PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company	**} Docket No. 2018-2-E**

Corrected Direct Testimony of Devi Glick

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

April 12, 2018

Table of Contents

1. INTRODUCTION AND QUALIFICATIONS 1

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS 3

3. AVOIDED GENERATON CAPACITY COST METHODOLOGY 5

4. WINTER RESERVE MARGIN 8

5. SCE&G'S AVOIDED COST CALCULATIONS 12

Avoided Energy 12

Avoided Generation Capacity Calculations 14

6. NET ENERGY METERING METHODOLOGY—2018 APPLICATION 21

Avoided Transmission and Distribution Capacity Value 22

Avoided Line Losses 26

Avoided Environmental Costs 31

1. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Devi Glick. I work at Synapse Energy Economics, Inc., located at 485 Massachusetts Avenue in Cambridge, Massachusetts.

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 20 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan; a bachelor's degree in environmental studies from Middlebury College; and more than five years of professional experience as a consultant, researcher, and analyst.

At Synapse and previously at Rocky Mountain Institute, I have focused on a wide range of energy and electricity issues, including: utility resource planning, distributed energy resource valuation, energy efficiency program impact analysis, and rate design effectiveness. For this work, I develop in-house models and perform analysis using industry-standard models.

On topics related to the costs and benefits of distributed generation, I have co-authored two studies reviewing valuation methodologies for solar PV. These studies have been highly cited in public utility proceedings for their recommendations around distributed energy resource pricing and rate design. Most recently, I evaluated various rate design options for distributed energy resources within the state of Hawaii.

My CV is attached as Exhibit DG-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. No.

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 2018 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. Avoided Generation Capacity Cost Methodology

4. Winter Reserve Margin Calculations
5. SCE&G's Avoided Cost Calculations
6. Net Energy Metering Methodology - 2018 Application

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

- DG-1 (Resume of Devi Glick), and
- DG-2 (Avoided Cost of Transmission and Distribution Detail).

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. This is the third proceeding of its kind, post-Act 236, and the first avoided cost rate filed in the wake of the cancelation of V.C. Summer nuclear units 2 and 3. SCE&G now proposes substantial changes to the avoided cost methodology approved by the PSC in prior dockets. The result is that solar QFs are denied the ability to defer the addition of any new capacity that the company proposes building, potentially charging ratepayers for expensive new generation plants that could have been avoided.

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

1. SCE&G failed to abide by this Commission's approved methodology for calculating the avoided generation capacity cost for solar QFs. This resulted in the elimination of an avoided capacity payment.
2. SCE&G relied on a very high winter reserve margin of 21 percent to develop a capacity expansion plan where solar QFs avoid minimal costs. This resulted in artificially low avoided cost payment rates in tariffs PR-1 and PR-2.
3. SCE&G made several methodological and technical errors in calculating avoided costs for qualifying facilities under PURPA, particularly with regards

to avoided generation capacity costs. These errors appear to be at odds with PURPA and result in artificially low avoided cost payment rates in tariffs PR-1 and PR-2.

4. 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 also recommend that the Commission require the Company to correct its methodological and technical errors associated with its QF avoided cost determination (including recalculating the avoided generation capacity cost using the prior approved methodology), so that QFs are compensated appropriately as required under 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.

I recommend that the Commission require the Company to complete a reserve margin study prior to the publication of the 2019 IRP. In the interim, the Company should recalculate the avoided cost of solar QFs based on a resource plan completed with last year's 14 percent reserve margin.

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 corrected 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. AVOIDED GENERATON CAPACITY COST METHODOLOGY

Q. What is the avoided generation capacity value methodology approved in Docket 2017-2-E?

A. The methodology approved in Docket 2017-2-E has three steps.

Step 1: Calculate the avoided capacity value over a 15-year planning horizon using a difference in revenue requirement methodology. Witness Lynch explained this step in his direct testimony to Docket 2017-2-E:

> Using a difference in revenue requirements methodology approved by the Commission in Order No. 2016-297, SCE&G calculates the difference in revenue requirements between the base case and the change case. Using the resource plan in its latest IRP or an updated resource plan if appropriate, SCE&G calculates the incremental capital investment related revenue required to support the existing resource plan and develops a change resource plan based on the assumption of a 100 MW capacity purchase at zero cost over the 15-year IRP planning horizon. The change in revenue requirement over the 15-year period between the two resource plans is associated with the 100 MW purchase and is stated as an average cost per kilowatt ("kW") year.[1]

SCE&G's avoided capacity cost in Docket 2017-2-E was $6.35 per kW-year.[2]

---

[1] Direct Testimony of Joseph M. Lynch, Docket No. 2017-2-E, page 8.

[2] Ibid, page 9.

Step 2: "Identif[y] 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."[3] Witness Lynch outlined this process in Docket 2016-2-E:

> SCE&G determined the critical peak hours by analyzing the hours when its load fell within 95% of seasonal peak in the last 15 years (page 17, lines 9-10).
>
> There are 380 critical peak hours within 95% of the summer peaks and 88 critical peak hours within 95% of the winter peaks. The winter hours are approximately 20% of the total. Accordingly, SCE&G assigns 80% of the annual avoided capacity cost…to the summer and 20% to the winter based on the number of hours occurring in each critical peak season (page 18, lines 2-7).

Table 1 outlines the seasonal capacity costs as calculated by SCE&G in Docket 2017-2-E.[4] The summer component was $5.08 per kW-year and the winter component was $1.27 per kW year. The summer capacity payment was $0.01965/kWh based on 264 critical peak hours in the summer season and the winter capacity payment was $0.00675/kWh based on 192 critical peak hours in the winter season.[5]

Table 1: Seasonal capacity values for Docket 2017-2-E

	Summer Component	Winter Component
$/kW-yr	$5.08	$1.27
Critical Peak Hours	264	192
$/kWh	$0.01965	$0.00675

[3] Direct Testimony of Joseph M. Lynch, Docket No. 2016-2-E, page 16.
[4] Ibid.
[5] Ibid.

Step 3: Calculate a single avoided cost value based on the production of a typical solar PV system. Witness Lynch explains this step in Docket 2017-2-E.

> An additional adjustment is made to the avoided energy and avoided capacity costs to calculate a single value for these components. This adjustment includes a projection of the amount of kWh energy that will be produced in each time period specified in the rate.[6]

In Docket 2017-2-E, SCE&G's utilized analysis for a typical PV system that generated electricity in 1,911 hours, and contributed critical capacity during 165 summer hours and 7 winter hours. SCE&G then applied these PV system results to the seasonal capacity costs to produce a final 15 year levelized avoided capacity cost of $0.00172/kWh.[7]

Q. Did SCE&G use the methodology approved in Docket 2017-2-E to calculate the avoided generation capacity value this year?

A. No, SCE&G did not.

Q. Please describe the methodology SCE&G used to calculate the avoided generation capacity cost for Docket 2018-2-E.

A. SCE&G's proposed new methodology asserted that a resource must provide capacity in the winter and summer in order to provide any capacity value. As solar PV doesn't typically generate during winter peaking hours, SCE&G has assigned it no annual capacity. Witness Lynch outlines this in his direct testimony:

> Since SCE&G's Reserve Margin Study shows that SCE&G needs as much capacity in the winter as it does in the summer, a resource has to provide capacity in the winter as well as the summer in order to avoid the need for capacity and thereby have capacity value. Because solar does not provide capacity during the winter period, the Company is unable to avoid any of

---

[6] Direct Testimony of Joseph M. Lynch, Docket No. 2017-2-E, page 15, line 10 – page 16, line 2.

[7] Direct Testimony of Joseph M. Lynch, Docket No. 2017-2-E, page 16.

its projected future capacity needs and, therefore the avoided capacity cost of solar for these winter months is zero.[8]

Q. Is this a different methodology or just a difference in calculations?

A. If SCE&G was simply updating its calculations, the Company would have calculated a new capacity value, identified the critical peak system hours, and then determined a final value based on the quantity of electricity generated by the QF during those critical peak hours. It doesn't appear that SCE&G has performed any of these steps.

Q. Does SCE&G provide any explanation for using a new methodology?

A. No, SCE&G does not provide any explanation.

Q. What are your recommendations regarding SCE&G's methodology for calculating avoided generation capacity cost?

A. The Commission should require that SCE&G recalculate the avoided generation capacity cost of distributed energy resources using the three-step methodology approved in Docket 2017-2-E. In doing these calculations, the Commission should require that SCE&G incorporate the recommendations outlined below in Section 5: SCE&G's Avoided Cost Calculations, and 1) include an opportunity cost in its revenue requirement calculations; 2) include a performance adjustment factor of 1.20.

4. WINTER RESERVE MARGIN

Q. What is a winter reserve margin?

A. According to the National Energy Regulatory Commission, "reserve margin is the difference between available capacity and peak demand, normalized by peak

[8] Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, page 15, line 9 – page 16, line 2.

demand shown as a percentage to maintain reliable operation while meeting unforeseen increases in demand (e.g. extreme weather) and unexpected outages of existing capacity."[9] A winter reserve margin tells the utility how much capacity it is required to have above its projected peak winter hour based on a 50/50 forecast.[10]

Q. What has SCE&G's winter reserve margin been historically?

A. SCE&G has historically used a 14 percent winter reserve margin.[11]

Q. What winter reserve margin did SCE&G use in this docket?

A. SCE&G has increased its winter reserve margin to 21 percent,[12,13] a 50 percent increase over the winter reserve margin used last year.

Q. What winter reserve margin do other peer utilities use?

A. The Company's proposed winter reserve margin is substantially higher then peers Duke Energy Carolinas, Duke Progress, Southern Company, and Santee Cooper, each of which use a winter reserve margin between 12 and 17 percent.[14,15,16,17,18]

---

[9] North American Electric Reliability Corporation. https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx

[10] With a 50/50 forecast of peak load, there is a 50 percent probability that the observed peak load will exceed the forecasted peak load (and a 50 percent probability that it will be lower).

[11] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2017-2-E, page 33.

[12] Direct Testimony of Joseph Lynch, Docket 2018-2-E, page 6.

[13] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2018-2-E, page 37.

[14] Southern Company. An Economic Study of System Planning Reserve Margin for the Southern Company System. January 2016.

[15] Duke Energy Progress South Carolina, 2017 IRP Annual Report. Integrated Resource Plan November 1, 2017.

[16] Duke Energy Process, North Carolina, 2017 IRP Update Report, Integrated Resource Plan, September 1, 2017.

[17] Duke Energy Carolinas South Carolina, 2017 IRP Annual Report Integrated Resource Plan September 1, 2017.

[18] Santee Cooper Integrated Resource Plan, November 2016, page 15.

Q. What are the impacts of this increase in the winter reserve margin?

A. Recognizing that a robust reserve margin is necessary to protect system reliability, this dramatic increase in SCE&G's winter reserve margin has a profound impact on system costs for ratepayers by requiring substantially more winter capacity than last year's plan. Due to this change, SCE&G adds significant new generation resources to its IRP at a cost of several hundred million dollars.[19] The change also shifts the Company's peak requirements from primarily summer to winter. This shift masks the capacity value for solar QFs.

Q. How did SCE&G develop its reserve margin methodology?

A. SCE&G witness Dr. Joseph Lynch used a 14 page study that relied solely on the relationship between load and weather to calculate the winter reserve margin. It is surprising that Dr. Lynch would rely on such limited analysis to propose increasing rate-payers costs by hundreds of millions of dollars. SCE&G states in a discovery response that "use of statistical regression to correlate loads and weather is a standard industry methodology."[20]

SCE&G provided no research to support the development or use of this methodology.[21] Regional peer utilities such as Duke and Southern Company use a different, more comprehensive methodology that balances physical reliability and customer costs. The Company did assert that it is familiar with the methods used by neighboring peer utilities.[22]

---

[19] For example, a 540 MW CC at $1000/kW costs $540 million.

[20] South Caroline Electric & Gas Company, South Carolina Coastal Conservation League and Southern Alliance for Clean Energy's First Data Request, Docket No. 2018-2-E. Response #25.

[21] Ibid.

[22] South Caroline Electric & Gas Company, South Carolina Coastal Conservation League and Southern Alliance for Clean Energy's First Data Request, Docket No. 2018-2-E. Response #26.

Q. Please describe the methodologies used by regional peer utilities to calculate their reserve margins, and how these methodologies differ from the one used by SCE&G.

A. Southern Company, Duke Energy Carolinas, and Duke Energy Progress utilize reserve margins that were calculated with extensive analysis focused on balancing the physical needs of the system and the economic cost imposed on customers.

- Southern Company (Georgia Power, Alabama Power, Gulf Power, Mississippi Power) utilized a system dispatch model named Strategic Energy and Risk Valuation Model (SERVM) to evaluate production costs relative to customer costs of outages. It published a 62-page study detailing what it deems to be an economically optimum 17 percent reserve margin.[23]
- Duke Energy Progress and Duke Energy Carolinas retained Astrape Consulting to conduct a resource adequacy study in both 2012 and 2016. Their 17 percent winter reserve margins also utilize a methodology that makes efforts to balance reliability and cost minimization.[24,25,26]

Q. What are your recommendations regarding SCE&G's winter reserve margin?

A. I have two recommendations:

1. The Commission should require that SCE&G hire an independent firm to conduct an analysis to determine an appropriate reserve margin for both winter and summer. This study should utilize a methodology that balances physical reliability with minimizing economic costs to the customers.

2. For purposes of this docket I recommend the Commission require SCE&G to use its historic 14 percent winter reserve margin. SCE&G has not fully justified the considerable increase in its planning reserve margin.

---

[23] Southern Company. An Economic Study of System Planning Reserve Margin for the Southern Company System. January 2016.

[24] Duke Energy Progress South Carolina, 2017 IRP

[25] Duke Energy Process, North Carolina, 2017 IRP

[26] Duke Energy Carolinas South Carolina, 2017 IRP

5. SCE&G'S AVOIDED COST CALCULATIONS

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

A. SCE&G's relies on an extremely high winter reserve margin of 21 percent in designing its capacity expansion plan. This inappropriately reduces the proposed avoided energy payments. SCE&G also utilizes a planning process that does not allow QFs to provide generation or capacity value to the system when it faces capacity shortfalls.

In calculating avoided capacity payments, SCE&G uses an unapproved avoided cost methodology that eliminates the avoided capacity payments to solar QFs. The Company made several other errors regarding the omission of an opportunity cost of QFs and a performance adjustment factor for solar QFs. These are all described in greater detail below.

Avoided Energy

Q. What are your recommendations regarding the Company's avoided energy calculations?

A. The Company relies on an extremely high 21 percent winter reserve margin requirement from its 2018 IRP.[27] This winter reserve margin forces SCE&G to include a new 540 MW CC in its resource plan for 2023 to comply with its artificially high winter reserve margin. The result is a higher cost for ratepayers and a lower avoided cost for QFs than they would be paid under an optimally planned system with a more reasonable reserve margin.

[27] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2018-9-E, page 37.

Q. How does SCE&G's treatment of generation shortfalls in its planning process affect the Company's avoided energy cost calculations?

A. The Company's resource planning process strongly impacts the avoided cost calculations. However, the IRP that the Company relies on for its resource plan is not typically approved by the Commission, nor revised in response to Intervenors' testimony. The most recent IRP was filed in February and has not yet received Intervenor input or any indication of Commission review. Because the Company included the construction of a 540 MW NGCC in 2023 in its most recent IRP, that proposed resource is incorporated into the avoided cost calculations. To date, the Company has not been required to test a range of scenarios or model the cost of a resource plan with DERs allowed to compete with or displace the CC or other higher cost resources.

This has allowed the company to plan away any generation shortfalls that could be more cost-effectively met with PV or other lower cost resources without explanation. The result is SCE&G builds a higher cost system that does not best serve the needs of the community, and DERs are awarded a lower marginal value then they would have with a more efficiently planned system.

Q. How does the Company's peak demand forecast affect its avoided energy costs?

A. SCE&G's near term energy forecasts have a significant impact on avoided energy and capacity costs by driving the need for generation capacity in its resource plans. This generation reduces the value that DERs can provide to the system. SCE&G's year-on-year increase in the near term forecasted peak load reflects a dramatic increase in demand, as compared to prior years' forecasts. I am concerned that this near-term jump is driving long-term planning decisions at a significant cost to ratepayers without justification.

Q. What is your recommendation regarding SCE&G's avoided energy cost calculations?

A. The Commission should require that SCE&G complete a proper reserve margin study, to be finished in time for the 2019 IRP. The Commission should also require that SCE&G complete a new capacity expansion plan using last year's reserve margin of 14 percent. SCE&G should then be required to re-calculate its avoided energy cost based on this new capacity expansion plan. If SCE&G aligns its winter reserve margin with that of its peers, that 540 MW CC currently planned for 2023 will not be needed for many years, if at all. That delay represents significantly lower costs for ratepayers. This will also lead to a more accurate avoided cost rate for QFs.

Avoided Generation Capacity Calculations

Q. Turning to avoided generation capacity costs, what is your assessment of SCE&G's avoided generation capacity costs calculations?

A. Based on the direct testimony of SCE&G Witness Lynch and the SCE&G 2018 IRP,[28] the Company appears to have made several errors, including:

1. Using an unapproved (and undefined) methodology;
2. Failing to include opportunity cost in its revenue requirement calculations; and
3. Failing to include a performance adjustment factor.

Q. Please describe the Company's errors in calculating the cost of avoided generation capacity.

A. As described in detail in section 3 of this testimony, SCE&G does not utilize the methodology approved in Docket 2017-2-E to calculate the avoided cost of generation capacity. SCE&G instead asserts that resources only have capacity value if they are available in both the summer and winter.[29] Furthermore, "because solar does not provide capacity during the winter period, the Company is unable to avoid any of its projected future capacity needs and, therefore, the

---

[28] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2018-9-E.

[29] Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, pages 15.

avoided capacity cost of solar for these winter months is zero."[30] The Company cites its Solar Capacity Benefits Study[31] to support this value.[32] However the study does not provide an explanation as to how exactly SCE&G calculated the value of zero or what methodology was used.

Q. What is the final value that SCE&G uses for avoided generation capacity?

A. Zero.

Q. If SCE&G had applied the methodology approved in Docket 2017-2-E to this year's updated resource plan, what value would SCE&G have gotten for avoided generation capacity?

A. SCE&G did not follow the methodology approved in Docket 2017-2-E, therefore there were no documents provided in discovery that would allow one to replicate the calculations that the Company did last year using an updated resource plan to come up with an exact value.

If SCE&G used the approved methodology to evaluate an updated resource plan (with a 14 percent reserve margin), one would expect the avoided generation cost to be significantly higher. There are two reasons for this: first, the 540 MW CC currently planned for 2023 to meet SCE&G's winter reserve margin would not be needed. Additionally, the system would shift back to summer peaking. Future capacity expansion plans would be driven by summer peaking load, which is significantly more likely to line up with solar generation. With the summer reserve margin set to a minimum of 14 percent, the observed winter reserve margin never drops below 17 percent.[33]

---

[30] Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, pages 15-16.

[31] Direct Testimony of Joseph M Lynch, Docket No.2018-2-E. Exhibit No JML-4. On Calculating the Capacity Benefits of Solar QFs.

[32] Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, page 14.

[33] Discovery Response 1: Confidential Attachment to Response 1, EPLAN 17_Summer-Winter_CC2023_(112017)

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, 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.

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 its 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 five separate years of firm capacity purchases in its 2018 IRP.[34] SCE&G's inclusion of 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

[34] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2018-2-E, page 37.

because it has been participating in the regional generation capacity marketplace as a purchaser for those delivery years. Table 2 details the annual generation capacity avoided cost ($/kW-yr) proposed by SCE&G last year, the annual generation capacity price SCE&G considered appropriate for its own capacity purchases last year, 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.

Table 2

SCE&G Avoided Cost 2017[35]	SCE&G Purchase 2016[36]	SCE&G Purchase 2017[37]	SCE&G Purchase 2018[38]	SCE&G Purchase 2019[39]	PJM CT CONE 2018/19[40]
$6.35	$61.10	$68.62	$70.92	$72.38	$102.32

Table 2, above, is very similar to the table provided by my colleague Dr. Thomas Vitolo in his direct testimony in the 2017 SCE&G fuel cost proceeding, 2017-2-E, and is still relevant. It shows that SCE&G's proposed generation capacity payments to QFs are well below the actual generation capacity revenue the QFs' inclusion could bring to the Company.

---

[35] Direct testimony of Joseph M. Lynch, Docket No. 2017-2-E, page 11, line 5.

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

[37] Ibid. Cell E4.

[38] Ibid. Cell F4.

[39] Ibid. Cell G4.

[40] 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.

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 its 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 preparing the 2019 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 the Company's error in failing to include a performance adjustment factor.

A. In the methodology approved in Docket 2017-2-E, 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. In Docket 2017-2-E SCE&G's 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."[41] 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.

[41] Direct Testimony of Joseph M. Lynch, Docket No. 2017-2-E, page 9, lines 3 and 17-20.

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.[42,43] In addition, Georgia Power uses an approach very similar to the PAF whereby a QF may provide less than 100

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

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

percent performance during key availability hours and still receive full capacity payments.[44,45]

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. 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 that the Commission require SCE&G to use the methodology approved in Docket 2017-2-E to calculate avoided generation capacity with the following modifications:

1. Revise the Company's resource plan based on a 14 percent winter reserve margin.
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.

---

[44] 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.

[45] 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.

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.

6. NET ENERGY METERING METHODOLOGY—2018 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 5, the Company incorrectly calculated avoided energy and avoided generation capacity values. These same errors extend to the DER calculations as well. The Company's errors with respect to avoided generation capacity in particular appear to be at odds with a plain reading of the Value of Solar methodology agreed to by parties in the settlement in Docket No. 2014-246-E (defining "avoided capacity" as the increase or reduction in fixed costs to the utility "of building and maintaining new conventional generation resources associated with the adoption of NEM"). Now that the Company gives zero capacity value for net metered DERs, these resources have no ability to avoid new capacity.

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.

These modifications to the NEM value are significant because ratepayers compensate SCE&G for the difference between retail rate and the determined total value of NEM distributed energy resources. If the Commission approves an artificially low avoided cost payment, ratepayers are being overcharged.

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.[46] For avoided energy and capacity values, the corrections noted in Section 5 of my testimony should be incorporated. 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 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 transmission capacity."[47] On the distribution system, SCE&G suggests that because it must

[46] Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, Table 6.

[47] Ibid. at page 28, line 15.

"plan for when the DER is not supplying power,"[48] the Company must plan as if the resource simply doesn't exist.

I do not agree. These positions entirely overlook the ways that DERs, in the aggregate and on average over time, reduce the need for T&D capacity investments. If the DERs alleviates some of the strain on the system during transmission or distribution system peaks, then those resources do, in fact, reduce pressure on that system and therefore help 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.[49] See the table in DCG-2 (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

---

[48] Direct Testimony of Joseph M. Lynch, Docket No. 2018-2-E, page 29, line 3.

[49] 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.[50]

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.[51] In Maine, the PUC adopted a value of 1.6 cents per kWh for avoided transmission capacity.[52] 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.[53] 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

---

[50] 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.

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

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

[53] 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.[54]

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.[55,56] 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 using the SCE&G IRP value.

---

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

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

[56] John D. Wilson, "Analysis for Solar Capacity Equivalent Values for the South Carolina Electric and Gas System." Table 4, PSC Docket No. 2017-2-E (Exhibit TJV-2).

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. What are line 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. This means that for every kWh of electricity that the utility sells it must generate one kWh plus the amount lost in transit. Electricity generated on site from solar PV does not have to travel through the electricity system, therefore the utility does not have to produce this additional electricity lost in transit. Loss values can range from SCE&G reported value of 0.246 cents/kWh over the IRP planning horizon up to more than 2.5 cents/kWh,[57] depending on the system.

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.[58] His 2018 testimony contains just nine lines.[59] Because nothing in his 2018 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

[57] Hansen, L., Lacy, V., Glick, D., A Review of Solar PV Benefit and Cost Studies, Second Edition. Rocky Mountain Institute. September 2013.

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

[59] Direct Testimony of Joseph M. Lynch, Docket No. 2016-2-E, page 31, line 5 through 13.

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.

Q. What are annual average system losses?

A. 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.[60] 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 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 solar 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 that solar DERs avoid. Ideally, SCE&G would calculate the system loss for each hour of the year, and then determine how many

[60] 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.

MWh were saved each hour due to line loss avoidance induced by solar DERs. 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 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 solar DERs.

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.[61]

On the distribution system, SCE&G models marginal losses as "approximately twice average losses."[62] However, SCE&G models "marginal losses equal to average losses on the transmission and sub-transmission system."[63]

---

[61] Direct Testimony of Joseph M. Lynch, Docket No. 2016-2-E, page 30, line 6.

[62] Ibid. page 31, line 15.

[63] Ibid. page 30, line 15.

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 does not produce electricity over every hour of the year. Solar will 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 solar generates. Then it should double that PV-generation weighted average losses to accurately calculate the marginal losses for solar.

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 losses. 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[64,65] indicates that "for transmission losses, the marginal losses are always twice the average losses."[66] While it is true that "the amount of losses on the transmission/sub-transmission system do not necessarily decrease with load"[67] 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.

---

[64] 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.

[65] 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.

[66] 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-QFsweb.pdf.

[67] Direct Testimony of Joseph M. Lynch, Docket No. 2016-2-E, page 31, line 8.

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 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 21 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 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 21 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."[68]. I disagree with that conclusion. To the extent that distributed energy generators help to alleviate costs associated with environmental compliance at SCE&G's

---

[68] Direct Testimony of Joseph M. Lynch, Docket No. 2017-2-E, page 31, line 1.

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.[69] 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 9, Row 10.

Q. Please summarize your recommendations regarding net energy metering methodology—2018 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.

---

[69] 80 Fed. Reg. 21302 (April 17, 2015)

Devi Glick, Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 2 I Cambridge, MA 02139
dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Associate*, January 2018 – Present

Conducts research and provides consulting on energy sector issues.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017

Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy and identified over a billion dollars in savings based on improved resource-planning processes.
- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO_2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement, and was submitted as an official federal comment, and led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales, and helped them identify alternative business models that would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

Prepared lesson plans, taught classes, graded papers and other coursework, met regularly with students.

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EP*A. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D.Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

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.