PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company	**} } } Docket No. 2017-2-E } }**

Direct Testimony of
Thomas Vitolo, PhD

On Behalf of
South Carolina Coastal Conservation League and Southern Alliance for Clean Energy

On the Topics of
Avoided Cost Calculations and the Costs and Benefits of Solar Net Energy Metering

March 22, 2017

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address for the record.

A. My name is Tommy Vitolo, and I am a Senior Associate with Synapse Energy Economics (Synapse) at 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and natural gas industry regulation, planning, and analysis. Our work covers a range of issues, including integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, the U.S. Department of Energy, the U.S. Department of Justice, the Federal Trade Commission and the National Association of Regulatory Utility Commissioners. Synapse has over 25 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have a PhD in systems engineering from Boston University; a master's in financial and industrial mathematics from Dublin City University, Ireland; bachelor's degrees in applied mathematics, computer science, and economics from North Carolina State University; and more than eight years of professional experience as a consultant, researcher, and analyst.

Since joining Synapse in 2011, I have focused on utility resource planning, variable resource integration, avoided costs, and other issues that typically involve statistical analysis, computer simulation modeling, and stochastic processes. I have filed testimony or reviewed utility filings in 24 states and two territories, primarily by evaluating numerical analysis, modeling, and decision strategies of resource plans and certificates of public convenience and necessity applications.

On topics related to the costs and benefits of distributed generation—including net metering issues, avoided costs, bill impacts, and appropriate rate design—I have developed or submitted testimony in Vermont, South Carolina, California, Utah, Wisconsin, and Maryland. Additionally, I have performed cost and benefits analyses of distributed generation for systems located in Maine, Massachusetts, Mississippi, New York, North Carolina, and Washington DC.

Prior to joining Synapse, I worked as a research assistant at MIT Lincoln Laboratory. My CV is attached as Exhibit TJV-1.

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

A. I am testifying on behalf of the South Carolina Coastal Conservation League (CCL) and Southern Alliance for Clean Energy (SACE).

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

A. Yes, I have testified in several dockets related to the costs and benefits of solar generation. I testified in Commission Docket No. 2014-246-E, In re: the Petition of the Office of Regulatory Staff to Establish Generic Proceeding Pursuant to the Distributed Energy Resource Program Act, Act No. 236 of 2014, Ratification No. 241, Senate Bill No. 1189, focusing on the methodology for calculating the costs and benefits of solar net energy metering. Last year I testified in Docket Nos. 2016-1-E, 2016-2-E, and 2016-3-E, the annual review of base rates for fuel costs of Duke Energy Progress, South Carolina Electric & Gas, and Duke Energy Carolinas, respectively.

Q. What is the purpose of your direct testimony in this proceeding?

A. The primary purpose of my testimony is both to provide input recommendations for improving on South Carolina Electric & Gas Company's ("SCE&G" or "the Company") avoided cost calculations offered to qualifying facilities ("QFs") under the Public Utilities Regulatory Policies Act of 1978 ("PURPA") and to provide input on the 2017 application of the Net Energy Metering ("NEM") Methodology for valuing the costs and benefits of Distributed Energy Resources ("DERs"). Additionally, my testimony addresses SCE&G's proposed PR-1 and PR-2 tariffs.

Q. How is the remainder of your testimony organized?

A. My testimony is organized as follows:

1. Introduction and Qualifications
2. Summary of Conclusions and Recommendations
3. SCE&G's Avoided Cost Calculations
4. Net Energy Metering Methodology: 2017 Application

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

- TJV-1 (Resume of Thomas John Vitolo),
- TJV-2 (Analysis of Solar Capacity Equivalent Values for the South Carolina Electric and Gas System), and
- TJV-3 (Avoided Cost of Transmission and Distribution Detail).

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. As discussed and supported in greater detail below, my primary conclusions are summarized as follows:

1. SCE&G made several methodological and technical errors in implementing the difference in revenue requirements method to determine avoided costs for qualifying facilities under PURPA, particularly with regards to avoided

generation capacity costs. These errors result in artificially low avoided cost payment rates in tariffs PR-1 and PR-2.

2. These errors carry over to the NEM Methodology and application, resulting in erroneous NEM component valuations. The Company also failed to recognize and value avoided costs associated with additional NEM Methodology components that are appropriate for consideration in this annual update. As an example, avoided transmission and distribution costs are capable of being reasonably quantified at this time and therefore should be included.

Q. Please summarize your primary recommendations.

A. I recommend that the Commission require the Company to correct its methodological and technical errors associated with its QF avoided cost determination, so that QFs are compensated appropriately under the requirement of the Public Utility Regulatory Policies Act of 1978 and subsequent requirements. The Company should file revised PR-1 and PR-2 tariffs correcting the errors prior to Commission approval of the new tariffs.

Similarly, I recommend that the Commission require the Company to apply those corrections to the DER avoided cost determinations so that DER resources considered within the NEM framework are valued correctly. The Company should revise the NEM tariff with the updated NEM valuation.

I recommend that the Commission require the Company to calculate its avoided transmission and distribution costs within the NEM methodology framework and update its avoided line loss values. The Company should calculate and add these values to its NEM valuation. The Company should file a revised NEM tariff with the updated NEM valuation prior to Commission approval of the new tariff.

Finally, the Company should evaluate and include avoided environmental costs in future NEM valuation updates.

3. SCE&G'S AVOIDED COST CALCULATIONS

Q. You conclude that SCE&G has made errors in its Avoided Cost Calculations. Please explain.

A. My review and testimony of the errors in SCE&G's avoided cost calculations primarily focus on the Company's avoided capacity calculations, given the significant decline in avoided capacity rates proposed by SCE&G in December 2016 and in this proceeding, as compared to rates approved in May 2016. In calculating avoided capacity payments, SCE&G made several errors which inappropriately reduce the proposed avoided capacity payments. These are described in greater detail below.

I also provide two recommendations related to SCE&G's avoided energy calculations, and one recommendation related to the timing of avoided cost tariff updates.

Avoided Energy

Q. Before turning to the avoided capacity calculations, what are your recommendations regarding the Company's avoided energy calculations?

A. In calculating avoided energy costs, SCE&G should conduct an additional resource model run using a 100 MW photovoltaic ("PV") profile generator in addition to its 100 MW model run of constant demand reduction (its "change case"). It is reasonable to model the avoided energy cost associated with QFs using a solar profile, because the bulk of new QFs in South Carolina are likely to be solar photovoltaic resources given the declining costs of solar power. PURPA allows for resource-specific calculations, and using a PV profile generator would more accurately reflect the utilities costs avoided by solar QFs being added to the system. This is also relevant for the NEM Methodology updates discussed later in my testimony. The clear majority of NEMs are DG PV; modeling their avoided energy with a solar profile rather than a generator that operates throughout the night is more sensible.

Q. Do you have any another input or recommendations regarding avoided energy calculations?

A. Yes. I also recommend that SCE&G further explain its peak season and hour designations. It is not clear from the Company's testimony how these were calculated or selected, and they do not match other peak hour designations, such as those in SCE&G's Residential Service, General Service, Residential Service Time-of-Use, or General Service Time-of-Use tariffs.[1,2,3,4]

Q. Did SCE&G differentiate between peak and off-peak, both hourly and seasonally, when calculating avoided energy costs?

A. It did. Specifically, as Witness Lynch describes on Page 5, Line 17, the Company defined the peak season as June, July, and August, with the off-peak season being the other nine months. It further defined the peak hours for the peak season to be 10 a.m. until 10 p.m., with peak hours on the off-peak season to be both 6 a.m. to 10 a.m. and 5 p.m. to 10 p.m., except for the months of May and October, which use the on-peak season's peak hours instead.

	June, July, Aug	Jan, Feb, March, Apr, Sept, Nov, Dec	May, Oct
Peak Season	Peak Hours 10am–10pm	—	—
Off-Peak Season	—	Peak Hours 6–10am, 5–10pm	Peak Hours 10am–10pm

Q. Did SCE&G choose the best months and hours for peak and off-peak?

A. I don't know. SCE&G did not provide an explanation for its choice of months and hours in its testimony this year or last. A paradoxical outcome that the Company did not highlight is that under SCE&G's definition of peak and off-peak, avoiding energy consumption during a peak season often results in less savings

[1] South Carolina Electric & Gas Company, "Rate 8 Residential Service."

[2] South Carolina Electric & Gas Company, "Rate 9 General Service."

[3] South Carolina Electric & Gas Company, "Rate 8 Residential Service Time of Use."

[4] South Carolina Electric & Gas Company, "Rate 8 General Service Time-of-Use."

than the corresponding off-peak season. For example, short-run peak hours costs during peak season are less than short-run peak hours costs during off-peak season;[5]

- short-run off-peak hours costs during peak season are less than short-run off-peak hours costs during off-peak season;[6]
- long-run peak hour costs during peak season are less than off-peak hour costs during off-peak season from 2017–2021;[7]
- long-run off-peak hours costs during peak season are less than long-run off-peak hours costs during off-peak season from 2017–2021;[8] and
- long-run off-peak hours costs during peak season are less than long-run off-peak hours costs during off-peak season from 2022–2026.[9]

Q. What is your recommendation regarding peak hours?

A. I recommend that the Company provide a more detailed explanation of its peak hour determination.

Avoided Generation Capacity Calculations

Q. Turning to avoided generation capacity calculations, what is your assessment of SCE&G's application of the Difference in Revenue Requirement method to calculate its avoided generation capacity costs?

A. Based on the direct testimony of SCE&G Witness Lynch and the SCE&G 2017 IRP,[10] the Company appears to have made several errors, including:

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[5] Direct Testimony of Joseph M. Lynch, Docket No. 2017-2-E, Page 7, Table 1.

[6] Ibid. Page 7, Table 1.

[7] Ibid. Page 7, Table 2.

[8] Ibid. Page 7, Table 2.

[9] Ibid. Page 7, Table 2.

[10] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2017-9-E.

1. Failing to include the 2019 generation capacity shortfall in its avoided generation cost calculations;
2. Failing to include opportunity cost in its revenue requirements calculations;
3. Using an erroneous method to determine the appropriate generation capacity payment split between summer and winter seasons; and
4. Failing to include a performance adjustment factor.

Q. Please describe the Company's error associated with determining years of future capacity shortfall.

A. In discussing changes between the 2016 and 2017 avoided cost analyses, Company Witness Lynch explains that "there were one-year purchases that could be avoided in 2018 and 2019, [but] in the 2017 IRP, however, the capacity purchases for 2018 and 2019 have already been made and therefore are no longer avoidable (Lynch, Page 11, Line 15). Despite the 2019 one-year purchase, SCE&G's 2017 IRP still demonstrates a need for generation capacity in 2019: the "SCE&G Forecast of Summer Loads and Resources–2017 IRP" table shows that the reserve margin in Year 2019 is only 13.6 percent, less than the summer planning reserve margin of 14.0 percent.[11,12] While the one-year purchase SCE&G has already made for 2019 is unavoidable, SCE&G's own metrics indicate that it will be required to procure additional generation capacity in 2019. Thus, the avoidable capacity calculations as determined by SCE&G's avoided capacity methodology must include avoidable generation capacity for Year 2019.

Q. In addition to 2019 and 2031, are there any other years for which SCE&G should include generation capacity revenue in determining its avoided costs?

A. Yes. SCE&G should include avoided generation capacity in all years of its analysis. I base this conclusion on two distinct issues: ambiguous retirement schedule and opportunity cost.

[11] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2017-9-E, Page 38, Row 15.

[12] Ibid. Page 37, line 18.

Q. Please explain SCE&G's ambiguous retirement schedule, and its relevance to avoided generation capacity cost.

A. SCE&G's avoided generation capacity methodology requires calculating the forecasted capacity need in future years, determining which resource will be built to meet that capacity need, and then netting out the cost of those additional generation capacity resources in the years of need. A critical input for this methodology is the precise year of retirement for every generation resource owned by SCE&G. This stringent requirement, however, cannot be met.

Consider the 250 MW McMeekin generation station located in Irmo. Without McMeekin, SCE&G falls below its reserve margin in 2027 rather than 2031.[13] In its 2012 IRP, the Company determined the least-cost option was "the retirement of the [McMeekin] coal-fired units [1 and 2] with the commercial operation of V.C. Summer Unit #3 in 2018."[14] The 2013 IRP reiterated that the McMeekin units were to "be retired when the addition of new nuclear capacity was available as a replacement."[15] The 2014 IRP was similar, this time again calling for the retirement of a variety of coal units including McMeekin, but stating that "McMeekin 1&2 is required to maintain system reliability until the new nuclear capacity is available,"[16] a position maintained in the 2015 IRP.[17] The 2016 IRP shows that not retiring McMeekin 1&2 will be more beneficial to ratepayers than retiring McMeekin. The same IRP states that even though mothballing McMeekin 1&2 will save more money still, SCE&G currently plans to continue to operate

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[13] Ibid. Page 38. When 250 MW of generation capacity is subtracted from line 13, the margin falls to 732 MW, resulting in a 12.9 percent reserve margin.

[14] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2012-9-E, page 29.

[15] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2013-9-E, page 29.

[16] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2014-9-E, page 34.

[17] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2015-9-E, page 36.

the McMeekin units indefinitely.[18] The 2017 IRP amplifies the ambiguity of McMeekin's future, stating that "it might be in SCE&G customers' best interests to keep the units operating for a while," with no indication of the length of time "a while" entails.[19] Five of the past six IRPs SCE&G has published have presented a different understanding of the future of McMeekin Station. This underscores not only the challenge of resource planning but also the unreliable nature of using the resource planning results for calculating avoided generation capacity.

McMeekin is not the only unit in question. The future of Urquhart 3 (95 MW) is as ambiguous as McMeekin 1&2 over the past six IRPs. Should Urquhart 3 retire as well as the McMeekin 1&2 units, SCE&G's generation capacity requirement is pressed forward another two years, to 2025. SCE&G takes great pains to make it clear that "its plans to retire the units in its 2012 Integrated Resource Plan … were subject to change if circumstances changed."[20] This further strengthens the point: that retirement plans in SCE&G's IRPs are not sufficiently reliable to use in determining the avoidance of future generation capacity purchases.

Q. Please explain the relevance of opportunity costs in SCE&G's revenue requirements calculation.

A. An opportunity cost is the loss of potential gain from other alternatives when one alternative is chosen. As discussed earlier, in years when SCE&G lacks adequate generation capacity to meet its reserve margin, QFs allow the Company to avoid procuring generation capacity. In years when SCE&G has excess capacity, on the other hand, SCE&G is expected to offer its excess capacity into the market, in order to generate additional revenue from otherwise unused or underutilized assets. The opportunity cost associated with excess generation capacity is the potential additional revenue not realized.

[18] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2016-9-E, page 35.

[19] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2017-9-E, pages 35 and 36.

[20] Ibid. Page 35 footnote.

SCE&G is expected to utilize its assets to provide safe, reliable power at just and reasonable rates. Doing so requires making best use of its resources on behalf of its ratepayers, including engaging in off-system sales of energy and capacity whenever prudent. The generation capacity provided by generators under contract is included when SCE&G considers its generation capacity position relative to the reserve margin. However, SCE&G does not appear to include this additional revenue when calculating the difference of revenue requirements between the base case and the with-QF case. The simplest way to correct this error is to include a market capacity value for all years wherein QF capacity would provide SCE&G with more generation capacity than their reserve margin requires.

Q. Absent a wholesale generation capacity market, how can SCE&G determine the value of selling contracts for generation capacity?

A. I believe that SCE&G is already making these estimations. For instance, SCE&G includes three separate years of firm capacity purchases in its 2017 IRP.[21,22] That SCE&G includes firm annual capacity purchases in its IRP is a clear indication that SCE&G already has an ability to predict the regional market price for generation capacity. Not only is SCE&G able to forecast the value of selling surplus capacity contracts, it already has market prices for Years 2017–2019 because it has been participating in the regional generation capacity marketplace as a purchaser for those delivery years. Table 1 details the annual generation capacity avoided cost ($/kW-yr) proposed by SCE&G, the annual generation capacity price SCE&G considered appropriate for its own capacity purchases, and the PJM combustion turbine cost of new entry for 2018/2019. The PJM value is included because it represents the total net revenue requirements a utility must recover, based on a bottom-up estimate of technology costs.

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[21] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2017-9-E, page 37.

[22] Ibid. Page 38, Row 12.

Table 1

SCE&G Proposed[23]	SCE&G Purchase 2016[24]	SCE&G Purchase 2017[25]	SCE&G Purchase 2018[26]	SCE&G Purchase 2019[27]	PJM CT CONE 2018/19[28]
$6.35	$61.10	$68.62	$70.92	$72.38	$102.32

Table 1, above, is very similar to the table provided in my testimony in the 2016 SCE&G fuel cost proceeding, 2016-2-E, and is still relevant. It shows that SCE&G's proposed generation capacity payments to QFs appear well below the actual generation capacity revenue the QF's inclusion could bring to the Company.

Q. What generation capacity value should SCE&G use?

A. SCE&G participates in a regional generation capacity bilateral marketplace rather than a wholesale capacity marketplace provided by an RTO such as PJM. Thus, values reflecting SCE&G's recent experience in the local generation capacity bilateral marketplace are instructive. SCE&G procured a bilateral contract for generation capacity for four consecutive years, with an annual increase exceeding the rate of inflation. Absent additional data specific to SCE&G's generation capacity market, I recommend that SCE&G use their capacity purchase price for the years 2017, 2018, and 2019. For the year 2020 and beyond, I recommend applying a forecasted inflation rate to the 2019 generation capacity value. When

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[23] Direct testimony of Joseph M. Lynch, Page 11, Line 4.

[24] Data response data response SACE#2c.xlsx, Capacity Values tab, Cell D4.

[25] Ibid. Cell E4.

[26] Ibid. Cell F4.

[27] Ibid. Cell G4.

[28] PJM. 2017. "2020/2021 RPM Base Residual Auction Planning Period Parameters." Table 3, 2019/2020 BRA Net CONE ICAP Terms, RTO. Converted from $/MW-Year to $/kW-yr.

preparing the 2018 IRP and calculating the avoided cost for next year's docket, SCE&G should gather generation capacity marketplace data to make a 15-year forecast of the value of generation capacity within the region.

Q. Please describe how the Company splits the generation capacity payment between summertime and wintertime peak hours.

A. The Company assigns 80 percent of the annual avoided capacity cost to the summertime hours and 20 percent to the wintertime hours, based on analysis from last year's docket, 2016-2-E.[29]

Q. Do you believe the Company is using the appropriate generation capacity payment split between summer and winter?

A. I do not. I believe that the Company is not assigning enough weight to summertime capacity. I have three specific reasons for reaching this conclusion. First, I believe that the analysis presented by Company Witness Lynch in last year's docket is flawed. Second, SCE&G's 2017 IRP shows that the summer peak is larger than the winter peak and is forecasted to grow more quickly than the winter peak. Finally, the hours within the top 1 percent of SCE&G load within each calendar year (1998–2015) occur overwhelmingly in the summer.

Q. Please elaborate on the flaw in Witness Lynch's method for determining the appropriate generation capacity payment between winter and summer.

A. When ensuring adequate generation capacity, it is important to consider resource adequacy separately for summer months and for winter months because many generators have slightly different summertime and wintertime generation capacities. In last year's docket, Company Witness Lynch presented analysis demonstrating the number of hours in which the load was within 95 percent of its seasonal peak.[30] The analysis tabulates the frequency with which winter load is within 95 percent of <u>winter</u> peak, not <u>annual</u> peak. SCE&G's analysis therefore

[29] Direct Testimony of Joseph M. Lynch, Docket No. 2016-2-E, Page 18, Line 2.

[30] Direct Testimony of Joseph M. Lynch, Docket No. 2016-2-E, Page 17, Line 10.

includes wintertime hours that have relatively high winter load, but not load high enough to be considered high annual load. SCE&G determined that 20 percent of all the hours close to its seasonal peak were wintertime hours, with the remaining 80 percent in the summertime.

From a planning perspective, the frequency with which hourly load nears the seasonal peak is irrelevant. The metric that matters is the frequency with which hourly load nears that year's forecasted annual peak, because it is load during the hours of the annual peak that determine generation capacity requirements, not the hours of seasonal peak. The appropriate metric, therefore, is the percent of hours in the winter that are close to the annual peak, not the winter peak. Because the historical winter peak is less than the historical summer peak in most years,[31] the SCE&G methodology overcounts wintertime hours, and therefore undercounts summertime hours.

Q. How does the 2017 SCE&G IRP support the claim that SCE&G is overweighing wintertime generation capacity?

A. The SCE&G methodology relied on historical data from 1998 until 2015. SCE&G's 2017 IRP demonstrates that the summertime peak exceeded the wintertime peak in both 2015 and 2016 by about 300 MW.[32] This gap exceeded the expectation of the 2015 IRP for both 2015 and 2016, as well as the 2016 IRP's expectation for 2016.[33] The 2017 IRP also forecasts that the summertime peak will grow faster than the wintertime peak—with the gap increasing from 169 MW this year to 599 MW 15 years from now.[34] The SCE&G analysis relied on

[31] Summer peak exceeded winter peak in 14 of the 18 years of SCE&G's study. See: South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2017-9-E, page 4.

[32] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2017-9-E, page 37.

[33] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2015-9-E, page 2; South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2016-9-E, page 2

[34] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2017-9-E, page 37.

historical load, and therefore doesn't account for the expected increase in the gap between the higher peak in the summertime and the lesser peak in the winter. In other words, not only did SCE&G undercount the frequency with which the historical peaks occurred in summer, it did not consider that it expects peak summertime hours in the future to be even larger than future wintertime peak hours.

Q. Are there data or analyses that demonstrate that SCE&G's peak load hours occur overwhelmingly in the summertime?

A. There are. A comprehensive analysis spanning 1998–2015 of the 1 percent of hours with the highest load on the SCE&G system demonstrate that 97.8 percent of peak hours occurred during the summer months (June–August) or winter months (December–February), with 95.5 percent of those peak hours occurring in the summer and only 4.5 percent occurring in the winter.[35]

Q. SCE&G's 2017 IRP indicates near-term contracting for 280 MW of solar PV. How will that new resource impact the net peak load hours?

A. The additional output of 280 MW of PV located in or very near the SCE&G territory was modeled with the PV output acting as a load reducer. Once the PV is incorporated, the numbers change very slightly. The 1 percent of hours with the highest load on the SCE&G system occurring during the summer months (June–August) or winter months (December–February) are reduced from 97.8 percent of peak hours to 97.4 percent of hours once the 280 MW of PV is included. The share of those peak hours occurring in the summertime is reduced from 95.5 percent to 94.3 percent.[36]

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[35] John D. Wilson, "Analysis for Solar Capacity Equivalent Values for the South Carolina Electric and Gas System." Table 2. 1474 summertime hours, 70 wintertime hours, 1579 total hours.

[36] John D. Wilson, "Analysis for Solar Capacity Equivalent Values for the South Carolina Electric and Gas System." Table 3. 1451 summertime hours, 87 wintertime hours, 1563 total hours.

Q. What generation capacity split do you recommend for summertime and wintertime?

A. Because the 280 MW of PV envisioned by SCE&G is not to my knowledge fully constructed, operational, and under contract—and because SCE&G's 2017 IRP shows summertime peak load growing more rapidly than wintertime peak load—I recommend a summertime share between the 95.5/4.5 percent split and the 94.3/5.7 percent split. I recommend that SCE&G retain its seasonal capacity payment construct, with 95 percent of the annual generation capacity value be applied to the summer months of June, July, and August, and the remaining 5 percent of the annual generation capacity value be applied to the winter months of December, January, and February.

Q. Please describe the Company's error in failing to include a performance adjustment factor.

A. The Company seeks to pay a QF for providing capacity based not on its nameplate rating or expected performance, but rather as a performance payment. SCE&G's proposed method divides avoided capacity costs ($6.35 per kW-year) "by the number of critical peak hours in each period…based on 264 critical peak hours in the summer season and…192 critical peak hours in the winter season" (Lynch, Page 9, Lines 3 and 17-20). SCE&G's approach is to subdivide the hours of the year into summer peak, winter peak, and off-peak and then pay for QF generation capacity on a per kWh basis rather than a per kW-yr basis, depending on the period in which the generation occurs. This approach has merit, because it both simplifies the tariff structure and provides a stronger incentive for the QF to produce power during peak hours when generation capacity is the most valuable.

However, this approach must be adjusted if it is to treat QF avoided generation capacity fairly when compared to the Company's own generation capacity. If an SCE&G generator were unavailable for 5 percent of the critical peak hours in a season, the Company would not argue that the generator was no longer fully used and useful as a generation capacity contributor and therefore ineligible for full cost recovery. The same would be true if the same generator was unavailable for

10 or 20 percent of the hours in a given year. We expect that utility-owned generators will have forced and planned outages and therefore do not require 100 percent availability during critical peak hours as a condition of cost recovery. To ensure that qualifying facilities are not subject to undue discrimination, this principle must also be applied to the QF capacity payments.

The appropriate way to provide QFs avoided generation capacity compensation based on performance while also treating QFs and utility generators indifferently is the use of a performance adjustment factor (PAF). The PAF is the reciprocal of the availability a generator must obtain to be eligible for full avoided generation capacity cost payments. The PAF value, a number greater than one, is then multiplied by the $/kW-yr avoided generation capacity value when calculating the avoided generation capacity rates. If the QF's performance mirrors the expected availability exactly, it will be paid the exact avoided generation capacity value. If it performs better or worse, the payment is commensurately higher or lower.

Q. Do other utilities use the PAF to adjust performance-based avoided generation capacity payments?

A. Yes. For example, Duke Energy Carolinas and Duke Energy Progress use a PAF in both North and South Carolina.[37,38] In addition, Georgia Power uses an approach very similar to the PAF whereby a QF may provide less than 100 percent performance during key availability hours and still receive full capacity payments.[39,40]

[37] North Carolina Utilities Commission Docket No. E-100 Sub 140.

[38] South Carolina Public Service Commission Docket No. 1995-1192-E.

[39] Georgia Power. 2015. "Georgia Power Company's Qualifying Facilities (QF) Fundamentals." Page 9. Available at http://www.psc.state.ga.us/electric/GPC_%20QF_Fundamentals_Guide-PPT.pdf.

[40] Georgia Power. 2007. "Georgia Power's Small Power Producers Fundamentals." Page 17. Available at http://www.psc.state.ga.us/electric/GP_SMALL_POWER_PROD_PPT_1.ppt.

Q. What PAF value should SCE&G use?

A. A PAF of 1.20 corresponds to an availability factor of 83.3 percent. I would expect that a utility-owned generator with an availability factor of 83.3 percent would be considered used and useful from a generation capacity perspective. A QF with the same performance should be equally compensated for its generation capacity contributions, suggesting that a PAF of 1.20 is appropriate. A PAF value of 1.20 has been vetted and litigated over many years in North Carolina.[41] Both Duke Energy Carolinas and Duke Energy Progress use a PAF in their South Carolina avoided generation capacity cost calculations. To the extent that the South Carolina Public Utility Commission would consider a utility-owned generator with availability factor less than 83.3 percent useful, it should consider a PAF even higher than 1.20.

Q. Please summarize your recommendations for calculating the value of avoided generation capacity for qualifying facilities.

A. I recommend a variety of methodological corrections, including:

1. Recognize that SCE&G's avoided generation capacity methodology requires including SCE&G's 2019 generation capacity shortfall in its calculations.
2. Include the additional revenue the Company would collect by selling marginal surplus generation capacity contracts made possible by the new QFs in the DRR calculation. Based on known market transactions in the SCE&G territory, the Company should use a capacity value of $68.62 per kW-yr in 2017, $70.92 per kW-yr in 2018, $72.38 per kW-yr in 2019, and the 2019 value adjusted for inflation for the year 2020 and beyond.
3. Revise the generation capacity payment split between summer and winter to 95 percent summer and 5 percent winter.
4. Include a performance adjustment factor of 1.20.

[41] North Carolina Utilities Commission Docket No. E-100 Sub 140. Note that the 1.20 PAF applies to all eligible qualifying facilities except hydroelectric facilities with no storage capabilities, which are assigned a 2.0 PAF.

Q. Other than correcting the avoided energy and avoided capacity payments, do you have any other concerns about the PR-1 and PR-2 tariffs?

A. I do, related to the schedule for updating the PR-2 rate. In 2016, the Commission approved a settlement agreement that allowed for SCE&G to update its PR-2 tariff on at least a biannual basis. I would recommend that the Commission revisit this determination and limit the PR-2 updates to once per year. The biannual frequency of the updates is concerning for two reasons. First, it creates substantial uncertainty for potential QF developers, because a developer could invest significant time and money preparing a project only to have an unscheduled PR-2 rate update with lower rates filed by SCE&G. Because an unscheduled price change could flip the economics of a potential project, it unfairly imposes substantial and unnecessary risk on QF developers. Second, as this testimony suggests, the difference of revenue requirement methodology the Company uses is remarkably complex and rather opaque, particularly for avoided generation capacity. The prospect of contested dockets with discovery, intervenors, and a careful auditing of the Company at least twice a year seems out of balance with the potential benefits. Annual updates or updates every two years are much more common, and are likely a better way to balance equity under PURPA with the real costs associated with each docket.

4. NET ENERGY METERING METHODOLOGY—2017 APPLICATION

Q. Did the Company correctly calculate the total value of NEM DERs?

A. I believe that the Total Value of NEM Distributed Energy Resources table, as shown in Table 6 of Witness Lynch's testimony, is both incorrect and incomplete. As just discussed in Section 3, the Company incorrectly calculated avoided energy and avoided generation capacity values. The Company should also include an avoided transmission and distribution capacity value and update its line loss calculations. Finally, SCE&G should evaluate and include a value for avoided environmental costs.

Q. How should SCE&G remedy the incorrectly calculated values presented in the NEM table submitted by Witness Lynch?

A. The Company should correct its methodologies and calculations for avoided energy in Row 1, avoided generation capacity in Row 2, avoided T&D capacity in Row 4, and avoided line losses in Row 12.[42] For avoided energy and capacity values, the corrections noted in Section 3 of my testimony should be incorporated. In future updates, SCE&G should further focus its calculations on NEM resources that may be different that some QF resources under PURPA. I make further recommendations below for including an avoided transmission and distribution value and for updating line losses. SCE&G should also evaluate and include in future updates an avoided environmental cost value in row 10.

Avoided Transmission and Distribution Capacity Value

Q. Please explain the avoided transmission and distribution capacity component.

A. This component of the NEM Methodology refers to a DER's contribution to deferring or avoiding the addition of transmission and/or distribution capacity resources needed to serve load. The value of avoided transmission and distribution (T&D) capacity should include an estimate of the costs of regional and local transmission projects that may be avoided or deferred because of distributed generation. Notably, avoided T&D capacity is relevant not only for the NEM Methodology application, but also reflects a value added by small QF resources and therefore should be reflected in SCE&G's PR-1 tariff.

Q. Do you agree with SCE&G's findings that DER resources never avoid any transmission or distribution capacity costs?

A. No. SCE&G Company Witness Lynch claims on Page 17, Line 4 that "customer-scale NEM resources are distributed across SCE&G's transmission system and have too small of an impact on any transmission circuit to result in avoided

[42] Witness Lynch Table 6.

transmission capacity." On the distribution system, SCE&G suggests that because it must "plan for when the DER is not supplying power," (Lynch, Page 17, Line 14) the Company must plan as if the resource simply doesn't exist.

I do not agree. These positions entirely overlook the ways that DER, in aggregate and on average over time, reduces the need for T&D capacity investments. If the DER alleviates some of the strain on the system during transmission or distribution system peaks, then that resource does, in fact, reduce pressure on that system and therefore helps to defer or avoid future upgrades to that system.

Q. Do other energy resources, such as energy efficiency, receive credit for deferring or avoiding T&D resources?

A. Yes. Energy efficiency resources are regularly credited with avoiding or deferring T&D investments.[43] See the table in TJV-3 (Avoided Cost of Transmission and Distribution Detail) for the results of ACEEE's survey of avoided costs of T&D for use in energy efficiency program screening. Although there is variation from utility to utility, most of the avoided T&D values are between $25 and $75 per kW-year.

Q. How are these values calculated for energy efficiency?

A. Methods for quantifying the value of avoided or deferred T&D investments from implementing energy efficiency vary in complexity, cost, and accuracy. In its October 2014 report, the Mendota Group described a range of such methods. More involved methods, such as the system planning approach and rate case marginal cost data with allocators, may provide somewhat more accuracy but at a significantly higher cost than simpler methods. Less resource-intensive methods for quantifying the value of avoided or deferred T&D include: the current values method, which defines the average cost to serve load as each system's net cost divided by its peak capability; the simple method, which analyzes the cost and

[43] Baatz, Brendon. 2015. "Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency." American Council for an Energy Efficient Economy (ACEEE).

capacity of a representative sample of recent T&D upgrade projects; and the historical/forecast method, which considers whether historical and forecast T&D investments are related to load growth, and weights these investments.[44]

Q. Are the T&D avoidance impacts of EE on the system different from DER impacts?

A. No, they are generally the same: if and when EE, DER and distribution-level QFs reduce load during times when the system is constrained, they avoid or defer T&D investments.

Q. Do other jurisdictions credit distributed energy resources with avoiding T&D investment?

A. Yes. Austin, Texas, found a value of 1.0 cents per kWh for avoided transmission capacity cost.[45] In Maine, the PUC adopted a value of 1.6 cents per kWh for avoided transmission capacity.[46] Avoided distribution capacity was not included in the Maine study because peak loads in the state have been and are forecasted to be generally flat, and thus capacity-related distribution investments were not anticipated. In contrast, SCE&G's 2017 IRP projects peak load to grow significantly over the period of analysis, suggesting that the benefit of avoiding distribution capacity investment in SCE&G's territory is likely to be substantial.[47] In 2014, the Minnesota Public Utilities Commission approved the structure and methodology for a value of solar (VOS) tariff that utilities can adopt in lieu of net metering. The VOS tariff framework calls for value components to be broken out, including avoided transmission capacity and avoided distribution capacity. In its Briefing Papers, Minnesota Public Utilities Commission staff found an avoided

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[44] The Mendota Group. 2014. "Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments for Public Service Company of Colorado." Colorado Public Utility Commission proceeding 14A-1057EG, Hearing Exhibit 1, Attachment SMW-2.

[45] Chakka, Babu 2014. "Austin Energy Value of Solar Methodology."

[46] Maine Public Utilities Commission. 2015. Maine Distributed Solar Valuation Study.

[47] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2017-9-E, page 2.

transmission capacity value of 1.51 cents per kWh and an avoided distribution capacity value of 0.9 cents per kWh for Xcel Energy.[48]

Q. How should SCE&G calculate the value of avoided T&D capacity for DERs?

A. Each method has pros and cons. If SCE&G does not wish to expend the resources to engage in a modeling exercise to calculate avoided T&D benefits, the Company could employ a simpler method, such as the historical/forecast analysis approach. By considering many years, both historical and forecast, this method does not disproportionately weigh infrequent, large investments. Although it does not incorporate time and spatial variation, this method is easily applied using publicly available data and is appropriate given SCE&G's forecasted load growth over the IRP period.

In the absence of more granular data on monthly system peaks, the benefits of DERs in terms of avoided T&D capacity can be approximated using the production profile that SCE&G uses for these resources for capacity planning purposes. The 2017 IRP indicates that the amount of firm solar capacity expected to be available on the system peak hour is 50 percent; other analysis pegs the capacity contribution at 66 percent.[49,50] If SCE&G expects that the bulk of the newly arriving DER capacity is likely to be solar PV capacity, and assuming that SCE&G's avoided T&D investment is likely to fall in the range of the avoided T&D values found for energy efficiency programs, then SCE&G's QF and DER benefits could be anywhere from $0 to $100/kW-year. Considering that most of the avoided T&D values used for energy efficiency programs fell in a narrower range, an avoided T&D value could be between $12.50 and $37.50/kW-year if

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[48] Minnesota Public Utilities Commission Staff. 2014. CSG Rate Briefing Papers, Docket No. E002/M-13-867.

[49] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2017-9-E, page 37.

[50] John D. Wilson, "Analysis for Solar Capacity Equivalent Values for the South Carolina Electric and Gas System." Table 4.

using the SCE&G IRP value; between $16.50 and $33.30 if using the Wilson capacity contribution value.

Whatever method the Company chooses, it is important to fairly and transparently assess and attribute avoided T&D benefits to these resources. While small QFs also avoid transmission and distribution capacity, the Company and Commission should be careful with the measurement standard used: whereas an avoided transmission and distribution capacity calculation applicable to tariff PR-1 must meet a "known and measurable" standard, calculations for the NEM table may meet a less stringent "quantifiable" standard.

Avoided Line Losses

Q. Do you find SCE&G's description of avoided line losses associated with DERs adequate?

A. No, I do not. Witness Lynch explained the Company's approach in detail in the 2016 proceeding, requiring four full pages to detail the line loss methodology.[51] His 2017 testimony contains just nine lines (Witness Lynch, Page 19, Line 15 through Page 20, Line 2). Because nothing in his 2017 testimony suggests a methodological change from 2016, I presume the Company has not changed its methodology for line loss calculation in the past year. While SCE&G correctly defined marginal distribution losses as twice average losses, the Company appears to have made two important errors in calculating line losses. The Company used annual average system losses as the basis for calculating marginal losses rather than losses associated with the temporal solar profile, and the Company failed to allocate transmission losses as marginal (e.g. twice average loss). These two errors both result in SCE&G failing to credit DERs with the full value of their line loss avoidance.

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[51] Direct Testimony of Joseph M. Lynch, Docket No. 2016-2-E, Pages 29–32.

Q. What are annual average system losses?

A. Because the wires that deliver electricity have losses, some of the power placed on the transmission system is lost, never arriving to load. The annual average system loss is the total MWh of energy lost over the course of the year divided by total MWh of energy placed on the system by the generators. This average does not represent the system loss for a specific hour or system load, but rather the average over 8,760 hours of high load and low load, daytime and nighttime.

Q. Why shouldn't annual average system loss be used to calculate the avoided line losses due to solar PV?

A. Real power losses increase with increased current flow.[52] This means that the line loss avoidance benefits of a DER are higher during times of high system load than times of low system load. For example, because daytime load is generally higher than nighttime load, solar PV DERs likely avoid more line losses per kWh of generation than a resource that operates on a full 24-hour basis. Similarly, annual load tends to peak on hot, sunny days—the very hours when distributed PV is producing at highest efficiency.

Q. How should SCE&G calculate system losses?

A. SCE&G should consider the temporal and seasonal nature of solar PV output when determining the line losses distributed PV avoids. Ideally, SCE&G would calculate the system loss for each hour of the year, and then determine how many MWh were saved each hour due to line loss avoidance induced by distributed generation PV. To the extent that this approach is overly burdensome, the Company could calculate the average system loss at 100 MW increments, ranging from peak load all the way down to the lowest load of the year. By assigning each hour's demand to a load bin representing a 100 MW range, the Company could determine the line loss avoidance benefits for various levels of load. The use of

[52] PJM, "Marginal Losses Implementation Training," 2007. Page 6. Available at: http://www.pjm.com/~/media/training/new-initiatives/ip-ml/marginal-losses-implementation-training.ashx.

average annual losses ignores that solar is most productive during periods of higher load and doesn't produce any electricity at all during periods of the lowest load. This likely undercounts the annual system line loss avoidance due to distributed solar PV.

Q. Please explain SCE&G's use of marginal line losses.

A. Witness Lynch explains marginal line losses as follows:

> Marginal losses represent line losses associated with the last few increments or decrements in the system load. As the system load increases on power lines, the losses associated with each increment in load tend to increase and, after a certain point, will increase at an increasing rate. In general, the losses associated with the last MW served will be greater than those associated with the MW just before it. Therefore, marginal losses tend to be greater than average losses and, since NEM DER reduces system loads on the margin, their avoided line losses should be based on marginal losses.[53]

On the distribution system, SCE&G models marginal losses as "approximately twice average losses."[54] However, SCE&G models "marginal losses equal to average losses on the transmission and sub-transmission system."[55]

Q. How do you recommend SCE&G's determine marginal line losses?

A. SCE&G is correct to double average losses in deriving marginal losses, as it does now in calculating marginal distribution system losses. But it doubles the wrong average. SCE&G is doubling an average of losses over every hour of the year. Solar PV does not produce electricity over every hour of the year. Solar PV will

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[53] Direct Testimony of Joseph M. Lynch, Docket No. 2016-2-E, Page 30, Line 6.

[54] Ibid. Page 31, Line 15.

[55] Ibid. Page 30, Line 15.

not avoid losses, for instance, at midnight, so it is incorrect, as SCE&G does, to include midnight in the average. To be accurate, SCE&G should calculate the average system losses during the hours when PV generates. Then it should double that PV-generation weighted average losses to accurately calculate the marginal losses for solar PV.

When calculating transmission losses, SCE&G currently uses the average line loss for all hours of the day, and doesn't double that average to derive marginal. Instead, it should use an annual system loss average weighted to the PV generation profile, and it should double that average transmission loss to arrive at the marginal transmission losses avoided by solar PV. Review of the literature[56,57] indicates that "for transmission losses, the marginal losses are always twice the average losses."[58] While it is true that "the amount of losses on the transmission/sub-transmission system do not necessarily decrease with load"[59] in a given hour, the system's behavior over the course of a year will behave consistently with Joule's first law, resulting in marginal losses double the average losses.

Q. Do avoided marginal T&D line losses also have capacity implications?

A. Yes, this is the case for NEM DER resources and QFs eligible for tariff PR-1 interconnected to the distribution system. Injecting power directly into the distribution system avoids the need for additional power to overcome losses in the T&D system. Therefore, the avoided energy <u>and</u> avoided generation capacity

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[56] Eldridge, B. et al. 2017. "Marginal Loss Calculations for the DCOPF." FERC Technical Report on Loss Estimation. Page 3. Available at: https://www.ferc.gov/legal/staff-reports/2017/marginallosscalculations.pdf.

[57] Ivanov, C. 2012. "Marginal Line Losses," for Cooperative Research Network, National Rural Electric Cooperative Association. Page 19. Available at https://www.michigan.gov/documents/energy/MECA_Response_to_EE_Q15_final_419596_7.pdf.

[58] Liu, L. and A. Zobian. 2002. "The Importance of Marginal Loss Pricing in an RTO Environment." The Electricity Journal 15(8):40-45. Page 2. Available at: http://www.ces-us.com/download/Reports_and_Publications/Losses%20paper%20-%20web.pdf.

[59] Direct Testimony of Joseph M. Lynch, Docket No. 2016-2-E, Page 31, Line 8.

should be grossed up by the avoided losses on the transmission and the distribution system for these generation resources.

Notably, a larger QF connected to the primary or secondary distribution system only avoids transmission and sub-transmission losses, in addition to the additional generation and transmission capacity necessary to overcome the line losses associated with that avoided loss. A DER or QF connected to the primary or secondary distribution system avoids energy losses commensurate with the cumulative T&D marginal loss factor, and the additional generation and transmission capacity necessary to overcome the line losses.

Q. Which projects should these loss factors apply to?

A. Any small generation resource connected at the distribution level should be reimbursed for both transmission-level and distribution-level savings. This includes both NEM DERs and QFs eligible for tariff PR-1. Larger resources connected to the distribution system avoided transmission and sub-transmission losses but may not avoid distribution system losses, and therefore should only be reimbursed for transmission-level savings. This applies to QFs eligible for PR-2 that are interconnected at the distribution level.

Q. Should there be an adjustment due to SCE&G's reserve margin?

A. Yes. SCE&G asserts it must ensure a reserve margin of 14 percent, representing additional generation capacity beyond the Company's expected annual peak load, in order to ensure reliable supply. DER resources have capacity value, and that capacity value also translates into a reduced reserve margin requirement. The avoided T&D line losses of 8 to 9 percent are quite reliable, and this portion of avoided generation capacity should be counted towards reducing the level of peak load for which SCE&G should plan.

Q. Please summarize your recommendations for calculating the value of avoided line losses for DERs.

A. I have four recommendations.

1. SCE&G should use not use straight average annual line losses, but instead use average annual T&D losses weighed to a PV profile to account for solar PV output's correlation with higher load, and therefore higher losses.
2. SCE&G should recognize that marginal transmission line losses, like marginal distribution line losses, are double the average line loss.
3. SCE&G should gross up avoided generation and transmission capacity calculations assigned to distribution-level DERs and QFs to reflect the avoided generation and transmission capacity otherwise needed to overcome line losses.
4. SCE&G should recognize that, in addition to the avoided generation and transmission capacity associated with overcoming line losses, the associated 14 percent reserve margin assigned to the generation capacity is also avoided. As such, that too should be reflected in avoided generation capacity calculations assigned to distribution-level DER and QF resources.

Avoided Environmental Costs

Q. How should SCE&G proceed with regards to the avoided environmental costs not covered by avoided criteria pollutants and avoided CO_2 costs?

A. SCE&G states that "at present, there are no environmental costs that are not already included in the other specific components of the methodology." (Witness Lynch, Page 19, Line 11). I disagree with that conclusion. To the extent that distributed energy generators help to alleviate costs associated with environmental compliance at SCE&G's other facilities, those savings should be reflected in the NEM calculation. One example is coal combustion residuals (CCR).

On December 19, 2014, EPA issued a final rule regulating CCR under Subtitle D of the Resource Conservation and Recovery Act. The rule applies to new and existing landfills and ash ponds. It establishes minimum siting and construction standards for new CCR facilities, requires existing ash ponds at operating coal plants to either install liners and ground water monitoring or permanently retire, and sets standards for long-term stability and closure care.[60] NEM resources will result in the reduced dispatch of SCE&G's coal units. The reduction implies less CCR generation, and therefore a potential delay in the need to construct new ash ponds or other CCR facilities. The reduction also suggests less CCR waste generated over the lifetime of the plant, and therefore a reduction in eventual CCR site cleanup costs. These avoided environmental costs are financial, quantifiable, and a direct result of DER generation. As such, savings such as these should be included in Witness Lynch's Table 6, Row 10.

Q. Please summarize your recommendations regarding net energy metering methodology—2017 application.

A. The Company should correct the errors associated with calculating avoided energy costs, avoided generation capacity costs, avoided T&D capacity costs, and avoided line losses associated with NEM resources. Additionally, SCE&G should both acknowledge that there are positive benefits associated with avoided environmental cost categories and resolve to provide appropriate values in next year's application.

Q. Does this conclude your testimony?

A. Yes.

[60] Citation: 80 Fed. Reg. 21302 (April 17, 2015)

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate,* 2015 – present*, Associate*, 2011 – 2015.

Conducts research, authors reports, and prepares expert testimony. Consults on issues related to renewable resources, distributed energy resources, PURPA and avoided costs, municipal utility planning, renewable energy and carbon markets, integrated resource planning, coal asset valuation, compliance, and cost-benefit analysis.

Jointown Group Co., Ltd., Wuhan, China. *Systems Engineer Intern*, Summer 2007.

Developed and implemented a modified (*s*,*S*) inventory management scheme for over 20,000 warehoused pharmaceutical products, resulting in more orders filled, lower carrying costs, and a reduction in the frequency of product expiration.

MIT Lincoln Laboratory, Division 6, Group 65, Lexington, MA. *Research Assistant*, 2003 **–** 2006.

Designed algorithm and implemented software to create autonomous wireless point-to-point topologies for aerial, land-based, and nautical vehicles as part of an Optical & RF Combined Link Experiment (ORCLE) funded by Defense Advanced Research Projects Agency (DARPA).

EDUCATION

Boston University, Boston, MA
Doctor of Philosophy in Systems Engineering, 2011. Developed algorithms to discover degree constrained minimum spanning trees in sparsely connected graphs.

Dublin City University, Dublin, Ireland
Master of Science in Financial and Industrial Mathematics, 2001. Researched partial differential equations modeling fluid flow over an erodible bed.

North Carolina State University, Raleigh, North Carolina
Bachelor of Science in Applied Mathematics, 2000. *Summa Cum Laude*.
Bachelor of Science in Computer Science, 1999. *Summa Cum Laude*.
Bachelor of Science in Economics, 1998. *Summa Cum Laude*.

TESTIMONY

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Stanton, E. A., B. Biewald, D. Hurley, P. Peterson, T. Vitolo. 2015. "Clean Energy Advocates Bootcamp: Understanding Supply and Demand in New England." Presentation in Cambridge, MA, February 12, 2015.

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Vitolo, T. 2014. Comments in New York Association for Energy Economics panel regarding the operation and economics of Indian Point Nuclear Plant, November 4, 2014.

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Vitolo T., J. Hu., L. Servi, V. Mehta. 2005. “Topology Formulation Algorithms for Wireless Networks with Reconfigurable Directional Links.” Proceedings of the IEEE Military Communications Conference, October 2005.

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ADDITIONAL EXPERIENCE

TEACHING

- Guest Lecturer, Harvard Law School, 2017 – present
- Guest Lecturer, Boston University City Planning and Urbans Affairs Program, 2015 – present
- Graduate Teaching Fellow, Boston University College of Engineering. *Introduction to Engineering Computation*, 2009
- Guest Lecturer, Boston University Department of Systems Engineering, *Case Studies in Inventory Management*, 2007-2008
- Guest Lecturer, Boston University Department of Systems Engineering, Solving Linear Programs with CPLEX, 2003-2008

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- *Constable*, Brookline, MA, 2010 – present
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- National Science Foundation IGERT Fellowship, 2006 – 2008
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- Computer Applications: Microsoft Office, LaTeX
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Resume dated February 2017.

Analysis of Solar Capacity Equivalent Values for the South Carolina Electric and Gas System

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March 21, 2017

The assessment of solar energy's contribution to meeting peak demands by South Carolina Electric and Gas Company (SCE&G) undervalues the actual capacity benefit of solar. This is particularly true in the summer and for tracking systems. SCE&G undervalues solar because the company assesses solar contribution to peak using what appears to be simplistic averages of solar capacity factors during certain hours, regardless of whether the system is peaking during those hours.[1] This method is flawed because it gives the same weight to on-peak solar generation (e.g., during the hottest, sunniest hour of a peak load afternoon) as to off-peak generation (e.g., during a summer thunderstorm).

Solar contributes far more to summer peak resource needs than SCE&G currently acknowledges. The contribution of solar power to peak resource needs is measured by the capacity equivalent value, the amount of on-peak power that solar power is expected to provide during peak demand periods. SCE&G's assessment of capacity equivalent values for solar in its Integrated Resource Plan (IRP) differs from this report in three critical ways.

- Fixed mount systems provide 66% on-peak power, about one-third greater summer capacity equivalent values than the value assumed in the IRP.
- Single axis tracking systems provide 74% on-peak power, nearly half again as much capacity equivalent than the value assumed in the IRP.
- Although winter capacity equivalent values are low, winter peaks are infrequent: Of 1,579 peak hours in this analysis, only 77 occurred during winter months.

Table 1, below, compares the values used in SCE&G's resource plan with the capacity equivalent value, calculated as discussed later in this report.

Table 1: Comparison of solar capacity equivalent values used for SCE&G IRP vs. values based on SACE analysis of Clean Power Research data

	Capacity Equivalent Value
Summer Capacity Equivalent	
IRP – PV solar[A]	50.0 %
Fixed mount PV system[B]	66.1 %
Single axis tracking PV system[B]	74.2 %
Winter Capacity Equivalent	
IRP – PV solar[A]	(not specified)
Fixed mount PV system[B]	3.1 %
Single axis tracking PV system[B]	6.5 %

Source A: SCE&G 2017 IRP, p. 37.
Source B: SACE analysis of Clean Power Research data.

[1] Capacity factor refers to the percent of maximum output for a generation resource. For example, a 50% capacity factor means that a generation resource is expected to generate 50% of the maximum possible output.

SACE's analysis of Clean Power Research's solar generation simulations showed that instead of 50%, the summer capacity equivalent value of solar power should be 66 - 74%, depending on solar technology.

These calculations are derived directly from two hourly datasets covering the 1998-2015 time period.[2] One dataset includes the actual hourly system load and year-ahead peak load forecast for the SCE&G planning area; these data are filed by SCE&G on FERC Form 714. The second dataset are simulated hourly generation profiles, relying on actual observed weather conditions, for fixed mount and a single axis tracking PV systems at 14 locations in or adjacent to South Carolina. These data were provided to SACE by Clean Power Research using its SolarAnywhere model (see attached documentation).[3]

By aligning historical system load data with simulated solar generation, the actual performance of solar PV systems can be evaluated under a range of recent meteorological conditions. The 1998-2015 coverage allows for nearly 135,000 comparisons of hourly system load with hourly solar generation. As such, it provides an opportunity to conduct a robust statistical analysis of the correlation of solar generation to system load during peak periods.

A. SCE&G's methods for calculating solar capacity equivalence value

Capacity equivalent values based on analysis of Clean Power Research data are significantly higher than those based on SCE&G's analysis and methods. SCE&G's methods give equal weight to solar generation during an on-peak hour (e.g., during the hottest, sunniest hour of a peak load afternoon) as during an off-peak hour (e.g., during a summer rainshower). This is true for each of the two different methods used by SCE&G to place a capacity value on solar power.

One method used by SCE&G to determine the capacity equivalent value for solar power is used in its integrated resource plans. Based on the description of these values, it appears that SCE&G calculates these values for the summer only, by averaging solar generation during certain hours.

- In 2013, SCE&G used a 61% capacity equivalent value.[4]

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[2] SCE&G data for calendar year 2004 are not available from the FERC website. Throughout this report, data reported for 1998-2015 does not include data from 2004.

[3] Using its SolarAnywhere model, Clean Power Research conducted hourly simulations for seven different configurations of solar photovoltaic (PV) systems at 147 locations across the Southeast region, including South Carolina. This analysis is based on the simulated hourly production data produced by Clean Power Research, as explained in the attached documentation.

[4] "… 700 megawatts of solar capacity in 2015 with 427 megawatts coincidental with the system peak …" SCE&G 2013 IRP, p. 33.

- In 2014, SCE&G used a 48% capacity equivalent value.[5]
- In 2015, SCE&G did not specify its capacity equivalent value in its IRP.
- In 2016 and 2017, SCE&G used a 50% capacity equivalent value.[6]

SCE&G has not specified the hours used for averaging the capacity factors, nor explained the substantial year-to-year changes. Furthermore, SCE&G appears to lack any capacity equivalent value for winter season planning purposes.

The second method used by SCE&G to place capacity value on solar power does not include the calculation of a system-wide capacity equivalent value, but rather embeds this calculation within its Public Utility Regulatory Policy Act (PURPA) calculations of avoided capacity costs, as reflected in related tariffs.[7] According to testimony filed by SCE&G, its PURPA avoided cost PR-1 and PR-2 tariffs assign capacity value based on the actual performance of solar systems during "critical peak hours."[8]

B. Flaws in SCE&G's solar capacity equivalence methods

SCE&G's two methods for evaluating solar capacity equivalence do not reflect the actual performance of solar on its system. Each method *inappropriately excludes* many hours in which system peak loads are observed and *inappropriately includes* many hours in which system peak loads are *not* observed.

SCE&G's method for evaluating solar capacity equivalence for its IRP appears to be an average of solar generation during some hours during the summer months (see footnote 5). However, because SCE&G has not explained its calculation of solar capacity equivalent values in recent IRPs, the ability to provide a detailed critique of those calculations is limited.

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[5] "Approximately 56% of the DC rating of solar capacity will be generating on a summer afternoon and contribute to reducing the summer peak demand. There will be no solar generation at the time of SCE&G's winter peak demand which usually occurs between 7 and 8 am." SCE&G 2014 IRP, p. 39.

[6] SCE&G 2016 IRP p. 38; SCE&G 2017 IRP, p. 37.

[7] In 2014, in response to SACE testimony describing a proposed method for calculating the capacity equivalent value, SCE&G witness Joseph Lynch testified that, "Determining the firm capacity level of a [Distributed Energy Resource (DER)] is a utility specific calculation which will be a function of its system load profile, various weather conditions such as solar radiation, cloud cover, wind speed -- all depending in part on the geographic location of the service territory. The determination of firm capacity level for a DER is more properly addressed in the docket where each utility files [its utility-specific rates]." South Carolina Electric & Gas, *Rebuttal Testimony of Joseph M. Lynch on behalf of South Carolina Electric & Gas Company,* South Carolina Public Service Commission Docket No. 2014-246-E (January 13, 2015), p. 6.

[8] SCE&G identified the set of critical peak hours where energy would have a capacity value on the system and spread the avoided capacity cost across those hours. A capacity credit is then paid for whatever QF energy is provided during the critical peak period. *Direct Testimony of Joseph M. Lynch on Behalf of South Carolina Electric & Gas Company*, South Carolina Public Service Commission Docket No. 2016-2-E (March 4, 2016), p. 16.

Nonetheless, the analysis of Clean Power Research's data provided in this report demonstrates that the IRPs undervalue the actual capacity benefit of solar power, as shown in Table 1.

(1) SCE&G's critical peak period inappropriately excludes many system peak load hours

The SCE&G system is not limited to peak hours during the critical peak hour periods defined in the PR-1 and PR-2 tariffs.[9] SCE&G defines its critical peak hours as between 6 am and 9 am, Monday through Friday, in the winter, and between 2 pm and 6 pm, Monday through Friday, in the summer.[10] With regard to reliability, however, what matters is not a standard period of time in which the system often peaks, but rather the hours in which the actual peak is relatively high compared to the forecast peak.

The importance of focusing on hours in which the actual peak is relatively high compared to forecast peak is related to the reason that utilities value capacity. Capacity is needed in order to serve peak demand, and the risk of not being able to serve peak demand is measured in a reliability assessment. A reliability assessment considers many factors in measuring that risk, the most important of which is the actual demand in a given hour. In contrast, SCE&G's critical peak hours method includes some hours with peak demand, but also many other hours in which demand is well below peak, hours in which the reliability risk is nearly zero. A better approach to measuring the contribution of solar power to system reliability is to conduct a robust statistical analysis of the correlation of solar generation to system load during peak periods.

Accurately identifying the peak periods is a critical element of this method. Hours with actual reliability risk occur more frequently in years with atypical weather – unusually hot summers or cold winters. Not all years are equal in a reliability assessment. For example, in 2009 the SCE&G peak was only 4,718 MW, whereas in 2007 it was 4,926 MW. Thus the performance of solar during peak hours in 2007 would have benefitted system reliability more than it would have during the less extreme 2009 peak hours when SCE&G likely had capacity to spare.

In order to evaluate solar generation during the hours that "matter" for purposes of system reliability, this analysis considers solar performance during the top 1% of hours (1998-2015) based on system load factor.[11] Table 2, below, demonstrates that summer peak hours may occur any time between 10 am and 10 pm EDT. Winter peaks are relatively rare, comprising

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[9] For the most recently proposed PR-1 and PR-2 tariffs, see *Direct Testimony of Allen W. Rooks on Behalf of South Carolina Electric & Gas Company*, South Carolina Public Service Commission Docket No. 2017-2-E (February 24, 2017), exhibits AWR-13, AWR-15.

[10] *Direct Testimony of Joseph M. Lynch on Behalf of South Carolina Electric & Gas Company*, South Carolina Public Service Commission Docket No. 2016-2-E (March 4, 2016), p. 17.

[11] Load factor is calculated as hourly load divided by the annual peak, as forecast in the prior year by SCE&G. For SCE&G, the top 1% load factor hours are hours with a load factor of 91% or greater.

only about 5% of the high load factor hours analyzed for this study. About 66% of high load factor hours occur during the SCE&G critical peak hours.[12] Thus, many peak hours during which reliability risks are higher are likely to occur outside the critical peak hours in the SCE&G tariffs.

Table 2: SCE&G peak hour distribution, 1998-2015

Hour Beginning		Summer						Winter					
EST	**EDT**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**
23	**0**	0	0	0	0	0	0	0	0	0	0	0	0
0	**1**	0	0	0	0	0	0	0	0	0	0	0	0
1	**2**	0	0	0	0	0	0	0	0	0	0	0	0
2	**3**	0	0	0	0	0	0	0	0	0	0	0	0
3	**4**	0	0	0	0	0	0	0	0	0	0	0	0
4	**5**	0	0	0	0	0	0	0	0	0	0	0	0
5	**6**	0	0	0	0	0	0	0	2	1	0	0	0
6	**7**	0	0	0	0	0	0	3	10	1	2	0	0
7	**8**	0	0	0	0	0	0	4	18	5	3	0	0
8	**9**	0	0	0	0	0	0	3	12	1	2	0	0
9	**10**	0	0	0	0	0	0	2	2	0	0	0	0
10	**11**	6	12	7	0	0	0	0	1	0	0	0	0
11	**12**	17	40	36	0	0	0	0	0	0	0	0	0
12	**13**	29	67	61	2	0	0	0	0	0	0	0	0
13	**14**	41	95	89	2	0	0	0	0	0	0	0	2
14	**15**	47	107	98	4	0	0	0	0	0	0	0	2
15	**16**	48	103	98	8	0	0	0	0	0	0	0	4
16	**17**	41	85	82	2	0	0	0	0	0	0	0	2
17	**18**	26	57	54	0	0	0	0	0	0	0	0	0
18	**19**	14	30	25	0	0	0	0	1	0	0	0	0
19	**20**	8	21	13	0	0	0	0	1	0	0	0	0
20	**21**	5	7	5	0	0	0	0	1	0	0	0	0
21	**22**	0	0	0	0	0	0	0	1	0	0	0	0
22	**23**	0	0	0	0	0	0	0	1	0	0	0	0
Monthly Total		**282**	**624**	**568**	**18**	**0**	**0**	**12**	**50**	**8**	**7**	**0**	**10**

Source: SCE&G data filed on FERC Form 714 for 1998-2015. The SCE&G critical peak hours are indicated by the boxes.

(2) Impact of solar deployment on SCE&G's peak hours

According to the 2017 SCE&G IRP, 280 MW of solar power have been deployed on the system.[13] Deployment of solar power affects the hours in which other resources are needed to address the system peak. Table 3 illustrates the impact of 280 MW on the hours in which the SCE&G system would peak, treating the 280 MW of solar power as a load reduction.[14] The impact of this level of solar deployment on solar peak hours is minimal; for example, net peak hours occur in winter months 6% of the time, an increase of only 5% from the baseline case.

[12] Day of week restrictions were not considered in this analysis.

[13] SCE&G 2017 IRP, p. 37.

[14] To adjust for the reduction in net demand but maintain the 1% load factor threshold, the cutoff for the load factor was reduced from 91% to 90% for the 280 MW analysis. Even with the lower cutoff level, the he number of hours included in the analysis was reduced from 1,579 to 1,563.

Thus, the addition of additional solar resources does not change the finding that SCE&G's critical peak period inappropriately excludes many system peak load hours.

Table 3: SCE&G peak hour distribution, net of 280 MW of solar systems, 1998-2015

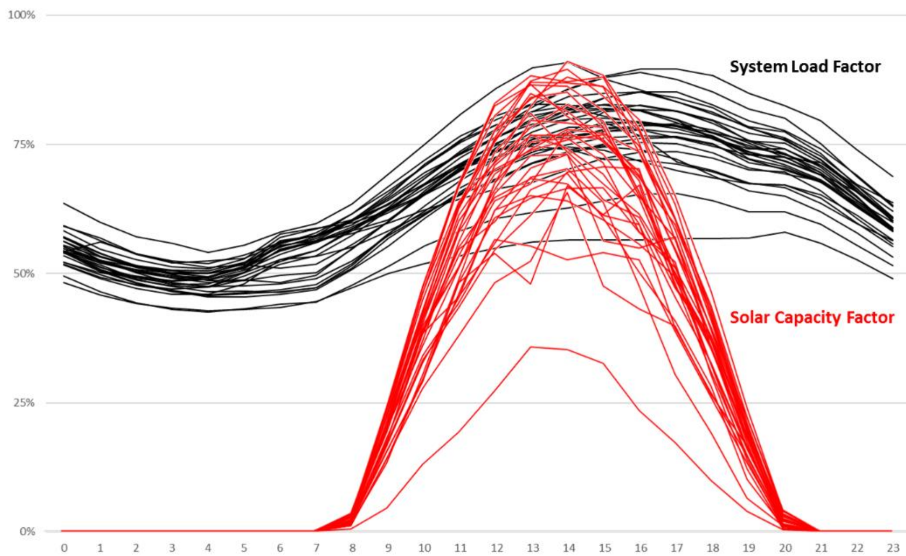
Hour Beginning		Summer						Winter					
EST	EDT	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
23	0	0	0	0	0	0	0	0	1	0	0	0	0
0	1	0	0	0	0	0	0	0	0	0	0	0	0
1	2	0	0	0	0	0	0	0	0	0	0	0	0
2	3	0	0	0	0	0	0	0	0	0	0	0	0
3	4	0	0	0	0	0	0	0	0	0	0	0	0
4	5	0	0	0	0	0	0	0	1	0	0	0	0
5	6	0	0	0	0	0	0	1	2	1	0	0	0
6	7	0	0	0	0	0	0	3	13	2	2	0	0
7	8	0	0	0	0	0	0	5	23	6	3	0	0
8	9	0	0	0	0	0	0	3	14	1	2	0	0
9	10	0	0	0	0	0	0	2	3	0	0	0	0
10	11	5	10	7	0	0	0	0	1	0	0	0	0
11	12	17	39	35	0	0	0	0	0	0	0	0	0
12	13	26	63	55	0	0	0	0	0	0	0	0	0
13	14	40	86	79	2	0	0	0	0	0	0	0	2
14	15	45	101	92	3	0	0	0	0	0	0	0	2
15	16	46	100	96	4	0	0	0	0	0	0	0	2
16	17	40	85	83	2	0	0	0	0	0	0	0	1
17	18	27	59	56	0	0	0	0	0	0	0	0	0
18	19	14	35	27	0	0	0	0	1	0	0	0	0
19	20	9	26	23	0	0	0	0	1	0	0	0	0
20	21	6	13	6	0	0	0	0	1	0	0	0	0
21	22	0	0	0	0	0	0	0	1	0	0	0	0
22	23	0	0	0	0	0	0	0	1	0	0	0	0
Monthly Total		275	617	559	11	0	0	14	63	10	7	0	7

Source: SCE&G data filed on FERC Form 714 for 1998-2015. The SCE&G critical peak hours are indicated by the boxes. Peak hours are selected based on a 1% system net load factor threshold. The net load factor for each hour is actual demand less solar generation divided by peak forecast demand less solar capacity. The 280 MW of solar generation and capacity are assumed to be south-facing fixed mount systems located at the six sites most closely associated with the SCE&G service area (see Table 6 and the attachment).

(3) SCE&G's critical peak period inappropriately includes many off-peak load hours

SCE&G's use of a critical peak period undervalues solar because it fails to track evidence that system load and solar generation are correlated, particularly in summer months. Figure 1, below, shows solar generation for an average fixed mount system for all hours of August 2015 in comparison to the SCE&G system load. On certain days, solar generation falls short of an optimal generation shape. For example, on August 7th at 1 pm EDT, solar generation is estimated at a 48% capacity factor.

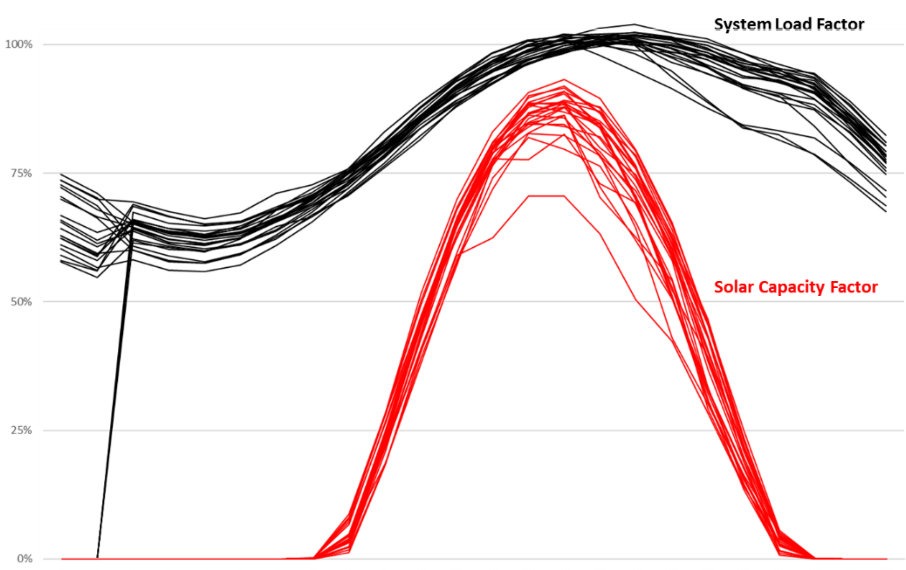
Figure 1: SCE&G load factor vs. solar capacity factor, August 2015



Source: Clean Power Research SolarAnywhere data analyzed in comparison to South Carolina Electric & Gas data filed on FERC Form 714 for 2015.

On peak days, however, solar capacity factors show a much higher consistency of output. In Figure 2, below, solar generation for the same average fixed mount system is shown for the top 25 peak days from 1998-2015. On peak days, solar generation is much more consistent, with only one instance of diminished output (July 8, 1998) like those seen in Figure 1. This makes intuitive sense because cloudy days tend to be more moderate in temperature, and loads are highest in the summer on sunny days.

Figure 2: SCE&G load factor vs. solar capacity factor, peak load days 1998-2015



Source: Clean Power Research SolarAnywhere data analyzed in comparison to South Carolina Electric & Gas data filed on FERC Form 714 for 1998-2015. Anomalous data from source file obtained from FERC.

Another way in which SCE&G's critical peak period method inappropriately includes many off-peak hours is by allocating 80% of capacity value to the summer period and 20% to the winter peak period. As demonstrated by the data in Tables 2 and 3, only 5-6% of peak hours occur in the winter peak period. By excessively weighting the winter peak period at 20%, the SCE&G PR-1 and PR-2 tariffs effectively overemphasize many winter hours in which loads fall far short of system peaks, thus overemphasizing hours without any significant reliability risk in the calculation.

(4) Impact of SCE&G's critical peak period on capacity equivalent values

Table 4, below, illustrates the impact of SCE&G's method on the capacity equivalent value. The capacity factor is calculated for all hours, SCE&G's critical peak hours, and actual system peak hours (top 1% of hours ranked by system load factor).

Table 4: Seasonal capacity factors by peak hour selection method, SCE&G 1998-2015

	Fixed Mount PV System	Single Axis Tracking PV System
Summer (June-September)		
All Hours	23.7 %	29.8 %
Critical Peak Hours	54.4 %	64.2 %
System Peak Hours	66.1 %	74.2 %
Winter (December-March)		
All Hours	19.1 %	20.5 %
Critical Peak Hours	9.2 %	18.2 %
System Peak Hours	3.1 %	6.5 %

Source: Clean Power Research SolarAnywhere data analyzed in comparison to South Carolina Electric & Gas data filed on FERC Form 714 for 1998-2015.

Based on these data, it appears that solar performs about 10-12% better during summer system peak hours than it does during SCE&G's summer critical peak hours. In the winter, solar performs about 6-12% worse during winter system peak hours than during the winter critical peak hours. However, as noted earlier, SCE&G's system history is dominated by summer peaks: Using the top 1% load factor threshold, about 95% of all peak hours occur during summer months.

Further analysis of these data indicate that the majority of the difference between the critical peak hours method and the system peak hours method can be explained by the inclusion of many hours in which system peak loads are not observed. Performing the system peak hours method calculation on just the critical peak period results in about a 1% change in the result for most technologies.[15] Thus, while the excluded hours are significant from a reliability assessment perspective, the performance of solar during those hours is not very different from the performance of solar during on-peak hours that happen to occur during the critical peak period.

(5) Consideration of different PV technologies by SCE&G's critical peak period method

Notwithstanding these problems with the critical peak hours method, its technology-neutral approach does give due consideration to the enhanced on-peak performance of certain PV generation technologies. As shown in Table 4, application of the critical peak hours method does recognize single axis tracking systems as providing more capacity during peak hours.

To further explore the potential impact of technology choice on capacity equivalent value, Clean Power Research provided data on a variety of PV system configurations reflecting a range of differing system deployments. With the exception of the west facing fixed mount system design, all system design configurations tested similarly to the other systems of the same technology class, as shown in Table 5.

Table 5: Performance of various solar PV system technologies, SCE&G 1998-2015

	Annual Capacity Factor	Capacity Equivalent Value	
		Winter	Summer
Fixed Mount PV Systems			
South facing, 20° tilt, 130 % DC/AC	21.7 %	2.9 %	66.6 %
South facing, 25° tilt, 115 % DC/AC	21.8 %	3.1 %	66.1 %
South facing, 25° tilt, 130 % DC/AC	21.7 %	2.9 %	66.6 %
West facing, 25° tilt, 130 % DC/AC	18.4 %	0.6 %	67.6 %
Single Axis Tracking Systems			
115 % DC/AC	25.7 %	6.5 %	74.4 %
130 % DC/AC	25.7 %	6.5 %	74.2 %
145 % DC/AC	25.6 %	6.5 %	74.1 %

Source: Clean Power Research SolarAnywhere data analyzed in comparison to South Carolina Electric & Gas data filed on FERC Form 714 for 1998-2015.

[15] West facing fixed mount systems should receive a higher capacity equivalent value than a south facing system. South facing systems tested at 54-55%, but the west facing system tested at 62%. The critical peak hours method should provide a portion of this value spread, as it undervalues solar capacity by only 6%, compared to an undervaluation of 12% for south facing systems.

C. Recommended improvements to solar capacity equivalence method

In summary, neither the simple 50% capacity equivalent factor used in the SCE&G IRP nor the more nuanced critical peak hours method fully capture the enhanced performance of solar on summer peak days. These practices undervalue the contribution of solar power to summer peak loads by as much as 24%. The system peak hours method used in this study includes peak hours excluded by SCE&G's methods, excludes non-peak hours included by SCE&G's method, and considers the impact of solar PV technology selection (which is not considered in SCE&G's IRP capacity equivalence values).

The shortcomings of the critical peak hour method are explained both by the omission of peak load hours that occur outside the SCE&G critical peak period, as well as the inclusion of load hours that occur during the critical peak period, but represent lower-than-peak system demand. These shortcomings could be addressed by shifting to different methods for both planning and tariff design. For example, SCE&G could revise its tariff to include an adjustment factor to align its critical peak hours method with the results shown in Table 1. A more nuanced approach would be to utilize an effective load carrying capacity (ELCC) calculation or an incremental capacity equivalent (ICE) calculation. The ELCC and ICE methods have been adopted by other utilities in order to evaluate the contribution of solar and other variable energy resources by placing the greatest weight on time periods with the highest reliability risks. Until some improvement is made, SCE&G's understatement of the capacity equivalence value of solar will continue to undervalue solar capacity both from a tariff perspective as well as from a resource planning perspective.

Notes on the Clean Power Research Data Used in This Analysis

The solar systems analyzed for this report were modeled by Clean Power Research using the SolarAnywhere Standard Resolution resource data. Although the modeled data cover 1998-2016, FERC Form 714 data are currently available only through 2015, and thus 2016 data are not analyzed in this report. SACE selected six of the modeled systems using two of the modeled technology for analysis in this report. The annual capacity factors and capacity equivalent values for each PV site on the South Carolina Electric & Gas system are provided in Table 6.

Documentation for the data modeled by Clean Power Research is attached.

Table 6: Fixed mount and single axis tracking system solar performance on South Carolina Electric & Gas system

	Annual Capacity Factor	Capacity Equivalent Value Capacity Factor During Top 1% System Load Factor Hours		
		Annual	Summer	Winter
Fixed South 25-115	**21.8%**	**63.1%**	**66.1%**	**3.1%**
Plant McIntosh, GA	22.0%	63.4%	66.4%	3.2%
Plant Vogtle, GA	21.6%	62.3%	65.3%	2.8%
Richard B Russell Dam, GA	21.9%	63.5%	66.5%	2.9%
Dover, GA	22.0%	64.0%	67.1%	2.9%
Lumberton, NC	21.7%	61.6%	64.5%	3.8%
Greenville, SC	21.9%	64.0%	67.0%	2.8%
Hagood Gas Plant, SC	22.1%	62.8%	65.7%	3.5%
Anderson, SC	22.1%	65.3%	68.5%	2.8%
McMeekin Coal Plant, SC	21.8%	64.3%	67.4%	3.1%
Spartanburg, SC	21.9%	63.2%	66.2%	2.6%
Pickens, SC	21.8%	63.4%	66.4%	2.6%
Plant Robinson, SC	21.5%	60.7%	63.6%	3.2%
Lancaster, SC	21.7%	62.3%	65.4%	2.9%
Johnsonville, SC	21.7%	63.0%	65.9%	3.8%
Tracking 130	**25.7%**	**70.9%**	**74.2%**	**6.5%**
Plant McIntosh, GA	26.1%	71.8%	75.1%	6.8%
Plant Vogtle, GA	25.5%	70.3%	73.5%	5.6%
Richard B Russell Dam, GA	25.8%	71.3%	74.6%	6.2%
Dover, GA	26.0%	72.3%	75.6%	6.0%
Lumberton, NC	25.5%	69.5%	72.5%	8.6%
Greenville, SC	25.8%	71.2%	74.5%	5.6%
Hagood Gas Plant, SC	26.2%	71.3%	74.4%	7.5%
Anderson, SC	26.1%	73.0%	76.3%	5.9%
McMeekin Coal Plant, SC	25.7%	72.3%	75.6%	6.7%
Spartanburg, SC	25.7%	70.1%	73.4%	5.4%
Pickens, SC	25.5%	70.3%	73.6%	5.4%
Plant Robinson, SC	25.3%	68.2%	71.3%	6.9%
Lancaster, SC	25.6%	70.1%	73.4%	6.2%
Johnsonville, SC	25.6%	71.4%	74.5%	8.3%

Source: Clean Power Research SolarAnywhere data analyzed in comparison to South Carolina Electric & Gas data filed on FERC Form 714 for 1998-2015. Sites included in this analysis include all sites in South Carolina, plus Georgia and North Carolina sites located close to the border. The six sites most closely associated with the SCE&G service territory are Plant McIntosh, Plant Vogtle, Lumberton, McMeekin Coal Plant, Plant Robinson, and Johnsonville.

Clean Power Research®

February 14, 2017

Southern Alliance for Clean Energy
P.O. Box 1842
Knoxville, TN 37901

Clean Power Research (CPR) has completed its hourly simulations for seven PV system configurations at each of 147 locations using its SolarAnywhere modeling services. The PV production datasets for these 1,029 systems may be scaled and aggregated by SACE as needed.

We have provided simulated PV production for each hour from January 1, 1998 through December 31, 2016 using the local SolarAnywhere Standard Resolution (approximately 10 km x 10 km x 1 hour resolution) resource data corresponding to the system location. CPR has provided a description of the data and details of the system configurations in the Appendix.

Sincerely,

Philip Gruenhagen

Philip Gruenhagen
Consulting Engineer

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Appendix

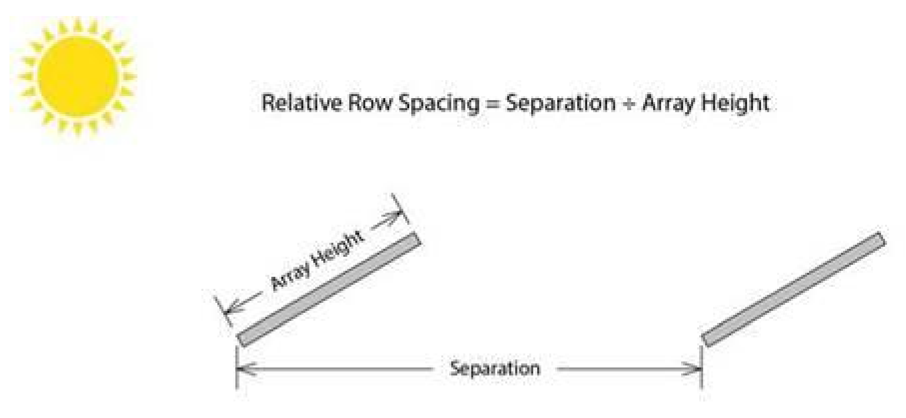
System Specifications

Table 1 lists the specifications for the seven PV systems that CPR modeled at each location. Each system has a 1.0 MW AC rating with losses. CPR designed the fixed system configurations to highlight differences due to three attributes: tilt, DC to AC ratio, and azimuth. Tracking system configurations only vary in DC to AC ratio. All three tracking systems are horizontal (0° tilt) and have a tracking rotational limit of +/- 52°. The tracking systems are identical except for the inverter AC maximum power rating, which we adjusted to provide the three different DC to AC ratios.

We configured all systems with 5,333 modules. Each module was rated at 250.1 Watts DC_{STC} (225 Watts DC_{PTC}), making the combined system rating 1,334 kW DC_{STC} (1,200 kW DC_{PTC}). Multiplying the 1,200 kW DC_{PTC} rating by the 98% average inverter efficiency rating yields a CEC-AC rating of 1,176 kW AC_{CEC}. After applying a general derate factor of 85% to account for other DC losses, we arrive at a rating of 1,000 kW (1.0 MW) AC with losses.

CPR laid out the arrays using 30 rows for fixed systems and 60 rows for tracking systems and a relative row spacing of 2.0. Relative row spacing does not indicate the absolute distance in feet or meters, but instead indicates the distance as a proportion of the height of the array, as shown in Figure 1.

Figure 1 - Relative Row Spacing



Clean Power Research®

Table 1 - PV System Configurations

	Fixed South 20-130	Fixed South 25-115	Fixed South 25-130	Fixed West 25-130	Tracking 115	Tracking 130	Tracking 145
Module Specifications							
Module Count	5,333	5,333	5,333	5,333	5,333	5,333	5,333
Module Rating (Watts DC_{STC})	250.1	250.1	250.1	250.1	250.1	250.1	250.1
Module NOCT	45.0° C	45.0° C	45.0° C	45.0° C	45.0° C	45.0° C	45.0° C
Efficiency Reduction (% per °C)	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Ventilation Quality	Average	Average	Average	Average	Average	Average	Average
Annual Degradation	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PV Array Specifications							
System STC Rating (kW DC_{STC})	1,334	1,334	1,334	1,334	1,334	1,334	1,334
Module Derate (PTC/STC Ratio)	90%	90%	90%	90%	90%	90%	90%
System PTC Rating (kW DC_{PTC})	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Inverter AC Max Power (kW)	1,025	1,159	1,025	1,025	1,159	1,025	920
DC_{STC} to Inverter AC Ratio	130%	115%	130%	130%	115%	130%	145%
Inverter Efficiency Rating	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
AC_{CEC} Rating (kW AC_{CEC})	1,176	1,176	1,176	1,176	1,176	1,176	1,176
General Derate Factor	85%	85%	85%	85%	85%	85%	85%
AC Rating with Losses (kW AC)	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Albedo	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Installation Specifications							
Array Azimuth[1,2]	180°	180°	180°	270°	180°	180°	180°
Module Row Count	30	30	30	30	60	60	60
Relative Row Spacing	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Array Tilt[3]	20°	25°	25°	25°	0°	0°	0°
Tracking Rotation Limit	n/a	n/a	n/a	n/a	+/- 52°	+/- 52°	+/- 52°

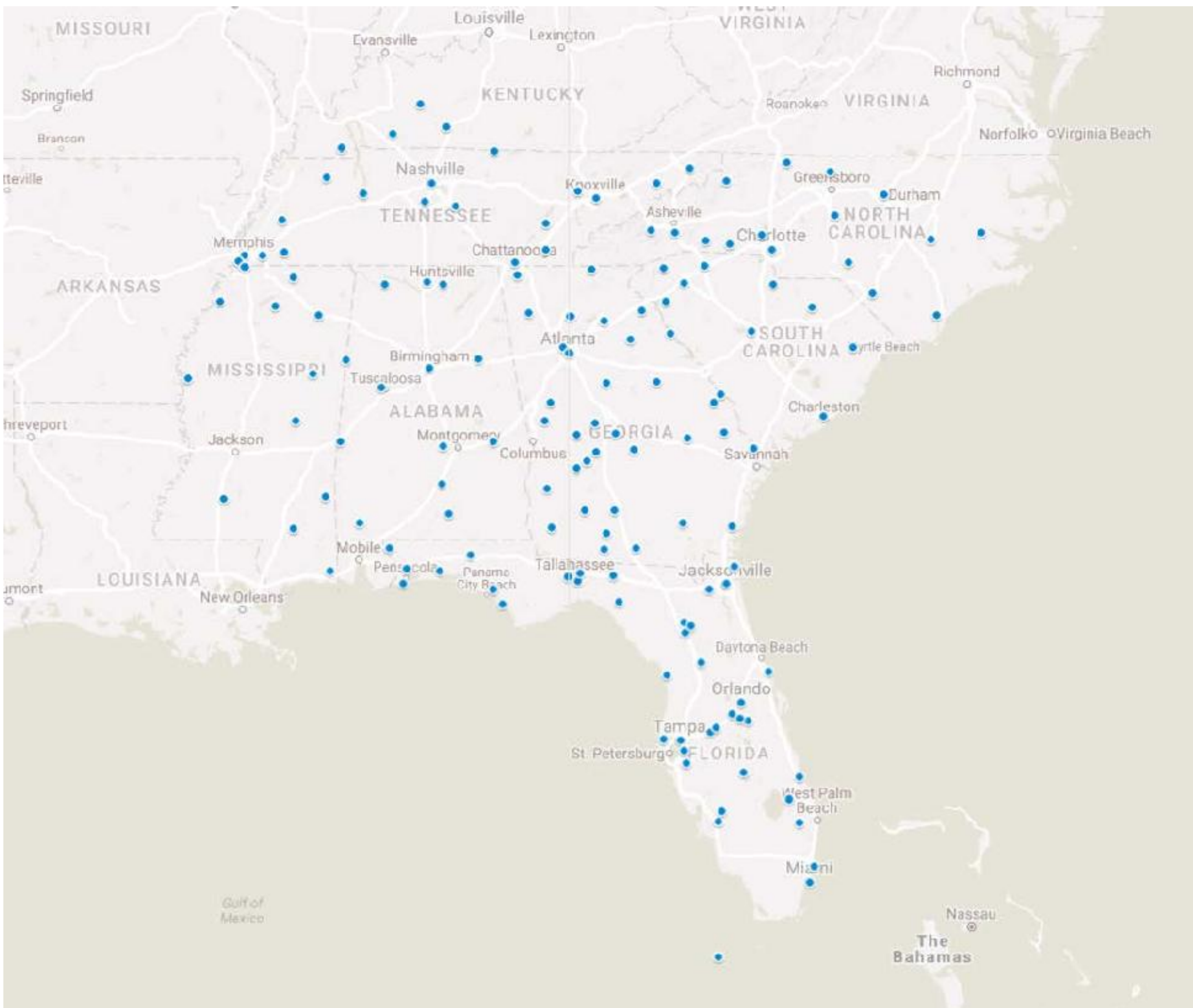
[1] Tracking systems are aligned north-south, tracking east-west.
[2] Solar south is 180°
[3] 0° is horizontal, 90° is vertical

System Locations

SACE provided a list of 147 locations, as shown in Figure 2. The system locations are provided in list form in Table 2. CPR modeled each of the seven system configurations at each of the locations listed.

A KMZ file for the system locations is also available. You can use this file with tools like Google Earth to visualize the location of the simulated systems (as shown in Figure 2).

Figure 2 - Map of System Locations



Modeling Results Data Files

The simulated hourly PV production data is available in individual comma separated values (CSV) format files for each system. Most spreadsheet programs can open CSV files. We've named the 1,029 files based on the location ID and system configuration. For example, you can find the results for the Fixed South 20-130 configuration modeled at Huntsville Downtown, AL (location ID A01) in the file named, "A01 Fixed South 20-130.csv." To save space and reduce download times, the CSV files have been compressed into a single WinZip archive named, "SimulationResults.zip."

There are five columns in each CSV file. The first (leftmost) two columns provide the start and end time of the period that the energy value in the third column corresponds to. All time stamps are in standard time for the locale where the system was located, with a UTC offset to indicate whether the time stamp is Eastern Standard Time (UTC -5:00) or Central Standard Time (UTC -6:00). Time stamps in these files do not use Daylight Saving Time.

Energy values are in kWh AC for each hour (equivalent to average kW AC per hour). The fourth column contains the ambient temperature for the period in degrees Celsius and the last column contains the observation type for the period, where AN means, "Archive Night," AD means, "Archive Day," and AM means, "Archive Missing." [4]

Clean Power Research makes use of satellite-derived irradiance data for PV modeling. When satellite imagery at some location is unavailable for one or more periods, the observation type will end with the letter 'M.' In this case, the energy value for that period should be considered invalid. A complete list of missing periods for each location is available in the file named, "MissingPeriods.xlsx."

Table 2 – System Locations

ID	Name	State	Latitude	Longitude
A01	Huntsville Downtown, AL	AL	34.73	-86.58
A02	Muscle Shoals, AL	AL	34.74	-87.6
A03	Chickamauga, GA	GA	34.87	-85.27
A04	Paradise Fossil Plant, KY	KY	37.2597	-86.9781
A05	Magnolia Power Plant CC, MS	MS	34.8353	-89.2018

[4] For a full list of irradiance observation type prefixes and suffixes, see https://www.solaranywhere.com/validation/data/file-formats/

A06	Oxford, MS	MS	34.42	-89.52
A07	Philadelphia, MS	MS	32.75	-89.15
A08	Gleason Power Plant CT, TN	TN	36.2451	-88.6121
A09	Johnson City, TN	TN	36.37	-82.3
A10	Oak Ridge, TN	TN	36.05	-84.25
A11	Murray, KY	KY	36.65	-88.35
A12	Cordova, TN	TN	35.14	-89.74
A13	Murfreesboro, TN	TN	35.85	-86.35
A14	Bowling Green, KY	KY	36.94	-86.52
A15	Hopkinsville, KY	KY	36.85	-87.45
A16	Tupelo, MS	MS	34.29	-88.76
A17	Starkville, MS	MS	33.45	-88.85
A18	Memphis Downtown, TN	TN	35.15	-90.05
A19	Nashville Downtown, TN	TN	36.16	-86.78
A20	Knoxville Downtown, TN	TN	35.96	-83.92
A21	Chattanooga Downtown, TN	TN	35.05	-85.31
A22	Cleveland, TN	TN	35.22	-84.79
A23	Caledonia CC, MS	MS	33.6478	-88.2721
A24	Lagoon Creek CT-CC, TN	TN	35.6532	-89.3937
A25	Johnsonville Fossil Plant, TN	TN	36.0278	-87.9864
A26	Watts Bar, TN	TN	35.6023	-84.7896
B08	Washington County CoGen Facility, AL	AL	31.2542	-88.0319
B09	E B Harris Electric Generating Gas Plant, AL	AL	32.3814	-86.5736

B10	Crist Coal Plant, FL	FL	30.5653	-87.2248
B11	Lansing Smith Coal and Gas Plant, FL	FL	30.2689	-85.7003
B12	Plant McIntosh, GA	GA	32.3562	-81.1686
B13	Deerhaven Generating Station, FL	FL	29.7589	-82.388
B14	Plant Mitchell, GA	GA	31.4447	-84.132
B15	Robins Gas Plant, GA	GA	32.5806	-83.5831
B16	Plant McManus, GA	GA	31.2125	-81.5458
B17	Plant Vogtle, GA	GA	33.1418	-81.7621
B18	Jack McDonough Plant, GA	GA	33.8228	-84.4757
B19	Plant Daniel, MS	MS	30.5335	-88.5574
B20	Brookhaven, MS	MS	31.62	-90.41
B21	Crystal River Nuclear Plant, FL	FL	28.9671	-82.6991
B22	West County Energy Center Gas Plant, FL	FL	26.6862	-80.3801
B23	Tampa Downtown, FL	FL	27.95	-82.46
B24	Fort Myers Gas Plant, FL	FL	26.6967	-81.7831
B25	Orlando Downtown, FL	FL	28.54	-81.39
B26	Arvah B Hopkins Gas Plant, FL	FL	30.4522	-84.4
B27	Miami Downtown, FL	FL	25.76	-80.19
B28	Jacksonville Downtown, FL	FL	30.35	-81.66
B29	L V Sutton Coal Plant, NC	NC	34.2828	-77.9861
B30	Shelby, NC	NC	35.31	-81.59
B31	HF Lee Power Plant, NC	NC	35.3734	-78.09
B32	Rockingham County CT Station, NC	NC	36.3302	-79.8285

B33	Durham Downtown, NC	NC	36	-78.9
B34	Lumberton, NC	NC	34.61	-79.09
B35	Lincoln CT Plant, NC	NC	35.4317	-81.0347
B36	Asheville Power Plant, NC	NC	35.4712	-82.5415
B37	Greenville, SC	SC	34.75	-82.39
B38	Hagood Gas Plant, SC	SC	32.8263	-79.9613
B39	Anderson, SC	SC	34.49	-82.72
B40	McMeekin Coal Plant, SC	SC	34.0556	-81.2167
C01	Huntsville West, AL	AL	34.76	-86.86
C02	Plant Allen, TN	TN	35.06	-90.15
C03	Plant Southaven, MS	MS	34.98	-90.04
C04	Franklin, TN	TN	35.9	-86.9
C05	Pensacola NAS, FL	FL	30.35	-87.27
C06	Walnut Hill, FL	FL	30.88	-87.51
C07	Tyndall AFB, FL	FL	30.04	-85.53
C08	Eglin AFB, FL	FL	30.53	-86.64
C09	Defuniak Springs, FL	FL	30.78	-86.1
C10	Plant McWilliams, AL	AL	31.4	-86.48
C11	Butler, GA	GA	32.56	-84.27
C12	Waycross, GA	GA	31.26	-82.41
C13	Atlanta Downtown, GA	GA	33.75	-84.39
C14	Big Bend Power Station, FL	FL	27.7974	-82.3963
C15	Hollywood Beach, FL	FL	26.01	-80.12

C16	Ft Pierce, FL	FL	27.39	-80.37
C17	Babcock Ranch, FL	FL	26.86	-81.74
C18	Martin Power Plant, FL	FL	27.05	-80.56
C19	Parrish Power Plant, FL	FL	27.6053	-82.352
C20	CD McIntosh Power Plant, FL	FL	28.0828	-81.9234
C21	Perry, FL	FL	30.07	-83.53
C22	Swainsboro, GA	GA	32.51	-82.34
C23	Spartanburg, SC	SC	34.99	-82.04
C24	Rutherfordton, NC	NC	35.36	-82.01
C25	Pickens, SC	SC	34.96	-82.75
C26	Gainesville, GA	GA	34.2	-83.78
C27	Canon, GA	GA	34.35	-83.13
C28	Athens, GA	GA	33.95	-83.34
C29	Blairsville, GA	GA	34.95	-84
C30	Canton, GA	GA	34.28	-84.37
C31	Rome, GA	GA	34.33	-85.09
C32	Waynesboro, MS	MS	31.65	-88.64
C33	Birmingham Downtown, AL	AL	33.52	-86.81
C34	Anniston Army Depot, AL	AL	33.66	-85.95
C35	Greenville, NC	NC	35.47	-77.2
C36	Sparta, GA	GA	33.32	-82.88
C37	Plant Robinson, SC	SC	34.401	-80.1591
C38	Lancaster, SC	SC	34.73	-80.84

C39	Johnsonville, SC	SC	33.82	-79.43
C40	Greenville, GA	GA	33.02	-84.71
C41	Richard B Russell Dam, GA	GA	34.02	-82.63
C42	Mt Airy, NC	NC	36.46	-80.6
C43	Bulldozer Rd, TN	TN	36.61	-85.67
C44	Camp Mackall, NC	NC	35.04	-79.51
C46	Tuscaloosa, AL	AL	33.24	-87.65
C47	Cuba, AL	AL	32.45	-88.37
C48	Camp Shelby, MS	MS	31.18	-89.19
C49	Sebring, FL	FL	27.46	-81.35
C50	Valdosta, GA	GA	30.88	-83.23
C51	Monticello, GA	GA	33.31	-83.74
C52	Lula, MS	MS	34.48	-90.47
C53	Tuskeegee, AL	AL	32.46	-85.69
C54	Boone, NC	NC	36.2	-81.66
C55	Waynesboro, NC	NC	35.51	-82.97
C56	Asheboro, NC	NC	35.72	-79.76
C57	Charlotte Downtown, NC	NC	35.22	-80.85
C58	Key West, FL	FL	24.58	-81.8
C59	Greenville, MS	MS	33.37	-91.03
C60	Greenville, TN	TN	36.16	-82.88
C61	Greenville, FL	FL	30.47	-83.62
C62	Greenville, AL	AL	31.83	-86.6

C63	Clearwater, FL	FL	27.98	-82.76
C64	New Smyrna Beach, FL	FL	29.02	-80.92
C65	Tallahassee Southwood, FL	FL	30.39	-84.24
C66	Tallahassee Killearn, FL	FL	30.51	-84.2
C67	Gainesville, FL	FL	29.61	-82.38
C68	Gainesville Airport, FL	FL	29.7	-82.27
C69	Disney World, FL	FL	28.37	-81.56
C70	Polk City, FL	FL	28.15	-81.83
C71	St. Cloud, FL	FL	28.25	-81.28
C72	Fernandina Beach, FL	FL	30.61	-81.52
C73	Baldwin, FL	FL	30.27	-81.95
C74	Kissimmee, FL	FL	28.29	-81.41
C75	Ocala, FL	FL	29.16	-82.09
D01	Cuthbert, GA	GA	31.7665	-84.7623
D02	Alexander, GA	GA	33.025	-81.8811
D03	Dover, GA	GA	32.591	-81.6997
D04	Empire, GA	GA	32.3443	-83.2763
D05	Montezuma, GA	GA	32.3016	-83.9228
D06	Colquitt, GA	GA	31.1871	-84.6893
D07	Americus, GA	GA	32.0602	-84.2643
D08	Tifton, GA	GA	31.45	-83.6
D09	Thomasville, GA	GA	30.87	-83.79
D10	Roberta, GA	GA	32.73	-83.94

D11	Hamilton, GA	GA	32.76	-84.8
D12	Andersonville, GA	GA	32.16	-84.09
D13	Moultrie, GA	GA	31.1	-83.74
D14	Somerville, TN	TN	35.19	-89.36

Avoided Cost of Transmission and Distribution Detail (nominal $)

Utility or jurisdiction	Source	Avoided T&D ($/kW-year)
Idaho Power	Idaho Power 2013	$0.00
Arizona Public Service	Mendota 2014	$0.00
Wisconsin	Cadmus 2013	$0.00
Indiana Michigan Power	I&M 2013	$0.00
State of Texas	Texas 2015	$0.00
Consumers Energy	Mendota 2014	$0.00
Vectren	Vectren 2014	$12.14
Nevada Power	NVE 2012	$12.23
Public Service Oklahoma	PSO 2014	$19.17
Ameren Missouri	Ameren 2014	$27.68
Xcel Energy Colorado	Xcel CO 2013	$28.40
Southwest Public Service	SPS 2013	$28.87
Potomac Edison	Exeter 2014	$30.69
Connecticut Light and Power	AESC 2013	$32.24
Baltimore Gas and Electric	Exeter 2014	$33.15
PGE Oregon	Mendota 2014	$33.20
National Grid Rhode Island	AESC 2013	$41.24
ComEd Illinois	Mendota 2014	$42.00
Consolidated Edison Non Network	Mendota 2014	$42.63
United Illuminating	AESC 2013	$47.82
MidAmerican South Dakota	Mendota 2014	$48.16
MidAmerican	Mendota 2014	$51.86
Northern Indiana Public Service	NIPSCO 2014	$52.25
PacifiCorp Oregon	Mendota 2014	$52.64
PacifiCorp Utah	Mendota 2014	$52.64
PacifiCorp Washington	Mendota 2014	$52.64
Xcel Energy Minnesota	Xcel MN 2012	$53.17
Southern California Edison	Mendota 2014	$53.49
Delmarva Power and Light	Exeter 2014	$55.43
Northwest Utilities	Mendota 2014	$65.59
Public Service New Hampshire	AESC 2013	$70.05
San Diego Gas and Electric	Mendota 2014	$73.32
Pacific Gas and Electric	Mendota 2014	$75.57
PEPCO	Exeter 2014	$79.12
Southern Maryland Electric Coop	Exeter 2014	$79.12
NSTAR	AESC 2013	$89.79
WMECO	AESC 2013	$98.35
Tucson Electric Power	Mendota 2014	$100.00
Unitil New Hampshire	AESC 2013	$102.29
Interstate Power and Light	Mendota 2014	$107.00
Consolidated Edison Network	Mendota 2014	$120.52
Vermont	AESC 2013	$158.15
Unitil Massachusetts	AESC 2013	$173.79
National Grid Massachusetts	AESC 2013	$200.01

Source: Baatz, Brendon. Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency. ACEEE: June 2015.