applicable to all customers entering the tariff during the year. Changes such as increased or decreased fuel prices and modified hourly utility load profiles due to higher solar penetration will be incorporated into each new annual calculation.

Customers who have already entered into the tariff in a previous year will not be affected by this annual adjustment. However, customers who have entered into a tariff in prior years will see their Value of Solar rates adjusted for the previous year's inflation rate as described later.

Commerce may also update the methodology to use the best available practices, as necessary.

Transparency Elements

The methodology incorporates two tables that are to be included in a utility's application to the Minnesota PUC for the use of a VOS tariff. These tables are designed to improve transparency and facilitate understanding among stakeholders and regulators.

- **VOS Data Table.** This table provides a utility-specific defined list of the key input assumptions that go into the VOS tariff calculation. This table is described in more detail later.
- **VOS Calculation Table.** This table includes the list of value components and their gross values, their load-match factors, their Loss Savings Factors, and the computation of the total levelized value.

Glossary

A glossary is provided at the end of this document defining some of the key terms used throughout this document.

[4] [4] NREL: Solar Resource Analysis and High-Penetration PV Potential (April 2010).
http://www.nrel.gov/docs/fy10osti/47956.pdf

Methodology: Assumptions

Fixed Assumptions

Table 3 and Table 4 present fixed assumptions, common to all utilities and incorporated into this methodology, that are to be applied to the calculation of 2014 VOS tariffs. These may be updated by Commerce in future years as necessary when performing the annual VOS update. Table 4 is described in more detail in the Avoided Environmental Cost subsection. Table terms can be found in the Glossary.

Published values from the Bureau of Labor and Statistics for the Urban Consumer Price Index (CPI) (ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt) were used to calculate an average annual inflation rate of 2.53% over the last 25 years (see equations below). This was taken as the expected general escalation rate.

$$25yrAvgAnnualInflation = \left(\frac{Nov2013\ UCPI}{Nov1988\ UCPI}\right)^{1/(2013-1988)} - 1 \quad (1)$$

$$25yrAvgAnnualInflation = \left[\left(\frac{224.939}{120.300}\right)^{1/25} - 1\right] = 2.53\% \quad (2)$$

The “Guaranteed NG Fuel Price Escalation” value of 4.77%, used as described later to calculate the Avoided Fuel Costs, is calculated from a best fit to the listed NYMEX futures prices (also shown in Table 3). This fit can be seen below in Figure 2.

Figure 2. Fit to NYMEX natural gas futures prices.

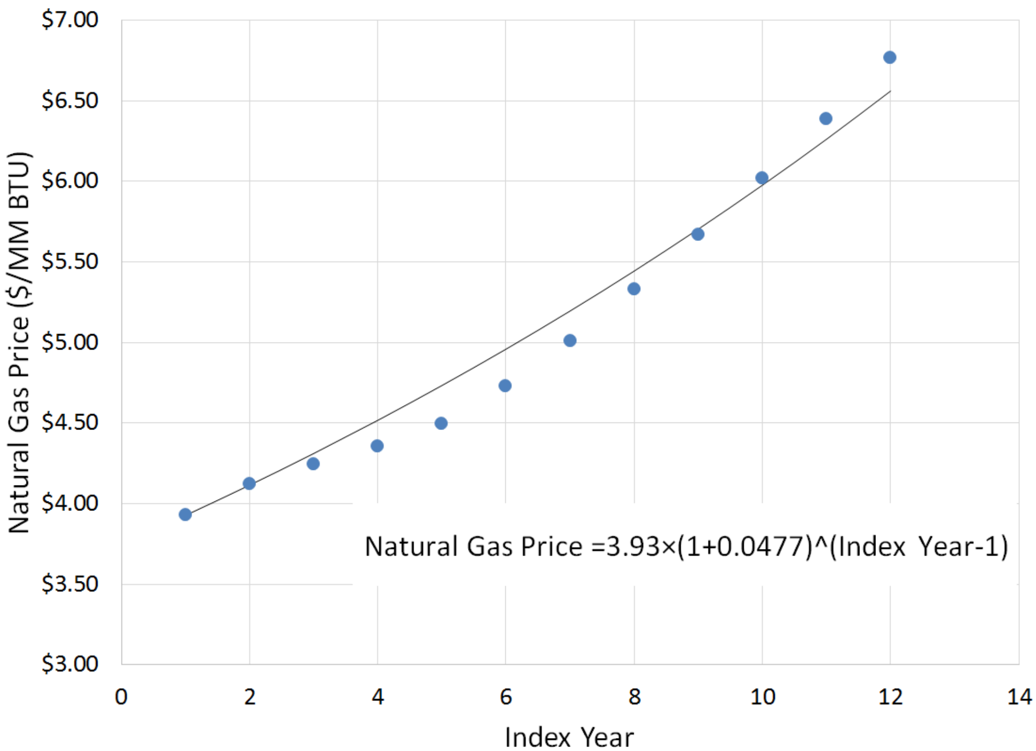


Table 3. Fixed assumptions to be used for 2014 VOS calculations – common to all utilities.

Guaranteed NG Fuel Prices						
Year				**Environmental Externalities**		
2014	$3.93	$ per MMBtu		Environmental discount rate (nominal)	5.61%	per year
2015	$4.12	$ per MMBtu		Environmental costs	(shown in separate table)	
2016	$4.25	$ per MMBtu				
2017	$4.36	$ per MMBtu		**Economic Assumptions**		
2018	$4.50	$ per MMBtu		General escalation rate	2.53%	per year
2019	$4.73	$ per MMBtu				
2020	$5.01	$ per MMBtu				
2021	$5.33	$ per MMBtu		**Treasury Yields**		
2022	$5.67	$ per MMBtu		1 Year	0.13%	
2023	$6.02	$ per MMBtu		2 Year	0.29%	
2024	$6.39	$ per MMBtu		3 Year	0.48%	
2025	$6.77	$ per MMBtu		5 Year	1.01%	
				7 Year	1.53%	
NG fuel price escalation	4.77%			10 Year	2.14%	
				20 Year	2.92%	
PV Assumptions				30 Year	3.27%	
PV degradation rate	0.50%	per year				
PV life	25	years				

Table 4. Fixed environmental externality costs by year.

Year	Analysis Year	CO_2 Cost ($/MMBtu)	PM10 Cost ($/MMBtu)	CO Cost ($/MMBtu)	NO_x Cost ($/MMBtu)	Pb Cost ($/MMBtu)	Total Cost ($/MMBtu)
2014	0	2.140	0.027	0.000	0.044	0.000	2.210
2015	1	2.255	0.028	0.000	0.045	0.000	2.327
2016	2	2.375	0.028	0.000	0.046	0.000	2.449
2017	3	2.499	0.029	0.000	0.047	0.000	2.575
2018	4	2.628	0.030	0.000	0.048	0.000	2.706
2019	5	2.829	0.030	0.000	0.050	0.000	2.909
2020	6	2.970	0.031	0.000	0.051	0.000	3.052
2021	7	3.045	0.032	0.000	0.052	0.000	3.130
2022	8	3.195	0.033	0.000	0.053	0.000	3.282
2023	9	3.351	0.034	0.000	0.055	0.000	3.439
2024	10	3.512	0.034	0.000	0.056	0.000	3.603
2025	11	3.679	0.035	0.000	0.058	0.000	3.772
2026	12	3.853	0.036	0.000	0.059	0.000	3.948
2027	13	4.033	0.037	0.000	0.061	0.000	4.131
2028	14	4.219	0.038	0.000	0.062	0.000	4.320
2029	15	4.413	0.039	0.000	0.064	0.000	4.516
2030	16	4.613	0.040	0.000	0.065	0.000	4.719
2031	17	4.730	0.041	0.000	0.067	0.000	4.839
2032	18	4.944	0.042	0.000	0.069	0.000	5.054
2033	19	5.165	0.043	0.000	0.070	0.000	5.278
2034	20	5.394	0.044	0.000	0.072	0.000	5.510
2035	21	5.631	0.045	0.000	0.074	0.000	5.750
2036	22	5.877	0.047	0.000	0.076	0.000	5.999
2037	23	6.131	0.048	0.000	0.078	0.000	6.257
2038	24	6.395	0.049	0.000	0.080	0.000	6.524

See explanation in the Avoided Environmental Cost section.

Utility-Specific Assumptions and Calculations

Some assumptions and calculations are unique to each utility. These include economic assumptions (such as discount rate) and technical calculations (such as ELCC). Utility-specific assumptions and calculations are determined by the utility, and are included in the VOS Data Table, a required transparency element.

The utility-specific calculations (such as capacity-related transmission capital cost) are determined using the methods described in this methodology.

An example VOS Data Table, showing the parameters to be included in the utility filing for the VOS tariff, is shown in Table 5. This table includes values that are given for example only. These example values carry forward in the example calculations.

Table 5. VOS Data Table (EXAMPLE DATA) — required format showing example parameters used in the example calculations.

	Input Data	Units
Economic Factors		
Start Year for VOS applicability	2014	
Discount rate (WACC)	8.00%	per year
Load Match Analysis (see calculation method)		
ELCC (no loss)	40%	% of rating
PLR (no loss)	30%	% of rating
Loss Savings - Energy	8%	% of PV output
Loss Savings - PLR	5%	% of PV output
Loss Savings - ELCC	9%	% of PV output
PV Energy (see calculation method)		
First year annual energy	1800	kWh per kW-AC
Transmission (see calculation method)		
Capacity-related transmission capital cost	$33	$ per kW-yr

	Input Data	Units
Power Generation		
Peaking CT, simple cycle		
Installed cost	900	$/kW
Heat rate	9,500	BTU/kWh
Intermediate peaking CCGT		
Installed cost	1,200	$/kW
Heat rate	6,500	BTU/kWh
Other		
Solar-weighted heat rate (see calc. method)	8000	BTU per kWh
Fuel Price Overhead	$0.50	$ per MMBtu
Generation life	50	years
Heat rate degradation	0.100%	per year
O&M cost (first Year) - Fixed	$5.00	per kW-yr
O&M cost (first Year) - Variable	$0.0010	$ per kWh
O&M cost escalation rate	2.00%	per year
Reserve planning margin	15%	
Distribution		
Capacity-related distribution capital cost	$200	$ per kW
Distribution capital cost escalation	2.00%	per year
Peak load	5000	MW
Peak load growth rate	1.00%	per year

Methodology: Technical Analysis

Load Analysis Period

The VOS methodology requires that a number of technical parameters (PV energy production, effective load carrying capability (ELCC) and peak load reduction (PLR) load-match factors, and electricity-loss factors) be calculated over a fixed period of time in order to account for day-to-day variations and seasonal effects, such as changes in solar radiation. For this reason, the load analysis period must cover a period of at least one year.

The data may start on any day of the year, and multiple years may be included, as long as all included years are contiguous and each included year is a complete one-year period. For example, valid load analysis periods may be 1/1/2012 0:00 to 12/31/2012 23:00 or 11/1/2010 0:00 to 10/31/2013 23:00.

Three types of time series data are required to perform the technical analysis:

- **Hourly Generation Load:** the hourly utility load over the Load Analysis Period. This is the sum of utility generation and import power needed to meet all customer load.
- **Hourly Distribution Load:** the hourly distribution load over the Load Analysis Period. The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses).
- **Hourly PV Fleet Production:** the hourly PV Fleet production over the Load Analysis Period. The PV fleet production is the aggregate generation of all of the PV systems in the PV fleet.

All three types of data must be provided as synchronized, time-stamped hourly values of average power over the same period, and corresponding to the same hourly intervals. Data must be available for every hour of the Load Analysis Period.

PV data using Typical Meteorological Year data is not time synchronized with time series production data, so it should not be used as the basis for PV production.

Data that is not in one-hour intervals must be converted to hourly data (for example, 15-minute meter data would have to be combined to obtain 1-hour data). Also, data values that represent energy must be converted to average power.

If data is missing or deemed erroneous for any time period less than or equal to 24 hours, the values corresponding to that period may be replaced with an equal number of values from the same time interval on the previous or next day if it contains valid data. This data replacement method may be used provided that it does not materially affect the results.

PV Energy Production

PV System Rating Convention

The methodology uses a rating convention for PV capacity based on AC delivered energy (not DC), taking into account losses internal to the PV system. A PV system rated output is calculated by multiplying the number of modules by the module PTC rating[5] [as listed by the California Energy Commission (CEC)[6]] to account for module de-rate effects. The result is then multiplied by the CEC-listed inverter efficiency rating[7] to account for inverter efficiency, and the result is multiplied by a loss factor to account for internal PV array losses (wiring losses, module mismatch and other losses).

If no CEC module PTC rating is available, the module PTC rating should be calculated as 0.90 times the module STC rating[8]. If no CEC inverter efficiency rating is available, an inverter efficiency of 0.95 should be used. If no measured or design loss factor is available, 0.85 should be used.

To summarize: [9]

Rating (kW-AC) = [Module Quantity] x [Module PTC rating (kW)] x [Inverter Efficiency Rating] x [Loss Factor]

Hourly PV Fleet Production

Hourly PV Fleet Production can be obtained using any one of the following three options:

1. <u>Utility Fleet - Metered Production</u>. Fleet production data can be created by combining actual metered production data for every PV system in the utility service territory, provided that there are a sufficient number of systems[10] installed to accurately derive a correct representation of aggregate PV production. Such metered data is to be gross PV output on the AC side of the

[5] PTC refers to PVUSA Test Conditions, which were developed to test and compare PV systems as part of the PVUSA (Photovoltaics for Utility Scale Applications) project. PTC are 1,000 Watts per square meter solar irradiance, 20 degrees C air temperature, and wind speed of 1 meter per second at 10 meters above ground level. PV manufacturers use Standard Test Conditions, or STC, to rate their PV products.
[6] CEC module PTC ratings for most modules can be found at: http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php
[7] CEC inverter efficiency ratings for most inverters can be found at: http://www.gosolarcalifornia.ca.gov/equipment/inverters.php
[8] PV manufacturers use Standard Test Conditions, or STC, to rate their PV products. STC are 1,000 Watts per square meter solar irradiance, 25 degrees C cell temperature, air mass equal to 1.5, and ASTM G173-03 standard spectrum.
[9] In some cases, this equation will have to be adapted to account for multiple module types and/or inverters. In such cases, the rating of each subsystem can be calculated independently and then added.
[10] A sufficient number of systems has been achieved when adding a single system of random orientation, tilt, tracking characteristics, and capacity (within reason) does not materially change the observed hourly PV Fleet Shape (see next subsection of PV Fleet Shape definition).

system, but before local customer loads are subtracted (i.e., PV must be separately metered from load). Metered data from individual systems is then aggregated by summing the measured output for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

2. Utility Fleet, Simulated Production. If metered data is not available, the aggregate output of all distributed PV systems in the utility service territory can be modeled using PV system technical specifications and hourly irradiance and temperature data. These systems must be deployed in sufficient numbers to accurately derive a correct representation of aggregate PV production. Modeling must take into account the system's location and each array's tracking capability (fixed, single-axis or dual-axis tracking), orientation (tilt and azimuth), module PTC ratings, inverter efficiency and power ratings, other loss factors and the effect of temperature on module output. Technical specifications for each system must be available to enable such modeling. Modeling must also make use of location-specific, time-correlated, measured or satellite-derived plane of array irradiance data. Ideally, the software will also support modeling of solar obstructions.

    - To make use of this option, detailed system specifications for every PV system in the utility's service territory must be obtained. At a minimum, system specifications must include:
        - Location (latitude and longitude)
        - System component ratings (e.g., module ratings an inverter ratings)
        - Tilt and azimuth angles
        - Tracking type (if applicable)
    - After simulating the power production for each system for each hour in the Load Analysis Period, power production must be aggregated by summing the power values for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

3. Expected Fleet, Simulated Production. If neither metered production data nor detailed PV system specifications are available, a diverse set of PV resources can be estimated by simulating groups of systems at major load centers in the utility's service territory with some assumed fleet configuration. To use this method, one or more of the largest load centers in the utility service territory may be used. If a single load center accounts for a high percentage of the utility's total load, a single location will suffice. If there are several large load centers in the territory, groups of systems can be created at each location with capacities proportional to the load in that area.

    - For each location, simulate multiple systems, each rated in proportion to the expected capacity, with azimuth and tilt angles such as the list of systems presented in Table 6. Note that the list of system configurations should represent the expected fleet composition. No method is explicitly provided to determine the expected fleet composition; however, a utility could analyze the fleet composition of PV fleets outside of its territory.

Table 6. (EXAMPLE) Azimuth and tilt angles

System	Azimuth	Tilt	% Capacity
1	90	20	3.5
2	135	15	3.0
3	135	30	6.5
4	180	0	6.0
5	180	15	16.0
6	180	25	22.5
7	180	35	18.0
8	235	15	8.5
9	235	30	9.0
10	270	20	7.0

- Simulate each of the PV systems for each hour in the Load Analysis Period. Aggregate power production for the systems is obtained by summing the power values for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.
- If the utility elects to perform a location-specific analysis for the Avoided Distribution Capacity Costs, then it should also take into account what the geographical distribution of the expected PV fleet would be. Again, this could be done by analyzing a PV fleet composition outside of the utility's territory. An alternative method that would be acceptable is to distribute the expected PV fleet across major load centers. Thereby assuming that PV capacity is likely to be added where significant load (and customer density) already exists.
- Regardless of location count and location weighting, the total fleet rating is taken as the sum of the individual system ratings.

PV Fleet Shape

Regardless of which of the three methods is selected for obtaining the Hourly PV Fleet production, the next step is divide each hour's value by the PV Fleet's aggregate AC rating to obtain the PV Fleet Shape. The units of the PV Fleet Shape are kWh per hour per kW-AC (or, equivalently, average kW per kW-AC).

Marginal PV Resource

The PV Fleet Shape is hourly production of a Marginal PV Resource having a rating of 1 kW-AC.

Annual Avoided Energy

Annual Avoided Energy (kWh per kW-AC per year) is the sum of the hourly PV Fleet Shape across all hours of the Load Analysis Period, divided by the numbers of years in the Load Analysis Period. The result is the annual output of the Marginal PV Resource.

$$Annual\ Avoided\ Energy\ (kWh) = \frac{\sum Hourly\ PV\ Fleet\ Production_h}{NumberOfYearsInLoadAnalysisPeriod} \qquad (3)$$

- Defined in this way, the Annual Avoided Energy does not include the effects of loss savings. As described in the Loss Analysis subsection, however, it will have to be calculated for the two loss cases (with losses and without losses).

Load-Match Factors

Capacity-related benefits are time dependent, so it is necessary to evaluate the effectiveness of PV in supporting loads during the critical peak hours. Two different measures of effective capacity are used:

- Effective Load Carrying Capability (ELCC)
- Peak Load Reduction (PLR)

Near term PV penetration levels are used in the calculation of the ELCC and PLR values so that the capacity-related value components will reflect the near term level of PV penetration on the grid. However, the ELCC and PLR will be re-calculated during the annual VOS adjustment and thus reflect any increase in future PV Penetration Levels.

Effective Load Carrying Capability (ELCC)

The Effective Load Carrying Capability (ELCC) is the measure of the effective capacity for distributed PV that can be applied to the avoided generation capacity costs, the avoided reserve capacity costs, the avoided generation fixed O&M costs, and the avoided transmission capacity costs (see Figure 1).

Using current MISO rules for non-wind variable generation (MISO BPM-011, Section 4.2.2.4, page 35)[11]: the ELCC will be calculated from the PV Fleet Shape for hours ending 2pm, 3pm, and 4pm Central Standard Time during June, July, and August over the most recent three years. If three years of data are unavailable, MISO requires "a minimum of 30 consecutive days of historical data during June, July, or August" for the hours ending 2pm, 3pm and 4pm Central Standard Time.

The ELCC is calculated by averaging the PV Fleet Shape over the specified hours, and then dividing by the rating of the Marginal PV Resource (1 kW-AC), which results in a percentage value. Additionally, the ELCC must be calculated for the two loss cases (with and without T&D losses, as described in the Loss Analysis subsection).

Peak Load Reduction (PLR)

The PLR is defined as the maximum distribution load over the Load Analysis Period (without the Marginal PV Resource) minus the maximum distribution load over the Load Analysis Period (with the Marginal PV Resource). The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses). In calculating the PLR, it is not sufficient to limit modeling to the peak hour. All hours over the Load Analysis Period must be included in the calculation. This is because the reduced peak load may not occur in the same hour as the original peak load.

The PLR is calculated as follows. First, determine the maximum Hourly Distribution Load (D1) over the Load Analysis Period. Next, create a second hourly distribution load time series by subtracting the effect of the Marginal PV Resource, i.e., by evaluating what the new distribution load would be each hour given the PV Fleet Shape. Next, determine the maximum load in the second time series (D2). Finally, calculate the PLR by subtracting D2 from D1.

In other words, the PLR represents the capability of the Marginal PV Resource to reduce the peak distribution load over the Load Analysis Period. PLR is expressed in kW per kW-AC.

Additionally, the PLR must be calculated for the two loss cases (with distribution losses and without distribution losses, as described in the Loss Analysis subsection).

[11] https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

Loss Savings Analysis

In order to calculate the required Loss Savings Factors on a marginal basis as described below, it will be necessary to calculate ELCC, PLR and Annual Avoided Energy each twice. They should be calculated first by *including* the effects of avoided marginal losses, and second by *excluding* them. For example, the ELCC would first be calculated by including avoided transmission and distribution losses, and then re-calculated assuming no losses, i.e., as if the Marginal PV Resource was a central (not distributed) resource.

The calculations should observe the following

Table 7. Losses to be considered.

Technical Parameter	Loss Savings Considered
Avoided Annual Energy	Avoided transmission and distribution losses for every hour of the load analysis period.
ELCC	Avoided transmission and distribution losses during the MISO defined hours.
PLR	Avoided distribution losses (not transmission) at peak.

When calculating avoided marginal losses, the analysis must satisfy the following requirements:

1. Avoided losses are to be calculated on an hourly basis over the Load Analysis Period. The avoided losses are to be calculated based on the generation (and import) power during the hour and the expected output of the Marginal PV Resource during the hour.

2. Avoided losses in the transmission system and distribution systems are to be evaluated separately using distinct loss factors based on the most recent study data available.

3. Avoided losses should be calculated on a marginal basis. The marginal avoided losses are the difference in hourly losses between the case without the Marginal PV Resource, and the case with the Marginal PV Resource. Avoided average hourly losses are not calculated. For example, if the Marginal PV Resource were to produce 1 kW of power for an hour in which total customer load is 1000 kW, then the avoided losses would be the calculated losses at 1000 kW of customer load minus the calculated losses at 999 kW of load.

4. Distribution losses should be based on the power entering the distribution system, after transmission losses.

5. Avoided transmission losses should take into account not only the marginal PV generation, but also the avoided marginal distribution losses.

6. Calculations of avoided losses should not include no-load losses (e.g., corona, leakage current). Only load-related losses should be included.

7. Calculations of avoided losses in any hour should take into account the non-linear relationship between losses and load (load-related losses are proportional to the square of the load, assuming constant voltage). For example, the total load-related losses during an hour with a load of 2X would be approximately 4 times the total load-related losses during an hour with a load of only X.

Loss Savings Factors

The Energy Loss Savings Factor (as a percentage) is defined for use within the VOS Calculation Table:

$$Annual\ Avoided\ Energy_{WithLosses} = Annual\ Avoided\ Energy_{WithoutLosses}\left(1 + Loss\ Savings_{Energy}\right) \quad (4)$$

Equation 3 is then rearranged to solve for the Energy Loss Savings Factor:

$$Loss\ Savings_{Energy} = \frac{Annual\ Avoided\ Energy_{WithLosses}}{Annual\ Avoided\ Energy_{WithoutLosses}} - 1 \quad (5)$$

Similarly, the PLR Loss Savings Factor is defined as:

$$Loss\ Savings_{PLR} = \frac{PLR_{WithLosses}}{PLR_{WithoutLosses}} - 1 \quad (6)$$

and the ELCC Loss Savings Factor is defined as:

$$Loss\ Savings_{ELCC} = \frac{ELCC_{WithLosses}}{ELCC_{WithoutLosses}} - 1 \quad (7)$$

Methodology: Economic Analysis

The following subsections provide a methodology for performing the economic calculations to derive gross values in $/kWh for each of the VOS components. These gross component values will then be entered into the VOS Calculation Table, which is the second of the two key transparency elements.

Important Note: The economic analysis is initially performed as if PV was centrally-located (without loss-saving benefits of distributed location) and with output perfectly correlated to load. Real-world adjustments are made later in the final VOS summation by including the results of the loss savings and load match analyses.

Discount Factors

By convention, the analysis year 0 corresponds to the year in which the VOS tariff will begin. As an example, if a VOS was done in 2013 for customers entering a VOS tariff between January 1, 2014 and December 31, 2014, then year 0 would be 2014, year 1 would be 2015, and so on.

For each year *i*, a discount factor is given by

$$DiscountFactor_i = \frac{1}{(1 + DiscountRate)^i} \qquad (8)$$

The *DiscountRate* is the utility Weighted Average Cost of Capital.

Similarly, a risk-free discount factor is given by:

$$RiskFreeDiscountFactor_i = \frac{1}{(1 + RiskFreeDiscountRate)^i} \qquad (9)$$

The *RiskFreeDiscountRate* is based on the yields of current Treasury securities[12] of 1, 2, 3, 5, 7, 10, 20, and 30 year maturation dates. The *RiskFreeDiscountRate* is used once in the calculation of the Avoided Fuel Costs.

Finally, an environmental discount factor is given by:

$$EnvironmentalDiscountFactor_i = \frac{1}{(1 + EnvironmentalDiscountRate)^i} \qquad (10)$$

[12] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

The *EnvironmentalDiscountRate* is based on the 3% *real* discount rate that has been determined to be an appropriate societal discount rate for future environmental benefits.[13] As the methodology requires a nominal discount rate, this 3% *real* discount rate is converted into its equivalent 5.61% nominal discount rate as follows:[14]

$$NominalDiscountRate = (1 + RealDiscountRate) \times (1 + GeneralEscalationRate) - 1 \quad (11)$$

The *EnvironmentalDiscountRate* is used once in the calculation of the Avoided Environmental Costs.

PV degradation is accounted for in the economic calculations by reductions of the annual PV production in future years. As such, the PV production in kWh per kW-AC for the marginal PV resource in year I is given by:

$$PVProduction_i = PVProduction_0 \times (1 - \mathrm{PVDegradationRate})^i \quad (12)$$

where PVDegradationRate is the annual rate of PV degradation, assumed to be 0.5% per year – the standard PV module warranty guarantees a maximum of 0.5% power degradation per annum. $PVProduction_0$ is the Annual Avoided Energy for the Marginal PV Resource.

PV capacity in year *i* for the Marginal PV Resource, taking into account degradation, equals:

$$PVCapacity_i = (1 - \mathrm{PVDegradationRate})^i \quad (13)$$

Avoided Fuel Cost

Avoided fuel costs are based on long-term, risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.

PV displaces energy generated from the marginal unit, so it avoids the cost of fuel associated with this generation. Furthermore, the PV system is assumed to have a service life of 25 years, so the uncertainty in fuel price fluctuations is also eliminated over this period. For this reason, the avoided fuel cost must take into account the fuel as if it were purchased under a guaranteed, long term contract.

[13] http://www.epa.gov/oms/climate/regulations/scc-tsd.pdf
[14] http://en.wikipedia.org/wiki/Nominal_interest_rate

The methodology provides for three options to accomplish this:

- **Futures Market.** This option is described in detail below, and is based on the NYMEX NG futures with a fixed escalation for years beyond the 12-year trading period.

- **Long Term Price Quotation.** This option is identical to the above option, except the input pricing data is based on an actual price quotation from an AA-rated NG supplier to lock in prices for the 25-year guaranteed period.

- **Utility-guaranteed Price.** This is the 25-year fuel price that is guaranteed by the utilities. Tariffs using the utility guaranteed price will include a mechanism for removing the usage fuel adjustment charges and provide fixed prices over the term.

Table 8 presents the calculation of the economic value of avoided fuel costs.

For the Futures Market option, Guaranteed NG prices are calculated as follows. Prices for the first 12 years are based on NYMEX futures, with each monthly price averaged to give a 12-month average in $ per MMBtu. Prices for years beyond this NYMEX limit are calculated by applying the assumed annual NYMEX price escalation. An assumed fuel price overhead amount, escalated by year using the assumed NYMEX price escalation, is added to the fuel price to give the burnertip fuel price.

The first-year solar-weighted heat rate is calculated as follows:

$$SolarWeighedHeatRate_0 = \frac{\sum HeatRate_j \times FleetProduction_j}{\sum FleetProduction_j} \qquad (14)$$

where the summation is over all hours *j* of the load analysis period, *HeatRate* is the actual heat rate of the plant on the margin, and *FleetProduction* is the Fleet Production Shape time series.

The solar-weighted heat rate for future years is calculated as:

$$SolarWeighedHeatRate_i = SolarWeighedHeatRate_0 \times (1 - \mathrm{HeatRateDegradationRate})^i \qquad (15)$$

The utility price in year *i* is:

$$UtilityPrice_i = \frac{BurnertipFuelPrice_i \times SolarWeighedHeatRate_i}{10^6} \qquad (16)$$

where the burnertip price is in $ per MMBtu and the heat rate is in Btu per kWh.

Utility cost is the product of the utility price and the per unit PV production. These costs are then discounted using the risk free discount rate and summed for all years. A risk-free discount rate (fitted to the US Treasury yields shown in Table 3) has been selected to account for the fact that there is no risk in the avoided fuel cost.

The VOS price (shown in red in Table 8) is the levelized amount that results in the same discounted amount as the utility price for the Avoided Fuel Cost component.

Avoided Plant O&M – Fixed

Economic value calculations for fixed plant O&M are presented in Table 9. The first year fixed value is escalated at the O&M escalation rate for future years.

Similarly, PV capacity has an initial value of one during the first year because it is applicable to PV systems installed in the first year. Note that effective capacity (load matching) is handled separately, and this table represents the "ideal" resource, as if PV were able to receive the same capacity credit as a fully dispatchable technology.

Fixed O&M is avoided only when the resource requiring fixed O&M is avoided. For example, if new generation is not needed for two years, then the associated fixed O&M is also not needed for two years. In the example calculation, generation is assumed to be needed for all years, so the avoided cost is calculated for all years.

The utility cost is the fixed O&M cost times the PV capacity divided by the utility capacity. Utility prices are the cost divided by the PV production. Costs are discounted using the utility discount factor and are summed for all years.

The VOS component value is calculated as before such that the discounted total is equal to the discounted utility cost.

Table 8. (EXAMPLE) Economic Value of Avoided Fuel Costs.

Year	Guaranteed NG Price	Burnertip NG Price	Heat Rate	Prices Utility	Prices VOS	p.u. PV Production	Costs Utility	Costs VOS	Discount Factor	Disc. Costs Utility	Disc. Costs VOS
	($/MMBtu)	($/MMBtu)	(Btu/kWh)	($/kWh)	($/kWh)	(kWh)	($)	($)	(risk free)	($)	($)
2014	$3.93	$4.43	8000	$0.035	$0.061	1,800	$64	$110	1.000	$64	$110
2015	$4.12	$4.65	8008	$0.037	$0.061	1,791	$67	$110	0.999	$67	$110
2016	$4.25	$4.79	8016	$0.038	$0.061	1,782	$68	$109	0.994	$68	$109
2017	$4.36	$4.93	8024	$0.040	$0.061	1,773	$70	$109	0.986	$69	$107
2018	$4.50	$5.10	8032	$0.041	$0.061	1,764	$72	$108	0.971	$70	$105
2019	$4.73	$5.36	8040	$0.043	$0.061	1,755	$76	$108	0.951	$72	$102
2020	$5.01	$5.67	8048	$0.046	$0.061	1,747	$80	$107	0.927	$74	$99
2021	$5.33	$6.03	8056	$0.049	$0.061	1,738	$84	$107	0.899	$76	$96
2022	$5.67	$6.40	8064	$0.052	$0.061	1,729	$89	$106	0.872	$78	$93
2023	$6.02	$6.78	8072	$0.055	$0.061	1,721	$94	$106	0.842	$79	$89
2024	$6.39	$7.18	8080	$0.058	$0.061	1,712	$99	$105	0.809	$80	$85
2025	$6.77	$7.60	8088	$0.061	$0.061	1,703	$105	$105	0.786	$82	$82
2026	$7.09	$7.96	8097	$0.064	$0.061	1,695	$109	$104	0.762	$83	$79
2027	$7.43	$8.34	8105	$0.068	$0.061	1,686	$114	$104	0.737	$84	$76
2028	$7.78	$8.74	8113	$0.071	$0.061	1,678	$119	$103	0.713	$85	$73
2029	$8.15	$9.16	8121	$0.074	$0.061	1,670	$124	$102	0.688	$85	$70
2030	$8.54	$9.60	8129	$0.078	$0.061	1,661	$130	$102	0.663	$86	$68
2031	$8.95	$10.06	8137	$0.082	$0.061	1,653	$135	$101	0.637	$86	$65
2032	$9.38	$10.54	8145	$0.086	$0.061	1,645	$141	$101	0.612	$86	$62
2033	$9.83	$11.04	8153	$0.090	$0.061	1,636	$147	$100	0.587	$87	$59
2034	$10.29	$11.57	8162	$0.094	$0.061	1,628	$154	$100	0.563	$86	$56
2035	$10.79	$12.12	8170	$0.099	$0.061	1,620	$160	$99	0.543	$87	$54
2036	$11.30	$12.70	8178	$0.104	$0.061	1,612	$167	$99	0.523	$88	$52
2037	$11.84	$13.30	8186	$0.109	$0.061	1,604	$175	$98	0.504	$88	$50
2038	$12.41	$13.94	8194	$0.114	$0.061	1,596	$182	$98	0.485	$88	$48

Validation: Present Value	Utility	VOS
	$1,999	$1,999

Table 9. (EXAMPLE) Economic value of avoided plant O&M – fixed

Year	O&M Fixed	Utility Capacity	PV Capacity	p.u. PV Production	Costs: Utility	Costs: VOS	Discount Factor	Disc. Costs: Utility	Disc. Costs: VOS	Prices: Utility	Prices: VOS
	($/kW)	(p.u.)	(kW)	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	$5.00	1.000	1.000	1800	$5	$6	1.000	$5	$6	$0.003	$0.003
2015	$5.10	0.999	0.995	1791	$5	$6	0.926	$5	$5	$0.003	$0.003
2016	$5.20	0.998	0.990	1782	$5	$6	0.857	$4	$5	$0.003	$0.003
2017	$5.31	0.997	0.985	1773	$5	$6	0.794	$4	$5	$0.003	$0.003
2018	$5.41	0.996	0.980	1764	$5	$6	0.735	$4	$4	$0.003	$0.003
2019	$5.52	0.995	0.975	1755	$5	$6	0.681	$4	$4	$0.003	$0.003
2020	$5.63	0.994	0.970	1747	$5	$6	0.630	$3	$4	$0.003	$0.003
2021	$5.74	0.993	0.966	1738	$6	$6	0.583	$3	$3	$0.003	$0.003
2022	$5.86	0.992	0.961	1729	$6	$6	0.540	$3	$3	$0.003	$0.003
2023	$5.98	0.991	0.956	1721	$6	$6	0.500	$3	$3	$0.003	$0.003
2024	$6.09	0.990	0.951	1712	$6	$6	0.463	$3	$3	$0.003	$0.003
2025	$6.22	0.989	0.946	1703	$6	$6	0.429	$3	$2	$0.003	$0.003
2026	$6.34	0.988	0.942	1695	$6	$6	0.397	$2	$2	$0.004	$0.003
2027	$6.47	0.987	0.937	1686	$6	$6	0.368	$2	$2	$0.004	$0.003
2028	$6.60	0.986	0.932	1678	$6	$6	0.340	$2	$2	$0.004	$0.003
2029	$6.73	0.985	0.928	1670	$6	$6	0.315	$2	$2	$0.004	$0.003
2030	$6.86	0.984	0.923	1661	$6	$6	0.292	$2	$2	$0.004	$0.003
2031	$7.00	0.983	0.918	1653	$7	$5	0.270	$2	$1	$0.004	$0.003
2032	$7.14	0.982	0.914	1645	$7	$5	0.250	$2	$1	$0.004	$0.003
2033	$7.28	0.981	0.909	1636	$7	$5	0.232	$2	$1	$0.004	$0.003
2034	$7.43	0.980	0.905	1628	$7	$5	0.215	$1	$1	$0.004	$0.003
2035	$7.58	0.979	0.900	1620	$7	$5	0.199	$1	$1	$0.004	$0.003
2036	$7.73	0.978	0.896	1612	$7	$5	0.184	$1	$1	$0.004	$0.003
2037	$7.88	0.977	0.891	1604	$7	$5	0.170	$1	$1	$0.004	$0.003
2038	$8.04	0.976	0.887	1596	$7	$5	0.158	$1	$1	$0.005	$0.003

Validation: Present Value	Utility	VOS
	$66	$66

Avoided Plant O&M – Variable

An example calculation of avoided plant O&M is displayed in Table 10. Utility prices are given in the VOS Data Table, escalated each year by the O&M escalation rate. As before, the per unit PV production is shown with annual degradation taken into account. The utility cost is the product of the utility price and the per unit production, and these costs are discounted. The VOS price of variable O&M is the levelized value resulting in the same total discounted cost.

Table 10. (EXAMPLE) Economic value of avoided plant O&M – variable.

	Prices			Costs			Disc. Costs	
Year	Utility ($/kWh)	VOS ($/kWh)	p.u. PV Production (kWh)	Utility ($)	VOS ($)	Discount Factor	Utility ($)	VOS ($)
2014	$0.0010	$0.0012	1,800	$2	$2	1.000	$2	$2
2015	$0.0010	$0.0012	1,791	$2	$2	0.926	$2	$2
2016	$0.0010	$0.0012	1,782	$2	$2	0.857	$2	$2
2017	$0.0011	$0.0012	1,773	$2	$2	0.794	$1	$2
2018	$0.0011	$0.0012	1,764	$2	$2	0.735	$1	$2
2019	$0.0011	$0.0012	1,755	$2	$2	0.681	$1	$1
2020	$0.0011	$0.0012	1,747	$2	$2	0.630	$1	$1
2021	$0.0011	$0.0012	1,738	$2	$2	0.583	$1	$1
2022	$0.0012	$0.0012	1,729	$2	$2	0.540	$1	$1
2023	$0.0012	$0.0012	1,721	$2	$2	0.500	$1	$1
2024	$0.0012	$0.0012	1,712	$2	$2	0.463	$1	$1
2025	$0.0012	$0.0012	1,703	$2	$2	0.429	$1	$1
2026	$0.0013	$0.0012	1,695	$2	$2	0.397	$1	$1
2027	$0.0013	$0.0012	1,686	$2	$2	0.368	$1	$1
2028	$0.0013	$0.0012	1,678	$2	$2	0.340	$1	$1
2029	$0.0013	$0.0012	1,670	$2	$2	0.315	$1	$1
2030	$0.0014	$0.0012	1,661	$2	$2	0.292	$1	$1
2031	$0.0014	$0.0012	1,653	$2	$2	0.270	$1	$1
2032	$0.0014	$0.0012	1,645	$2	$2	0.250	$1	$0
2033	$0.0015	$0.0012	1,636	$2	$2	0.232	$1	$0
2034	$0.0015	$0.0012	1,628	$2	$2	0.215	$1	$0
2035	$0.0015	$0.0012	1,620	$2	$2	0.199	$0	$0
2036	$0.0015	$0.0012	1,612	$2	$2	0.184	$0	$0
2037	$0.0016	$0.0012	1,604	$3	$2	0.170	$0	$0
2038	$0.0016	$0.0012	1,596	$3	$2	0.158	$0	$0

Validation: Present Value	**$24**	**$24**

Avoided Generation Capacity Cost

The solar-weighted capacity cost is based on the installed capital cost of a peaking combustion turbine and the installed capital cost of a combined cycle gas turbine, interpolated based on heat rate:

$$Cost = Cost_{CCGT} + (HeatRate_{PV} - HeatRate_{CCGT}) \times \frac{Cost_{CT} - Cost_{CCGT}}{HeatRate_{CT} - HeatRate_{CCGT}} \qquad (17)$$

Where $HeatRate_{PV}$ is the solar-weighted heat rate calculated in equation (14).

Using equation (17) with the CT/CCGT heat rates and costs from the example VOS Data Table, we calculated a solar-weighted capacity cost of $1,050 per kW. In the example, the amortized cost is $86 per kW-yr.

Table 11 illustrates how utility costs are calculated by taking into account the degrading heat rate of the marginal unit and PV. For example, in year 2015, the utility cost is $86 per kW-yr x 0.999 / 0.995 to give $85 for each unit of effective PV capacity. Utility prices are back-calculated for reference from the per unit PV production. Again, the VOS price is selected to give the same total discounted cost as the utility costs for the Generation Capacity Cost component.

Table 11. (EXAMPLE) Economic value of avoided generation capacity cost.

Year	Capacity Cost	Utility Capacity	PV Capacity	p.u. PV Production	Costs Utility	Costs VOS	Discount Factor	Disc. Costs Utility	Disc. Costs VOS	Prices Utility	Prices VOS
	($/kW-yr)	(p.u.)	(kW)	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	$86	1.000	1.000	1800	$86	$87	1.000	$86	$87	$0.048	$0.048
2015	$86	0.999	0.995	1791	$85	$86	0.926	$79	$80	$0.048	$0.048
2016	$86	0.998	0.990	1782	$85	$86	0.857	$73	$73	$0.048	$0.048
2017	$86	0.997	0.985	1773	$85	$85	0.794	$67	$68	$0.048	$0.048
2018	$86	0.996	0.980	1764	$84	$85	0.735	$62	$62	$0.048	$0.048
2019	$86	0.995	0.975	1755	$84	$84	0.681	$57	$57	$0.048	$0.048
2020	$86	0.994	0.970	1747	$84	$84	0.630	$53	$53	$0.048	$0.048
2021	$86	0.993	0.966	1738	$83	$84	0.583	$49	$49	$0.048	$0.048
2022	$86	0.992	0.961	1729	$83	$83	0.540	$45	$45	$0.048	$0.048
2023	$86	0.991	0.956	1721	$83	$83	0.500	$41	$41	$0.048	$0.048
2024	$86	0.990	0.951	1712	$82	$82	0.463	$38	$38	$0.048	$0.048
2025	$86	0.989	0.946	1703	$82	$82	0.429	$35	$35	$0.048	$0.048
2026	$86	0.988	0.942	1695	$82	$81	0.397	$32	$32	$0.048	$0.048
2027	$86	0.987	0.937	1686	$81	$81	0.368	$30	$30	$0.048	$0.048
2028	$86	0.986	0.932	1678	$81	$81	0.340	$28	$27	$0.048	$0.048
2029	$86	0.985	0.928	1670	$81	$80	0.315	$25	$25	$0.048	$0.048
2030	$86	0.984	0.923	1661	$80	$80	0.292	$23	$23	$0.048	$0.048
2031	$86	0.983	0.918	1653	$80	$79	0.270	$22	$21	$0.049	$0.048
2032	$86	0.982	0.914	1645	$80	$79	0.250	$20	$20	$0.049	$0.048
2033	$86	0.981	0.909	1636	$80	$79	0.232	$18	$18	$0.049	$0.048
2034	$86	0.980	0.905	1628	$79	$78	0.215	$17	$17	$0.049	$0.048
2035	$86	0.979	0.900	1620	$79	$78	0.199	$16	$15	$0.049	$0.048
2036	$86	0.978	0.896	1612	$79	$77	0.184	$14	$14	$0.049	$0.048
2037	$86	0.977	0.891	1604	$78	$77	0.170	$13	$13	$0.049	$0.048
2038	$86	0.976	0.887	1596	$78	$77	0.158	$12	$12	$0.049	$0.048

Validation: Present Value	**$958**	**$958**

Avoided Reserve Capacity Cost

An example of the calculation of avoided reserve capacity cost is shown in Table 12. This is identical to the generation capacity cost calculation, except utility costs are multiplied by the reserve capacity margin. In the example, the reserve capacity margin is 15%, so the utility cost for 2014 is calculated as $86 per unit effective capacity x 15% = $13. The rest of the calculation is identical to the capacity cost calculation.

Avoided Transmission Capacity Cost

Avoided transmission costs are calculated the same way as avoided generation costs except in two ways. First, transmission capacity is assumed not to degrade over time (PV degradation is still accounted for). Second, avoided transmission capacity costs are calculated based on the utility's 5-year average MISO OATT Schedule 9 charge in Start Year USD, e.g., in 2014 USD if year one of the VOS tariff was 2014. Table 13 shows the example calculation.

Table 12. (EXAMPLE) Economic value of avoided reserve capacity cost.

Year	Capacity Cost	Gen. Capacity	PV Capacity	p.u. PV Production	Costs		Discount Factor	Disc. Costs		Prices	
					Utility	VOS		Utility	VOS	Utility	VOS
	($/kW-yr)	(p.u.)	(kW)	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	$86	1.000	1.000	1800	$13	$13	1.000	$13	$13	$0.007	$0.007
2015	$86	0.999	0.995	1791	$13	$13	0.926	$12	$12	$0.007	$0.007
2016	$86	0.998	0.990	1782	$13	$13	0.857	$11	$11	$0.007	$0.007
2017	$86	0.997	0.985	1773	$13	$13	0.794	$10	$10	$0.007	$0.007
2018	$86	0.996	0.980	1764	$13	$13	0.735	$9	$9	$0.007	$0.007
2019	$86	0.995	0.975	1755	$13	$13	0.681	$9	$9	$0.007	$0.007
2020	$86	0.994	0.970	1747	$13	$13	0.630	$8	$8	$0.007	$0.007
2021	$86	0.993	0.966	1738	$13	$13	0.583	$7	$7	$0.007	$0.007
2022	$86	0.992	0.961	1729	$12	$12	0.540	$7	$7	$0.007	$0.007
2023	$86	0.991	0.956	1721	$12	$12	0.500	$6	$6	$0.007	$0.007
2024	$86	0.990	0.951	1712	$12	$12	0.463	$6	$6	$0.007	$0.007
2025	$86	0.989	0.946	1703	$12	$12	0.429	$5	$5	$0.007	$0.007
2026	$86	0.988	0.942	1695	$12	$12	0.397	$5	$5	$0.007	$0.007
2027	$86	0.987	0.937	1686	$12	$12	0.368	$4	$4	$0.007	$0.007
2028	$86	0.986	0.932	1678	$12	$12	0.340	$4	$4	$0.007	$0.007
2029	$86	0.985	0.928	1670	$12	$12	0.315	$4	$4	$0.007	$0.007
2030	$86	0.984	0.923	1661	$12	$12	0.292	$4	$3	$0.007	$0.007
2031	$86	0.983	0.918	1653	$12	$12	0.270	$3	$3	$0.007	$0.007
2032	$86	0.982	0.914	1645	$12	$12	0.250	$3	$3	$0.007	$0.007
2033	$86	0.981	0.909	1636	$12	$12	0.232	$3	$3	$0.007	$0.007
2034	$86	0.980	0.905	1628	$12	$12	0.215	$3	$3	$0.007	$0.007
2035	$86	0.979	0.900	1620	$12	$12	0.199	$2	$2	$0.007	$0.007
2036	$86	0.978	0.896	1612	$12	$12	0.184	$2	$2	$0.007	$0.007
2037	$86	0.977	0.891	1604	$12	$12	0.170	$2	$2	$0.007	$0.007
2038	$86	0.976	0.887	1596	$12	$12	0.158	$2	$2	$0.007	$0.007

Validation: Present Value		Utility	VOS
Validation: Present Value		$144	$144

Table 13. (EXAMPLE) Economic value of avoided transmission capacity cost.

Year	Capacity Cost	Trans. Capacity	PV Capacity	p.u. PV Production	Costs Utility	Costs VOS	Discount Factor	Disc. Costs Utility	Disc. Costs VOS	Prices Utility	Prices VOS
	($/kW-yr)	(p.u.)	(kW)	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	$33	1.000	1.000	1800	$33	$33	1.000	$33	$33	$0.018	$0.018
2015	$33	1.000	0.995	1791	$33	$33	0.926	$30	$30	$0.018	$0.018
2016	$33	1.000	0.990	1782	$33	$33	0.857	$28	$28	$0.018	$0.018
2017	$33	1.000	0.985	1773	$33	$33	0.794	$26	$26	$0.018	$0.018
2018	$33	1.000	0.980	1764	$32	$32	0.735	$24	$24	$0.018	$0.018
2019	$33	1.000	0.975	1755	$32	$32	0.681	$22	$22	$0.018	$0.018
2020	$33	1.000	0.970	1747	$32	$32	0.630	$20	$20	$0.018	$0.018
2021	$33	1.000	0.966	1738	$32	$32	0.583	$19	$19	$0.018	$0.018
2022	$33	1.000	0.961	1729	$32	$32	0.540	$17	$17	$0.018	$0.018
2023	$33	1.000	0.956	1721	$32	$32	0.500	$16	$16	$0.018	$0.018
2024	$33	1.000	0.951	1712	$31	$31	0.463	$15	$15	$0.018	$0.018
2025	$33	1.000	0.946	1703	$31	$31	0.429	$13	$13	$0.018	$0.018
2026	$33	1.000	0.942	1695	$31	$31	0.397	$12	$12	$0.018	$0.018
2027	$33	1.000	0.937	1686	$31	$31	0.368	$11	$11	$0.018	$0.018
2028	$33	1.000	0.932	1678	$31	$31	0.340	$10	$10	$0.018	$0.018
2029	$33	1.000	0.928	1670	$31	$31	0.315	$10	$10	$0.018	$0.018
2030	$33	1.000	0.923	1661	$30	$30	0.292	$9	$9	$0.018	$0.018
2031	$33	1.000	0.918	1653	$30	$30	0.270	$8	$8	$0.018	$0.018
2032	$33	1.000	0.914	1645	$30	$30	0.250	$8	$8	$0.018	$0.018
2033	$33	1.000	0.909	1636	$30	$30	0.232	$7	$7	$0.018	$0.018
2034	$33	1.000	0.905	1628	$30	$30	0.215	$6	$6	$0.018	$0.018
2035	$33	1.000	0.900	1620	$30	$30	0.199	$6	$6	$0.018	$0.018
2036	$33	1.000	0.896	1612	$30	$30	0.184	$5	$5	$0.018	$0.018
2037	$33	1.000	0.891	1604	$29	$29	0.170	$5	$5	$0.018	$0.018
2038	$33	1.000	0.887	1596	$29	$29	0.158	$5	$5	$0.018	$0.018

Validation: Present Value	Utility	VOS
	$365	$365

Avoided Distribution Capacity Cost

Avoided distribution capacity costs may be calculated in either of two ways:

- **System-wide Avoided Costs**. These are calculated using utility-wide costs and lead to a VOS rate that is "averaged" and applicable to all solar customers. This method is described below in the methodology.

- **Location-specific Avoided Costs**. These are calculated using location-specific costs, growth rates, etc., and lead to location-specific VOS rates. This method provides the utility with a means for offering a higher-value VOS rate in areas where capacity is most needed (areas of highest value). The details of this method are site specific and not included in the methodology, however they are to be implemented in accordance with the requirements set for the below.

System-wide Avoided Costs

System wide costs and peak growth rates are determined using actual data from each of the last 10 years. The costs and growth rate must be taken over the same time period because the historical investments must be tied to the growth associated with those investments.

All costs for each year for FERC accounts 360, 361, 362, 365, 366, and 367 should be included. These costs, however, should be adjusted to consider only capacity-related amounts. As such, the capacity-related percentages shown in Table 14 will be utility specific.

Table 14. (EXAMPLE) Determination of deferrable costs.

Account	Account Name	Additions ($) [A]	Retirements ($) [R]	Net Additions ($) = [A] - [R]	Capacity Related?	Deferrable ($)
	DISTRIBUTION PLANT					
360	Land and Land Rights	13,931,928	233,588	13,698,340	100%	13,698,340
361	Structures and Improvements	35,910,551	279,744	35,630,807	100%	35,630,807
362	Station Equipment	478,389,052	20,808,913	457,580,139	100%	457,580,139
363	Storage Battery Equipment					
364	Poles, Towers, and Fixtures	310,476,864	9,489,470	300,987,394		
365	Overhead Conductors and Devices	349,818,997	22,090,380	327,728,617	25%	81,932,154
366	Underground Conduit	210,115,953	10,512,018	199,603,935	25%	49,900,984
367	Underground Conductors and Devices	902,527,963	32,232,966	870,294,997	25%	217,573,749
368	Line Transformers	389,984,149	19,941,075	370,043,074		
369	Services	267,451,206	5,014,559	262,436,647		
370	Meters	118,461,196	4,371,827	114,089,369		
371	Installations on Customer Premises	22,705,193		22,705,193		
372	Leased Property on Customer Premises					
373	Street Lighting and Signal Systems	53,413,993	3,022,447	50,391,546		
374	Asset Retirement Costs for Distribution Plant	15,474,098	2,432,400	13,041,698		
TOTAL		3,168,661,143	130,429,387	3,038,231,756		$856,316,173

Cost per unit growth ($ per kW) is calculated by taking all of the total deferrable cost for each year, adjusting for inflation, and dividing by the kW increase in peak annual load over the 10 years.

Future growth in peak load is assumed to be at the same rate as the last 10 years. It is calculated using the ratio of peak loads of the most recent year (year 10) and the peak load from the earlier year (year 1):

$$GrowthRate = \left(\frac{P_{10}}{P_1}\right)^{1/10} - 1 \qquad (18)$$

A sample economic value calculation is presented in Table 15. The distribution cost for the first year ($200 per kW in the example) is taken from the analysis of historical cost and growth as described above. This cost is escalated each year using the rate in the VOS Data Table.

For each future year, the amount of new distribution capacity is calculated based on the growth rate, and this is multiplied by the cost per kW to get the cost for the year. The total discounted cost is calculated ($149M) and amortized over the 25 years.

PV is assumed to be installed in sufficient capacity to allow this investment stream to be deferred for one year. The total discounted cost of the deferred time series is calculated ($140M) and amortized.

Utility costs are calculated using the difference between the amortized costs of the conventional plan and the amortized cost of the deferred plan. For example, the utility cost for 2022 is ($14M - $13M)/54MW x 1000 W/kW = $14 per effective kW of PV. As before, utility prices are back-calculated using PV production, and the VOS component rate is calculated such that the total discounted amount equals the discounted utility cost.

Location-specific Avoided Costs

As an alternative to system-wide costs for distribution, location-specific costs may be used. When calculating location-specific costs, the calculation should follow the same method of the system-wide avoided cost method, but use local technical and cost data. The calculation should satisfy the following requirements:

- The distribution cost VOS should be calculated for each distribution planning area, defined as the minimum area in which capacity needs cannot be met by transferring loads internally from one circuit to another.
- Distribution loads (the sum of all relevant feeders), peak load growth rates and capital costs should be based on the distribution planning area.
- Local Fleet Production Shapes may be used, if desired. Alternatively, the system-level Fleet Production Shape may be used.

- Anticipated capital costs should be evaluated based on capacity related investments only (as above) using budgetary engineering cost estimates. All anticipated capital investments in the planning area should be included. Planned capital investments should be assumed to meet capacity requirements for the number of years defined by the amount of new capacity added (in MW) divided by the local growth rate (MW per year). Beyond this time period, which is beyond the planning horizon, new capacity investments should be assumed each year using the system-wide method.
- Planning areas for which engineering cost estimates are not available may be combined, and the VOS calculated using the system-wide method.

Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

		Conventional Distribution Planning				Deferred Distribution Planning			
Year	Distribution Cost	New Dist. Capacity	Capital Cost	Disc. Capital Cost	Amortized	Def. Dist. Capacity	Def. Capital Cost	Disc. Capital Cost	Amortized
	($/kW)	(MW)	($M)	($M)	$M/yr	(MW)	($M)	($M)	$M/yr
2014	$200	50	$10	$10	$14				$13
2015	$204	50	$10	$9	$14	50	$10	$9	$13
2016	$208	51	$11	$9	$14	50	$10	$9	$13
2017	$212	51	$11	$9	$14	51	$11	$9	$13
2018	$216	52	$11	$8	$14	51	$11	$8	$13
2019	$221	52	$11	$8	$14	52	$11	$8	$13
2020	$225	53	$12	$7	$14	52	$12	$7	$13
2021	$230	53	$12	$7	$14	53	$12	$7	$13
2022	$234	54	$13	$7	$14	53	$12	$7	$13
2023	$239	54	$13	$6	$14	54	$13	$6	$13
2024	$244	55	$13	$6	$14	54	$13	$6	$13
2025	$249	55	$14	$6	$14	55	$14	$6	$13
2026	$254	56	$14	$6	$14	55	$14	$6	$13
2027	$259	56	$15	$5	$14	56	$14	$5	$13
2028	$264	57	$15	$5	$14	56	$15	$5	$13
2029	$269	57	$15	$5	$14	57	$15	$5	$13
2030	$275	58	$16	$5	$14	57	$16	$5	$13
2031	$280	59	$16	$4	$14	58	$16	$4	$13
2032	$286	59	$17	$4	$14	59	$17	$4	$13
2033	$291	60	$17	$4	$14	59	$17	$4	$13
2034	$297	60	$18	$4	$14	60	$18	$4	$13
2035	$303	61	$18	$4	$14	60	$18	$4	$13
2036	$309	62	$19	$4	$14	61	$19	$3	$13
2037	$315	62	$20	$3	$14	62	$19	$3	$13
2038	$322	63	$20	$3	$14	62	$20	$3	$13
2039	$328					63	$21	$3	
				$149				$140	

CONTINUED Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

Year	p.u. PV Production	Costs		Discount Factor	Disc. Costs		Prices	
		Utility	VOS		Utility	VOS	Utility	VOS
	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	1800	$16	$15	1.000	$16	$15	$0.009	$0.008
2015	1791	$15	$15	0.926	$14	$14	$0.009	$0.008
2016	1782	$15	$15	0.857	$13	$13	$0.009	$0.008
2017	1773	$15	$15	0.794	$12	$12	$0.009	$0.008
2018	1764	$15	$15	0.735	$11	$11	$0.009	$0.008
2019	1755	$15	$15	0.681	$10	$10	$0.008	$0.008
2020	1747	$15	$15	0.630	$9	$9	$0.008	$0.008
2021	1738	$15	$15	0.583	$9	$8	$0.008	$0.008
2022	1729	$14	$14	0.540	$8	$8	$0.008	$0.008
2023	1721	$14	$14	0.500	$7	$7	$0.008	$0.008
2024	1712	$14	$14	0.463	$7	$7	$0.008	$0.008
2025	1703	$14	$14	0.429	$6	$6	$0.008	$0.008
2026	1695	$14	$14	0.397	$6	$6	$0.008	$0.008
2027	1686	$14	$14	0.368	$5	$5	$0.008	$0.008
2028	1678	$14	$14	0.340	$5	$5	$0.008	$0.008
2029	1670	$13	$14	0.315	$4	$4	$0.008	$0.008
2030	1661	$13	$14	0.292	$4	$4	$0.008	$0.008
2031	1653	$13	$14	0.270	$4	$4	$0.008	$0.008
2032	1645	$13	$14	0.250	$3	$3	$0.008	$0.008
2033	1636	$13	$14	0.232	$3	$3	$0.008	$0.008
2034	1628	$13	$14	0.215	$3	$3	$0.008	$0.008
2035	1620	$13	$14	0.199	$3	$3	$0.008	$0.008
2036	1612	$13	$13	0.184	$2	$2	$0.008	$0.008
2037	1604	$12	$13	0.170	$2	$2	$0.008	$0.008
2038	1596	$12	$13	0.158	$2	$2	$0.008	$0.008
2039								

Validation: Present Value	$166	$166

Avoided Environmental Cost

Environmental costs are included as a required component and are based on existing Minnesota and EPA externality costs. CO_2 and non-CO_2 natural gas emissions factors (lb per MM BTU of natural gas) are taken from the EPA[15] and NaturalGas.org,[16] both of which have nearly identical numbers for the emissions factors. Avoided environmental costs are based on the federal social cost of CO_2 emissions[17] plus the Minnesota PUC-established externality costs for non-CO_2 emissions[18].

The externality cost of CO_2 emissions shown in Table 4 are calculated as follows. The EPA Social Cost of Carbon (CO_2) estimated for a given year is published in 2007 dollars per metric ton. These costs are adjusted for inflation (converted to current dollars), converted to dollars per short ton, and then converted to cost per unit fuel consumption using the assumed values in Table 16.

For example, the EPA externality cost for 2020 (3.0% discount rate, average) is $43 per metric ton of CO_2 emissions in 2007 dollars. This is converted to current dollars by multiplying by a CPI adjustment factor; for 2014, the CPI adjustment factor is of 1.12. The resulting CO_2 costs per metric ton in current dollars are then converted to dollars per short ton by dividing by 1.102. Finally, the costs are escalated using the general escalation rate of 2.53% per year to give $50.77 per ton. Which equates to $51.22 per ton of CO_2, divided by 2000 pounds per ton, and multiplied by 117.0 pounds of CO_2 per MMBtu = $2.970 per MMBtu in 2020 dollars.

Table 16. Natural Gas Emissions.

	NG Emissions (lb/MMBtu)
PM10	0.007
CO	0.04
NOX	0.092
Pb	0.00
CO2	117.0

[15] http://www.epa.gov/climatechange/ghgemissions/ind-assumptions.html and http://www.epa.gov/ttnchie1/ap42/
[16] http://www.naturalgas.org/environment/naturalgas.asp
[17] See http://www.epa.gov/climatechange/EPAactivities/economics/scc.html, EPA technical document appendix, May 2013.
[18] "Notice of Updated Environmental Externality Values," issued June 5, 2013, PUC docket numbers E-999/CI-93-583 and E-999/CI-00-1636.

All pollutants other than CO_2 are calculated using the Minnesota externality costs using the following method. Externality costs are taken as the midpoint of the low and high values for the urban scenario, adjusted to current dollars, and converted to a fuel-based value using Table 16.

For example, MN's published costs for PM10 are $6,291 per ton (low case) and $9,056 per ton (high case). These are averaged to be ($6291+$9056)/2 = $7674 per ton of PM10 emissions. For 2020, these are escalated using the general escalation rate of 2.53% per year to $8,917 per ton. Which equates to $8,917 per ton of PM10, divided by 2000 pounds per ton, multiplied by 0.007 pounds of PM10 per MMBtu = $0.031 per MMBtu. Similar calculations are done for the other pollutants.

In the example shown in Table 17, the environmental cost is the sum of the costs of all pollutants. For example, in 2020, the total cost of $3.052 per MMBtu corresponds to the 2020 total cost in Table 4. This cost is multiplied by the heat rate for the year (see Avoided Fuel Cost calculation) and divided by 10^6 (to convert Btus to MMBtus), which results in the environmental cost in dollars per kWh for each year. The remainder of the calculation follows the same method as the avoided variable O&M costs but using the environmental discount factor (see Discount Factors for a description of the environmental discount factor and its calculation).

Avoided Voltage Control Cost

This is reserved for future updates to the methodology.

Solar Integration Cost

This is reserved for future updates to the methodology.

Table 17. (EXAMPLE) Economic value of avoided environmental cost.

Year	Env. Cost ($/MMBtu)	Heat Rate (Btu/kWh)	Prices Utility ($/kWh)	Prices VOS ($/kWh)	p.u. PV Production (kWh)	Costs Utility ($)	Costs VOS ($)	Discount Factor	Disc. Costs Utility ($)	Disc. Costs VOS ($)
2014	2.210	8000	$0.018	$0.029	1,800	$32	$52	1.000	$32	$52
2015	2.327	8008	$0.019	$0.029	1,791	$33	$52	0.947	$32	$49
2016	2.449	8016	$0.020	$0.029	1,782	$35	$52	0.897	$31	$46
2017	2.575	8024	$0.021	$0.029	1,773	$37	$51	0.849	$31	$44
2018	2.706	8032	$0.022	$0.029	1,764	$38	$51	0.804	$31	$41
2019	2.909	8040	$0.023	$0.029	1,755	$41	$51	0.761	$31	$39
2020	3.052	8048	$0.025	$0.029	1,747	$43	$51	0.721	$31	$36
2021	3.130	8056	$0.025	$0.029	1,738	$44	$50	0.682	$30	$34
2022	3.282	8064	$0.026	$0.029	1,729	$46	$50	0.646	$30	$32
2023	3.439	8072	$0.028	$0.029	1,721	$48	$50	0.612	$29	$30
2024	3.603	8080	$0.029	$0.029	1,712	$50	$50	0.579	$29	$29
2025	3.772	8088	$0.031	$0.029	1,703	$52	$49	0.549	$29	$27
2026	3.948	8097	$0.032	$0.029	1,695	$54	$49	0.519	$28	$25
2027	4.131	8105	$0.033	$0.029	1,686	$56	$49	0.492	$28	$24
2028	4.320	8113	$0.035	$0.029	1,678	$59	$49	0.466	$27	$23
2029	4.516	8121	$0.037	$0.029	1,670	$61	$48	0.441	$27	$21
2030	4.719	8129	$0.038	$0.029	1,661	$64	$48	0.417	$27	$20
2031	4.839	8137	$0.039	$0.029	1,653	$65	$48	0.395	$26	$19
2032	5.054	8145	$0.041	$0.029	1,645	$68	$48	0.374	$25	$18
2033	5.278	8153	$0.043	$0.029	1,636	$70	$47	0.354	$25	$17
2034	5.510	8162	$0.045	$0.029	1,628	$73	$47	0.336	$25	$16
2035	5.750	8170	$0.047	$0.029	1,620	$76	$47	0.318	$24	$15
2036	5.999	8178	$0.049	$0.029	1,612	$79	$47	0.301	$24	$14
2037	6.257	8186	$0.051	$0.029	1,604	$82	$46	0.285	$23	$13
2038	6.524	8194	$0.053	$0.029	1,596	$85	$46	0.270	$23	$12

Validation: Present Value	**$697**	**$697**

VOS Example Calculation

The economic value, load match, distributed loss savings, and distributed PV value are combined in the required VOS Levelized Calculation Chart. An example is presented in Figure 3 using the assumptions made for the example calculation. Actual VOS results will differ from those shown in the example, but utilities will include in their application a VOS Levelized Calculation Chart in the same format. For completeness, Figure 4 (not required of the utilities) is presented showing graphically the relative importance of the components in the example.

Figure 3. (EXAMPLE) VOS Levelized Calculation Chart (Required).

25 Year Levelized Value	Gross Starting Value ($/kWh)	×	Load Match Factor (%)	× (1 +	Loss Savings Factor (%)	)	=	Distributed PV Value ($/kWh)
Avoided Fuel Cost	$0.061				8%			$0.066
Avoided Plant O&M - Fixed	$0.003		40%		9%			$0.001
Avoided Plant O&M - Variable	$0.001				8%			$0.001
Avoided Gen Capacity Cost	$0.048		40%		9%			$0.021
Avoided Reserve Capacity Cost	$0.007		40%		9%			$0.003
Avoided Trans. Capacity Cost	$0.018		40%		9%			$0.008
Avoided Dist. Capacity Cost	$0.008		30%		5%			$0.003
Avoided Environmental Cost	$0.029				8%			$0.031
Avoided Voltage Control Cost								
Solar Integration Cost								
								$0.135

Having calculated the levelized VOS credit, an inflation-adjusted VOS can then be found. An EXAMPLE inflation-adjusted VOS is provided in Figure 5 by using the general escalation rate as the annual inflation rate for all years of the analysis period. Both the inflation-adjusted VOS and the levelized VOS in Figure 5 represent the same long-term value. The methodology requires that the inflation-adjusted (nominal) VOS be used and updated annually to account for the current year's inflation rate.

To calculate the inflation-adjusted VOS for the first year, the products of the levelized VOS, PV production and the discount factor are summed for each year of the analysis period and then divided by the sum of the products of the escalation factor, PV production, and the discount factor for each year of the analysis period, as shown below in Equation (19).

Figure 4. (EXAMPLE) Levelized value components.

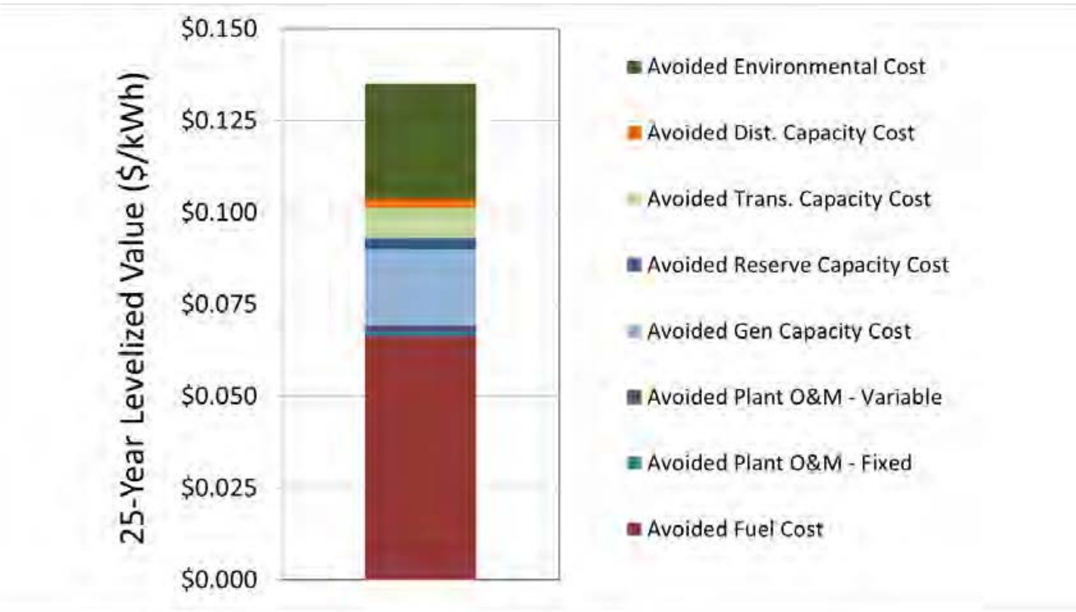
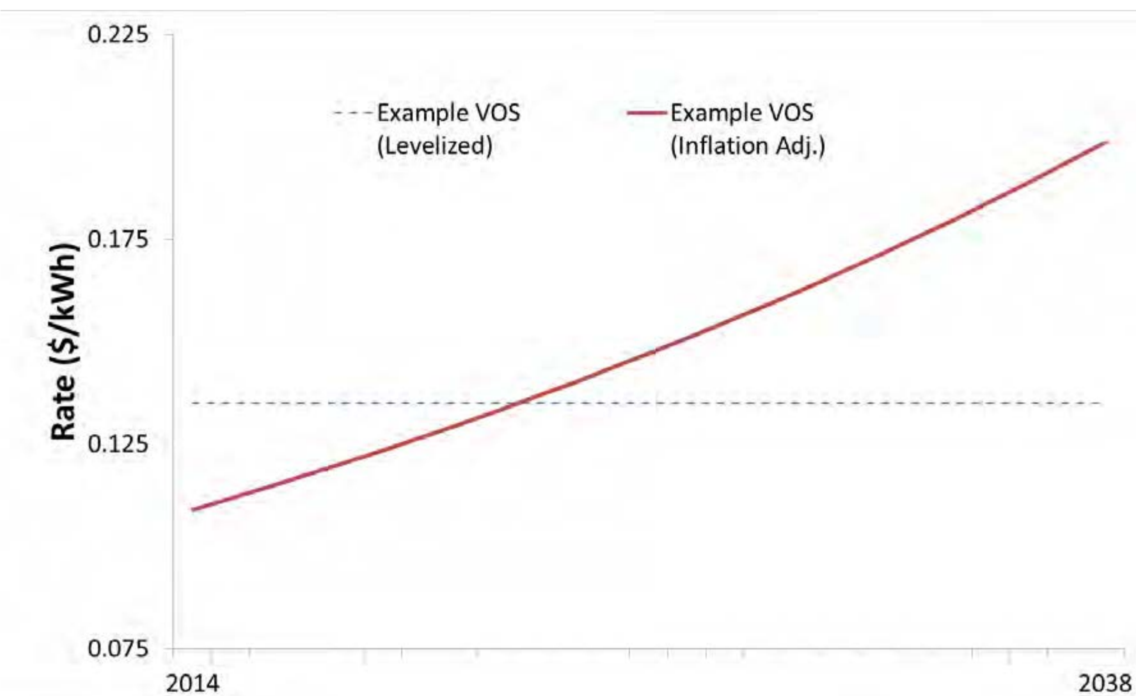


Figure 5. (EXAMPLE) Inflation-Adjusted VOS.



$$InflationAdjustedVOS_{Year0}\left(\frac{\$}{kWh}\right) \quad (19)$$

$$= \frac{\sum_i LevelizedVOS \times PVProduction_i \times DiscountFactor_i}{\sum_i EscalationFactor_i \times PVProduction_i \times DiscountFactor_i}$$

Once the first-year inflation-adjusted VOS is calculated, the value will then be updated on an annual basis in accordance with the observed inflation-rate. Table 18 provides the calculation of the EXAMPLE inflation-adjusted VOS shown in Figure 5. In this EXAMPLE, the inflation rate in future years is set equal to the general escalation rate of 2.53%.

Table 18. (EXAMPLE) Calculation of inflation-adjusted VOS.

Year	Discount Factor	PV Production (kWh)	Escalation Factor	Example VOS (Levelized)	Disc. Cost ($)	Example VOS (Inflation Adj.)	Disc. Cost ($)
2014	1.000	1800	1.000	0.135	243	0.109	196
2015	0.926	1791	1.025	0.135	224	0.112	185
2016	0.857	1782	1.051	0.135	206	0.115	175
2017	0.794	1773	1.078	0.135	190	0.117	165
2018	0.735	1764	1.105	0.135	175	0.120	156
2019	0.681	1755	1.133	0.135	161	0.123	147
2020	0.630	1747	1.162	0.135	149	0.127	139
2021	0.583	1738	1.192	0.135	137	0.130	132
2022	0.540	1729	1.222	0.135	126	0.133	124
2023	0.500	1721	1.253	0.135	116	0.136	117
2024	0.463	1712	1.284	0.135	107	0.140	111
2025	0.429	1703	1.317	0.135	99	0.143	105
2026	0.397	1695	1.350	0.135	91	0.147	99
2027	0.368	1686	1.385	0.135	84	0.151	94
2028	0.340	1678	1.420	0.135	77	0.155	88
2029	0.315	1670	1.456	0.135	71	0.159	83
2030	0.292	1661	1.493	0.135	65	0.163	79
2031	0.270	1653	1.530	0.135	60	0.167	74
2032	0.250	1645	1.569	0.135	56	0.171	70
2033	0.232	1636	1.609	0.135	51	0.175	66
2034	0.215	1628	1.650	0.135	47	0.180	63
2035	0.199	1620	1.692	0.135	43	0.184	59
2036	0.184	1612	1.735	0.135	40	0.189	56
2037	0.170	1604	1.779	0.135	37	0.194	53
2038	0.158	1596	1.824	0.135	34	0.199	50
					2689		2689

Glossary

Table 19. Input data definitions

Input Data	Used in Methodology Section	Definition
Annual Energy	PV Energy Production	The annual PV production (kWh per year) per Marginal PV Resource (initially 1 kW-AC) in the first year (before any PV degradation) of the marginal PV resource. This is calculated in the Annual Energy section of PV Energy Production and used in the Equipment Degradation section.
Capacity-related distribution capital cost	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
Capacity-related transmission capital cost	Avoided Transmission Capacity Cost	The cost per kW of new construction of transmission, including lines, towers, insulators, transmission substations, etc. Only capacity-related costs should be included.
Discount rate (WACC)	Multiple	The utility's weighted average cost of capital, including interest on bonds and shareholder return.
Distribution capital cost escalation	Avoided Distribution Capacity Cost	Used to calculate future distribution costs.
ELCC (no loss), PLR (no loss)	Load Match Factors	The "Effective Load Carrying Capability" and the "Peak Load Reduction" of a PV resource expressed as percentages of rated capacity (kW-AC). These are described more fully in the Load Match section.
Environmental Costs	Avoided Environmental Cost	The costs required to calculate environmental impacts of conventional generation. These are described more fully in the Avoided Environmental Cost section

Input Data	Used in Methodology Section	Definition
Environmental Discount Rate	Avoided Environmental Cost	The societal discount rate corresponding to the EPA future year cost data, used to calculate the present value of future environmental costs.
Fuel Price Overhead	Avoided Fuel Cost	The difference in cost of fuel as delivered to the plant and the cost of fuel as available in market prices. This cost reflects transmission, delivery, and taxes.
General escalation rate	Avoided Environmental Cost, Example Results	The annual escalation rate corresponding to the most recent 25 years of CPI index data[19], used to convert constant dollar environmental costs into current dollars and to translate levelized VOS into inflation-adjusted VOS.
Generation Capacity Degradation	Avoided Generation Capacity Cost	The percentage decrease in the generation capacity per year
Generation Life	Avoided Generation Capacity Cost	The assumed service life of new generation assets.
Guaranteed NG Fuel Price Escalation	Avoided Fuel Cost	The escalation value to be applied for years in which futures prices are not available.
Guaranteed NG Fuel Prices	Avoided Fuel Cost	The annual average prices to be used when the utility elects to use the Futures Market option. These are not applicable when the utility elects to use options other than the Futures Market option. They are calculated as the annual average of monthly NYMEX NG futures[20], updated 8/27/2013.

[19] www.bls.gov

[20] See for example http://futures.tradingcharts.com/marketquotes/NG.html.

Input Data	Used in Methodology Section	Definition
Heat rate degradation	Avoided Generation Capacity Cost	The percentage increase in the heat rate (BTU per kWh) per year
Installed cost and heat rate for CT and CCGT	Avoided Generation Capacity Cost	The capital costs for these units (including all construction costs, land, ad valorem taxes, etc.) and their heat rates.
Loss Savings (Energy, PLR, and ELCC)	Loss Savings Analysis	The additional savings associated with Energy, PRL and ELCC, expressed as a percentage. These are described more fully in the Loss Savings section.
O&M cost escalation rate	Avoided Plant O&M – Fixed, Avoided Plant O&M – Variable	Used to calculate future O&M costs.
O&M fixed costs	Avoided Plant O&M – Fixed	The costs to operate and maintain the plant that are not dependent on the amount of energy generated.
O&M variable costs	Avoided Plant O&M – Variable	The costs to operate and maintain the plant (excluding fuel costs) that are dependent on the amount of energy generated.
Peak Load	Avoided Distribution Capacity Cost	The utility peak load as expected in the year prior to the VOS start year.
Peak load growth rate	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
PV Degradation	Equipment Degradation Factors	The reduction in percent per year of PV capacity and PV energy due to degradation of the modules. The value of 0.5 percent is the median value of 2000 observed degradation rates.[21]

[21] D. Jordan and S. Kurtz, “Photovoltaic Degradation Rates – An Analytical Review,” NREL, June 2012.

Input Data	Used in Methodology Section	Definition
PV Life	Multiple	The assumed service life of PV. This value is also used to define the study period for which avoided costs are determined and the period over which the VOS rate would apply.
Reserve planning margin	Avoided Reserve Capacity Cost	The planning margin required to ensure reliability.
Solar-weighted heat rate	Avoided Fuel Costs	This is described in the described in the Avoided Fuel Costs section.
Start Year for VOS applicability	Multiple	This is the first year in which the VOS would apply and the first year for which avoided costs are calculated.
Transmission capital cost escalation	Avoided Transmission Capacity Cost	Used to adjust costs for future capital investments.
Transmission life	Avoided Transmission Capacity Cost	The assumed service life of new transmission assets.
Treasury Yields	Escalation and Discount Rates	Yields for U.S. Treasuries, used as the basis of the risk-free discount rate calculation.[22]
Years until new transmission capacity is needed	Avoided Transmission Capacity Cost	This is used to test whether avoided costs for a given analysis year should be calculated and included.

[22] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

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A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation

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Executive Summary

As distributed solar generation ("DSG") system prices continue to fall and this energy resource becomes more accessible thanks to financing options and regulatory programs, regulators, utilities and other stakeholders are increasingly interested in investigating DSG benefits and costs. Understandably, regulators seek to understand whether policies, such as net energy metering ("NEM"), put in place to encourage adoption of DSG are appropriate and cost-effective. This paper first offers lessons learned from the 16 regional and utility-specific DSG studies summarized in a recent review by the Rocky Mountain Institute ("RMI"),[1] and then proposes a standardized valuation methodology for public utility commissions to consider implementing in future studies.

As RMI's meta-study shows, recent DSG studies have varied widely due to differences in study assumptions, key parameters, and methodologies. A stark example came to light in early 2013 in Arizona, where two DSG benefit and cost studies were released in consecutive order by that State's largest utility and then by the solar industry. The utility-funded study showed a net solar value of less than four cents per kilowatt-hour ("kWh"), while the industry-funded study found a value in excess of 21 cents per kWh. A standard methodology would be helpful as legislators, regulators and the public attempt to determine whether to curtail or expand DSG policies.

Valuations vary by utility, but the authors contend that valuation methodologies should not. The authors suggest standardized approaches for the various benefits and costs, and explain how to calculate them regardless of the structure of the program or rate in which this valuation is used. Whether considering net NEM, value of solar tariffs, fixed-rate feed-in tariffs, or incentive programs, parties will always want to determine the value provided by DSG. The authors seek to fill that need, without endorsing any particular DSG policy in this paper.

Major Conclusions

Three conclusions stand out based on their potential to impact valuations:

- DSG primarily offsets combined-cycle natural gas facilities, which should be reflected in avoided energy costs.
- DSG installations are predictable and should be included in utility forecasts of capacity needs, so DSG should be credited with a capacity value upon interconnection.
- The societal benefits of DSG policies, such as job growth, health benefits and environmental benefits, should be included in valuations, as these were typically among the reasons for policy enactment in the first place.

[1] *A Review of Solar PV Benefit & Cost Studies* (RMI), July 2013 ("RMI 2013 Study"), *available at* http://www.rmi.org/elab_empower.

I. Introduction

There is an acute need for a standardized approach to distributed solar generation ("DSG") benefit and cost studies. In the first half of 2013, a steady flow of reports, news stories, workshops and conference panels have discussed whether to reform or repeal net energy metering ("NEM"), which is the bill credit arrangement that allows solar customers to receive full credit on their energy bills for any power they deliver to the grid.[2] The calls for change are founded on the claim that NEM customers who "zero out" their utility bill must not be paying their fair share for the utility infrastructure that they are using, and that those costs must have shifted to other, non-solar customers. Only a thorough benefit and cost analysis can provide regulators with an answer to whether this claim is valid in a given utility service area. As the simplicity and certainty of NEM have made it the vehicle for nearly all of the 400,000+ customer-sited solar arrays installed in the United States,[3] changes to such a successful policy should only be made based on careful analysis. This is especially so in light of a body of studies finding that solar customers may actually be subsidizing utilities and other customers.

The topic of NEM impacts on utility economics and on rates for non-solar customers seems to have risen to the top of utility priorities with the publication of an industry trade group report in January 2013 calling NEM "the largest near-term threat to the utility model."[4] Extrapolating from the current NEM penetration of just over 0.1% of U.S. energy generation to very high market penetration assumptions (e.g., if "everyone goes solar"), some have speculated that unchecked NEM growth will lead to a "utility death spiral." One Wall Street rating agency questioned the value of utility stocks in light of the continued success of NEM programs, claiming that it was "a scheme similar to net metering that led to the destabilization of the power markets in Spain in late 2008."[5]

[2] NEM allows utility customers with renewable energy generators to offset part or all of their electric load, both at the time of generation and through kWh credits for any excess generation. This enables customers with solar arrays to take credit at night for excess energy generated during the day, for instance. Forty-three states have implemented NEM (*see* www.freeingthegrid.org for details on state NEM policies).
[3] Larry Sherwood, *U.S. Solar Market Trends 2012* (Interstate Renewable Energy Council), at p. 5 (316,000 photovoltaic installations connected to the grid at year-end 2012, with 95,000 in 2012 alone), July 2013, *available at* http://www.irecusa.org/wp-content/uploads/2013/07/Solar-Report-Final-July-2013-1.pdf. Forecasts for 2013 installations surpass 2012. *See, e.g., U.S. Solar Market Insight Report Q1 2013*, Greentech Media, Executive Summary, at p. 14, June 2013, *available at* http://www.greentechmedia.com/research/ussmi.
[4] Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business* (Edison Electric Institute), at p. 4, Jan. 2013.
[5] *Solar Panels Cast Shadow on U.S. Utility Rate Design* (FitchRatings), July 17, 2013, *available at* http://www.fitchratings.com/gws/en/fitchwire/fitchwirearticle/Solar-Panels-Cast?pr_id=796776. The piece was wrong on its facts. The Spanish model used a feed-in tariff ("FIT") based on solar energy costs and set at over US $0.60/kWh, leading to a massive build-out in a single year when solar prices dipped below the FIT rates. See *Spain's Solar Market Crash Offers a Cautionary Tale About Feed-In Tariffs*, N.Y. Times, Aug. 18, 2009, *available at* http://www.nytimes.com/gwire/2009/08/18/18greenwire-spains-solar-market-crash-offers-a-cautionary-88308.html?pagewanted=all (for up to 44 eurocent incentives, and using 0.711 average euro to U.S. dollar exchange rate in 2008, per IRS tables).

Numerous trade and industry publications have joined the chorus, with little indication that the rhetoric will abate anytime soon.[6]

DSG benefit and cost studies are important beyond the context of NEM. To address concerns about the cost-effectiveness of NEM, Austin Energy implemented the first Value of Solar Tariff ("VOST") in 2012, which is now under consideration in other jurisdictions. Under the Austin Energy approach, all of the customer's energy needs are provided by the utility, just as they would be if the customer did not have DSG, and the utility credits the residential solar customer for the value of all of the energy produced by the customer's solar array.[7] Though intended to offer a new approach to address the valuation issue, Austin Energy's VOST did little to quell the larger debate; indeed, this new policy highlights the fact that valuation is the key issue for any solar policy—NEM, VOST or otherwise.

Austin Energy's VOST rate, as initially calculated, was about three cents higher than retail rates, giving customers an even greater return than the NEM policy that the VOST replaced. However, as with NEM, discussions about "value of solar" rates have now turned to how to calculate the benefits of customer-generated energy. Claiming the use of their own VOST approach, City Public Service, the municipal utility serving San Antonio, Texas (just 80 miles from Austin) used an undisclosed, annualized value approach to conclude that the value of customer-sited energy from solar arrays was roughly half of the retail rate. A competing study for San Antonio, sponsored by Solar San Antonio and using publicly available data, showed twice that value.[8] As with NEM, the VOST approach is still subject to significant variation in valuation methodologies.

In early 2013, competing studies looking at DSG values for Arizona Public Service ("APS") kept the debate over valuation raging. APS funded a study that concluded DSG value was only 3.56 cents per kilowatt-hour ("kWh"), based on the present value of a kWh from DSG in the year 2025. Subsequently, APS filed an application to either change the rate schedule available to NEM customers or switch to a Feed-In Tariff ("FiT"), with both approaches relying on valuation in the range of 4 to 5.5 cents per kWh. At the same time, a solar industry-sponsored study found a 21 to 24 cent range for the value of each kWh of DSG, far exceeding costs, which it found to be in the range of 14 to 16 cents per kWh.[9] The lack of a consistent study approach drives the disparity in results.

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[6] *See* David Roberts, *Solar panels could destroy U.S. utilities, according to U.S. utilities*, Grist, April 2013, *available at* http://grist.org/climate-energy/solar-panels-could-destroy-u-s-utilities-according-to-u-s-utilities/; Herman Trabish, *Solar's Net Metering Under Attack*, GreenTech Media, May 2012, *available at* http://www.greentechmedia.com/articles/read/solars-net-metering-under-attack.

[7] *See* Austin Energy's Residential Solar Tariff, *available at* www.austinenergy.com/About%20Us/Rates/pdfs/Residential/ResidentialSolar.pdf (last accessed September 9, 2013).

[8] *See* N. Jones and B. Norris, *The Value of Distributed Solar Electric Generation to San Antonio*, March 2013 ("San Antonio Study"), *available at* www.solarsanantonio.org/wp-content/uploads/2013/04/Value-of-Solar-at-San-Antonio-03-13-2013.pdf.

[9] Arizona Corporation Commission Docket No. E-01345A-13-0248 regarding NEM valuation opened with APS's application in July, 2013, and is available at http://edocket.azcc.gov/. The May 2013 APS study prepared by SAIC is available at http://www.solarfuturearizona.com/2013SolarValueStudy.pdf. The May 2013 solar industry-sponsored study prepared by Crossborder Energy is available at http://www.solarfuturearizona.com/TheBenefitsandCostsofSolarDistributedGenerationforAPS.pdf.

Figure 1 displays the 150% difference between the Austin Energy and San Antonio City Public Service DSG valuations, alongside the 6X difference in values found in the two APS studies.

Figure 1: Disparate DSG Valuations in Texas Studies (cents/kWh).

The figure above shows that Austin Energy's latest valuation of 12.8 cents per kWh is 150% greater the 5.1 cent valuation by City Public Service in San Antonio, just 80 miles away. Even more dramatic is the difference in DSG values for APS, with 3.56 cents by the utility consultant and a range of 21.5 to 23.7 cents by the solar industry consultant.

Overview of a proposed standardized approach. This paper explains how to calculate the benefits and costs of DSG, regardless of the structure of the program or rate in which this valuation is used. Whether considering NEM, VOST, FiTs or incentive programs, parties will always want to understand DSG value. Indeed, accuracy in resource and energy valuation is the cornerstone of sound utility ratemaking and a critical element of economic efficiency. Fortunately, at least 16 studies of individual utilities or regions have been performed over the past several years, providing a backdrop for the types of benefits and costs to consider. While the variation in the purposes, assumptions and approaches in these studies has been wide, the body of published work is sufficient to draw some conclusions about best practices via a meta-analysis.

Rocky Mountain Institute ("RMI"), a Colorado-based not-for-profit research organization, looked at these 16 studies and summarized the range of valuations for each benefit and cost category in *A Review of Solar PV Benefit and Cost Studies* ("RMI 2013 Study"), providing a very useful tool for regulators determining whether a new study has considered all of the relevant benefits and costs. As well, an IREC-led report in early 2012 summarized these key benefits and costs and provided a generalized, high-level approach for their inclusion in any study ("Solar ABCs Report").[10] Together, the Solar ABCs Report and the RMI 2013 Study provide a detailed summation of efforts to date to assess the net benefits and costs of DSG.

This paper discusses various studies, but does not attempt to replicate RMI's thorough meta-analysis. Rather, this paper proposes *how* each benefit should be calculated and *why*. To assist state utility commissions and other regulators as they consider DSG valuation studies and the fate of NEM, VOST, or other programs or rate designs, we offer a set of recommended best practices regulators can use to ensure that a DSG benefit and cost study accurately measures the net impact of DSG.[11]

This paper synthesizes the prevalent and preferred methods of quantifying the categories of benefits and costs of DSG. One point of agreement is that DSG-related energy benefits are well accepted and are typically employed in cost-effectiveness testing, as well as in avoided cost calculations. Additional benefits and costs, related to capacity, transmission and distribution ("T&D") costs, line losses, ancillary services, fuel price impacts, market price impacts, environmental compliance costs, and administrative expenses are less uniformly treated in regulation and in the literature, and are addressed here in an effort to establish more commonality in approach. The quantification of societal benefits (beyond utility compliance costs) is also addressed. While typically not quantified in cost-effectiveness tests, these benefits—especially as related to evaluation of the risk associated with alternate resources—also merit more uniform treatment.

Organizationally, this paper covers the types of studies undertaken in relation to DSG valuation and overarching issues in DSG valuation studies, followed by the benefits and costs considered in various studies, the rationale for them, and the authors' recommendations on how to approach them.

The premise of this paper is that while calculated values will differ from one utility to the next, the approach used to calculate the benefits and costs of distributed solar generation should be uniform.

II. DSG Benefit and Cost Studies

A history of DSG benefit and cost studies. There have been an increasing number of studies conducted and published over the past 10-15 years addressing the value of DSG and other distributed energy resources. The first comprehensive effort to

[10] J. Keyes and J. Wiedman, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering* (Solar America Board of Codes and Standards), January 2012 ("SolarABCs Report"), *available at* www.solarabcs.org/about/publications/reports/rateimpact.

[11] In addition, the Interstate Renewable Energy Council. Inc. ("IREC") is proactively working with state utility commissions to ask these questions before studies are undertaken, with the expectation that having clarified the assumptions, commissioners will be more confident in the results.

characterize the value of distributed energy resources was *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, published by RMI in 2002. Drawing from hundreds of sources, pilot project reports, and studies, *Small Is Profitable* set the stage for more specific technology-based studies, including the NEM cost-benefit studies and solar valuation studies that followed. Studies specific to DSG systems have appeared with increasing frequency since the Vote Solar Initiative published Ed Smeloff's *Quantifying the Benefits of Solar Power for California* in 2005 and Clean Power Research ("CPR") published its evaluation of *The Value of Solar to Austin Energy and the City of Austin* in 2006.

The reasons behind the appearance of these studies are several. DSG represents an increasingly affordable, interconnected form of distributed generation, creating the potential for significant penetration of small-scale generation into grids generally built around a central station model. In addition, economic and policy pressure on rebates and other mechanisms to foster DSG penetration has increased interest in improving understanding of the DSG value proposition. Utilities, policymakers, regulators, advocates, and service and hardware providers share a common interest in understanding what benefits and costs might be associated with such increased deployment of DSG, and whether net benefits outweigh net costs under a variety of deployment and analysis scenarios.

Many recent DSG valuation studies have been cost-effectiveness analyses of NEM policies for a given utility or group of utilities. NEM has proven to be one of the major drivers of distributed generation in the United States; 43 states and the District of Columbia feature some form of NEM.[12] The success of NEM as a policy to drive distributed generation market growth has caused several states to examine the impact that the policy has on other non-participating ratepayers. Efforts are currently underway in California, Arizona, Hawaii, Colorado, Nevada, North Carolina and Georgia to quantify the benefits and costs of the policy in order to inform the appropriate level of support for distributed energy generation, particularly rooftop solar photovoltaic ("PV") generation. Other states may follow soon, even those with relatively few DSG installations; for example, the Louisiana Public Service Commission indicated that it would launch a cost-benefit analysis for net-metered systems.

Another major use for DSG value analysis is in resource planning and other regulatory proceedings. In December 2012, Lawrence Berkeley National Laboratory ("LBNL") published a review of how several utilities account for solar resources in *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes.*[13] At this writing, Integrated Resource Plan ("IRP"), avoided cost, or renewable plan dockets are, or soon will be, underway at several utilities[14] where the value of DSG is directly at issue. In addition, the state of Minnesota has recently adopted legislation that establishes a

[12] *See* Database of State Incentives for Renewables and Energy Efficiency ("DSIRE"): Summary Maps – Net Metering Policies, *available at* www.dsireusa.org (last accessed Aug. 18. 2013).
[13] Andrew Mills & Ryan Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, December 2012 ("LBNL Utility Solar Study 2012"), *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.
[14] *See, e.g.,* Georgia Public Service Commission Docket No. 36989 (Georgia Power Rate Case); North Carolina Utilities Commission Docket No. E-100, Sub 136 (Biennial Avoided Cost); Colorado Public Utilities Commission Docket No. 13A-0836E (Public Service Company Compliance Plan).

Value of Solar rate for DSG.[15] The authors anticipate that additional valuation studies will result from one or more of these proceedings.

As of this writing, relatively few jurisdictions have conducted full cost-effectiveness studies for DSG and fewer still provide sufficient detail to guide development of a common methodology. CPR's Austin Energy study, updated in 2012, established an approach that has been applied in other regions, including a recent study on the value of DSG in Pennsylvania and New Jersey.[16] The California Public Utilities Commission ("CPUC") and APS commissioned comprehensive studies in 2009; both commissioned revised studies in 2013.[17] In January 2013, Vermont's Public Service Department[18] completed a cost-benefit analysis of NEM policy.

While not identical in structure, these works typify the recent reports and illustrate some commonalities in approaching the valuation of distributed energy. NEM-specific studies include the 2009 California Energy and Environmental Economics ("E3") Study, Crossborder Energy's 2013 updated look at that E3 study,[19] Crossborder Energy's 2013 analysis of DSG cost-effectiveness in Arizona,[20] and the Public Service Department's own analysis for Vermont.

As noted earlier, this paper complements IREC's recent publication, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*.[21] That paper reviews the DSG valuation studies that had been published to date and provides general approaches to calculating the widely recognized categories of benefits and costs that are relevant to the consideration of the cost-effectiveness of VOST, NEM, and other policy mechanisms impacting DSG. The intent of this examination is to dive deeper, find more common ground for discussion and foster greater consistency in how these values are determined across jurisdictions.

Also as noted earlier, this paper benefits from analysis recently published by RMI, entitled *A Review of Solar PV Benefit and cost Studies*.[22] That report reviews 16 studies in a meta-analysis that examines methodologies and assumptions in great detail. Figure 2 is from that study, and characterizes the differences and similarities in the studies. As

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[15] Minn. Stat. § 216B.164, subd. 10 (2013): Chapter 85--H.F. No. 729, Article 9, Distributed Generation, Section 10.

[16] Richard Perez, Thomas Hoff, and Benjamin Norris, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania,* 2012 ("CPR 2012 MSEIA Study"), *available at* http://communitypowernetwork.com/sites/default/files/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf.

[17] APS studies: *Distributed Renewable Energy Operating Impacts and Valuation Study*, RW Beck, Jan. 2009, available at http://www.solarfuturearizona.com/SolarDEStudy.pdf; *2013 Updated Solar PV Value Report*, SAIC, May 2013, available at http://www.solarfuturearizona.com/2013SolarValueStudy.pdf.
CPUC studies conducted by Energy and Environment Economics ("E3"):
http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm.

[18] *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012,* January 15, 2013 ("Vermont Study"), *available at* www.leg.state.vt.us/reports/2013ExternalReports/285580.pdf.

[19] Thomas Beach and Patrick McGuire, *Evaluating the Benefits and Costs of Net Energy Metering in California* (Vote Solar Initiative), 2013 ("Crossborder 2013 California Study"), *available at* http://www.seia.org/research-resources/evaluating-benefits-costs-net-energy-metering-california.

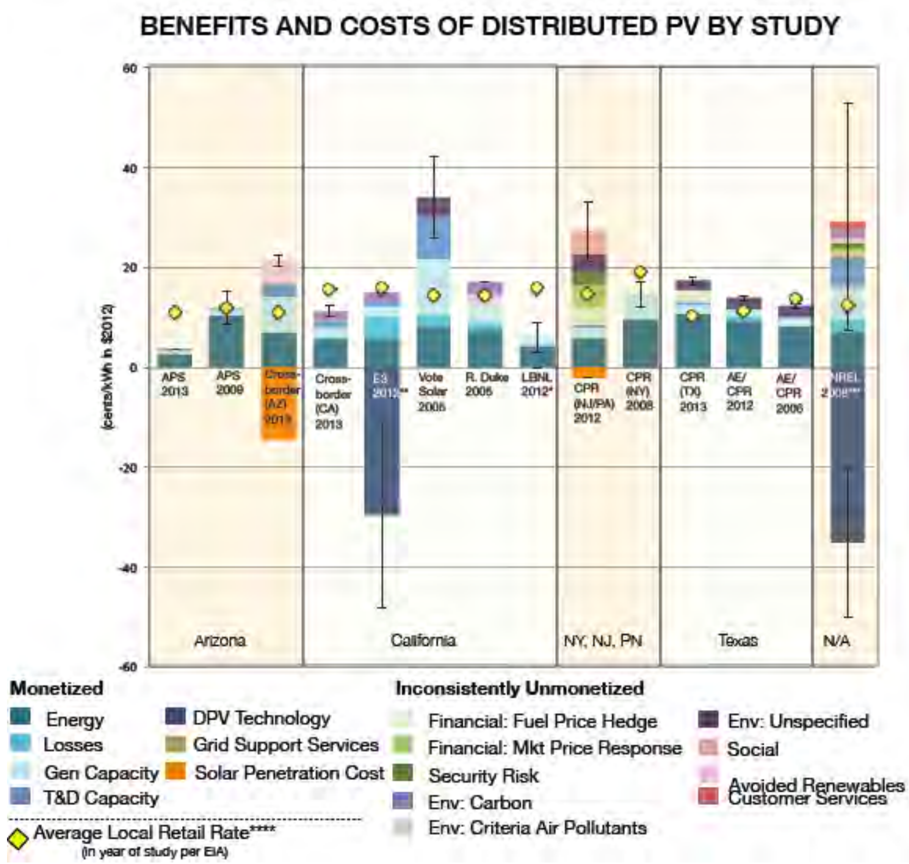
[20] Thomas Beach and Patrick McGuire, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service* (Vote Solar Initiative), at p.12, 2013 ("Crossborder 2013 Arizona Study"), *available at* http://www.solarfuturearizona.com/TheBenefitsandCostsofSolarDistributedGenerationforAPS.pdf.

[21] *See* SolarABCs Report, *supra*, footnote 10.

[22] *See* RMI 2013 Study, *supra*, footnote 1.

well as considering benefits and costs the RMI 2013 Study points out that the various studies differ significantly in the amount of DSG penetration considered, which can drastically impact values. Another important differentiator is whether the studies are based on high-level, often secondary, review of benefits and costs, or whether they rely on more granular and detailed modeling of impacts.[23]

Figure 2: Rocky Mountain Institute Summary of DSG Benefits and Costs



The RMI 2013 Study figure is reprinted here to make three important points. First and foremost, the calculated benefits often exceed residential retail rates, shown in the figure with diamonds, implying that NEM would not entail a subsidy flowing from non-solar to solar customers. Second, commercial customers almost always have unbundled rates and NEM has minimal impact on their demand charges because they still have demand after the sun sets. That means that DSG benefits compared to commercial customer energy rates would be strongly positive based on almost all of these studies. And third, costs are accounted for in varying ways: three studies show costs including lost retail rate payments, with large bars below the zero line indicating total costs, one shows costs other than retail rate payments (CPR NJ/PA), and the rest include costs as a deduction within the benefits calculation. As an overarching point,

[23] *Id.* at p. 21.

the RMI 2013 Study figure confirms that there is no single standard DSG valuation methodology today.

Types of Studies. Distributed solar valuation requires quantitative analysis of a wide range of data in an organized way. Fortunately, there are abundant existing approaches that can contribute to estimation of DSG value. This section briefly introduces the two major types of studies that underlie DSG valuation. The first category of studies is input and production cost models. These have general application in the utility industry in the comparison of resource alternatives. The second category, DSG-specific studies, includes three sub-types, depending on the purpose for which the study was conducted. In practice, most DSG-specific studies rely on inputs from input and production cost models.

A. Input and Production Cost Models

Utility planners and industry experts rely on a wide range of models and analytical tools for calculating costs associated with generation and systems. Power flow, dispatch, and planning models all provide input to the financial models used to evaluate DSG cost effectiveness and value. While detailed treatment of the utility models providing input to the DSG models is beyond the scope of this paper, they impact the DSG models and need to be understood. Often, these utility models are deemed proprietary, creating "black box" solutions regarding what generation is needed and when. Among the most critical decisions made at this juncture is whether the generation that will be offset by DSG is a relatively efficient natural gas combined-cycle combustion turbine ("CCGT")or a less efficient single cycle "peaker" plant running on natural gas, or some combination of the two.

As most of the gas-fired energy delivered by utilities comes from CCGTs, and peakers will still be needed to handle changes in load, models should reflect that DSG is primarily offsetting CCGTs. However, the APS 2013 study is an example in which the input model results are confounding, and there is no way to review the black box solution. Oddly, APS found that baseload coal would be displaced for part of the year. We believe that such an example deserves more careful study; it is a nearly universal truth that coal plants are run as much as possible. While many coal plants have been shut down in the past decade, those that remain are typically only curtailed for maintenance. Regulators should consider whether input assumptions such as coal or nuclear displacement are reasonable, particularly if the results are based on proprietary, opaque modeling.

Capacity needs in planning models are typically forecasted several years in the future and, because of the legacy of the central station utility plant paradigm, in large increments of capacity. These so-called "lumpy" capacity investments generally overshoot capacity requirements in order to ensure resource adequacy in the face of multi-year development lead times. As a result, the opportunity for DSG to provide useful capacity is generally seen as too little and too early. For example, a typical utility resource plan might state that capacity is adequate until the year 2018, at which time the company forecasts a need for an additional 200 megawatts ("MW") of generation capacity. In such a situation, traditional resource planning and avoided cost estimates assign no capacity value to DSG installed on customer roofs before 2018, and none in

2018 unless the systems provide the equivalent to 200 MW of capacity. This ignores the benefit of DSG's modularity—the utility does not need 200 MW in 2018, at that point it only starts to need more than it already has available. DSG can provide for that capacity through incremental installations starting in 2018. Likewise, if the utility has projects under development prior to 2018, it could have deferred or avoided some of that need if it had accurately predicted and valued DSG installations.

Today, many input and production cost planning models include the opportunity to adjust assumptions about customer adoption of DSG (and energy efficiency), which assume that those resources are going to play a role in the utility's near term capacity requirements. With these adjustments, the in-service requirement date can possibly be deferred, generating both energy and capacity savings attributable to the distributed resources. Accordingly, models that do not address DSG installations are inadequate and could lead to costly overbuilding and, given planning and construction lead times associated with large plants, premature expenditure of development costs.

B. DSG-Specific Studies

DSG-specific studies often start with inputs from the models just described. These studies are themselves usually of three types:

Studies of studies. Like this white paper, these studies start with work conducted by one or more experts and organize the information and data in a form that addresses questions of interest. In some cases, the authors report the results and the source conditions for the data. In others, study authors attempt to adjust the results for different local conditions. The RMI 2013 Study on solar PV reports the results of 16 different studies spanning some eight years. These studies provide useful introductions to the emerging discipline and demonstrate the ways in which differences in assumptions, methodologies, and underlying data can impact outcomes. In addition, when adjusting for outlier conditions, the studies can demonstrate where there exists relatively strong coherence in approach and results.

Cost-Benefit Analysis studies. Cost-benefit studies focus on using avoided cost methodologies and cost-benefit test approaches to review large-scale DSG initiatives and programs. They seek to answer the question of whether total costs or total benefits are greater over a specified period of time. For these studies, forward-looking cost estimates for DSG interconnection, lost revenues, avoided RPS costs, and incentive programs are important inputs. The best-known examples of this study approach were conducted by E3, reviewing the California Solar Initiative and NEM programs, and those by Crossborder Energy, reviewing the E3 reports. Most of the studies reviewed by the RMI 2013 Study are of this sort. There are several cost-benefit analysis varietals, as described in the California Standard Practice Manual and summarized in the box below.

Value of Solar studies. Smeloff and CPR pioneered the "value of solar" genre of study. As the name implies, this study approach focuses on using avoided cost and financial analysis methods in discerning the future investment value of distributed solar to the utility, ratepayers, and society. Generally, these evaluations ignore utility lost revenues, instead focusing on valuation that can be used in designing and setting incentive levels, program limits, and other features of utility DSG programs. The studies stop short of rate or tariff design features, and as a result, do not typically address lost revenue issues. Perhaps best known is the Austin Energy Value of Solar study conducted by CPR in 2006 and updated in 2012.[24]

With reference to the California Standard Practice Manual study descriptions summarized in the prior box, the type of test that the authors suggest in this paper is a blend of the Ratepayer Impact Measure ("RIM") and Societal Cost Test ("SCT") approaches. The RIM test addresses the impact on non-participating ratepayers in terms of how benefits and costs impact the utility and are passed along to those ratepayers. That necessarily does not account for the participating ratepayers' outlay for DSG systems, nor should it. The SCT approach looks at whether it is a good idea for society as a whole to pursue a policy, and includes participating ratepayers' investment in DSG systems. The authors contend that the participants' investment is outside of the scope of the appropriate investigation. The goal should be to determine whether non-participants have a net benefit from the installation of DSG systems. As the job creation, health and environmental benefits accrue to non-participants just as much as they accrue to participants, there is no apparent reason why societal benefits should not be included. In its consideration of benefits, this approach aligns with the VOST methodology which aims to include all benefits that can reasonably be quantified and assigned to utility operations.

Utilities often object, stating that valuing societal benefits conflates customers with citizens, and note that utility rates must be based on costs directly impacting utilities. By this line of reasoning, job creation and health benefits may be the basis of legislative policies supportive of DSG, but should not be considered when developing DSG tariffs. We are reluctant to accept an artificial division between citizens and utility customers; the overlap is complete for most benefits and costs. Moreover, a major reason for establishing NEM, VOST or other DSG programs is primarily related to the same broad societal benefits that drive utility regulatory systems—economic efficiency, and rates and services in the public interest—so those benefits should be considered in any programmatic or policy analysis.

Recommendation: Use a blend of the Ratepayer Impact Measure ("RIM") and Societal Cost Test ("SCT") Cost-Benefit Tests

[24] Author K. Rábago, while at Austin Energy, helped establish the nations' first VOST. *See* K. Rábago, *The Value of Solar Rate: Designing an Improved Residential Solar Tariff*, Solar Industry, at p. 20, Feb. 2013, *available at* http://solarindustrymag.com/digitaleditions/Main.php?MagID=3&MagNo=59.

Cost-Benefit Tests

The California Standard Practice Manual is used for economic analysis of demand-side management ("DSM") programs in California. The cost-benefit tests in the Standard Practice Manual have also been used to evaluate DSG value, most notably in California, where the tests have been applied to a review of the cost effectiveness of the California Solar Initiative. The various tests differ in the perspective from which cost effectiveness is assessed.

- ***Participant Cost Test* ("PCT").** Measures benefits and costs to program participants.
- ***Ratepayer Impact Measure ("RIM") Test.*** Measures changes in electric service rates due to changes in utility revenues and costs resulting from the assessed program.
- ***Program Administrator Cost Test ("PACT").*** Measures the benefits and costs to the program administrator, without consideration of the effect on actual revenues. This test differs from the RIM test in that it considers only the revenue requirement, ignoring changes in revenue collection, typically called "lost revenues."
- ***Total Resources Cost Test ("TRC").*** Measures the total net economic effects of the program, including both participants' and program administrator's benefits and costs, without regard to who incurs the costs or receives the benefits. For a utility-specific program, the test can be thought of as measuring the overall economic welfare over the entire utility service territory.
- ***Societal Cost Test ("SCT").*** The SCT is similar to the TRC, but broadens the universe of affected individuals to society as a whole, rather than just those in the program administrator territory. The SCT is also a vehicle for consideration of non-monetized externalities, such as induced economic development effects, which are not considered in the TRC.

III. Key Structural Issues for DSG Benefit and Cost Studies

Underlying study assumptions and major study components. The evaluation of the cost-effectiveness of a given DSG policy, particularly NEM, is a complex undertaking with many potential moving parts. Before delving into the specific benefits and costs, it is important to recognize that the ultimate outcome of the analysis is highly dependent on the base financial and framework assumptions that go into the effort. Much of the work involves forecasting—estimating the future benefits and costs, performance, and cumulative impacts associated with increasing penetration of distributed generation into the electric grid. It is important to develop a common set of base assumptions that reflect the resource being studied and to be as transparent as possible about these assumptions when reporting the results of the analysis. At the outset of a study, it is important to define these structural parameters. Below we present key questions for regulators to explore at the onset of a study:

Q1: WHAT DISCOUNT RATE WILL BE USED?

The discount rate should reflect how society evaluates costs over time. Utilities use a discount rate based on the time value of money, using the rate of return available for investments with similarly low risk, now in the 6% to 9% range. However, society may prefer the use of a lower discount rate, closer to the rate of inflation. The difference is important. High discount rates improve the evaluation of resources with continuously escalating or high end-of-life costs. For instance, an 8% discount rate may favor a natural gas generator because much of the cost (the fuel, operation and maintenance) to run the generator is incurred over the life of the generator, while the cost of DSG is almost entirely at the front end. A low discount rate improves the valuation of resources with high initial costs and low or zero end-of-life costs. The same analysis based on a 3% inflation rate may favor DSG resources, as there are no fuel costs over time and the operations and maintenance ("O&M") costs are low because there are fewer or no moving parts. While the utility's discount rate is appropriate when considering utility procurement because those funds could be invested elsewhere at competitive rates, the utility is not procuring the DSG resources in the case of NEM, VOST or FiT arrangements. It is worth questioning whether the future benefits of DSG resources should be heavily discounted, based on the utility's cost of capital, when the customer (or a third party owning a system at the customer's site) is making the investment. As utility valuation techniques improve, is it reasonable to discount future benefits and costs by the inflation rate rather than the utility's cost of capital.

Recommendation: We recommend using a lower discount rate for DSG than a typical utility discount rate to account for differences in DSG economics.

Q2: WHAT IS BEING CONSIDERED – ALL GENERATION OR EXPORTS ONLY?

Under NEM, utility customers can take advantage of a federal law[25] allowing for on-site generation to offset consumption, with the opportunity to sell excess generation to the utility at the utility's avoided cost. Because the customer has a right to avoid any and all consumption from the utility, studies of NEM cost-effectiveness will often look only at the utility cost associated with exports to the grid. The assumption under NEM is effectively that at or below the total consumption level, the value of offset consumption is the retail rate. This valuation is supported by the concept behind cost-of-service rate regulation—that the retail rate is the accumulation of costs to generate and deliver energy for the customer.[26] Note that to the extent that NEM benefits are calculated to

[25] *See* Public Utility Regulatory Policies Act ("PURPA"), 16 U.S.C. *et seq.*
[26] VOST studies, on the other hand, presume a difference between the value of generation at or near the point of consumption and the level of the rate. That is, the customer with DSG may well be generating electricity of greater value than that being provided by the utility.

outweigh costs, consideration of all generation amplifies the calculated net benefit. However, if NEM costs outweigh benefits, the opposite is true.

Recommendation: We recommend assessing only DSG exports to the grid.

Q3: OVER WHAT TIMEFRAME WILL THE STUDY EXAMINE THE BENEFITS AND COSTS OF DSG?

Utility planners routinely consider the lifecycle benefits and costs of traditional utility generators, typically over a period in excess of 30 years. Solar arrays have no moving parts and are generally expected to last for at least 30 years, with much less maintenance than fossil-fired generation. Solar module warranties are typically for 25 years, and many of the earliest modules from the 1960s and 1970s are still operational, indicating that modules in production today should last for at least 30 years. This useful life assumption creates some data challenges, as utilities often plan over shorter time horizons (10-20 years) in terms of estimating load growth and the resources necessary to meet that load. As described below, methods can be used to estimate the value in future years that interpolate between current market prices or knowledge, and the most forward market price available or data that can accurately be estimated, just as planners do for fossil-fired generators that are expected to last for decades.

Recommendation: We suggest that the most appropriate timeframe for evaluating DSG and related policy is 30 years, as that matches the currently anticipated life span of the technology.

Q4: WHAT DOES UTILITY LOAD LOOK LIKE IN THE FUTURE?

Key to determining the value of DSG is a reasonable expectation of what customer loads will look like in the future, as much of the value of distributed resources derives from the utility's ability to plan around customer-owned generation. Other DSG rate or program options involving sale of all output to the utility do not reduce utility loads, as customer facilities contribute to the available capacity of utility resources as small contracted generators.

Recommendation: Given that NEM resources are interconnected behind customer meters, and result in lower utility loads, we recommend that the assigned capacity value of the distributed systems reflect the fact that the utility can plan for lower loads than it otherwise would have.

Q5: WHAT LEVEL OF MARKET PENETRATION FOR DSG IS ASSUMED IN THE FUTURE?

Many benefits and costs are sensitive to how much customer-owned generation capacity is on the grid. Most studies assume current, low penetration rates. Several of the studies consider higher penetration levels, as well, typically out to 15% or 20% of peak load, with some outlier studies looking at 30% and 40% penetration levels. In a high-penetration scenario, the utility may face higher integration expenses that might undermine the specific infrastructure benefits of distributed generation. Studies that address the issue often find that marginal capacity benefits decline with high penetration.

On the other hand, some studies such as those by APS, conclude that capacity benefits are dependent on having enough DSG to offset the next natural gas generator, and therefore that there are no capacity benefits in low-penetration scenarios. Market penetration estimates should also be reasonable in light of current supply chain capacity and local market conditions. Generally, the most important penetration level to consider for policy purposes is the next increment. If a utility currently has 0.1% of its needs met by DSG and a study shows that growth to 5% is cost-effective, but growth to 40% is not, then it would be economically efficient to allow the program to grow to 5% and then be reevaluated.

Recommendation: We recommend the establishment of an expected level of DSG penetration, and the development of low and high sensitivities to consider the full range of future impacts.

Q6: WHAT MODELS ARE USED TO PROVIDE ANALYTICAL INPUTS?

Analysts have used a wide variety of tools to calculate the benefits and costs of DSG. There is almost no commonality at the model level, even though many of the analyses address similar or identical issues. Several studies use some version of investment and dispatch models in order to determine which resources are displaced by solar and the resulting impacts. As noted earlier, utility DSG studies have often relied on proprietary models for these inputs. The fact that CPR and Professor Richard Perez[27] have published a number of studies creates some commonality among those studies, but over time, even the CPR approaches have evolved as tools have been improved.

Recommendation: We suggest that transparent input models accessible to all stakeholders are the proper foundation for confidence and utility of DSG studies. If necessary, non-disclosure agreements can be used to overcome data sharing sensitivities.

Q7: WHAT GEOGRAPHIC BOUNDARIES ARE ASSUMED IN THE ANALYSIS?

Value of solar analysis is heavily influenced by local resource and market conditions. Most published studies are geographically scoped at the state, service territory, or interconnected region level. Given its leadership in solar deployment, California also leads as the subject of studies and as a data source. Some studies relating to economic development and environmental impacts use a national and regional scope.

Recommendation: We suggest that it is important to account for the range in local values that characterize the broader geographical area selected for the study. In some cases, quantification according to similar geographical sub-regions may be appropriate.

Q8: WHAT SYSTEM BOUNDARIES ARE ASSUMED?

The majority of studies consider benefits and costs in the generation, transmission, and distribution portions of the system. Of the studies that consider environmental impacts,

[27] Richard Perez is a Research Professor at the University at Albany-SUNY.

most only look at avoided utility environmental compliance costs at the generation level.

Recommendation: We recommend considering impacts associated with adjacent utility systems, especially at higher (above 10%) penetration levels of DSG. [28]

Q9: FROM WHOSE PERSPECTIVE ARE BENEFITS AND COSTS MEASURED?

Nearly all the studies consider impacts from the perspective of the utility and ratepayers. Several also consider customer and societal benefit and costs. Cost-benefit studies apply California Standard Practice Manual tests for Demand Side Management, discussed earlier.

Recommendation: We suggest that rate impacts and societal benefits and costs should be assessed.

Q10: ARE BENEFITS AND COSTS ESTIMATED ON AN ANNUALIZED OR LEVELIZED BASIS?

When a DSG system is installed, it is like commissioning a 30-year power plant that will, if properly maintained, produce energy and other benefits during that entire period. Several studies look at snapshots of benefits and costs in a given year, which fails to answer the basic question of whether DSG is cost-effective over its lifetime. Levelization involves calculating the stream of benefits and costs over an extended period and discounting to a single present value. Such levelized estimates are routinely used by utilities in evaluating alternative and competing resource options. As such, levelization of the entire stream of benefits and costs is appropriate.

Recommendation: We recommend use of a levelized approach to estimating benefits and costs over the entire DSG life of 30 years.

Q11: WHAT DATA AND DATA SOURCES ARE USED?

As the number of solar valuation studies has increased, so has the frequency with which newer studies cite data provided in prior studies. There are two reasons behind this trend, cost and availability of data, which we discuss in detail below.

As with any modeling exercise, models are only as good as the data fed into them. The ability to precisely calculate the benefits of DSG often rests on the availability and granularity of utility operational and cost data. More granular data yields more reliable analysis about the impacts of DSG deployment and operation.

Calculating many of the benefit and cost categories requires that analysts address utility-specific or regional conditions that can vary significantly from utility to utility, even within the same state. In addition, the availability of the type of granular data needed

[28] Mills and Wiser point out that consideration of inter-system sales of capacity or renewable energy credits could mitigate reductions in incremental solar value that could accompany high penetration rates. *See* A. Mills & R. Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, at p. 23, December 2012, *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

to accurately project location and time-specific benefits varies from one utility to the next. Much of the data needed to quantify the benefits of DSG resides with utilities.

Fortunately, additional data, such as energy market prices, is often publicly available, or can be released by the utility without proprietary concerns. In some limited cases, the utility may have proprietary, competitive, or other concerns with plant- or contract-specific information. And in some cases, the form and format of utility data may require adjustments.

These problems are not insurmountable. Utility general rate cases and regulatory filings with the Federal Energy Regulatory Commission ("FERC") are good sources for data relevant to utility peak demand and for the components of cost of service, including transmission costs, line loss factors, O&M costs, and costs of specific distribution upgrades or investments, among other cost categories. Additionally, the federal Energy Information Administration ("EIA") and various state agencies compile utility cost data that can be used as a reference to determine heat rates, the costs of O&M associated with various plants, and the overall capital cost of new construction of generating capacity.[29]

Recommendation: Require that utilities provide the following data sets, both current information and projected data for 30 years[30]:

1) The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the DSG.
2) Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of NEM policy.
3) Hourly production profiles for NEM generators. The use of time-correlated solar data is important to correctly assess the match of solar output with system loads. In the case of solar PV, this could vary according to the orientation of the system. For example, while south-facing systems may have greater overall output, west or southwest facing systems may produce more overall value with fewer kWh because of peak production occurring later in the day than a south-facing system.
4) Line losses based on hourly load data, so that marginal avoided line losses due to DSG can be calculated.
5) Both the initial capital cost and the fixed and variable O&M costs for the utility's marginal generation unit.
6) Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth.
7) Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of DSG, in order to capture the potential for avoiding or deferring circuit upgrades.

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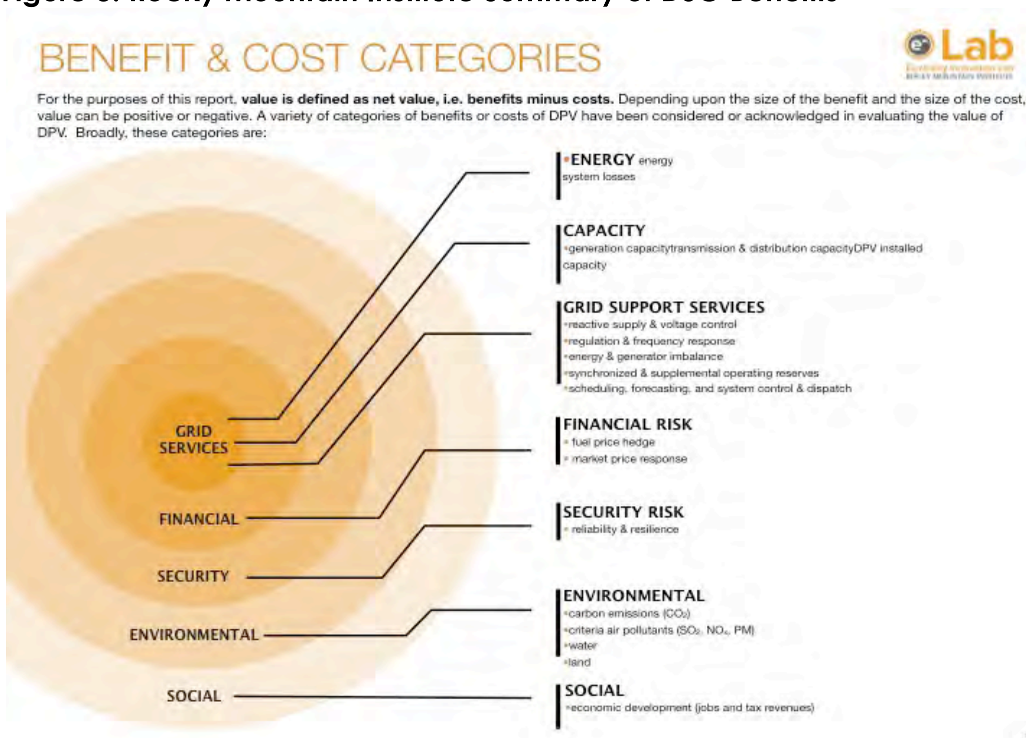
[29] *See Updated Capital Cost Estimates for Electricity Generation Plants* (EIA), November 2012, *available at* http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf (providing estimate of capital cost, fixed O&M, and variable O&M for generation plants with various technical characteristics).
[30] Note: Where a utility or jurisdiction does not regularly collect some portion of this data, there may be methods to estimate a reasonable value to assign to DSG.

IV. Recommendations for Calculating the Benefits of DSG

Benefits of DSG get categorized and ordered in various ways from study to study, typically based on the relative magnitude of the benefits. The RMI 2013 Study is structured around a list of "services," encompassing flows of benefits and costs to and from solar PV. That list is replicated here in an effort to coordinate with that study.[31] The RMI services categories are depicted in the graphic below.

Figure 3: Rocky Mountain Institute Summary of DSG Benefits



While replicating the RMI services categories, we have subdivided them in recognition that the divide between utility avoided costs and other societal benefits is not clear from the list above. For instance, utilities can avoid certain environmental compliance costs, which are direct utility avoided costs, while other environmental benefits inure to society more generally. As another example, reliability or resiliency is only a utility avoided cost to the extent that the utility was going to take some other measures to achieve the levels enabled by DSG. If DSG enables higher reliability than would have otherwise been achieved, that is undoubtedly a benefit, though it is most notably realized by utility customers when a storm event does not cause a major service interruption, which may occur once in a decade. As a further example, market price

[31] *See* RMI 2013 Study.

response benefits can be felt by the utility itself but will also extend to citizens who are customers of nearby utilities.

To track utility avoided costs and societal benefits separately, separate subsections are provided below, with the final three RMI environmental and social benefit categories covered after utility avoided costs. We note where some categories listed under utility avoided costs have societal benefits as well, and we separately create an environment category under utility avoided costs to capture utility avoided environmental compliance costs.

Calculating Utility Avoided Costs

1. *Avoided energy benefits*

To determine the value of avoided generation costs, the first step is to identify the marginal generation displaced. In most instances, the next marginal generator will be a natural gas-fired simple-cycle combustion turbine ("CT") or a more efficient CCGT. Avoiding the operation of that marginal generating facility to produce the next increment of electricity means that the solar generator allows the utility to avoid both variable O&M activities (i.e., those activities and expenses that vary with the volume of output of the CT or CCGT plant) and the fuel that would be consumed to produce that next unit at the time that the customer-generator allows the utility to avoid that operation.

To calculate the avoided generation cost over the life of the DSG system—assumed throughout this paper to be 30 years—the calculation must estimate the market price of energy throughout that time span. Given the limitations on the availability of data, including the future price of a historically volatile commodity like natural gas, many studies have used interpolation and extrapolation to estimate gas prices in the 30 year horizon by taking the readily attainable current market price for natural gas and referencing it against the most forward natural gas price available.

Additionally, the calculation of avoided generation costs over time must account for degradation in the marginal generation plant and adjust expected heat rates (i.e., the measure of efficiency by which a unit creates electricity by burning fuel for heat to power a turbine). Over time, the marginal generation plant will become less efficient and require incrementally more fuel to reach the same production levels. Production cost modeling enables the utility to cumulate value of avoided costs throughout the useful life of the solar generating system. However, due to built in constraints or other issues, such modeling can produce results that are illogical, as has been seen in Arizona (baseload coal generation displaced by DSG) and Colorado (high cost of frequent unit startups reducing energy benefits).

A standard approach to determining the value of avoided generation over the life of a DSG system is to develop: (1) an hourly market price shape for each month and (2) a forecast of annual average market prices into the future.[32] One way to forecast the annual market prices, with less reliance on forward market prices, is to project the rolled-in costs of the marginal generation unit, accounting for variable O&M and

[32] E3 Study, Appendix A at pp.10-11.

Comparison with PURPA Avoided Cost Calculations

Value of solar analysis literature is complemented by other studies and reports related to the issue. These include studies relating to avoided cost methodologies under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), and those addressing utility resource planning evaluation of distributed resources.

Because both the cost-benefit and value-of-solar approaches start with avoided cost calculations, publications and processes used in conducting such calculations are informative in establishing the costs and benefits of DSG. State utility commissions and public utility regulators have approached PURPA valuation of avoided costs quite differently, and FERC has rarely constrained the approach selected. Rather than attempt to discern a consensus approach, a more fruitful approach is to consider what PURPA allows.

IREC recently published a paper to do this, cataloguing the kinds of DSG-related avoided cost calculations that could improve understanding of DSG value, and citing most of the utility avoided costs discussed in this paper.

See the full report:
http://www.irecusa.org/wp-content/uploads/2013/05/Unlocking-DG-Value.pdf

degradation of heat rate efficiency in future years. This method still relies on forecasts of natural gas prices in future years, but provides more certainty for variable O&M costs.[33]

In the Vermont study, the Public Service Department assumed that the New England Independent System Operator ("ISO-NE") wholesale market would provide the marginal generation price for energy displaced by solar generation. To account for the high correlation of solar PV with system peak, and therefore the offset of higher value generation, the Department created a hypothetical avoided cost for 2011 using real output data that was matched with actual hourly market data from the ISO-NE market.[34] This adjusted hourly market price was then scaled to future years by utilizing an energy price forecast, based on the forward market energy prices for the first five years and for the forward natural gas prices for years five to ten.[35] Prices for years after year ten were based on an extrapolation of the market prices for electricity and natural gas for years one through ten.

As CPR observes, there are inherent shortcomings in relying on future market prices for marginal generation decades into the future.[36] A more straightforward method would be to "explicitly specify the marginal generator and then to calculate the cost of the generation from this unit."[37] In this way the avoided fuel and O&M cost savings are roughly equivalent to capturing the future wholesale price. Of course, this approach still relies on forward projections in the natural gas market.

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[33] CPR 2012 MSEIA Study at pp. 28-29.
[34] Vermont Study at p. 16.
[35] *Id.*
[36] CPR 2012 MSEIA Study at pp. 28-29.
[37] *Id.* at p. 29.

2. *Calculating system losses*

DSG sited at or near load avoids the inefficiencies associated with delivering power over great distances to the end-use customer due to electric resistance and conversion losses. When a DSG customer does not consume all output as it is being produced, the excess is exported to the grid and consumed by neighboring customers on the same circuit, with minimal losses in comparison to electricity generated by and delivered from a utility's centralized but distant plant. Without DSG and its local load reduction impact, utilities are forced to generate additional electricity to compensate for line losses, decreasing the economic efficiency of each unit of electricity that is delivered.

Including avoided line losses as a benefit is relatively straightforward and should be non-controversial. For instance, FERC's regulations implementing PURPA recognize that distributed generation can account for avoided line losses.[38] This benefit exists for all types of DG technologies and, to some extent, in all locations. Typically, average line losses are in the range of 7%, and higher during heavier load periods, which can correlate with high irradiance periods for many utilities.[39] Additional losses termed "lost and unaccounted for energy" are also likely associated with T&D functions and, with further research, may also be avoided by DSG.[40]

Average line loss is often used as the primary approach to adjusting energy and capacity-related benefits. However, because line losses are not uniform across the year or day, the use of average losses ignores significant value because it fails to quantify the "true reduction in losses on a marginal basis."[41] Considering losses on a marginal basis is more accurate and should be standard practice as it reflects the likely correlation of solar PV to heavy loading periods where congestion and transformer thermal conditions tend to exacerbate losses. In its Austin Energy study, CPR evaluated marginal T&D losses at times of seasonable peak demand using load flow analysis. CPR decided to average the marginal energy losses on the distribution system, for purposes of the study, and added marginal transmission losses in order to report hourly marginal loss savings due to solar generation. According to one APS study, the degree of line losses may decrease as penetration increases.[42]

As with the effect of reducing market prices by reducing load at times of peak demand, and therefore reducing marginal wholesale prices (see below), DSG-induced reduction of losses at times of peak load has a spillover effect. The ability of customers to serve on-site load without use of the distribution system reduces transformer

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[38] *See* FERC Order No. 69, 45 Fed. Reg. 12214 at 12227.("If the load served by the [QF] is closer to the [QF] than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.").

[39] For example, the E3 study assumes an average loss factor of 1.073, which indicates that 7.3% more energy is supplied to the grid than is ultimately delivered and metered by the end-use customers. In contrast, Vermont's study noted that the Department's energy efficiency screening tool concluded that typical marginal line losses are about 9%. Vermont Study at p.17.

[40] *See*, *e.g.*, A. Lovins *et al.*, Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size, Rocky Mountain Institute, at p. 212, August 2002; U.S. Energy Information Administration's Annual Energy Review, *available at* http://www.eia.gov/totalenergy/data/annual/diagram5.cfm.

[41] CPR 2012 MSEIA Study at p. 27.

[42] *Distributed Renewable Energy Operating Impacts and Valuation Study, R. W. Beck for Arizona Public Service, Jan. 2009, at p. 4-7 and Table 4-3. (Finding that a "law of diminishing returns" applies to solar distributed energy installations.) Available at: http://www.solarfuturearizona.com/SolarDEStudy.pdf.*

overheating, a major driver of transformer wear and tear, and in turn allows customers to receive power from utility generators at lower marginal loss rates. Without on- or near-peak DSG, all customers would face higher marginal loss rates with the contribution to thermal transformer conditions caused by all customers seeking grid delivered power for all on-site needs at times of peak load.

With consideration of the line losses avoided in relation to both the energy that did not have to be delivered due to DSG, and the marginal improvement in line losses to deliver power for the rest of utility's customers' needs, the appropriate methodology developed by CPR is to look at total line losses without DSG and total line losses with DSG. In practice this can equal 15-20% of the energy value.

Separately, line losses figure into capacity value as well, as a peak demand reduction of 100 MW means in turn that a generation capacity of more than 100 MW is avoided. This aspect of avoided line losses should be included with generation and T&D capacity benefits, discussed below.

3. *Calculating generation capacity*

Determining the capacity benefits of intermittent, renewable generation is a more complex undertaking than analyzing energy value, but there is a demonstrated capacity value for DSG systems. Capacity value of generation exists where a utility can count on generation to meet its peak demand and thereby avoid purchasing additional capacity to generate and deliver electricity to meet that peak demand.

While individual DSG systems (without energy storage) provide little firm capacity value to a utility given the potential for cloud cover, there is compelling research supporting the consideration of the aggregate value of DSG systems in determining capacity value. A recent study by LBNL demonstrates that geographic diversity tends to smooth the variability of solar generation output, making it more dependable as a capacity resource.[43] As well, FERC considered the fact that distributed solar and wind should produce some capacity value when considered in the aggregate when it was developing its avoided cost pricing regulations.[44] Capacity value for DSG systems should look to the characteristics of all DSG generators in the aggregate, including the smoothing benefits of geographic diversity.

Solving for Intermittency. CPR developed the most prominent and widely used method to address the intermittency of DSG technologies. This method recognizes a capacity value for intermittent, non-dispatchable resources, and is referred to the as the "effective load carrying capability" ("ELCC"). ELCC is a statistical measure of capacity that is "effectively" available to a utility to meet load. "The ELCC of a generating unit in a utility grid is defined as the load increase (MW) that the system can carry while

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[43] *See* Andrew Mills and Ryan Wiser, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power* (Lawrence Berkeley National Laboratory), LBNL-3884E, September 2010.
[44] FERC Order No. 69, 45 Fed. Reg. 12214 at 12227 ("In some instances, the small amounts of capacity provided from [QFs] taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual [QF] may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively comprise the equivalent of capacity.").

maintaining the designated reliability criteria (e.g., constant loss of load probability)."[45] In this way, ELCC provides a reliable statistical method to project the capacity value of intermittent resources.

On the other hand, the ELCC method can be data intensive and complex to some stakeholders. Simpler methods may also yield reasonable results. For example, an alternate method, based on the utility's load duration curve, looks at the solar capacity available for the highest load hours, usually the top 50 hours.

Implemented in a rate, a capacity credit for DSG denominated in kWh represents the best approach. This ensures that DSG only receives capacity credit for actual generation.

Valuing Small, Distributed Capacity Additions. An often controversial issue in determining avoided capacity value is the fact that distributed generation provides small, incremental additions and utility resource planning typically adds capacity in large, or "lumpy," blocks of capacity additions. For example, if a utility has ample capacity to meet its reserve margin and its next capacity addition will be a 500 MW CCGT, a utility might argue that incremental additions of 1 MW or 20 MW do not allow them to avoid capacity costs. FERC's regulations recognize that distributed generation provides a more flexible manner to meet growing capacity needs and can allow a utility to defer or avoid the "lumpy" capacity additions.[46] Therefore, it is inappropriate to hold that there is no capacity benefit for deployment of distributed generation in years that come before the time where the "lumpy" capacity investment is required. Distributed generation resources, like other demand-side resources that are continuously pursued to address load growth and to reduce peak demand, provide immediate benefit and a hedge against unexpected outages that could lead to a shortage in capacity. There is, therefore, no good reason to value DSG capacity for its long-term value only in years where it physically displaces the next marginal generating unit.

One solution around the valuation of incremental capacity additions versus lumpy additions that would follow more traditional utility planning is laid out in Crossborder Energy's 2013 update to the 2009 E3 Net Metering Cost-effectiveness study for California. In the E3 study, a mix of short-run and long-run avoided capacity costs are applied to renewable generators based on the fact that additional capacity would not be required until a certain year, called the "Resource Balance Year" in the E3 study. Crossborder's update recognizes the incremental value of small capacity additions for the years leading up to the Resource Balance Year and uses a long-run capacity value methodology for the life of the distributed generation system.[47] In other words, utilities are responsible for predicting load growth and planning accordingly, so the full penetration of DSG installations should already be built into their plans, reflecting the incremental capacity benefits these systems provide.

Adding It All Together: Determining the capacity credit for DSG systems. There are two basic approaches taken to determine capacity credit: (1) determine the market value

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[45] CPR 2012 MSEIA Study at pp. 32-33.
[46] 18 C.F.R. 292.304(e)(2)(vii) (providing that avoided cost may value "the smaller increments and shorter lead times available with additions of capacity from qualifying facilities").
[47] Crossborder 2012 California Study, Appendix B.1.

of avoided capacity; or (2) estimate the marginal costs of operating the marginal generator, typically a CCGT.[48] For the same reasons that it is less than ideal to rely solely on the future projected market price for energy, it is also unreliable to credit DSG based on the projected future capacity market. The preferred approach is to determine the capacity credit by looking at the capital and O&M costs of the marginal generator.[49]

The resulting value is often termed a capacity credit—a credit for the utility capacity avoided by DSG. It is important to recognize that this credit is different from the "capacity value" of DSG. Capacity value is a term for the percentage of energy delivered as a fraction of what would be delivered if the DSG unit was always working at its rated capacity, that is, as if the sun were directly overhead with no clouds and the temperature was a constant 72 degrees at all times. Capacity value is typically in the range of 15-25% in the United States, depending on location. Because DSG generates electricity during daylight hours, often with high coincidence with peak demand periods, it earns a capacity credit based on the higher value of its generation during the hours in which it operates—a higher amount than simple capacity value. Alternatively, for a utility with an early evening peak or a winter peak, the capacity credit may be based on a lower percentage of its rated capacity than the capacity value.

Once the ELCC is determined for DSG resources for a given utility, the calculation of generation capacity is straightforward. The capacity credit for a DSG system is "the capital cost ($/MW) of the displaced unit times the effective capacity provided by PV."[50] Inherent in the ELCC calculation are the line losses associated with capacity, as discussed earlier.

4. *Calculating transmission and distribution capacity*

Distributed solar generation, by its nature, is usually located in close proximity to load on the distribution system, which may help reduce congestion and wear and tear on T&D resources. These benefits can reduce, defer, or avoid operating expenses and capital investments. Tactical and strategic targeting of distributed solar resources could increase this value.

The ability of DSG systems to yield T&D benefits is location-specific and also depends on the extent to which system output correlates to cost-causing local load conditions, especially before and during peak load periods. Utilities undertake system resource planning (i.e., planning for upgrades or additions to T&D capacity) to meet peak load conditions, so the correlation of DSG output to peak load conditions is important to understand. On the distribution system, unlike the bulk transmission system, this is a more difficult undertaking because local cost-causing load conditions (i.e., the timing, duration, and ramping rates associated with peak load on a given circuit) will vary according to a number of factors. These factors include customer mix, weather conditions, system age and condition, and others. As a simple example, a circuit that carries predominantly single-family residential load is likely to rise relatively smoothly to a peak in early evening, when solar PV output is waning. A circuit primarily serving

[48] CPR 2012 MSEIA Study at p. 32.
[49] *Id.* at pp. 32-33.
[50] *Id.*

commercial customers in a downtown setting will typically peak in the early afternoon. All other things being equal, DSG systems on circuits primarily serving commercial customers are more likely to avoid distribution capacity costs.

It is also important to consider system-wide T&D impacts. Transmission lines, and to an extent, substations, serve enough of a cross-section of the customer base to peak at approximately the same time as the utility as a whole. DSG coincidence with system peak means that DSG, even located on residential circuits, contributes to reduced demand at the substation level and above. Based on interconnection procedures, DSG systems in the aggregate on a circuit do not produce enough to export power off of the circuit; they simply reduce the need for service to the circuit. The avoided need for transmission infrastructure creates an avoided cost value to a utility and should be reflected as a benefit for DSG systems. Combining any granular distribution value with avoided, peak-related transmission costs, all DSG may demonstrate significant T&D value in allowing the utility to defer upgrades or avoid capital investments.

Estimating T&D Capacity Value. To determine the ability of DSG systems to defer T&D upgrades or capacity additions, it is critical to have current information on the system planning activities of utilities, and to periodically update that information. Often, the cost information is obtainable through rate case proceedings, where the utility ultimately seeks to include the upgrade or capital project in rate base. To make use of any cost data, however, it is important to have a sufficient amount of hourly data on both load and solar resource profiles. Much of the relevant information is also contained in utility maintenance cost data, grid upgrade and replacement plans, and capital investment plans. Beyond the planning horizon, expense and investment trends must be extrapolated to match the expected useful generating life of DSG.

With the data in hand, T&D capacity savings potential can be determined in a two-step process.[51] As described by CPR, "The first step is to perform an economic screening of all areas to determine the expansion plan costs and load growth rates for each planning area. The second step is to perform a technical load-matching analysis for the most promising locations."

For solar PV profiles, output can be estimated at particular places using irradiance data and various methods of estimating the output profile.[52] By looking at the load profile for a year, it is possible to isolate peak days at the circuit or substation level and calculate a capacity credit by measuring the net load with solar PV production. By reducing absolute peak load, DSG systems may allow a utility to avoid overloading transformers, substations or other distribution system components and, thereby, to defer expensive capital upgrades.

To determine deferral value, it is necessary to monetize the length of time that DSG allows a utility to defer a capital upgrade. Deferring an upgrade allows a utility to avoid the carrying cost or the cost of ownership of an asset and defers substantial expenditures that may be, at least to some extent, debt financed. Generally, the

[51] *Id.* at p. 33 (citing T. E. Hoff, *Identifying Distributed Generation and Demand Side Management Investment Opportunities*, Energy Journal: 17(4), 1996).
[52] M. Ralph, A. Ellis, D. Borneo, G. Corey, and S. Baldwin, *Transmission and Distribution Deferment Using PV and Energy Storage*, published in Photovoltaic Specialists Conference (PVSC), 2011 37th IEEE, June 2011, *available at* http://energy.sandia.gov/wp/wp-content/gallery/uploads/TransandDistDeferment.pdf.

avoided capital is multiplied by the utility's weighted average cost of capital or authorized rate of return to determine the value of deferring that investment.[53] However, as noted earlier, a lower discount rate could be used. For instance, the avoidance of a million dollar transmission upgrade five years from now—for a utility with a 7% discount rate—is arguably worth that amount divided by (1.07)^5, or approximately $713,000. From the ratepayers' perspective, avoiding the million dollar upgrade in five years might be worth more; based on an estimated inflation rate of 3%, the value would be $862,000.

System-Wide Marginal Transmission and Distribution Costs. When conducting a statewide or utility-wide analysis, it may be difficult to hone in on specific locations to determine the ability of DSG systems to enable deferment or avoidance of system upgrade activity. In some cases, distribution deferral value manifests in changes in distribution load projection profiles and should be calculated as the difference in what would have happened without the DSG. E3's approach to valuing avoided T&D takes a broader look at the ability to avoid costs and estimates T&D avoided costs in a similar manner to other demand-side programs, such as energy efficiency. E3's avoided cost methodology develops "allocators" to assign capacity value to specific hours in the year and then allocates estimates of marginal T&D costs to hours. E3 acknowledges that it lacks sufficient data to base its allocators on local loads and that, ideally, "T&D allocators would be based upon local loads, and T&D costs would be allocated to the hours with the highest loads."[54]

E3 determined that temperature data, which is available in a more granular form for specific locations in the many climate zones of California's major utilities, would be a suitable proxy method for allocating T&D costs. After determining these allocators and assigning them to specific hours, E3 determined the marginal distribution costs by climate zone, using a load-weighted average. Since marginal transmission costs are specific to each utility, those are added to the marginal distribution costs to arrive at the overall marginal T&D for a specific climate zone. This approach lacks the potential for capturing high-value, location-specific deferral potential, but it does approximate some value without requiring extensive project planning cost and load data for specific feeders, circuits, and substations. E3's methodology may be suitable in circumstances where there is limited local load data to develop what E3 described as an "ideal" methodology, but it does come with drawbacks. For example, allocating costs to certain hours by temperature may not correlate to peak conditions in certain locations.

Alternative Approaches to T&D Valuation. Clean Power Research also approached T&D value broadly in its study of Pennsylvania and New Jersey, taking utility-wide average loads in a conservative approach to valuation. CPR's Pennsylvania and New Jersey report notes that T&D value may vary widely from one feeder to another and that "it would be advisable to . . . systematically identify the highest value areas."[55]

Where information on specific upgrade projects is known, and there is sufficiently detailed local load data, a more detailed analysis of deferral potential should yield far more accurate results that better reflect the T&D value of DSG. For example, CPR was

[53] *Id.*
[54] E3 Study, Appendix A at p. 16.
[55] CPR 2012 MSEIA Study at p. 20.

ablle to take a more granular and area-specific look at T&D deferral values of DSG in its Austin Energy study, where it had specific distribution system costs for discrete sections of the city's distribution system.[56]

In Vermont, the Public Service Department took a reliability-focused approach. Noting that T&D upgrades are driven by reliability concerns, the Department determined that the "critical value is how much generation the grid can rely on seeing at peak times." To capture this benefit, the Department calculated a "reliability" peak coincidence value by calculating the average generator performance of illustrative generators for June, July and August afternoons.[57] The resulting number reflects the percentage of a system's nameplate capacity that is assumed to be available coincident with peak, as if it is "always running or perfectly dispatchable."[58] Accordingly, the generation system receives the same treatment as firm capacity in terms of value for providing T&D upgrade deferrals at that coincident level of output.

The risk of the Vermont approach is that it may overstate the ability of certain generators to provide actual deferral of T&D upgrades, since system planners often require absolute assurance that they could meet load in the event that a particular distributed generation unit went down. Another apparent weakness of this approach is the inability to target or identify location-specific values in the dynamic, granular nature of the distribution system.

T&D Capacity Value Summary. Distributed solar systems provide energy at or near the point of energy consumption. When they are generating, the loads they serve are therefore are less dependent on T&D services than other loads. In addition, because DSG provides energy in coincidence with a key driver of consumption—solar insolation—these resources can reduce wear and tear. Calculating the T&D benefits of DSG requires data that allows estimation of marginal T&D energy and capacity related costs. Ideally, utilities will collect location-specific data that can support individualized assessment of DSG system value. In the absence of such data, system-wide estimations of T&D offset and deferral value can be used with reasonable confidence.

5. Calculating grid support (ancillary) services

Grid support services, also referred to as ancillary services in many studies, include VAR support, and voltage ride-through. Existing studies often include estimates of ancillary services benefits as well as costs associated with DSG, as reported in the RMI 2013 Study. Costs, also called grid integration costs, are discussed below.

Currently, DSG systems utilize inverters to change direct current to alternating current with output at a set voltage and without VAR output, and with the presumed functionality of disconnecting in the event of circuit voltage above or below set limits. This disconnection feature has become a concern, as a voltage dip with the loss of a major utility generator could lead to thousands of inverters disconnecting DSG systems, reducing voltage inputs and exacerbating the problem. In practice, inverters could be

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[57] Vermont Study at p. 19 (The Department looked at ten two-axis tracking solar PV systems, four fixed solar PV systems, and two small wind generators.).
[58] *Id.* at p. 19.

much more functional or "smart"; indeed Germany is in the process of changing out hundreds of thousands of inverters to achieve added functionality.

Because U.S. electrical codes generally preclude inverters that provide ancillary services, many valuation studies have concluded that no ancillary service value should be calculated. While that approach had some merit in the past, when more versatile inverters where generally unavailable and regulatory change seemed far off, the present circumstances warrant a near-term recognition of ancillary services value. With proof of the viability of advanced inverters, it is highly likely that advanced inverters will be standard in the next few years, and ancillary services will be provided by DSG.

A group of Western utilities and transmission planners recently issued a joint letter on the issue of advanced inverters, calling for the deployment as soon as feasible to avoid the sort of cascading problem described above, which could lead to system-wide blackouts.[59] With the utilities themselves calling for advanced inverter deployment, and costs expected to be only $150 more than current inverters, there will be good reason to collect the data and develop the techniques to quantify ancillary services benefits of DSG. Modeling these ancillary services is important to inform policy decisions such as whether to require such technology as a condition of interconnection, and under what circumstances.

6. *Calculating financial services: fuel price hedge*[60]

DSG provides a fuel cost price hedge benefit by reducing reliance on fuel sources that are susceptible to shortages and market price volatility. In addition DSG provides a hedge against uncertainty regarding future regulation of greenhouse gas and other emissions, which also impact fuel prices. DSG customer exports help hedge against these price increases by reducing the volatility risk associated with base fuel prices—effectively blending price stability into the total utility portfolio.

The ideal method to capture the risk premium of natural gas uncertainty is to consider the difference between an investment with "substantial fuel price uncertainty" and one where the uncertainty or risk has been removed, such as through a hypothetical 30-year fixed price gas contract. As CPR explains, a utility could quantitatively set aside the entire fuel cost obligation up front, investing the dollars into a risk free instrument while entering into natural gas futures contracts for future gas needs.[61] Performing this calculation for each year that DSG operates isolates the risk premium and provides the value of the price hedge of avoiding purchases involving that risk premium.

Interestingly, utilities often used to hedge against fuel price volatility, but do less such hedging now. That leads some utilities to conclude that since the fuel price hedge benefit is not avoiding a utility cost, it should not be included. In practice, the risk of fuel price volatility is falling on customers even if the utility is not mitigating the risk. Reducing that risk has value to utility customers, even if the utility would not otherwise protect against it.

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[59] *See* L. Vestal, *Utility Brass Call for Smart-Inverter Requirement on Solar Installations*, California Energy Markets No. 1244, at p. 10, August 11, 2013.
[60] Clean Power Research now uses the term "Fuel Price Guarantee" in order to distinguish this benefit from traditional utility fuel price hedging actions.
[61] CPR 2012 MSEIA Study at p. 31.

7. *Calculating financial services: market price response*

Another portfolio benefit of DSG is measured in reductions to market prices for energy and capacity. By reducing demand during peak hours, when the price of electricity is at its highest, DSG reduces the overall load on utility systems and reduces the amount of energy and capacity purchased on the market. In this way, DSG reduces the cost of wholesale energy and capacity to all ratepayers.[62] This benefit is not captured by E3's methodology; it is reflected in CPR's most recent Pennsylvania and New Jersey study, where it is illustrated and explained in much greater detail.[63]

The premise of this benefit is that total expenditures on energy and capacity are less with DSG generation than without. The total expenditure, as CPR explains, is the current price of power times the current load at any given point in time. Because the amount of load affects the price of power, a reduced load condition, such as occurs as a result of DSG generation, reduces the market price of all other power purchases at those times.[64] While this change in market price is incrementally small, it represents a potentially significant system-wide benefit. This means that all customers, including non-solar customers, enjoy the benefit of lower prices during these reduced load conditions. As CPR notes, however, the reduction in price cannot be directly measured, as it is based on a hypothetical of what the price would have been without the load reduction, and must be modeled. The total value of market price reductions is the total cost savings calculated by summing the savings over all time periods during which DSG operates.[65] A similar analysis for capacity market prices can be conducted as well.

8. *Calculating security services: reliability and resiliency*

Particularly with the extended blackouts from Hurricane Sandy in 2012, a value is being attributed to added reliability and resiliency due to DSG, at both the grid and the individual customer levels. For grid benefits, this value in particular is difficult to quantify; it depends on the assumed risk of extended blackouts, the assumed cost to strengthen the grid to avoid that risk, and the assumed ability of DSG to strengthen the grid. With utility generation and T&D out of service, DSG can only do so much, and storm conditions often occur during periods of limited sunshine, so it is particularly hard to determine what DSG can do in this regard.

The ancillary services benefit discussed earlier is closely related to this benefit when considering the potential for the grid as a whole to continue operation. Even at the level of a circuit outage, the ancillary services benefit is capturing the value of providing VAR support and voltage ride-through. Arguably, the ancillary services benefit captures this level of grid support.

On the other hand, CPR noted in its first Austin Energy study that reliability and resiliency are very real DSG benefits at the individual customer level. The hospital with traditional backup generation powers up during an outage, and can be supported during a prolonged outage by the addition of DSG. Instead of relying entirely on the traditional generation and a substantial fuel supply, it can get by with less fuel. Likewise the

[62] *Id.* at 15.
[63] *Id.* at pp. 33-43.
[64] CPR 2012 MSEIA Study at p. 34.
[65] *Id.* at p. 36.

residential customer with a medical condition requiring certainty can rely on DSG plus battery storage rather than a generator.

To the extent that utilities have an obligation to provided heightened reliability to vulnerable customers, DSG can be counted as avoiding those utility costs. On a larger scale, to the extent that customers enjoy greater reliability than the utility would otherwise provide, that is a benefit to participating customers that can be included.

9. Calculating environmental services

A. Utility avoided compliance costs. The cost of complying with regulatory and statutory environmental requirements is a real operating expense of a generating plant and should be included in the avoided cost of generation. This avoided cost typically is included in the studies as a direct utility cost. In the CPUC's 2010 CSI Impact Evaluation report, conducted by Itron, the CSI general market program and the Self-Generation Incentive Program ("SGIP") were estimated to be responsible for reducing over 400,000 tons of CO_2 emissions in 2010. Additionally, the report estimated that the CSI general market program and the SGIP provided over 52,000 pounds of PM_{10} and over 92,000 pounds of NOx emissions reductions in 2010.[66] These reductions can be quantified and calculated against the market price for the relative compliance instrument. To the extent these values are fully reflected in the cost of the avoided energy, they should not be counted again in a DSG valuation analysis. It is important to account for only residual environmental compliance costs in estimating the benefit of DSG.

While certain emissions credit markets will be geographically tied to a small area with no established compliance market, the markets for NOx, SOx, and CO_2 are more readily identified and quantified with publicly available sources. Accordingly, any study of DSG should include the value of avoided compliance costs reflected in air emissions, land use, and any consumption and discharge costs associated with water.

Likewise, utilities in states with Renewable Portfolio Standards ("RPS") avoid RPS compliance costs due to DSG. For example, if a utility must comply with a 20% RPS and has a billion megawatt hours ("MWh") of annual load, it has to secure 200 million MWh of renewable generation. If instead, 100 million MWh is generated by DSG facilities, the utility's annual load is reduced by that amount and its RPS compliance obligation is reduced by 20 million MWh. The utility's cost of procuring those 20 million MWh should be considered, to the extent that the procurement is greater than the utility's avoided natural gas energy and capacity costs already attributed to those 20 million MWh.

Quantification of societal benefits is particularly difficult and controversial. Regarding environmental benefits, avoided utility compliance costs capture what society has decided are the proper tradeoffs of electricity generation for pollution, but society recognizes additional value related to not generating electricity from fossil generation in the first place. If DSG within a given utility service territory avoids a 100 million MWh of gas-fired generation, the utility avoids paying for the required clean up the emissions

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[66] *California Solar Initiative 2010 Impact Evaluation* (California Public Utilities Commission), prepared by Itron, at p. ES-2, 2011, *available at* http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf.

that never occurred. However, had the utility generated those 100 million MWh, millions of pounds of pollutants would have gotten past the required emissions controls, and not emitting all of those pollutants is a significant benefit to the society.

While most utility avoided costs benefit the utility's ratepayers directly, societal benefits tend to be spread beyond the utility's customers. Job creation can be expected to center in the utility's service territory, but will also lead to jobs in adjoining service territories. Emissions benefits are even more dispersed. The benefits are regional or global, with utility generation often far removed from utility customers. This is the traditional "tragedy of the commons[67]" problem, but on a global scale. As with the problem of colonial farmers not having an incentive to care for the commons on which their cows grazed, utilities use the environment but have no incentive to care for it beyond what is legally required. By recognizing the value of not emitting pollutants in a DSG valuation study, analysts capture this value that utilities would otherwise ignore. To say that this benefit is realized by society, but somehow not by utility customers, is to ignore the reality that society is made up of utility customers.

Again, we use the benefits categories outlined in the RMI 2013 Study, of which the last three address societal benefits and are listed here.

B. Carbon. The RMI 2013 Study breaks out carbon as a separate avoided cost, based on the significant uncertainty of carbon regulation. On the one hand, carbon markets and restrictions on carbon emissions have been frequently discussed, and tied to climate change. On the other hand, almost no carbon restrictions are currently in place, despite all of the discussion. Studies now five years old that presumed carbon costs by 2013 have been proven wrong. However, with the establishment of a carbon market in California, and the continuation of carbon markets in Europe, the likelihood of carbon costs throughout the U.S. is well beyond zero.

Even in the absence of a carbon market or carbon restrictions, the benefits of not emitting carbon are considered to be real by many people. While some have touted the benefits of carbon for plant life, the widespread view appears to be that emitting more carbon has a negative impact. One way to approach this is to consider what customers are willing to pay for reduced emissions of both carbon and other matter. For instance, Austin Energy uses the premium value for their GreenChoice® green power product in the absence of compliance cost information in its Value of Solar rate.

Another carbon valuation option is to use the added utility cost to comply with RPS targets. The argument for this approach is that if society has determined that a 20% RPS is appropriate, and renewable energy costs an extra $10 per MWH to procure, then it would presumably value additional avoided emissions (both carbon and other matter) at the same rate. However, RPS systems are compliance systems that integrate price impact controls, credit trading schemes, and other features that impact compliance certificate prices without direct relationship to the value of associated emissions reductions. Caution should be used in applying a regulatory system designed to minimize the cost of compliance with an effort to accurately value benefits net of costs.

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[67] G. Hardin, "The Tragedy of the Commons," Science 13 December 1968: 1243-1248. Available at: http://www.sciencemag.org/content/162/3859/1243.full?sid=f031fb58-2f56-4c25-ac0e-d802771c92ef

Where a state has a RPS mandate for its utilities, DSG provides a dual benefit. First, it lowers the number of retail sales that comprise the compliance baseline. Second, it results in the export of 100% renewable generation to the grid to offset some mix of renewable and fossil-fuel generation being produced to meet customer load.[68] The first benefit was discussed above, under avoided utility compliance costs. The second benefit accounts for the fact that energy exports from DSG are 100% renewable generation and arguably should be valued at 100% of the RPS value for purposes of a cost-benefit study.[69]

Another way to look at this is to say that all exports from a DSG system should receive the value of a market-priced renewable energy certificate, even where such a generator cannot easily create a tradable certificate.[70] This is justified because DSG exports help meet other customers' load on the utility's grid with 100% renewable energy and displace grid delivered electricity, which is only partially renewable. If a state has an RPS of 33% renewables, as does California, then DSG exports give rise to at least a 67% improvement in the renewable component of electricity.[71]

C. Airborne Emissions Other than Carbon and Health Benefits. Exceeding utility compliance with air regulations can be taken into account in a manner akin to that described for valuation of avoided carbon emissions. The public health impacts of fossil fuel generation have been well documented, though not well reflected in electricity pricing. In particular, air pollution can increase the severity of asthma attacks and other respiratory illnesses in vulnerable populations living in close proximity to fossil fuel-fired plants. Impacts on crops and forest lands have also been documented.

DSG reduces fossil fuel generation, especially from less efficient peaker plants and potentially from thermal plants that emit higher levels of pollution during startup operations. We are not aware of a dominant methodology, but note that public health literature will continue to grow in the area of recognizing and quantifying the public health impacts of electric generation, including health impacts related to climate change. Valuing emissions of carbon and other matter based on green energy pricing programs or RPS compliance costs, as described earlier, is an effective way to capture this benefit. Even outside of states with such programs, the value of reduced emissions is not zero; the value ascribed by nearby states with programs could serve as a proxy.

D. Avoided Water Pollution and Conservation Benefits. The utility industry uses and consumes a substantial portion of the nation's freshwater supplies for thermoelectric generation.[72] The benefit of not using the water for fossil-fuel generation should be

[68] A third benefit associated with reducing overall market costs for renewable energy certificates may also manifest with increased DSG penetration.
[69] Crossborder 2013 California Study at pp.18-21.
[70] For example, owners of California NEM systems rarely bother to establish RECs related to their output given required documentation, and the treatment of RECs from NEM systems in a lower value "bucket" than RECs from systems with in-state wholesale sales to utilities.
[71] Crossborder 2013 California Study at p. 18.
[72] *How It Works: Water for Energy* (Union of Concerned Scientists), July 2013, *available at* http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-overview.html.

based on the value of the water to society, that is, the value of conserving water for other beneficial uses.

Valuing water is intrinsically difficult. The tangle of water rights laws among the states complicate the determination of water value. To the extent that utilities have specific contracts for delivery or withdrawal of water to serve particular plants, it is likely that those expenses are already captured as an operating expense of the plant, but those are often at historic, ultra-low rates. Where a plant uses potable water, the value should be based on what society is willing to pay for that water. Likewise, where a plant is using non-potable, reclaimed water for cooling purposes, the appropriate value might be the price that someone would pay for an alternate use, such as irrigation.

The value to society of conserving water, which is of growing importance in water constrained regions of the country, is not adequately captured by the contract price for water or in the retail price that one would pay for an alternate use. We are not aware of a dominant methodology for measuring the conservation value of water, but this value should be considered as utilities consume a tremendous amount of water each year and will be increasingly competing for finite water resources. Avoiding the increased risk associated with maintaining secure, reliable, and affordable supplies of water is a benefit that DSG, with its 30-year expected operating life, delivers to all customers of the utility system.

10. Calculating social services: economic development

Installation and construction associated with onsite generation facilities is inherently local in nature, as contractors or installers must be within reasonably close geographic proximity to economically install a system and be present for building inspections. Accordingly, the solar industry creates local jobs and generates revenue locally. Economic activity associated with the growing rooftop solar industry creates additional tax revenue at the state and local levels as installers purchase supplies, goods and other related services subject to state and local sales tax, and pay payroll taxes. Locally spent dollars displace those frequently sent out of state for fuel and other supplies.

Taking a conservative approach, CPR's Pennsylvania and New Jersey study focused solely on tax enhancement value, which derives from the jobs created by the PV industry in those states. CPR used representative job creation numbers from previous studies in Ontario and Germany that quantify the number of jobs created by installing a unit of solar PV. CPR used assumptions that construction of solar PV involves a higher concentration of locally traceable jobs than construction of a centralized CCGT plant and determined the net local benefit of a solar project on the economy.

There remains a legitimate regulatory policy question of whether economic development benefits should be considered in calculating the value of DSG for use in setting electricity rates, or avoided cost calculations, even though there is a long history of economic development factors influencing commercial rates and line-extension fees. In any event, the economic development and tax base benefits of DSG deployment and operation should be consider when evaluating the societal cost-effectiveness of the technology and policies to support it.

Checklist of Key Requirements for a Thorough Evaluation of DSG Benefits

☑ **Energy benefits should be based on the utility not running a CT or a CCGT.** It is highly unlikely that DSG will offset coal or nuclear generation. Some combination of intermediate and peaking natural gas generation, with widely accepted natural gas price forecasts, should establish the energy value.

☑ **Line losses should be based on marginal losses.** Losses are related to load and DSG lowers circuit loads, which in turn lowers losses for utility service to other customers. Average line losses do not capture all of the loss savings; any study needs to capture both the losses related to the energy not delivered to the customer and the reduced losses to serve customers who do not have DSG.

☑ **Generation capacity benefits should be evaluated from day one.** DSG should be credited for capacity based on its Effective Load Carrying Capacity ("ELCC") from the day it is installed. If the utility has adequate capacity already, it may not have taken into account DSG penetration in its planning and overbuilt other generation; the DSG units that are actually operating during utility peaks should be credited with capacity value rather than a plant that is never deployed.

☑ **T&D capacity benefits should be assessed.** If the utility has any transmission plans, then DSG is helping to defer a major expense and should be included. On distribution circuits, watch for a focus on circuits serving residential customers, which tend to peak in the early evening when solar energy is minimal. Circuits serving commercial customers tend to peak during the early afternoon on sunny days, and a capacity value should be recognized for them in the form of avoided or deferred investment costs.

☑ **Ancillary services should be evaluated.** Inverters that can provide grid support are being mass-produced, and utility CEOs in the United States are calling for their use; ancillary services will almost certainly be available in the near future. Modeling the costs and benefits of ancillary services can also inform policy decisions like those related to interconnection technology requirements. and provides a hedging benefit.

☑ **A fuel price hedge value should be included.** In the past, utilities regularly bought natural gas futures contracts or secured long-term contracts to avoid price volatility. The fact that this is rarely done now and the customer is bearing the price volatility risk does not diminish the fact that adding solar generation reduces the reliance on fuels and provides a hedging benefit.

☑ **A market price response should be included.** DSG reduces the utility's demand for energy and capacity from the marketplace, and reducing demand lowers market prices. That means that the utility can purchase for less, saving money.

☑ **Grid reliability and resiliency benefits should be assessed.** Blackouts cause widespread economic losses that can be avoided in some situations with DSG. As well, customers who need more reliable service than average can be served with a combination of DSG, storage and generation that is less expensive than the otherwise necessary standby generator.

☑ **The utility's avoided environmental compliance costs should be evaluated.** DSG leads to less utility generation, and lower emissions of NOx, SOx and particulates, lowering the utilities costs to capture those pollutants.

☑ **Societal benefits should be assessed.** DSG policies were implemented on the basis of environmental, health and economic benefits, and should not be ignored or not quantified.

V. Recommendations for Calculating the Costs of DSG

Distributed solar generation comes with a variety of costs. These include the costs for the purchase and installation of the DSG equipment, the costs associated with interconnecting DSG to the electric grid, the costs of incentives, the cost associated with administration and billing, and indirect costs associated with lost revenues and other system-wide impacts. As with cost of service regulation in general, the important principles of cost causation and cost allocation are critical in dealing with DSG costs as well.

DSG cost estimation depends on the perspective from which one seeks to examine policies. Some costs, depending on perspective, should not be treated as costs in a DSG valuation study at all. For example, the cost of a DSG system net of incentives and compensation that the individual solar customer ultimately bears—the net investment cost, does not impact other customers. Whether a customer pays $100,000 or $20,000 for a five kilowatt ("kW") DSG system, the avoided utility costs and the societal benefits are unchanged.

In general, solar valuation studies address costs in varying degrees according to the aim of the individual study. A convenient way to characterize solar costs is according to who bears them. Costs relevant to determining value or cost effectiveness can generally be grouped into three categories:

1. Customer Costs—Customer costs are costs incurred by or accruing to the customers who use DSG. These include purchase and installation costs, insurance costs, maintenance costs, and inverter replacement, all net of incentives or payments received.
2. Utility and Ratepayer Costs—Utility and ratepayer costs are costs incurred by the utility and ratepayers due to the operation of DSG systems in the utility grid. These include integration and ancillary services costs, billing and metering costs, administration costs, and rebate and incentive expenses. In NEM valuation studies, utility lost revenues are potentially a significant utility cost, under the assumption that there are no other mechanisms to adjust for these losses.[73]
3. Decline in Value for Incremental Solar Additions at High Market Penetration—A number of studies also identify modeled impacts associated with significant penetration of solar on the utility system. Most studies characterize low penetration as less than 5% of peak demand or total energy met by solar generation, and characterize high penetration as 10%-15% or more. These

[73] Lost revenues arise when market penetration of consumption-reducing measures like energy efficiency and distributed generation have sales impacts that exceed those forecasted in the last rate-setting procedure, and only last until the next rate-setting, when a true-up can occur. Between rate cases, trackers or other mechanisms to mitigate impacts of regulatory lag can also be installed. Valuation studies themselves do not dictate whether lost revenues occur or are recovered. This is a function of tariff design. In some jurisdictions, for example, stand-by charges are used to adjust for revenue losses under NEM. In others, Buy All-Sell All arrangements or Net Billing models are used.

impacts can be accounted for as a cost or as an adjustment to value credit for solar energy when long-term impacts are considered.

When evaluating the cost-effectiveness of NEM, most utilities have access to cost-of-service data that can measure energy-related impacts. As noted earlier, the most direct and obvious source of potential cost or benefit of NEM policy is the mechanism that sets NEM customers apart from general ratepayers—the ability to use electricity not consumed instantaneously (i.e., exported energy) against future purchases of electricity in the form of a kWh or monetary bill credit. The value that customers derive from these bill credits is solely assignable to NEM as a policy, as distinguished from changes in behind-the-meter consumption that could occur under PURPA, in the absence of NEM policy. Accordingly, it is only appropriate to examine the net value of exports, and not behind the meter consumption, as a cost to non-participating ratepayers. It is also appropriate to note that NEM export costs are likely different depending on the class of customer generating excess solar energy. The good news is that the easy starting point for calculating NEM export energy costs is the monthly sum of the bill credits appearing on the customer bill, already adjusted by customer class. These credit costs can then be netted against the value of avoided produced or purchased energy.

1. Recommendations for calculating customer costs

Most value of solar studies focus on utility, ratepayer, and society costs, but not private costs. Therefore, these studies do not address customer investments or expenses in DSG. On the other hand, these costs are part of the total cost effectiveness of solar and have been addressed in broader societal perspective studies or in evaluating cost effectiveness for a solar incentive program. NEM and VOST programs are not intended to be incentive programs, but rather to fairly compensate customers for DSG.

When customer costs are included for a broader societal test, a major challenge in evaluating forward-looking solar customer costs associated with a long-term policy relates to accurately predicting the market prices for solar systems and installation as well as maintenance costs.

Regarding customer O&M costs, NREL has estimated costs between 0.05 and 0.15 cents per kWh.[74] E3 estimates customer O&M costs at $20 per kW with an escalator of .02% per year, factors inverter replacement at $25 per kW, once every 10 years, and estimates insurance expenses at $20 per kW, escalating at .02% per year.[75] Together, these O&M costs are fractions of a cent when converted to kWh, in line with the NREL estimate.

As noted, customer costs are rarely relevant to DSG policy valuation studies. The relevant question when evaluating DSG programs is what the net effect is on other utility customers.

2. Recommendations for calculating utility costs

[74] *Photovoltaics Value Analysis* (National Renewable Energy Laboratory), February 2008, *available at* http://www.nrel.gov/analysis/pdfs/42303.pdf.

[75] *Technical Potential for Local Distributed Photovoltaics in California: Preliminary Assessment* (Energy & Environmental Economics, Inc.), March 2012 ("E3 Technical Potential Study 2012"), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf.

The most significant utility cost for NEM program valuation purposes is avoided revenue. A customer who used to pay $1000 per year to her utility and then installed a NEM system and cut her bills to only $200 per year is seen as costing the utility $800 of lost revenue. Again, to the extent that the customer could install the same system under PURPA and reduce her bill to $300 per year, the net cost of the NEM program would only be $100, representing the extra savings that she realized due to the NEM program. For a VOST program, the intent is to determine the value of the benefits and credit that amount to customers for all generation. In effect, the cost of the program is automatically equated to the benefits of the program, net of charges for consumption or network services.

The second largest utility or societal cost of DSG programs is the cost of incentives, though this cost is declining rapidly. Incentive costs are direct costs when the utility provides the funding from ratepayers, but are indirect when considering taxpayer-funded incentives. While incentive costs are real, they are primarily justified on market-stimulation bases, and scheduled to expire in a matter of years. Given that independent rationale for incentives, incentive costs are generally not included in DSG valuations. As the installed cost of DSG has declined, the need for incentives and rebates has diminished, with the California market reaching the end of its state incentive program almost entirely, and federal incentives slated to end in 2016.

Integration costs are the third most important utility cost for NEM programs, and the leading factor for value of solar studies addressing utility costs. Integration costs include the direct costs associated with administration of utility functions associated with distributed solar systems, rebates and incentives, and other administrative tasks. Direct costs can be addressed as a cost or as a decrement to the benefits of DSG, since these costs enable the benefits.

Reports of utility costs vary most significantly with the assumed solar penetration rate used in the study. Integration costs are variously labeled as “integration costs,” “grid support expenses,” or “benefits overhead.” Estimates of these costs range from 0.1 to 1 cent per kWh in studies that attempt to account for increased variability in the overall generation mix and resulting increases in ancillary services costs starting from very low solar penetration rates. Solar integration costs for a 15% market penetration level were estimated at 2.2 to 2.3 cents per kWh by Perez and Hoff, based on an analysis that focuses on the need and cost of storage to complement solar intermittency in order to provide firm capacity.[76] Navigant and Sandia performed an assessment of high penetration of utility scale solar in 2011 and estimated integration costs associated with increasing production to account for solar variability at between 0.31 cents for low penetration and 0.82 cents for higher penetration of roughly one gigawatt of installed solar.[77]

In states like California, where utilities are prohibited from charging solar customers for interconnection costs or upgrades, interconnection costs may be a substantial source of costs directly assignable to a DSG program. Where this is the case, it is necessary to have real, disaggregated data that tracks the exact interconnection costs of DSG. In

[76] CPR 2012 MSEIA Study at p. 47.
[77] *Large Scale PV Integration Study* (Navigant), July 2011, *available at* http://www.navigant.com/insights/library/energy/2011/large-scale-pv-integration-study/.

the E3 study, for example, utilities did not have sufficient detail on interconnection costs in 2009 to provide a clear or transparent picture on the extent of those costs, or whether the costs incurred were reasonable and not blended in with other upgrades that would have occurred without the solar generator's interconnection. Interconnection costs should, in theory, be clearly identifiable through utility-provided data. In analyzing the value of distributed solar, these costs should also be amortized against the useful life of the measures.

In states where customers are responsible for interconnection costs and upgrades, however, this would not be a cost assignable to DSG policy. As with other customer costs, this is not a cost borne by the utility and should not be factored into an evaluation of the impact of a DSG policy on other customers.

Experience and more sophisticated modeling will be required to understand the shape and ultimate level of the integration cost curve. While integration costs are likely low at low market penetration levels, they are also likely to increase with market penetration. But these increases may decline as solar systems become more widely dispersed and as utilities begin targeting deployment to high-value locations within the grid. In addition, increased deployment of other distributed technologies, such as electric vehicles, distributed storage, load control, and smart grid technologies will impact the costs associated with larger scale DSG deployment.

The billing and administration costs associated with DSG encompass the one-time setup expenses of processing and verifying applications and the ongoing expense of administering unique features of solar customer bills. In states with modest numbers of solar customers, it is not uncommon to manually adjust solar customer bills, with associated incremental costs. Depending on the utility's accounting practices and billing capabilities, solar-specific billings cost should be relatively easily segregated and allocated. In states with automated processes, the ongoing incremental costs of administering solar customer accounts should be, as was determined in the Vermont study, nearly zero.[78]

In some cases, utilities will incur costs directly associated with DSG that are not fairly assignable to DSG policy. For example, in Texas, renewable energy generators under one MW are classed as "microgenerators," subject to registration and reporting requirements under the state's renewable energy portfolio standard law.[79] To the extent that the utility acts as a program manager and aggregator of renewable energy certificates assigned by solar generators, these costs are not fairly assigned to NEM or other solar promotional program unless also offset by the value of the assigned certificates.

3. Recommendations for calculating decline in value for incremental solar additions at high market penetration

The incremental positive value of additional solar deployment within a particular utility service territory is anticipated to decline as solar penetration levels increase. There are two major drivers of these impacts, which are not technically costs, but actually

[78] Vermont Study at p. 15.
[79] *See* 16 Tex. Admin. Code 15, *available at* http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.173/25.173.pdf.

decrement adjustments that impact value of solar in the context of expanding markets and higher solar penetration.

These impacts address the value of additional deployments and not past installations, and not replacement installations. The two major drivers are the expected reduction in capacity credit for solar and reduced peak energy value as market penetration increases. Capacity credits for solar are typically higher than capacity factor due to good solar coincidence with peak demand periods. However, as more solar is added to a system, the difference between peak and non-peak demand dissipates. Without storage, solar has a limited ability to reduce a system peak that is essentially shifted forward into evening hours. As a result, the incremental capacity benefit of solar is reduced for incremental additions as penetration increases. This impact could reduce capacity credit by 20-40% as penetration rates approach 15%.[80]

To the extent that solar energy is generated at periods of high utility cost, it provides great value. As the penetration rate of solar increases, peak market prices are likely suppressed, reducing the value of incremental solar energy. E3 estimated the reduced energy value at 15% over ten years in a study for California.[81]

Much work is needed in measuring and modeling the impact of high penetrations of DSG to address exactly how much DSG creates high penetration impacts, and inserting this clarity in valuation and cost effectiveness studies. Most states receive less than 0.5% of peak energy from distributed solar generation, while most studies looking at high penetration model levels at 10-15%. As noted earlier, the most relevant costs to consider are those that will occur at more modest penetrations. For example, if capacity benefits decline significantly at higher penetrations, that does not justify finding low capacity benefits at early stages.

Other important issues to be addressed include the impacts of different assumptions regarding geographic region, system size, and long-term changes in energy demand. It is important to note that both the capacity credit and energy value deterioration could be mitigated through consideration of energy sales from areas of high solar penetration to areas of lower penetration. For example, utilities facing near term surplus capacity situations could incur short-term lost revenues that could be mitigated over the period that solar systems operate, creating the potential for net benefits over that longer term.

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[80] *See* LBNL Utility Solar Study 2012, *supra*, footnote 13.
[81] *See* E3 Technical Potential Study 2012, *supra*, footnote 74.

Checklist of Key Requirements for a Thorough Evaluation of DSG Costs

☑ **Is lost revenue or utility costs the basis of the study?** For NEM studies, lost revenue is the standard (what the DSG customer would have otherwise paid the utility). For other studies and even some NEM studies, the cost to serve the DSG customer is addressed instead, which should lead to an inquiry in particular regarding allocation of capacity costs.

☑ **Assumptions about administrative costs must reflect an industrywide move towards automation.** With higher penetration, costs per DSG customer tend to decline, so administrative costs should assume automation of processes.

☑ **Interconnection costs should not be included.** If the DSG customer pays for the interconnection, this should not be included as a cost to the utility. As well, the utility's interconnection costs should be compared to national averages to determine whether they are reasonable.

☑ **Integration costs should not be based on unrealistic future penetration levels.** Studies tend to find minimal grid upgrade requirements at DSG penetrations below a few percent. Looking ahead to what the grid might need to accommodate 50% penetration unnecessarily adds costs that are not actually being incurred.

VI. Conclusion

Valuations vary by utility, but valuation methodologies should not. In this report IREC and Rabago Consulting LCC suggests a standardized approach for calculating DSG benefits and costs that we hope proves helpful to regulators as they embark on commissioning or reviewing valuation studies. Please see the mini-guide at the end of this report for a quick reference guide to the recommendations in this report.

IREC

REGULATOR'S MINI-GUIDEBOOK

Calculating the Benefits and Costs of Distributed Solar Generation

Valuations vary by utility, but valuation methodologies should not. IREC and Rábago Energy LLC suggest a standardized approach for calculating DSG benefits and costs in the white paper "A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation." We hope that this paper proves helpful to regulators as they embark on commissioning or reviewing valuation studies. Below is a high-level summary of the recommendations in the white paper. Please see the full report for more detail per section.

A. KEY QUESTIONS TO ASK AT THE ONSET OF A STUDY

Q1: WHAT DISCOUNT RATE WILL BE USED?

Recommendation: We recommend using a lower discount rate for DSG than a typical utility discount rate to account for differences in DSG economics.

Q2: WHAT IS BEING CONSIDERED – ALL GENERATION OR EXPORTS ONLY?

Recommendation: We recommend assessing only DSG exports to the grid.

Q3: OVER WHAT TIMEFRAME WILL THE STUDY EXAMINE THE BENEFITS AND COSTS OF DSG?

Recommendation: Expect DSG to last for thirty years, as that matches the life span of the technology given historical performance and product warranties. Interpolate between current market prices (or knowledge) and the most forward market price available or data that can accurately be estimated, just as planners do for fossil-fired generators that are expected to last for decades.

Q4: WHAT DOES UTILITY LOAD LOOK LIKE IN THE FUTURE?

Recommendation: Given that NEM resources are interconnected behind customer meters, and result in lower utility loads, the utility can plan for lower loads than it otherwise would have. In contrast, other DSG rate or program options involving sale of all output to the utility do not reduce utility loads, but rather the customer facilities contribute to the available capacity of utility resources.

Q5: WHAT LEVEL OF MARKET PENETRATION FOR DSG IS ASSUMED IN THE FUTURE?

Recommendation: The most important penetration level to consider for policy purposes is the next increment: what is likely to happen in the next three to five years. If a utility currently has 0.1% of its needs met by DSG, consideration of whether growth to 1% or even 5% is cost-effective is relevant, but consideration of whether higher penetrations are cost-effective can be considered at a future date.

Q6: WHAT MODELS ARE USED TO PROVIDE ANALYTICAL INPUTS?
Recommendation: Transparent input models that all stakeholders can access will establish a foundation for greater confidence in the results of the DSG studies. When needed, the use of non-disclosure agreements can be used to overcome data sharing sensitivities.

Q7: WHAT GEOGRAPHIC BOUNDARIES ARE ASSUMED IN THE ANALYSIS?
Recommendation: It is important to account for the range in local values that characterize the broader geographical area selected for the study. In some cases, quantification according to similar geographical sub-regions may be appropriate.

Q8: WHAT SYSTEM BOUNDARIES ARE ASSUMED?

Recommendation: It may also be appropriate to consider impacts associated with adjacent utility systems, especially at higher (above 10%) penetration levels of DSG. [82]

Q9: FROM WHOSE PERSPECTIVE ARE BENEFITS AND COSTS MEASURED?

Recommendation: We recommend that ratepayer and societal benefits and costs should be assessed.

Q10: ARE BENEFITS AND COSTS ESTIMATED ON AN ANNUALIZED OR LEVELIZED BASIS?

Recommendation: We recommend use of a levelized approach to estimating benefits and costs over the full assumed DSG life of 30 years. Levelization involves calculating the stream of benefits and costs over an extended period and discounting to a single present value. Such levelized estimates are routinely used by utilities in evaluating alternative and competing resource options.

B. DATA SETS NEEDED FROM UTILITIES

- ☑ The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the DSG
- ☑ Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of NEM policy
- ☑ Hourly production profiles for NEM generators, including south-facing and west-facing arrays
- ☑ Line losses based on hourly load data, so that marginal avoided line losses due to DSG can be calculated
- ☑ Both the initial capital cost and the fixed and variable O&M costs for the utility's marginal generation unit

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[82] Mills and Wiser point out that consideration of inter-system sales of capacity or renewable energy credits could mitigate reductions in incremental solar value that could accompany high penetration rates. *See* A. Mills & R. Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, at p. 23, December 2012 (nt Processes energy credits could *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

☑ Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth
☑ Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of DSG, in order to capture the potential for avoiding or deferring circuit upgrades

Note: where a utility or jurisdiction does not regularly collect some portion of this data, there may be methods to estimate a reasonable value to assign to DSG.

C. RECOMMENDATIONS FOR ASSESSING BENEFITS

1. **The following benefits should be assessed:**
    1. Energy
    2. System Losses
    3. Generation Capacity
    4. Transmission and Distribution Capacity
    5. Grid Support Services
    6. Financial: Fuel Price Hedge
    7. Financial: Market Price Response
    8. Security: Reliability and Resiliency
    9. Environment: Carbon& Other Factors
    10. Social: Economic Development
2. **Energy benefits should be based on the utility not running a CT or a CCGT.** It is highly unlikely that DSG will offset coal or nuclear generation. Some combination of intermediate and peaking natural gas generation, with widely accepted natural gas price forecasts, should establish the energy value.
3. **Line losses should be based on marginal losses.** Losses are related to load and DSG lowers circuit loads, which in turn lowers losses for utility service to other customers. Average line losses do not capture all of the loss savings; any study needs to capture both the losses related to the energy not delivered to the customer and the reduced losses to serve customers who do not have DSG.
4. **Generation capacity benefits should be evaluated from day one.** DSG should be credited for capacity based on its Effective Load Carrying Capacity ("ELCC") from the day it is installed. If the utility has adequate capacity already, it may not have taken into account DSG penetration in its planning and overbuilt other generation; the DSG units that are actually operating during utility peaks should be credited with capacity value rather than a plant that is never deployed.
5. **T&D capacity benefits should be assessed.** If the utility has any transmission plans, then DSG is helping to defer a major expense and should be included. On distribution circuits, watch for a focus on circuits serving residential customers, which tend to peak in the early evening when solar energy is minimal. Circuits serving commercial customers tend to peak during the early afternoon on sunny days, and a capacity value should be recognized for them in the form of avoided or deferred investment costs.
6. **Ancillary services should be evaluated.** Inverters that can provide grid support are being mass-produced, and utility CEOs in the United States are calling for

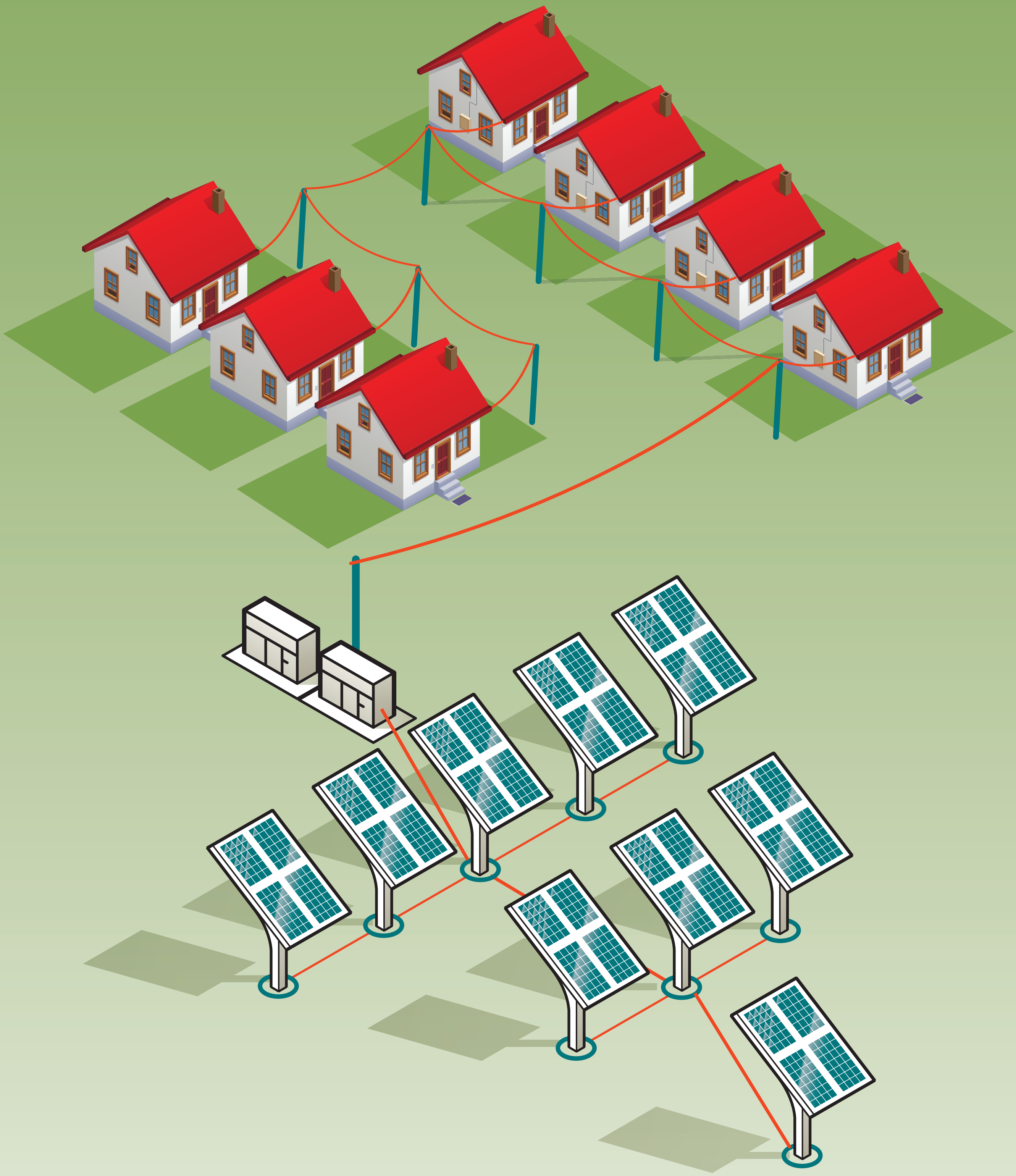
their use; ancillary services will almost certainly be available in the near future. Modeling the benefits and costs of ancillary services can also inform policy decisions like those related to interconnection technology requirements.

7. **A fuel price hedge value should be included.** In the past, utilities regularly bought natural gas futures contracts or secured long-term contracts to avoid price volatility. The fact that this is rarely done now and that the customer is bearing the price volatility risk does not diminish the fact that adding solar generation reduces the reliance on fuels and provides a hedging benefit.
8. **A market price response should be included.** DSG reduces the utility's demand for energy and capacity from the marketplace, and reducing demand lowers market prices. That means that the utility can purchase these services for less, saving money.
9. **Grid reliability and resiliency benefits should be assessed.** Blackouts cause widespread economic losses that can be reduced or avoided in some situations with DSG. As well, customers who need more reliable service than average can be served with a combination of DSG, storage and generation that is less expensive than the otherwise necessary standby generator.
10. **The utility's avoided environmental compliance and residual environmental costs should be evaluated.** DSG leads to less utility generation, and lower emissions of NOx, SOx and particulates, lowering the utilities costs to capture or control those pollutants.
11. **Societal benefits should be assessed.** DSG policies were implemented on the basis of environmental, health and economic benefits, which should not be ignored and should be quantified.

D. RECOMMENDATIONS FOR ASSESSING COSTS

1. **Determine whether lost revenue or utility costs are the basis of the study.** For NEM studies, lost revenue is the standard (what the DSG customer would have otherwise paid the utility). For other studies and even some NEM studies, the cost to serve the DSG customer is addressed instead, which should lead to an inquiry in particular regarding allocation of capacity costs.
2. **Assumptions about administrative costs should reflect an industry-wide move towards automation.** With higher penetration, costs per DSG customer tend to decline, so administrative costs should assume automation of processes.
3. **Interconnection costs should not be included.** If the DSG customer pays for the interconnection, this should not be included as a cost to the utility. As well, the utility's interconnection costs should be compared to national averages to determine whether they are reasonable.
4. **Integration costs should not be based on unrealistic future penetration levels.** Studies tend to find minimal grid upgrade requirements at DSG penetrations below a few percent. Looking ahead to what the grid might need to accommodate 50% penetration unnecessarily adds costs that are not actually being incurred.

Model Rules for Shared Renewable Energy Programs



IREC Interstate Renewable Energy Council, Inc.

THE Vote Solar INITIATIVE

Model Rules For Shared Renewable Energy Programs

IREC believes clean energy is critical to achieving a sustainable and economically strong future. To pave this clean energy path, IREC works to expand consumer access to clean energy; generates information and objective analysis grounded in best practices and standards; and leads programs to build a quality clean energy workforce, including a unique credentialing program for training programs and instructors. Since 1982, IREC's programs and policies have benefitted energy consumers, policymakers, utilities and the clean energy industry.

IREC wishes to thank the following individuals who reviewed the model rules and provided feedback: Colin Murchie, Jason Coughlin, Joy Hughes, John Covert, Anya Schoolman, David Amster-Olszewski, Paul Spencer, Karl Rábago, Stephen Frantz, and Jennifer Martin.

IREC

Vote Solar

Table of Contents

Shared renewable energy programs enable multiple customers to share the economic benefits from one renewable energy system via their individual utility bills. Shared renewable energy represents a critical means of expanding access to renewable energy to more Americans.

I. Background

In November 2010, the Interstate Renewable Energy Council, Inc. (IREC) released the original version of our *Community Renewables Model Program Rules*. The intent of the *Model Program Rules* is to assist stakeholders in developing local or statewide, shared renewable energy programs that expand renewable energy access to more consumers. IREC worked closely with The Vote Solar Initiative (Vote Solar) to develop the *Model Program Rules*, taking into account the various approaches in place at that time around the United States, including efforts in Massachusetts, Colorado, California, Washington and Utah. In advance of publication, IREC and Vote Solar vetted the *Model Program Rules* with utilities, industry participants and other stakeholders, and their feedback was used to further refine the *Model Program Rules*.

Since issuing the first version of the *Model Program Rules*, IREC has participated actively in the growing shared renewable energy market, advising interested entities on program development and participating in regulatory proceedings in California, Colorado and Delaware to implement programs. In addition, IREC has continued to collaborate with Vote Solar to ensure that we are effectively advancing a common vision.

These current *Model Rules for Shared Renewable Energy Programs* represent an update to our initial model rules based on policy and market evolution over the past several years. Like the first version of the *Model Program Rules*, this updated version has been vetted with a wide range of stakeholders. As discussed in more detail below, we have moved from using the term “community renewables” to the term “shared renewable energy” or “shared renewables.” We believe this new term better reflects the core innovation in these programs, which is enabling multiple consumers to share the benefits of a single renewable energy facility. Regardless of the change in nomenclature, the intent of the *Model Program Rules* remains the same: to assist stakeholders in developing shared renewable energy programs to broaden renewable energy access to more consumers. We believe the additional information and increased level of detail in this updated version of the *Model Program Rules* will help state and local stakeholders create programs that meet their particular needs and interests.

II. The Opportunity Shared Renewable Energy Programs Represent

As renewable energy becomes increasingly cost-competitive with traditional electricity sources, more and more Americans are turning to renewable sources to meet their energy needs. Hundreds of thousands of home and business owners across the United States have invested in renewable energy and are generating their own electricity. However, the majority of residential and commercial energy consumers cannot install renewable energy systems on their own property. This may be because these consumers do not have adequate or appropriate roof area, or they rent, or due to a number of other reasons. In fact, a report from the National Renewable Energy Laboratory (NREL) estimated that only about one-quarter of U.S. residential buildings are physically suitable for installing solar on their roofs, a figure that does not even take into account the ownership status of the building.[1] In cases where homeowners and businesses do have a suitable site, they may have other reasons for not wishing to install solar on-site. For example, they may not want contractors installing and maintaining a system on their roof, or they may be planning to move in the near future and are therefore unprepared to make such a property investment. In the end, for whatever reason, the majority of energy customers are currently unable to invest in renewable energy generation, despite their desire to green their energy supply.[2]

Shared renewable energy programs address this issue by allowing a single renewable energy facility to serve multiple, dispersed energy consumers, and enabling these consumers to receive direct benefits on their utility bill from their investment in renewable energy. Shared renewables programs can allow renewable energy developers to tap a market that is currently underserved but potentially quite large. For example, if just five percent of U.S. households were to invest in a five-kilowatt (kW) interest in a shared solar system—the size of a typical residential rooftop solar installation—it would result in over 28 gigawatts (GW) of additional solar capacity,[3] equivalent to the output of over 50 coal-burning power plants.[4]

While we refer to shared renewables throughout these *Model Program Rules*, which support any type of renewable energy generation, it is important to note that shared solar programs are currently the most prevalent form of shared renewables programs in the United States. Nonetheless, shared renewables programs that rely on other renewable generation, such as wind, may make sense for certain communities and some already exist today.[5]

Although typically still considered distributed generation, shared renewable energy facilities are often larger than typical customer-sited systems, which can result in lower costs due to economies of scale. The ability to site shared renewable energy facilities in optimal locations instead of being restricted to a particular customer's roof, the opportunity for new financing arrangements, and the potential simplicity of customer participation are other reasons shared renewable energy is gaining popularity.

III. Guiding Principles for Shared Renewable Energy Programs

Four key principles guide IREC's approach with respect to shared renewable energy program development. The first three principles are definitional in nature; it is these characteristics that distinguish shared renewable energy programs from other types of programs. The final principle is a best practice that IREC believes to be important when designing shared renewable energy programs.

First, shared renewable energy programs should expand renewable energy access to a broader group of energy consumers, including those who cannot install renewable energy on their own properties. As described above, most Americans are currently unable to benefit directly from renewable energy generation because they cannot install renewable energy on-site. As a matter of equity between energy consumers this barrier should be removed as it unnecessarily limits participation in generally available renewable energy programs. Moreover, shared renewables programs allow greater energy consumers to participate in renewable energy generation, unlocking a substantial new market for renewable energy developers and thereby strengthening the renewable energy industry.

Second, participants in a shared renewable energy program should receive tangible economic benefits on their utility bills. By providing credits on participating customers' utility bills, shared renewable energy programs offer a clear, intuitive way for customers to save money by choosing renewable energy. Similarly, net energy metering (NEM) has been very successful in motivating energy consumers to invest in renewable energy because it is a straightforward and simple concept. In addition, consumers participating in NEM programs have been shown to install more energy efficiency measures than nonparticipants, again because they are highly motivated to reduce their energy bills and maximize the efficacy of their on-site renewable energy system.[6] Keeping the benefits of participation in a shared renewables program on customers' bills maintains the linkage between a customer's participation in the program, their reduced energy use, and their lower bill. Even in cases where participants may pay more initially for participation in a shared renewable energy program, programs should be designed such that participants receive a valuable hedge benefit by locking in a rate through their participation in the program, which will save them money as standard electricity rates rise over time.

Third, shared renewable energy programs should be flexible enough to account for energy consumers' preferences. Consumers are more likely to purchase a product that is specifically tailored to suit their personal values and priorities. Therefore, we recommend that shared renewable energy programs be flexible with regard to business models so that developers and utilities can innovate to meet consumer desires. This can include preferences for specific technologies, project locations, or ownership models. For example, in IREC's experience, consumers are highly motivated to participate in shared renewable energy when the generation facilities are located in or nearby their communities. Structuring a program to allow for the realization of these preferences can broaden interest and participation in the program.

Fourth, and finally, shared renewable energy programs should be additive to and supportive of existing renewable energy programs, and not undermine them. Over the previous decades, renewable energy companies have invested considerable resources in building their businesses. This private investment in time and resources has helped expand markets for renewable energy in partnership with utility-run renewable energy programs. The success of both wholesale and retail oriented distributed generation programs has resulted in dramatic reductions in the cost of renewable energy. For this reason, it makes little sense to undermine successful programs, and the businesses based upon these programs, when seeking to expand access to new customer segments. Similarly, shared renewables programs should be designed so that they result in new "steel in the ground" instead of re-purposing existing renewable energy generation. In this way, shared renewable energy programs can promote renewable energy market development as effectively as possible. Shared renewables programs represent, in some cases, another mechanism by which a utility can meet renewable energy goals, for example as dictated in state Renewables Portfolio Standards (RPS), on top of the various existing mechanisms and programs that utilities may already be pursuing. In other cases, a shared renewables program can enable a state or utility to go above and beyond current RPS requirements.

IV. Understanding Shared Renewables Terms and Nomenclature

In this section, we clarify what we mean by "shared renewable energy." In addition, we explain the relationship between shared renewables and three other renewable energy programs: NEM, group purchasing and green tariffs.

A. Shared Renewables Versus Renewable Energy Project Investments

As interest in renewable energy has grown, various approaches have emerged to allow broader groups of consumers to benefit directly from renewable energy generation. IREC divides these approaches into two categories.

Shared renewable energy programs or shared renewables programs—the focus of these *Model Program Rules*—refer to programs that enable multiple customers to share the economic benefits of one renewable energy system via their individual utility bills. Participants purchase an interest in generation from a common renewable energy system, and directly receive the benefits of their participation on their utility bills.

Renewable energy project investments, on the other hand, refer to investments made by individuals in one or more renewable energy projects, similar to any other investments that individuals might make as part of their investment portfolio. The investment could be as direct as a membership in a limited liability company (LLC) that owns and operates a renewable energy system, or it could be via a company such as Mosaic,[7] which offers interested investors an easy platform for supporting specific solar projects and earning attractive returns. The funds invested and the resulting earnings are unrelated to participants' energy bills. Other similar programs, such as RE-volv, [8] have relied on a donation model in which interested participants donate to the construction of a renewable energy system in a community, sometimes receiving a tax deduction or a gift in return.

IREC focuses on shared renewables programs because they provide participants a direct utility bill benefit similar to what they might experience through other on-site renewable energy generation programs that have been extremely popular to date. Setting up these programs can raise thorny regulatory and policy issues so policy guidance on developing shared renewables programs is particularly vital.

B. Relationship of Shared Renewables to Net Energy Metering

Shared renewable energy programs rely on utility bill credits to distribute the benefits of participation in the shared system to the participants. In this way, a shared renewables program looks similar to NEM, which also uses a bill credit mechanism to compensate consumers that have installed renewable energy generation facilities on-site.[9] NEM policies are in place in 43 states, Washington D.C., and four territories.[10] NEM has been one of the most successful policies to motivate energy consumers to invest in renewable energy, especially solar energy, because it is conceptually simple and it allows participants to directly lower their bill in a clearly intuitive way.[11] NEM credits are typically valued at the participant's retail rate, such that a participant receives essentially a one-to-one kilowatt-hour (kWh) offset on their bill for energy generated by that participant's net-metered system. In contrast, the bill credit for a shared renewable energy facility may be valued through a different process than a NEM credit, as discussed in section V.

In some states, NEM has been expanded to allow for meter aggregation, or aggregate net metering (ANM), which permits a single NEM participant to offset their load from multiple meters through NEM credits generated from a single renewable energy system connected to one of the participant's meters. As with traditional NEM, ANM credits are also typically valued at or near the NEM participant's retail rate, although valuation can vary depending on how ANM rules treat meters on different rates. In some cases, meter aggregation is allowed only for meters on the same or contiguous properties; in other cases, the meters may be further apart or there are no geographical limitations.[12]

In still other states, virtual net metering (VNM) has been implemented to extend NEM to situations where multiple participants receive bill credits from a single net-metered renewable energy facility. Although VNM and ANM are used interchangeably in some states, IREC distinguishes between ANM (one customer, multiple meters) and VNM (multiple customers, multiple meters) for the sake of clarity. Because VNM is nested within a state's NEM paradigm, VNM credits are typically valued at, or at least based off of, participants' retail rate (or rates). The bill credit mechanism in a shared renewables program closely resembles VNM except that it need not have this direct tie to the existing NEM program, including with respect to how bill credits are valued. Nonetheless, in some places, the policies are conflated. In these updated *Model Program Rules*, however, IREC intentionally separates shared renewables from the NEM framework to allow for program design flexibility while retaining intuitive appeal and other benefits of a bill credit mechanism to distribute the benefits of participation in a renewable energy system.

C. Relationship of Shared Renewables to Group Purchasing

Shared renewables programs bear some resemblance to group purchasing programs in that both types of programs allow energy consumers to leverage their combined purchasing power in order to receive a lower price for renewable energy. Group purchasing involves a group of energy consumers joining together to negotiate for better prices for the purchase of renewable energy systems for installation on their sites. For example, some communities have launched "Solarize" programs in which groups of consumers organize a bulk purchase of solar systems in order to receive a lower price.[13] Once the purchase is complete, however, each customer in the group has an individual solar system installed on their own home to serve their own load. By contrast, participants in a shared renewables program leverage their combined purchasing power to support the construction of a single renewable energy facility, whose generation they all share. Both types of programs can expand renewable energy access to more consumers, however shared renewables programs in particular allow consumers to participate even if they cannot install a renewable energy system on their properties.

D. Relationship of Shared Renewables to Green Tariffs

Finally, shared renewables programs are similar in some ways to green tariffs. Electricity suppliers, either vertically integrated utilities or competitive suppliers can offer their customers a green tariff option, also referred to as green pricing or green marketing. Under these programs, energy consumers typically pay a premium for electricity generated from clean power resources, such as solar or wind. The premium covers costs incurred by the electricity supplier from adding green power to its power generation mix.

Like shared renewable energy programs, green tariffs can offer more energy consumers the chance to "green" their energy supply. Unlike shared renewables programs, however, green tariffs may not result in the construction of new renewable energy generation, particularly if they rely on short-term contracts for renewable energy credits (RECs) to "green" the power being provided to participants in the tariff. Moreover, a green tariff may be offered as a more expensive option overlaid on the participant's underlying rate for power from the utility. Under this arrangement, participants lose an important tangible economic benefit of renewable energy: the ability to lock in the price for electricity as a hedge against future rate increases due to fossil fuel price volatility. Finally, green tariffs have historically not provided the flexibility of most shared renewable energy programs in terms of allowing participants to choose specific project locations, technologies, or ownership models. Experience has shown that energy consumers are keenly interested in greening their energy supply through programs that result in new generation, provide them with tangible economic benefits and result in clean energy facilities located near their communities. For these reasons, as shared renewables programs continue to expand, care must be taken to ensure that green tariff programs do not inadvertently foreclose opportunities for energy consumers to participate in shared renewables programs that would meet consumer preferences for green energy with the characteristics described above. IREC supports the development of green tariff programs to expand consumer access to renewable energy, and we are optimistic that green tariff programs can be developed that meet our guiding principles for shared renewables.

V. Core Components to Consider for Shared Renewable Energy Programs

IREC believes five foundational issues require particular attention with respect to the development of shared renewable energy programs: (1) program administration; (2) the method of allocating the benefits of participation; (3) valuation of the energy produced by the system; (4) shared renewable energy facility size and location; and (5) shared renewable energy facility ownership and its implications for financing.

A. Program Administration

Shared renewable energy programs have many moving parts: program design, marketing and consumer sign-up, facility maintenance, and utility interface and participant changes, among others. All of these components necessitate a formal program structure, which could be administered by a utility, a participant or a third party.

Utility program administration is the predominant model for shared renewable energy programs across the United States. Based on IREC's review of the shared renewable energy programs we were aware of in March 2013, 79 percent, or 30 out of 38 programs, were run by utilities or a utility-sponsored third party. This framework allows an entity with significant experience in administering complex energy programs to administer the details of a shared renewables program, which may have many participants. For example, Tucson Electric Power (TEP), an investor-owned utility in Arizona, administers its shared solar program called Bright Tucson Community Solar Program. The program was launched in March 2011 with an initial goal to develop 1.6 megawatts (MW) of new TEP-owned solar generating capacity over the following three years. To date, the program has been much more successful than originally planned. As of July 2012, the TEP Bright Tucson program included 777 customers, who were subscribed to a total of 4.13 MW in TEP- or third-party-owned solar installations. Such a large program with such rapid success may have been difficult for participants to manage, whereas TEP's experience and administrative infrastructure allowed it to manage the Bright Tucson program effectively.

Even in a smaller program, administrative experience can be an important asset. For example, Colorado Springs Utilities, a municipal utility, allows its customers to lease panels from three community solar garden project developers. The total pilot program size is 2 MW and it focuses on residential customers and educational institutions as participants. As of October 2012, Springs Utilities had over 300 residential and educational customers participating in its program. As its program matures, Springs Utilities' administrative and customer service experience will continue to be critical.

In some cases, utilities may engage a third party to help to develop and/or administer a shared renewables program. For example, the Clean Energy Collective (CEC) has partnered with numerous utilities and community groups to develop shared solar programs.[14] Typically, under the CEC model, customers own the shared facility and receive bill credits based on their interest in the facility, and CEC handles administration, on-bill crediting, facility construction, operation and maintenance.

Nonetheless, some programs have used a customer-administration model, which have been met with success. Vermont's group billing approach is a prime example. The Vermont program allows for a group of energy consumers located within the same utility service territory to choose to combine meters in order to offset that billing against a single renewable energy facility.[15] In this case, the utility bills and credits all participants in the group individually, and the group is responsible for the other aspects of program design and management. Specifically, in order to participate in group billing, the group must file the following information with the Public Service Board and other entities as required: the customers and meters that are to be included as part of the group; the method for adding and removing meters; information regarding credit allocation to each customer-meter; the contact person responsible for communications; and a dispute resolution process. According to IREC's research, Vermont has over 50 group systems across multiple utility service territories, with fewer than 10 accounts per group. In considering a group billing approach, however, it is important to remember that it may be difficult to administer on a larger scale, with more customers participating.

B. Allocating the Benefits of Participation

Allocating benefits to shared renewable energy program participants—that is, transferring value from the shared renewable energy system to participating energy consumers—is another critical element of developing a successful shared renewable energy program. As in our original *Model Program Rules*, IREC continues to recommend allocating benefits via a monetary bill credit on a participant's monthly bill.

While it may seem simpler to allocate benefits via a direct payment to participants, outside of the utility billing process, direct payments face several challenges. In particular, these payments may result in taxable income, which would reduce the benefit energy consumers receive from investing in greening their energy supply. In addition, payments could raise complicated securities issues. The U.S. Department of Energy (DOE) has a *Guide to Community Shared Solar*, which goes into additional detail about potential securities concerns, and is a good reference on this point.[16]

Because it is fundamentally a billing mechanism, allocating benefits via a bill credit may avoid many of the tax and security law implications and other challenges raised by allocating benefits via payment, which are discussed in more detail below. Moreover, many energy consumers are motivated to offset as much of their energy bill as possible, which has been a major driver behind the success of NEM programs. A shared renewables program can maintain this direct relationship between energy consumers' investments in renewable energy and a reduction in their utility bills by relying on a bill credit mechanism to allocate the benefits of participation in a shared renewable energy facility.

Bill credits for shared renewables are typically translated into dollars to make the process easier to administer for utilities. By contrast, in most NEM programs, credits for excess generation not consumed on site are reflected as kWh credits on the bill. Under NEM, these kWh credits provide a one-to-one offset for the kWh a participant uses later in a billing period, when their system is not producing energy or when they consume more energy than the system is producing. Although this structure can work well for NEM, where most electricity produced by an on-site system is immediately used on-site, it can be more difficult to administer for a shared renewable energy system, where the generation source is separated from the participants who would like to receive electricity from that system. Providing kWh credits can be particularly difficult to track if a customer is on a time-of-use rate structure as kWh production would have to be tracked and applied to the customer's bills within the time-of-use periods contained in the customer's tariff. This can produce a major administrative burden if credits are allocated by hand. In order to simplify bill credit administration, as well as to more easily allow for appropriate bill credit valuation, IREC recommends a monetary bill credit. As with NEM, IREC recommends perpetual rollover of any excess credit to participants' next utility bill.

C. Valuation of the Energy Produced by the Shared Renewable Energy System

In addition to deciding how to *allocate* the benefits of participation in a shared renewable energy program, it is also critical to decide how to *value* those benefits. Determining the appropriate monetary value to assign to kWh credits can be a complex process. While establishing the value of the generation alone may be relatively easy, understanding the wider costs and benefits of a shared renewable energy system is more difficult. As more programs have struggled with this valuation process, two distinct categories of approaches have emerged, and still others are being proposed.

(1) Embedded cost-based approach. This approach is based on the structure of a utility's electric rate design, including the generation, transmission and possibly the distribution cost components of retail rates, similar to a traditional NEM bill credit. We refer to it as "embedded cost" because it is based on the cost structure embedded in energy consumers' current rates. Programs have typically valued the credit based on the retail rate in effect for each participant versus at the facility location, which offers at least two distinct benefits.[17] First, it maintains the ability of renewable energy to act as a price hedge against future utility rate increases for a particular participant. And second, it allows energy consumers whose retail rates contain demand charge components to realize the grid benefits stemming from their participation in a shared renewables program.

As far as the components of the credit, there appears to be general consensus that bill credits should incorporate the generation cost component of a utility's retail rate, as a shared renewable facility is supplanting utility generation for a participant. The inclusion of transmission and/or distribution cost components of rates in the bill credit has proven more contentious. On the issue of transmission credit, depending on the structure of the program, participants might not utilize the transmission system in order to deliver power from their shared renewable energy facility so stakeholders argue that they should not pay for transmission that they do not use. This argument is particularly strong in situations where a shared renewable energy facility is hosted on a participant's site or on the same distribution feeder as a participant. In these cases program participants typically consume most or all of the energy before it even reaches the substation. Delaware's shared renewables program rules address this by allowing participants to receive a full retail rate credit if they host or are on the same feeder as the shared renewables facility, and a lower credit if they are on a different feeder.[18]

The distribution cost component is the most controversial component of embedded-cost-based credit valuation and utilities often argue that they do not receive sufficient net benefits from shared renewable energy facilities to cover distribution costs incurred from delivering energy to participants. Therefore, utilities often argue that inclusion of the full distribution cost component in bill credits results in a cost-shift to nonparticipating ratepayers; care must be taken, however, to study this assumption in order to determine if it is accurate. For example, under California's VNM program, credits created by shared renewable energy facilities are valued at a fully bundled retail rate. As a result, participants *do not* pay distribution charges.[19] California's approach appears sensible because California's virtual net-metering program is available only to occupants of multitenant buildings. Thus, California participants will be located within the same building on the same distribution circuit and, as a result, use of the distribution system will be nonexistent or minimal. In contrast, Xcel's Solar*Rewards Community program, developed under Colorado's Community Solar Gardens rules, accounts for a participant's use of the transmission and distribution systems by backing out certain related charges from a participant's "total aggregate retail rate" bill credit. In this way, a participant is primarily credited for generation-related costs collected through base rates or riders.[20] One of the justifications for taking this approach in Xcel's program was that community solar gardens could be located anywhere within Xcel's service territory, as could participants, and therefore they relied on the transmission and distribution systems.

For non-residential energy consumers, developing an embedded-cost-based credit also generally necessitates consideration of how to treat time-of-use rates and non-kWh-based charges, such as demand charges. With respect to demand charges, Colorado's Community Solar Garden rules addressed this issue by integrating such charges into a participant's "total aggregate retail rate," which is required to include "all billed components." The total aggregate retail rate is used to calculate the participant's bill credit when it is multiplied by the participant's share of the community solar garden. For participants on a demand tariff, the total aggregate retail rate is determined by "dividing the total electric charges to be paid by the customer to the investor owned [utility] for the most recent calendar year (including demand charges) by the customers' total electricity consumption for that year."[21] Other options may work as well. For example, a shared solar facility's contribution to coincident or non-coincident peak loads could be calculated and the value of these contributions could be assigned to the facility. This revenue stream could be used to facilitate financing of the project similar to how other renewable energy systems are financed.

(2) Value-based approach. The value-based approach to bill credits is based on the value of shared renewable energy generation, usually to the participants' utility and its ratepayers. This value includes the value of the new generation source to the utility, and also the value of avoided transmission and distribution costs, such as system infrastructure costs and avoided line losses. Although sometimes more difficult to calculate, some states are considering including other components in renewable energy valuation, such as avoided carbon dioxide emissions and associated costs, and improved security and resiliency in the face of natural disasters or acts of terrorism. As with the embedded-cost-based approach, which components to include and how to value them can be the subject of debate. In the end, the key difference between an embedded-cost approach and a value-based approach is that, under a value-based approach, the bill credit is generally the same for all participants as the credit is no longer based on an individual participant's retail rate which is often based on their customer class or other considerations. For this reason, a value-based bill credit approach can be easier to administer, especially if different customer classes are allowed to participate in a single shared renewable energy facility.

Until recently, Holy Cross Energy (HCE), headquartered in Glenwood Springs, Colorado, was the only utility that had implemented a value-based approach to bill credits for its shared solar program.[22] The CEC partnered with HCE to create this program in 2009. Under this program, participants purchase specific panels in solar arrays being installed within HCE's service territory. In return, the participant receives a bill-credit of $0.11 per kWh for each kWh generated by the panels purchased by the participant. This rate is approximately 30 percent higher than HCE's current retail rates and represents the value HCE believed the arrays bring to HCE's generation portfolio, including the purchase of Renewable Energy Credits (RECs). Automated on-bill credits are achieved through CEC's proprietary RemoteMeter technology. Colorado Springs Utilities recently joined HCE in offering a value-based credit of $0.09 per kWh along with an upfront REC payment per kW of capacity for the value of RECs received over the life of the solar array. Springs Utilities uses the RECs to meet its renewable energy standard. On-bill credits are provided through proprietary metering technologies that integrate with the utility's billing software that were developed separately by developers participating in the program such as SunShare[23] and CEC.

While still relatively rare, value-based approaches to determining bill credits represent an intriguing means of arriving at a bill credit pricing mechanism that moves away from utility embedded costs drawn from retail rates and towards approaches that rely more on the value of the facilities to the utility and its ratepayers. Since HCE's pioneering in this area, CEC has implemented a similar model with San Miguel Power Association[24] and Poudre Valley Rural Electric Association.[25] In addition, the concept of value-based rates for renewable energy is being considered outside of shared renewable energy programs and may have implications for how NEM programs are developed as well. For example, Austin Energy, in partnership with Clean Power Research, has developed a new Value of Solar Tariff (VOST) tariff to replace its NEM tariff, which is based on a value-of-solar rate instead of traditional retail-rate-based NEM.[26] The development of value of solar tariffs needs to be handled carefully to ensure that projects supported by the tariff continue to be able to clearly communicate the investment case to participants and financial institutions involved in financing the project.

(3) Other Valuation Approaches. As the number of shared renewable energy programs grows, utilities and other stakeholders have begun to develop new ways to provide tangible economic benefits to participants on their electricity bills. For example, stakeholders in California are developing a shared renewables offering that is based off of a green tariff framework, but permits participants to lock in a specific rate for renewable energy from shared facilities that meets up to 100 percent of their electricity needs.[27] Accordingly, although the customer may end up paying a modest premium for renewable energy today, locking in the energy rate provides a hedge benefit to a participant over time. In addition under the valuation methodologies being explored, the utility may also levy other program costs on the participant's bill, such as the costs of integration or delivery. The utility may also provide credit for any benefits the new renewable generation may provide, for example by exempting the participant from a renewable energy standard compliance charge, or through a "value of solar credit" or a credit reflecting a particular facility's locational benefits. IREC continues to participate in efforts to address the issue of valuation.

In our original *Model Program Rules*, IREC recommended an embedded cost-based approach, and specifically one rooted in the retail rate in effect for each participant. We stated that valuing the kWh credit at the retail rate in effect for the participant maintains the ability of the project to act as a price hedge against future utility rate increases. In addition, our original *Model Program Rules* took a nuanced approach to compensating utilities for a project's impact on the distribution system by specifying that participants on the same distribution circuit as the shared renewable energy facility would have their kWh credits valued at their full retail rate. Finally, the original *Model Program Rules* also allowed for a stakeholder process to determine an appropriate level of compensation to the utility for delivery of the electricity to participants not on the same feeder as the facility—via a "reasonable charge"—once a number of factors have been taken into account. Colorado's community solar gardens program incorporates a similar "reasonable charge, as determined by the Commission" to cover the utility's costs of delivering electricity to participants' premises, integrating the solar generation with the utility's system, and administering the program.[28]

IREC continues to believe that the embedded-cost based approach may work for some programs. However, we also believe that a value-based approach or other emerging approaches may be solid options for other programs. In this updated *Model Program Rules*, IREC does not recommend one approach over another. Instead, we provide model language for the embedded-cost based and value-based types of bill credit approaches, which are the two most evolved approaches to date, and leave it to individual programs to evaluate their particular situation and to select the approach that works best for them. For the value-based approach, IREC recommends a process by which the appropriate regulatory authority determines the appropriate bill credit value by considering the costs as well as the benefits of shared renewable energy, including but not limited to avoided fuel expenses, avoid line losses, and capacity benefits.[29]

We encourage those designing a shared renewables program to keep in mind the trade-off between in-depth analysis and getting a program off the ground. It may make sense to identify a proxy value for the shared renewable energy generation that can be applied while a longer-term cost-benefit study is undertaken.

For any valuation approach, it is also important to consider who owns and receives the value for any RECs generated. RECs represent the renewable or "green" attributes of one megawatt-hour (MWh) generated from an eligible renewable energy resource, and are typically used by utilities in order to comply with RPS requirements. Some states also have Solar RECs or SRECs, which are specific to energy generated from eligible solar facilities. It is important to specify who owns the RECs from a shared renewable energy facility, in particular because RECs may carry a dollar value that, in some states, could significantly improve a project's bottom line for participants. In IREC's *Model Program Rules*, ownership of the RECs stays with the participants unless otherwise accounted for under separate contracts.

A final consideration related to valuation of shared renewable energy is how to treat net excess generation, in other words, a scenario in which a participant's bill credit from a shared renewable facility exceeds the charges on their electric bill in a given billing period. IREC recommends that credits for net excess generation be rolled over to the participant's next bill.

This is the simplest approach and helps address possible issues concerning jurisdiction of the Federal Energy Regulatory Commission over wholesale power sales.

D. Shared Renewable Energy Facility Size and Location

In our original *Model Program Rules*, IREC specified a renewable system size cap of two MW. This size cap was chosen because a two-MW system maintains economies of scale both in the installed cost of the system and in the participation/marketing costs for a business engaged in developing shared renewable energy systems, and still allows for relatively low-cost interconnection on most utility distribution systems.[30] In addition, smaller facilities are more likely to be able to take advantage of locations closer to load, such as rooftops or brownfields, which can result in both grid and environmental benefits.[31] IREC continues to believe that a two-MW cap can make sense for some programs. In these revised *Model Program Rules*, however, we omit a facility size recommendation because we have observed that in some cases local stakeholders wish to enable larger installations. Larger installations may be subject to greater review under existing state interconnection standards and, depending on their location, may result in fewer grid and environmental benefits than smaller systems located closer to load. Nonetheless, they may be desirable to a particular community for other reasons, for example because participants wish to offset a combined load of larger than two MW, or because a community has a large plot of land that can host a larger system, or because participants are seeking to achieve the lowest cost possible. At this point, IREC believes it is best for stakeholders to have flexibility in developing shared renewable energy programs, with systems sized to meet their particular needs or preferences

Another important consideration with respect to system size is whether to require that a shared renewable energy facility be hosted at a site with on-site load, beyond just parasitic load, or whether these facilities can be stand-alone facilities. In order to allow for maximum flexibility, IREC specifically allows for both circumstances in our *Model Program Rules*.

E. Shared Renewable Energy Facility Ownership and Financing Implications

Shared renewable energy facilities can be owned by participants directly, by the utility or by a third party, such as a renewable energy developer. The type of ownership structure affects what types of local, state and federal funding and incentives are available based on factors such the owner’s credit rating and tax appetite. In order to maximize the availability of funding and to ensure available incentives are used as efficiently as possible, IREC’s *Model Program Rules* support flexibility in facility ownership to allow for direct ownership, third-party ownership, and utility ownership of shared renewable energy systems.

An important aspect of allowing utility ownership is a requirement that all system purchase costs, operation and maintenance costs, necessary investment returns, and other costs related to a utility-owned system must be recovered from participants enrolled in a utility program. This requirement is important to maintaining a level playing field between utility offerings and offerings of other parties by ensuring that all costs incurred by a utility to operate a shared renewable energy system are recovered from program participants the same as occurs with other competitive providers, and not from non-participating ratepayers.

In addition, it is important to recognize that third-party ownership of a renewable energy system can be critical to tapping into funders who are able to fully utilize available federal tax credits.

The efficient utilization of federal tax credits can result in a reduction in the cost of renewable energy by almost 50 percent.[32] Recognizing the important role third-party ownership can play in increasing access to renewable energy, at least 22 states, Washington, D.C. and Puerto Rico explicitly authorize or at least allow for third-party ownership of renewable energy generation facilities.[33] In addition, legislation enacting VNM or shared renewable energy programs in Colorado, Massachusetts and Delaware has similarly explicitly enabled third-party ownership of shared renewable energy systems.[34]

F. Additional Program Considerations

Beyond the five core components discussed above, there are several additional program considerations that inform provisions in our *Model Program Rules*, including the number of program participants, the portability and transferability of a subscription, and participation of low-income energy consumers.

1. Number of Program Participants

Regarding the minimum number of participants, IREC considered conflicting program impacts raised by stakeholders. On one hand, if a program requires too many participants, gathering up the minimum number of participants can make participation by smaller systems difficult. On the other hand, if a program requires just one participant, then the “shared” aspect of a shared renewables program is taken out of the picture, which is a key motivator for some stakeholders. After considering these two concerns, IREC recommends a minimum of two participants in a shared renewable energy system. This requirement will allow duplex owners, small apartment buildings, and small commercial establishments to participate. According to IREC’s research, existing programs have taken varying approaches to this issue. Colorado’s Solar Gardens Act rules stipulate that a shared system must have a minimum of 10 participants. Vermont and California, on the other hand, require a minimum of two participants.

2. Portability and Transferability of Participation

Inevitably participants may need to modify or discontinue their participation in a shared renewable energy facility, for example because their energy consumption has changed or they have moved. It is important for shared renewables programs to consider how to treat such changes. In particular, it is critical to determine whether or not to allow participants to bring their subscriptions in a shared renewable energy facility with them if they move within a program’s territory (“portability”), and whether or not to allow participants to transfer their subscriptions to another energy consumer if they move outside of a program’s territory (“transferability”). In our *Model Program Rules*, IREC recommends as much flexibility as possible in this regard, allowing for both portability and transferability of subscriptions. At the same time, we recognize that portability and transferability pose some level of administrative burden. For example, in some instances it may be administratively much easier to require a participant in a program to relinquish their interest in a shared renewables facility rather than allow them to directly transfer that interest to another qualified customer if they move outside of the utility service territory where the facility is located. Given that only half of Americans stay in a residence for longer than 10 years,[35] and that renters, younger and more urban households are likely to move even more frequently, it is essential to consider and specify how these situations will be treated with respect to program participation, regardless of the ultimate approach taken.

3. Low-Income Energy Consumer Participation

There has been increasing attention paid to including low-income households in shared renewable energy programs, and in renewable energy initiatives in general. For example, Colorado included low-income participation as a priority in their Solar Gardens program.[36] The Colorado Utilities Commission's rules for the program require utilities to reserve at least five percent of their renewable energy purchases from new community solar gardens for eligible low-income participants either through dedicated low-income solar gardens or as low-income set asides within other solar gardens, to the extent there is demand.[37] In implementing the program, the Public Service Company of Colorado (PSCo) requires solar gardens to provide an explicit plan for achieving this five-percent target.[38] It is not clear yet how successful this method of promoting low-income participation in shared renewable energy will be. Renewable energy and low-income advocates are continuing to brainstorm ways to make renewable energy available to low-income communities, which have traditionally been difficult to reach with existing programs. Delta-Montrose Electric Association in Colorado has sought to increase participation among low-income coop members by allowing for a solar lease with as little as $10 upfront. At this price point, the customer is able to lease 2.67 watts of capacity in the DMEA community solar array. While such a framework may raise administrative costs, it represents an innovative way to encourage participation among low-income households in shared solar by lowering the barrier upfront costs can present.

There are a number of challenges to facilitating low-income participation in renewable energy, including both on-site and shared renewables programs. To begin with, the long-term return on investment, which can be the selling point for these programs for higher-income energy consumers, is not a motivator for low-income individuals and families, who typically need a positive cash flow on day one. In other words, these opportunities present poor front-end economics that make them unappealing to low-income energy consumers. In addition, the current economic recession and the constrained lending environment makes loans even more difficult to obtain for low-income energy consumers, who may already be struggling with lack of capital and low credit ratings. Beyond the economics, renewable energy programs have not historically been marketed well to low-income individuals and families, who may benefit from multilingual and multicultural marketing to explain the value of such programs to them.

At the same time, there are a number of factors specific to low-income energy consumers that may motivate them to participate in renewable energy programs, including in particular shared renewables programs. For example, low-income individuals and families that have high energy costs will see a proportionately greater economic benefit to reducing those costs with renewable energy generation. There are also strong fairness and justice reasons for encouraging low-income participation in renewable energy: it should not just be a resource for middle- and high-income communities.

Likewise, from an environmental justice perspective, low-income communities are often the sites for polluting traditional power plants and as a result they face disproportionate health impacts from pollution generated by these facilities. Shared renewable energy offers one potential way to turn this trend into a positive development opportunity for low-income communities, by siting shared renewable energy projects in these communities. These projects can create high quality jobs for low-income families in the rapidly growing clean energy sector. For example, the California Environmental Justice Alliance has called for shared renewable energy programs to include a requirement to site a percentage of shared renewable generation in "disadvantaged communities."

Ultimately, encouraging participation by low-income energy consumers or siting guidelines requires creative thinking about program design. However we are actively considering how to encourage participation in shared solar by low-income energy consumers and we hope to be able to offer more information on this front going forward. To lower the barrier to entry to shared solar programs, we have lowered the minimum subscription size from one kW to one panel in order to lower the initial cost of participation in a shared solar program.

VI. Shared Renewables in States with Restructured Energy Markets

Shared renewable energy may face unique conditions in restructured states, where competitive supply of electricity has been introduced.[39] While retail suppliers in these states are largely unregulated, the design of retail choice markets and the interaction among the relevant players inherently presents certain opportunities and challenges that do not exist in vertically integrated states. Ultimately, retail choice itself opens up possibilities for shared renewable facilities without necessarily requiring additional policy changes, though certain policy changes can help facilitate greater consumer adoption.

Offering energy consumers renewable energy options, including shared renewables, may give some suppliers a marketing advantage in attracting customers. Indeed, some suppliers already offer shared renewables in restructured states. For example, in Massachusetts, retail suppliers that also operate as solar developers are able to facilitate participation among their customers in shared renewable energy facilities and then allocate the resulting bill credits under Massachusetts' VNM rules. The participants pay the retail supplier as they would under their regular tariff.

One challenge to implementing shared renewable energy in restructured states is that it may complicate the billing process. In retail choice states, billing requires an exchange of data between the supplier and the utility and accurate billing requires that both parties have a common understanding of what each piece of customer usage data represents. The potential for miscommunication exists for traditional customer-sited facilities, but is likely be magnified in a more complicated shared renewables arrangement. While the general parameters of the billing process are determined by state law, the responsibility for accomplishing reconciliation rests with utilities and suppliers, and in some states, the reconciliation process may differ among utilities. The provision of bill credits to retail supply customers, including to participants in a shared renewable energy facility, must be harmonized with the billing protocols in a particular state. If the utility handles this crediting and reconciliation, and bears the associated administrative burden, it is more likely that a retail supplier can bear the other costs of administering a shared renewable energy facility. Shared renewable energy becomes much more difficult, if not impossible, if retail suppliers are required to manage bill credit reconciliation because the administrative burden could be substantial, especially if participants include customers of more than one utility. On the other hand, the utility has the advantage of having a sophisticated billing system that is typically already calibrated to deal with the necessary state-mandated reconciliation and crediting processes. Moreover, the utility will likely recover any costs associated with revising or updating its billing system across a much broader base than a retail supplier.

A further complication arises when customers that participate, or wish to participate, in a shared renewables facility are served by different retail suppliers. In these circumstances, utility responsibility for the reconciliation process becomes even more critical, in order to relieve retail suppliers of the administrative burden as well as to alleviate the difficulty of a retail supplier coordinating in this way with a direct competitor. This complication is likely to be an issue only where a shared renewables facility is not being sponsored by a retail supplier, for example, where state law allows some other type of intermediary to offer shared subscriptions to a facility. Presumably, any programs offered by retail suppliers would avoid this possibility by requiring participants to be, or become, full customers of the supplier. Perhaps due to this competitive issue, IREC is not aware of such a structure being used to date.

Another important consideration is that retail suppliers are typically not required by law to offer any particular programs.[40] Therefore, if a retail choice customer wanted to participate in a shared renewable energy facility, but that customer's supplier does not provide such an option, the customer would need to break its contract to find a supplier that would offer it. Because of the time involved in setting up a retail choice contract, and penalties that the customer would incur in breaking it, there is little incentive to switch suppliers for this reason alone. It is possible that a consumer could elect to wait until an existing supply contract expires to pursue participation in a shared renewables program; however, availability could be limited and time sensitive so there is no guarantee that an attractive offer would exist when the customer's existing contract expired. The negative implications of switching could be mitigated in various ways by suppliers (e.g., offering to pay customer contract penalties as a customer recruitment tool) or through a regulatory regime that promotes flexible enrollment procedures.

Finally, it is important to note that the implications of restructured markets for the development of shared renewables programs are likely to be limited because the majority of retail choice load belongs to larger commercial and industrial customers. By contrast, many shared renewable energy programs target smaller commercial and residential customers, who, in many states, usually opt to stay with their utility service rather than rely on competitive suppliers. Moreover, in the wholesale market, these smaller customers' loads are aggregated based on the customer groups' load profiles and auctioned off through MW blocks. Therefore, retail suppliers typically serve and bill these customers under large portfolios and not individually. As a result, these small customers would need to be extracted from the portfolio and managed manually in order to participate in a shared renewable energy program. Such individual management poses a significant burden on retail suppliers and a thus represents a barrier to smaller customers' participation in shared renewables.

As comfort with the concept of shared solar continues to increase, we may see more interest in developing such programs in states with restructured energy markets. Likewise, as consumers become more aware of their energy options, we may see them leverage their market power and drive retail suppliers to offer more renewable energy options, including shared renewables. At this time, we have not modified our model rules to explicitly address shared renewables programs in restructured states, but we believe that the model still may serve as a useful starting point for such programs, as the same considerations are relevant. IREC believes there is substantial potential for shared renewable energy programs in restructured states, and we plan to continue to monitor interest in and development of programs, and to analyze opportunities and barriers particular to these markets.

Model Rules For Shared Renewable Energy Programs

This section contains model rules for shared renewables programs, which are based on IREC's experience monitoring and assisting in the development of shared renewables programs around the United States. They are intended to serve as a guide for renewable energy stakeholders to consider along with their community's particular interests, constraints and priorities.

In addition to a few minor linguistic and stylistic changes, they are updated as follows:

- The term "Shared Renewable Energy Facility" replaces the term "Community Energy Generating Facility."
- The term "Participant" replaces "Subscriber."
- The term "Bill Credit" is defined and replaces the term "Net Metering Credits."
- The two-MW size limit on Shared Renewable Energy Facilities is removed.
- A Subscription minimum of one panel replaces a minimum of one kilowatt.
- In addition to the embedded cost-based valuation approach to bill credit valuation in our original model rules, a value-based approach is also included as a second option. Program developers can choose between the two options depending on their particular circumstances.

I. Definitions

As used within these rules, unless the context otherwise requires:

a. "**Bill Credit**" means the monetary value of the kilowatt-hours (kWh) generated by the Shared Renewable Energy Facility allocated to a Participant to offset that Participant's electricity bill.

b. "**Biomass**" means a power source that is comprised of, but not limited to, combustible residues or gases from forest products manufacturing; waste, byproducts, or products from agricultural and orchard crops; waste or co products from livestock and poultry operations; waste or byproducts from food processing, urban wood waste, municipal liquid waste treatment operations, and landfill gas.[41]

c. **"Shared Renewable Energy Facility"** means Renewable Energy Generation that is located in or near the service territory of an Electricity Provider where the electricity generated by the facility is credited to the Participants to the facility. A Shared Renewable Energy Facility may be located either as a stand-alone facility, called herein a stand-alone Shared Renewable Energy Facility, or behind the meter of a participating Participant, called herein a hosted Shared Renewable Energy Facility. A Shared Renewable Energy Facility must have at least two Participants.

d. **"Electricity Provider"** means the entity providing electricity service to Participants.

e. **"Locational Benefits"** mean the benefits accruing to the Electricity Provider due to the location of the Shared Renewable Energy Facility on the distribution grid. Locational Benefits include such benefits as avoided transmission and distribution system upgrades, reduced transmission and distribution level line losses, and ancillary services.

f. **"Renewable Energy Credit"** means a tradable instrument that includes all renewable and environmental attributes associated with the production of electricity from a Shared Renewable Energy Facility.

g. **"Renewable Energy Generation"** means an electrical energy generation system that uses one or more of the following fuels or energy sources: Biomass, solar energy, geothermal energy, wind energy, ocean energy, hydroelectric power, or hydrogen produced from any of these resources.

h. **"Participant"** means a retail customer of a utility who owns a Subscription and who has identified one or more individual meters or accounts to which the Subscription shall be attributed. Such individual meters or accounts shall be within the same Electricity Provider's distribution service territory as the Shared Renewable Energy Facility.

i. **"Participant Organization"** means an organization whose purpose is to beneficially own and operate a Shared Renewable Energy Facility for the Participants of the Shared Renewable Energy Facility. A Participant Organization may be any for-profit or non-profit entity permitted by [state] law. The Shared Renewable Energy Facility may also be built, owned, and operated by a third party under contract with the Participant Organization.

j. **"Subscription"** means an interest in a Shared Renewable Energy Facility. Each Subscription shall be sized to represent at least one panel in the Shared Renewable Energy Facility's generating capacity; provided, however, that the Subscription is sized to produce no more than 120% of the Participant's average annual electrical consumption. For Participants participating in meter aggregation, 120% of the Participant's aggregate electrical consumption may be based on the individual meters or accounts that the Participant wishes to aggregate pursuant to these rules. In sizing the Subscription, a deduction shall be made for the amount of any existing renewable energy generation at the Participant's premises or any Subscriptions owned by the Participant in other Shared Renewable Energy Facilities.

k. **"Total Aggregate Retail Rate"** means the total retail rate that would be charged to a Participant if all electric rate components of the Participant's electric bill, including any riders or other additional tariffs, except for minimum monthly charges, such as meter reading fees or customer charges, were expressed as per kWh charges.

II. General Provisions

a. Subscriptions in a Shared Renewable Energy Facility may be transferred or assigned to a Participant Organization or to any person or entity that qualifies to be a Participant under these rules.

b. New Participants may be added at the beginning of each billing cycle. The owner of a Shared Renewable Energy Facility or its designated agent shall inform the Electricity Provider of the following information concerning the Participants in the Shared Renewable Energy Facility on no more than a monthly basis: (1) a list of individual Participants by name, address, account number or meter number; (2) the proportional interest of each Participant in the Shared Renewable Energy Facility; and (3) for Participants who participate in meter aggregation, the rank order for the additional meters or accounts to which Bill Credits are to be applied.

c. A Participant may change the individual meters or accounts to which the Shared Renewable Energy Facility's electricity generation shall be attributed for that Participant no more than once quarterly, so long as the individual meters or accounts are eligible to participate.

d. An Electricity Provider may require that Participants participating in a Shared Renewable Energy Facility have their meters read on the same billing cycle.

e. If the full electrical output of a stand-alone Shared Renewable Energy Facility or the excess generation from a hosted Shared Renewable Energy Facility is not fully allocated to Participants, the Electricity Provider shall purchase the unsubscribed energy at a kWh rate that reflects the full value of the generation. Such rate shall include the avoided cost of the energy, including any Locational Benefits of the Shared Renewable Energy Facility.

f. If a Participant ceases to be a customer within the distribution service territory within which the Shared Renewable Energy Facility is located, the Participant must transfer or assign their Subscription back to their Participant Organization or to any person or entity that qualifies to be a Participant under these rules.

g. If the Participant ceases to be a customer of the Electricity Provider or switches Electricity Providers, the Electricity Provider is not required to provide compensation to the Participant for any unused Bill Credits.

h. A Shared Renewable Energy Facility shall be deemed to be located on the premises of each Participant for the purpose of determining eligibility for state and local incentives.

i. Neither the owners of, nor the Participants to, a Shared Renewable Energy Facility shall be considered public utilities subject to regulation by the [responsible agency having regulatory oversight] solely as a result of their interest in the Shared Renewable Energy Facility.

j. Prices paid for Subscriptions in a Shared Renewable Energy Facility shall not be subject to regulation by the [responsible agency having regulatory oversight].

k. A Participant owns the Renewable Energy Credits (RECs) associated with the electricity allocated to the Participant's Subscription, unless such RECs were explicitly contracted for through a transaction independent of any interconnection tariff or program contract. For a Shared Renewable Energy Facility located behind the meter of a participating Participant, the host Participant owns the RECs associated with the electricity consumed on-site, unless the RECs were explicitly contracted for through a separate transaction independent of any Shared Renewable Energy or interconnection tariff or contract.

l. The dispute resolution procedures available to parties in the Electricity Provider's interconnection tariff shall be available for the purposes of resolving disputes between an Electricity Provider and Participants or their designated representative for disputes involving the Electricity Provider's allocation of Bill

Credits to the Participant's electricity bill consistent with the allocations provided pursuant to Rule II.b. The Electricity Provider shall not be responsible for resolving disputes related to the agreements between a Participant, the owner of a Shared Renewable Energy Facility, and/or a Participant Organization or any other party. This provision shall in no way limit any other rights the Participant may have related to an Electricity Provider's provision of electric service or other matters as provided by, but not limited to, tariff, decision of [responsible regulatory body or agency], or statute.

III. Bill Credit Provisions

a. An Electricity Provider shall not limit the cumulative, aggregate generating capacity of Shared Renewable Energy Facilities.

b. For a Shared Renewable Energy Facility, the total amount of electricity expressed in kWh available for allocation to Participants, and the total amount of RECs generated by the Shared Renewable Energy Facility and allocated to Participants, shall be determined by a production meter paid for by the owner(s) of the Shared Renewable Energy Facility. It shall be the Electricity Provider's responsibility to read the production meter.

c. For a hosted Shared Renewable Energy Facility, the determination of the quantity of Bill Credits available to Participants of that facility, including the host Participant, shall be based on any energy production of the Shared Renewable Energy Facility that exceeds the host Participant's instantaneous on-site consumption during the applicable billing period and the Participants' Subscriptions in that Shared Renewable Energy Facility.

d. For a stand-alone Shared Renewable Energy Facility, the determination of the quantity of Bill Credits available to each Participant of that Shared Renewable Energy Facility shall be based on the total exported generation of the Shared Renewable Energy Facility and each Participant's Subscription in that Shared Renewable Energy Facility.

e. The Electricity Provider shall carry over any excess Bill Credits earned by a Participant and not used in the current billing period to offset the Participant's consumption in subsequent billing periods until all credits are used or electric service is terminated. Any excess Bill Credits shall not reduce any fixed monthly customer charges imposed by the Electricity Provider.

IV. Embedded Cost-Based Approach to Bill Credit Valuation

a. For Participants that host a Shared Renewable Energy Facility or where participating Participants are located on the same distribution feeder as the Shared Renewable Energy Facility, the value of the Bill Credits for the host Participant and those Participants on the same distribution feeder shall be calculated by multiplying the Participant's share of the kWh electricity production from the Shared Renewable Energy Facility by the retail rate for the Participant. For Participants on tariffs that contain demand charges, the retail rate for the Participant shall be calculated as the Total Aggregate Retail Rate for the Participant.

b. For all other Participants in a Shared Renewable Energy Facility, value of the Bill Credits allocated to each Participant shall be calculated by multiplying the Participant's share of the electricity production from the Shared Renewable Energy Facility by the retail rate as charged to the Participant, adjusted for cost and benefits, including locational benefits, [42] provided by the Shared Renewable Energy Facility. The [responsible agency having regulatory oversight] shall ensure that any costs included in this cost-benefit analysis are not already recovered by the Electricity Provider from the Participant through other charges.

V. Value-Based Approach to Bill Credit Valuation

a. For all Shared Renewable Energy Facilities, the value of Bill Credits allocated to each Participant shall be calculated by multiplying the Participant's share of the kWh electricity production from the Shared Renewable Energy Facility by the value of the electricity produced as determined by the [responsible regulatory body or agency], taking into account both the costs and benefits of the Shared Renewable Energy Facility. The benefits of the Shared Renewable Energy Facility shall include but not be limited to the avoided cost of generation, capacity benefits, avoided line losses, avoided transmission and distribution investments, environmental benefits or avoided environmental compliance costs, and any other Locational Benefits.[43]

Endnotes

1 Paul Denholm & Robert Margolis, Nat'l Renewable Energy Lab., *Supply Curves for Rooftop Solar PV-Generated Electricity for the United States* 4 (Nov. 2008), *available at* http://www.nrel.gov/docs/fy09osti/44073.pdf.

2 SEIA Solar Survey 2012 (http://www.seia.org/research-resources/america-votes-solar-national-solar-survey-2012), Gallup poll March 2013 (http://www.usnews.com/news/articles/2013/04/01/poll-americans-overwhelmingly-support-alternative-energy).

3 *See* http://quickfacts.census.gov/qfd/states/00000.html (114,761,359 U.S. households in 2011).

4 Union of Concerned Scientists, http://www.ucsusa.org/clean_energy/coalvswind/c01.html.

5 For more detail on U.S. community wind efforts, see http://www.windustry.org.

6 *See CPUC California Solar Initiative 2009 Impact Evaluation, Final Report* § 10, (June 2010), *available at* http://www.cpuc.ca.gov/PUC/energy/Solar/eval09.htm.

7 Mosaic, https://joinmosaic.com.

8 RE-volv, http://re-volv.org.

9 For a more in depth explanation of NEM, see DSIRE, Solar Policy Guide: Net Metering, www.dsireusa.org/solar/solarpolicyguide/?id=17, and IREC, *Net Metering Model Rules* (2009), *available at* http://irecusa.org/wp-content/uploads/2010/08/IREC_NM_Model_October_2009-1-22.pdf.

10 DSIRE, NEM Summary Map (Feb. 2013), http://www.dsireusa.org/documents/summarymaps/net_metering_map.pdf.

11 Larry Sherwood, IREC, *U.S. Solar Market Trends 2011*, at 7, *available at* http://www.irecusa.org/wp-content/uploads/IRECSolarMarketTrends-2012-Web-8-28-12.pdf (showing that 93 percent of systems were net-metered as of 2011).

12 Keyes & Fox LLP, on behalf of NAURC, *Exploring Aggregated Net Metering in Arizona*, Summary of Policies in Other States (Part 3) (Jan. 2011), *available at* http://www.naruc.org/grants/Documents/SERCAT_Arizona_2010.pdf.

13 *See* NREL, *The Solarize Guidebook: A Community Guide to Collective Purchasing of Residential PV Systems* (May 2012), *available at* http://www.nrel.gov/docs/fy12osti/54738.pdf.

14 For more information on the CEC, see www.easycleanenergy.com.

15 Vermont's group billing rules also apply to a single consumer with multiple electric meters. For more detail on the Vermont program, see the Vermont Net Metering web site at http://psb.vermont.gov/utilityindustries/electric/backgroundinfo/netmetering and the DSIRE Vermont Net Metering web site at www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=VT02R.

16 U.S. Dept. of Energy, *A Guide to Community Shared Solar: Utility, Private, and Non-Profit Project Development* (Nov. 2010), *available at* www.nrel.gov/docs/fy12osti/54570.pdf.

17 *See e.g.,* CPUC, D.11-07-031, *California Solar Initiative Phase One Modifications* 5-22 (July 20, 2011), *available at*

http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/139683.PDF (California); CPUC, D.08-10-036, *Decision Establishing Multifamily Affordable Solar Housing Program within the California Solar Initiative* 31-40 (Oct. 20, 2008), *available at* http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/92455.PDF (California); C.R.S. § 40-2-127(5)(b)(II) (Colorado); 26 Del. Code § 1014(e) (Delaware).

In a few cases, like Massachusetts "neighborhood net metering" program, the credit is valued based on the retail rate in effect *where the project is located*. This may be easier to administer in some ways because the program administrator needs to only consider one retail rate rather than (potentially) several different rates of many participants, which could include customers in the residential, commercial and industrial sectors. *See* 220 CMR § 18.04(3); *see also* DSIRE, Mass. Net Metering, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MA01R&re=0&ee=0.

[18] *See* 26 Del. Code § 1014(e)(2); 26 Del. Admin. Code § 3001-8.4.

[19] *See* CPUC, D.11-07-031 & D.08-10-036, *supra* note 17.

[20] *See* CO PUC, Docket 11A-418E, Recommended Decision of Administrative Law Judge Paul C. Gomez Approving Application with Modifications, at 46-54 (March 8, 2012); Xcel Energy, *2012 Renewable Energy Standard Compliance Plan*, Vol. 1, § 9 (May 13, 2011); CO PUC, Docket 11A-418E, Direct Testimony and Exhibits of Scott B. Brockett, at 4-13 (May 13, 2011).

[21] 4 C.C.R. 723-3 § 3665(c)(1)(A)-(B) (referring to C.R.S. § 40-2-127(5)(b)(II)).

[22] *See* CEC HCE FAQ, http://www.easycleanenergy.com/faq.aspx.

[23] *See* http://mysunshare.com for more information on SunShare LLC.

[24] *See* San Miguel Power Association Community Solar, http://www.smpasolar.com/learn.aspx.

[25] *See* Poudre Valley Community Solar, http://www.pvreasolar.com/learn.aspx.

[26] *See* Austin Energy, Residential Solar Rate, http://www.austinenergy.com/energy%20efficiency/Programs/Rebates/Solar%20Rebates/proposedValueSolarRate.pdf; Karl Rábago, Leslie Libby & Tim Harvey, Austin Energy, and Benjamin Norris & Thomas E. Hoff, Clean Power Research, *Designing Austin Energy's Solar Tariff Using a Distributed Value PV Calculator*, World Renewable Energy Forum 2012, *available at* http://www.cleanpower.com/wp-content/uploads/090_DesigningAustinEnergysSolarTariff.pdf.

[27] *See* PG&E A.12-04-020 In the Matter of the Application of Pacific Gas and Electric Company to Establish a Green Option Tariff (U39E), and SDG&E A.12-01-008 Application of San Diego Gas & Electric Company (U902E) For Authority To Implement Optional Pilot Program To Increase Customer Access To Solar Generated Electricity. Dockets are available at http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:1:596995556267001:::::

[28] *See* C.R.S. § 40-2-127(5)(b)(II). While IREC supported the incorporation of such a "reasonable charge," we participated in the Colorado rulemaking to calculate the charge and we ultimately did not support the outcome. IREC submitted an alternative proposal in the docket, 11A-418E,

https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=11A-418E.

29 Additional discussion of design of bill credits can be found in R. Thomas Beach & Patrick G. McGuire, Community Solar California, *The Design of Bill Credits for Community Solar Facilities in* California (January 2012); *see also* Joseph Wiedman & Jason Keyes, IREC, SolarABCs, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering* (Jan. 2012), *available at* http://www.solarabcs.org/about/publications/reports/rateimpact/pdfs/rateimpact_full.pdf.

30 Most state interconnection procedures specify 2 MW as the cutoff for Level 2 "Fast Track" interconnection procedures. Systems interconnecting at the distribution level that are able to take advantage of Level 2 interconnection procedures will generally proceed in a relatively quick and inexpensive fashion through the utility interconnection process.

31 *See* Joseph F. Wiedman & Erica M. Schroeder, Keyes, Fox & Wiedman, Tom Beach, Crossborder Energy, IREC, *12,000 MW of Distributed Generation by 2020: Benefits, Costs and Policy Implications* (July 2012), *available at* http://www.irecusa.org/wp-content/uploads/Final-12-GW-report-7.31.12.pdf.

32 This estimate is based on the federal 30-percent investment tax credit (ITC), which is scheduled to decline to 10 percent in 2016 if no action is taken before that. For more detail on the ITC, see http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F.

33 *See* DSIRE Third-Party Ownership Map, http://www.dsireusa.org/documents/summarymaps/3rd_Party_PPA_map.pdf

34 *See* C.R.S. § 40-2-127(2)(b)(I)(A) (Colorado); 26 Del. Code § 1014(d)-(e) (Delaware); Mass.Gen.Laws, ch. 164, § 1G et seq. (Massachusetts).

35 See Paul Emrath, Ph.D., National Association of Home Builders, *How Long Buyers Remain In Their Homes,* (Feb. 2009), available at http://www.nahb.org/generic.aspx?sectionID=734&genericContentID=110770&channelID=311

36 C.R.S. § 40-2-127(1)(b)(II), (5)(a)(IV)(B), (5)(e).

37 4 C.C.R. 723-3 § 3665(d)(V).

38 2012 PSCo RES Plan, Vol. 1 at § 5, 25.

39 Fully restructured states include Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas and Washington D.C

40 *See* Justin Barnes & Laurel Varnado, N.C. Solar Center, IREC, *The Intersection of Retail Choice and Net Metering: An Overview of Policy Practice and Issues* (Dec. 2010), *available at* http://irecusa.org/wp-content/uploads/2010/12/FINAL-Intersection-of-Retail-Choice-and-Net-Metering-Report.docx.pdf (includes a table of state net metering policies, as they apply to retail choice states).

41 The definition of Biomass may need to be adjusted to reflect state renewable portfolio standard definitions.

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[42] Additional discussion of design of bill credits can be found in R. Thomas Beach & Patrick G. McGuire, Community Solar California, *The Design of Bill Credits for Community Solar Facilities in* California (January 2012); *see also* Joseph Wiedman & Jason Keyes, IREC, SolarABCs, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering* (Jan. 2012), *available at* http://www.solarabcs.org/about/publications/reports/rateimpact/pdfs/rateimpact_full.pdf.

[43] For a more thorough discussion of the benefits of distributed generation to consider for the purposes of valuation, see Keyes, Fox & Wiedman, LLP, *Unlocking Distributed Generation Value: A PURPA-Based Approach to State Policy Design*, available at http://www.irecusa.org/wp-content/uploads/2013/05/Unlocking-DG-Value.pdf.