SURREBUTTAL 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

DOCKET NO. 2018-2-E

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. Have you previously submitted direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my surrebuttal testimony is to discuss the rebuttal testimony of Joseph Lynch on behalf of the South Carolina Electric & Gas Company ("SCE&G" or "the Company"), in response to my direct testimony in this docket.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony addresses Company Witness Lynch's comments on the following:

1. Introduction
2. Winter reserve margin
    i. Reserve margin methodology
    ii. System planning
    iii. Reserve margin's impact on avoided capacity costs
    iv. Reserve margin's impact on avoided energy costs
3. Avoided capacity costs
4. Avoided transmission and distribution costs
5. Avoided line losses
6. Avoided environmental costs

1. INTRODUCTION

Q. Witness Lynch points out that some of the issues you raise in your direct testimony have been raised by your colleague Dr. Thomas Vitolo in prior Commission proceedings. How do you respond to this?

A. Witness Lynch is correct that some of the issues raised in my direct testimony have been raised before by my colleague. However, these issues are still important for the Commission to consider, especially under the new circumstances the Company now faces with the cancelation of V.C. Summer Units 2 and 3. In light of this and other dramatic changes in the Company's resource plan, it is even more important for the Commission to evaluate whether SCE&G is appropriately valuing solar QFs' contribution to SCE&G's system.

2. WINTER RESERVE MARGIN

Reserve Margin Methodology

Q. Witness Lynch defends SCE&G's use of a "component methodology" to calculate its reserve margin, stating it "strikes a reasonable and appropriate balance" between reliability and cost. Do you agree that this is an appropriate methodology for SCE&G to use to calculate its reserve margin?

A. No. Witness Lynch states that SCE&G sets its reserve margin using "data and judgment" but does not provide any evidence to support the choice or adequacy of the methodology.

In my direct testimony, I recommended that "[t]he 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 customers."[1] I also listed several tools and software utilized by peer utilities. I did not recommend any of these specific tools, nor state how the outputs should specifically be used.

Witness Lynch's response specifically focused on SERVM, which is used by Duke and Southern Company, stating that while the methodologies are confidential and propriety, he does not believe SERVM would adequately account for SCE&G's risks. It is surprising that Witness Lynch could make an accurate assessment of the software's suitability for SCE&G based on such limited public information and no access to the actual methodology.

Witness Lynch also referenced a Brattle Group study on the ERCOT region where SERVM's economic reserve margin didn't meet ERCOT's reliability criteria of an LOLE. His conclusion that, "it therefore appears that SERVM does not always give a reasonable answer,"[2] is a valid justification for not taking a reserve margin output by SERVM and dropping it into an Integrated Resource Plan without any

[1] Direct Testimony of Devi Glick, Docket No. 2018-2-E at page 11, lines 19-22.

[2] Rebuttal Testimony of Joseph Lynch, Docket No. 2018-2-E at page 22, lines 5-6.

further review. However, Witness Lynch's point is hardly a legitimate reason to discount all sophisticated methodologies and modeling software used by peer utilities. Instead, SCE&G should explore how other utilities balance consideration of reliability and customer cost to inform the development of a more robust methodology. This would better serve the needs of the customers and the system. In his direct testimony, Office of Regulatory Staff Witness Brian Horii notes that SCE&G has used a more sophisticated approach in the past, specifically SCE&G used the Loss of Load Probability Method or LOLP in its 2012 reserve margin study.[3]

System Planning

Q. What does Witness Lynch identify as the main driver of winter peak energy demand in his rebuttal testimony?

A. Witness Lynch asserts that because "…winter peak is significantly affected by energy consumed by heating strips, the winter peak will be little affected by conservation."[4] Specifically, many SCE&G customers "use heat strips as supplemental heating to warm residences and business in very cold weathers," which Witness Lynch goes on to describe as using "very inefficient resistant heating," and further, many customers "use space heaters to supplement the heating in their homes and business, which is an extremely inefficient heating source."[5]

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[3] Direct Testimony of Brian Horii, Docket No. 2018-2-E at page 11, lines 12-14.

[4] Rebuttal Testimony of Joseph Lynch, Docket No. 2018-2-E at page 7,line 17.

[5] *Id.* at page 9, lines 17-20.

Q. How does Witness Lynch explain the large gap between the summer and winter reserve margin in his rebuttal testimony?

A. Witness Lynch asserts that "SCE&G's demand side risk is greater in winter than in summer."[6] He goes on to quantify the difference between summer and winter peak weather risk as 300 MW.[7]

Q. Witness Lynch asserts that in recent years the need to establish a winter reserve margin has become evident. Is it reasonable to have a winter reserve margin?

A. It is always reasonable for a utility to have both a summer and a winter reserve margin. However, a reserve margin alone is insufficient to account for variability in demand. The Company also needs to plan its system to moderate demand side risk. SCE&G appears to be treating customer demand and demand-side risk as exogenous forces that must be accommodated by building new, large thermal generating capacity – a self-serving result that creates higher costs for customers. Demand-side solutions are energy and capacity resources that can moderate customer demand and reduce demand variability, producing a lower cost electricity system.

Winter-focused energy efficiency has historically been a low priority for SCE&G. Indeed, as detailed in a recent filing in Commission Docket Number 2018-42-E, SCE&G has failed to adequately consider the role of demand-side management and energy efficiency resources to address any energy or capacity needs resulting from the abandonment of the V.C. Summer nuclear units or to address winter peak demand.[8] Now that SCE&G asserts winter peak is contributing to future capacity needs, SCE&G can and should focus energy efficiency programs on reducing winter-time demand-side risk. Doing so will reduce winter peak

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[6] *Id.* at page 19, lines 15-16.

[7] *Id.* at page 19, line 18.

[8] Comments of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy, Docket No. 2018-42-E at p. 8 (describing data responses from SCE&G indicating that "it has fail[ed] to investigate the role DSM can play in avoiding the cost of generation to replace the failed nuclear plants," and has "no further information" about its plans to utilize DSM and EE to address winter peaking beyond its vague statements on this topic in its 2018 Integrated Resource Plan).

variability, driving down winter reserve margin requirements and creating a lower cost system for customers.

Q. Witness Lynch asserts several times that SCE&G's capacity needs are now greater in the winter then in the summer. Is it reasonable for SCE&G to develop their future resource plan based on this premise that it now has a winter peaking system?

A. No. While it is true that SCE&G's system was winter peaking in 2017, it is not reasonable to accept this as the new status quo going forward. Instead, this should point to the need for SCE&G to immediately pursue winter demand side measures, where a moderate amount of investment can easily manage and moderate demand-side variability. As outlined above, and in the testimony of Witness Lynch, SCE&G's winter peak demand is driven by heating needs, which in turn are driven by cold weather. Variability in the occurrence of extreme cold days, Lynch asserts, poses a significantly higher risk in the winter than in the summer.

This high demand-side risk is driven, as Witness Lynch himself offers, by use of ***inefficient*** heating appliances. With targeted demand-side thermal efficiency measures, such as more efficient heating appliances and weatherization, peaks would decrease and weather-related spikes that the system currently sees would be moderated significantly in the winter.

To illustrate this, consider a customer with electric resistance heat, a space heater, and a poorly insulated home. Whenever the ambient temperature inside the home drops below 60 degrees, the customer turns his or her heat on. When the outside temperature is quite cold (say below 20 degrees), the customer needs to use a space heater as well. This causes a spike in his or her electricity consumption. If the customer upgrades to a more efficient heating system or has the house weatherized, less electricity will be required to keep the house at 60 degrees, and the supplemental space heater will be used less frequently. This lower trigger temperature would be further outside of the normal distribution of temperature that SCE&G regularly experiences, and therefore would occur less often. The end result would be a decrease in the total amount of electricity needed to heat the customer's home, a decrease in daily peak load, and moderation of extreme weather-related peaks.

New or expanded efficiency programs might take two to three years to fully deploy. SCE&G should immediately expand current cost-effective programs that reduce winter peak demand. And SCE&G's next Integrated Resource Plan and Application for Approval of a Portfolio of Demand Side Management programs should reflect a plan to expand current programs and implement new programs to reduce net wintertime peak and wintertime variability, and thereby return the system to a summertime peak. SCE&G's energy efficiency program analysis should be updated to include the avoided capacity value of winter peak focused efficiency. SCE&G derives two new specific capacity avoidance benefits from winter energy efficiency. First, reducing winter peak allows the deferral of generation capacity. Second, by reducing the variability of winter peaks, SCE&G reduces the demand-side risk component of its reserve margin, further reducing future capacity needs.

Reserve Margin's Impact on the Avoided Capacity Cost

Q How would a more appropriate winter reserve margin impact the avoided capacity value proposed for solar QFs in this docket?

A The avoided cost for solar QFs is calculated based on SCE&G's Integrated Resource Plan, which is built to meet the system reserve margin. There are two things that SCE&G should do to properly calculate it's avoided capacity cost: 1) Recalculate its current reserve margin based on a more robust reserve margin methodology; and 2) Reduce its winter demand-side risk over the long term by utilizing thermal efficiency measures. By addressing winter demand-side risk, SCE&G's system will no longer have years where winter peaks exceed summer peaks due to the Company's underinvestment in needed winter energy efficiency programs. Capacity needs will continue to be driven by summer peaks and solar PV will have a higher capacity value. This is supported by Lynch himself who stated “a significant amount of solar capacity is coming onto the system, which alleviates some of the summer capacity needs.”[9]

Reserve Margin’s Impact on the Avoided Energy Cost

Q. How would a more appropriate winter reserve margin impact the avoided energy value proposed for solar in this proceeding?

A. As mentioned above, the reserve margin impacts the resource plan, which, in turn, is the basis for the difference in revenue requirement calculations. SCE&G provided to Intervenors simple excel-based spreadsheets that appeared to be the basis for the 2018 Integrated Resource Plan. Such spreadsheets, while useful for getting a high-level understanding of load and capacity needs, are not suitable for optimizing a system to balance supply and demand side resources over a long-term planning horizon.

I recreated SCE&G’s Forecast of Summer and Winter Loads and Resources from its 2018 Integrated Resource Plan with a more reasonable winter reserve margin (DCG_Exhibit 3). If SCE&G were to use a 17 percent annual reserve margin, to match a conservative reserve margin level used by peer utilities,[10] its system would be shown to peak in the summer, and summer peaks would drive capacity additions. Even at a 14 percent *annual* reserve margin, the *winter* reserve margin would always stay above or around 17 percent (DCG_Exhibit 4).

With a 17 percent reserve margin, no new large capacity additions would be needed until the summer of 2025 at the earliest. The baseload 540 MW combined cycle unit planned for 2023 would not be needed anymore, and the first major capacity need would be pushed back by at least a year and a half. As this analysis suggests, it is very important for the Commission to approve only a reasonable, accurate reserve margin in order to avoid a situation in which ratepayers are charged for a new power plant before one is actually needed.

[9] Rebuttal Testimony of Joseph Lynch, Docket No. 2018-2-E at page 20, lines 9-12.

[10] Direct Testimony of Devi Glick, Docket 2018-2-E at page 15.

Also, calculating the difference in revenue requirement using this lower and more reasonable reserve margin demonstrates that energy purchased now from utility-scale solar power plants actually has a higher value to ratepayers than suggested by Witness Lynch. If the 540 MW combined cycle unit is delayed because it is not needed, during the intervening time, marginal load will be served by something with a higher variable cost. Those higher variable cost resources would be avoided by solar, developed under the PR-2 rates established in this docket. Overall, costs to ratepayers, under this scenario with more reasonable reserve margins and more accurate avoided costs, should be lower than under SCE&G's proposed avoided cost rates.

3. AVOIDED CAPACITY COSTS

Q. Witness Lynch claims that "adding a capacity payment to PR-1 and PR-2 when there are no associated avoided capacity costs would contravene PURPA regulation" and that "SCE&G's customers ultimately would pay more for this purchased power then PURPA intends." How do you respond?

A. Witness Lynch is correct that adding a capacity payment ***when*** they are no associated avoided costs would raise customer costs. However, he has failed to adequately demonstrate that there are no avoided capacity costs associated with solar QFs over the long-run.

Witness Lynch asserts in his direct testimony that "the addition of 100 MW of solar has no effect on the resource plan."[11] However, this statement was based on several extremely important modeling decisions and assumptions around methodology, reserve margin, and resources planning that were incorrectly made. If the Commission doesn't critically review the decisions summarized below, they will be 1) allowing SCE&G to continue building a system that is significantly more expensive for SCE&G customers than it needs to be, and 2) significantly undervalues PR-1 and PR-2 rates.

[11] Rebuttal Testimony of Joseph Lynch, Docket No. 2018-2-E at page 14, line 13.

1. DRR Methodology - The Company appears to have selected a methodology that gives them the answer they want. As discussed extensively by my colleague Dr. Thomas Vitolo in his testimony last year, the difference in revenue requirement methodology is not an industry standard. It is unclear why SCE&G selected it, but what is clear is that it produced the result they wanted to see.

2. Reserve Margin Study - The assertion that solar does not influence the resource plan is based on the reserve margin study, which shows that SCE&G needs as much capacity in the winter as it does in the summer. As discussed above, this study uses an incomplete methodology and accepts the premise that the system will continue to be winter peaking. This is absolutely not a reasonable assumption. A few extreme winter-peaking days are not justification for massively shifting supply-side planning. What this demand-side risk should prompt is serious consideration of winter demand-side measures as a part of its least-cost resource plan to moderate peaks.

3. Integrated Resource Plan - SCE&G is using an unapproved Integrated Resource Plan as the basis for its difference in revenue requirement calculations. The Company can plan new thermal resources without justification, and has no mandate to consider demand-side resources or evaluate which portfolio of resources produces the least cost system.

Q **Witness Lynch claims in rebuttal that SCE&G is using the same avoided capacity methodology previously approved by Commission. Do you agree? Please explain.**

A While it is true that the Company continues to use the DRR method, its methodology for calculating avoided capacity costs is starkly different, as every party in this docket has pointed out. This is a departure from what the Commission approved in past dockets, and also runs afoul of PURPA. A simple illustration demonstrates the perverse outcome of SCE&G’s flawed method.

SCE&G claims to have ***both*** a summer and winter capacity need, with its winter capacity need exceeding its summer capacity need. Let's say, for simplicity's sake, that the Company needs 100 MW of summer capacity and 125 MW of winter capacity. SCE&G chooses two capacity resources to meet its needs: one 125 MW EE resource that only has value in winter, and one 100 MW solar QF. In the Company's new methodology, the solar QF gets ***zero*** capacity value, even though it meets a clear summer capacity need, thereby allowing the Company to avoid investing in another capacity resource. Under the Company's new method, only a resource like a natural gas peaking plant that was able to meet both summer and winter capacity needs could get full value. This outcome defies common sense, and does not comply with PURPA's requirement that QFs be given full credit for the costs that they allow utilities to avoid.

Q. When discussing opportunity costs and performance adjustment factors, Witness Lynch says that solar does not have firm or dependable capacity because of its intermittent nature. How do you respond to this?

A. I do not agree with this, and in fact SCE&G's own planning documents, including its 2018 Integrated Resource Plan, contradict this statement. It is certainly true that solar generators and a combustion turbine with the same nameplate capacity aren't fully interchangeable for reliability planning. However, that hasn't been suggested by anyone in this docket. When discussing a large solar generator on SCE&G's system, Witness Lynch states that "a solar QF does not have firm capacity as it is an intermittent resource."[12] Yet the Company takes a markedly different view in its 2018 Integrated Resource Plan, stating that 35 percent of the 865 MW of solar capacity coming online is considered firm capacity.[13]

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[12] Rebuttal Testimony of Joseph Lynch, Docket No. 2018-2-E at page 23, lines 7-8.

[13] South Carolina Electric & Gas Co. Integrated Resource Plan, South Carolina Public Service Commission, Docket No. 2018-9-E, page 40.

Q. Must a generator produce power to its full nameplate capability during all high-load hours to be considered useful for reliability purposes?

A. No. In fact, no utility-owned, QF, or customer-owned generator provides capacity at full output during every high-load hour over the course of a year. Generators become unavailable for a variety of reasons, including planned outages, forced outages, and fuel unavailability. A utility-owned combustion turbine, although it may be considered "more dependable,"[14] is taken off-line for maintenance and does not always generate when called upon. Yet the Company gets full compensation because the unit is deemed used and useful.

SCE&G's treatment of solar PV in its Integrated Resource Plan demonstrates that the Company does value generation capacity from generators with different availabilities with respect to reliability and planning. QFs are paid for their contribution to generation capacity on a performance basis, so a QF that isn't generating in all capacity hours won't receive a full avoided capacity payment. A Performance Adjustment Factor (PAF) allows a QF generator that has availability like those in the utility fleet to receive full compensation for contributing to the Company's generation capacity needs. This adjustment ensures that QFs and utility-owned generators are not treated differently.

Q. How does SCE&G's handling of solar PV and reserve margin differ between DERs and other solar resources?

A. Witness Lynch states that "DER resources do not result in a reserve margin benefit for the Company."[15] SCE&G's Integrated Resource Plan assigns 35 percent of the nameplate of solar capacity to its system capacity calculations, which contribute to its Total System Capacity, Total Production Capability, and hence to its Margin.[16] In other words, for resource planning purposes, SCE&G attributes solar PV capacity to its reserve margin. Because DERs are on the

[14] *Id.* at page 24, line 7.

[15] *Id.* at page 31, line 7.

[16] SCE&G, 2018 IRP. "SCE&G Forecast of Summer Loads and Resources – 2018 IRP," Rows 7, 11, 13, and 14.

customer side of the meter, the Company perceives the output not as power generation, but as a reduction in power demand. This reduction in power demand then manifests itself as a reduction in the Company's load forecast. SCE&G's 14 percent summer reserve margin ensures that for every 100 MW of load, it procures 114 MW of Total summer Production Capability. To the extent that DERs result in 100 MW of reduced load, they result in 114 MW of reduced Total Production Capability requirement. In addition to generation capacity grossed up for line losses, every 1 MW of DERs allow the avoidance of 0.14 MW of reserve margin generation capacity in the summer. Therefore, the avoided generation capacity benefit of DERs should be grossed up by the reserve margin requirement.

4. AVOIDED TRANSMISSION AND DISTRIBUTION COSTS

Q. When discussing the impact of solar capacity on the transmission system, Witness Lynch asserts that the amount of NEM solar capacity distributed throughout the system has no expected impact on the need for future transmission lines. Do you agree with this conclusion?

A. No. Witness Lynch states that solar capacity impact on a single transmission line amounts to 0.1 percent of total load. However, small benefits can add up to large impacts in aggregate and over time. Even small reductions in new load can allow the Company to defer or avoid system upgrades or builds, or can reduce the size of needed additions. These savings can occur over different time frames, from one year to a decade or longer. And they bring real monetary benefits, by avoiding not just the investment, but also the associated cost of capital, taxes, and insurance.

Further, even in small amounts, DER produces operations and maintenance savings by reducing wear and tear on the transmission system. DER can decrease maintenance frequency as well. It does this by reducing the frequent peak loads at or near the design capacity of the equipment that can reduce life span.

Finally, SCE&G proposed another avoided cost that could be considered "small." According to Witness Lynch's rebuttal testimony, the rate component for avoided criteria pollutants (NO_X and SO_2) is $0.00008/kwh (15-year levelized). This amount pales in comparison to the examples of avoided T&D costs that I provided in my direct testimony—largely ranging from $12.50 to $37.50/kW-year.

Q. On page 26, Witness Lynch states that, for distribution planning, SCE&G assumes solar output is zero. Is that appropriate?

A. It is not. This assumption is problematic for several reasons. As detailed in my direct testimony, NEM resources are likely providing substantial benefits to the distribution system that should be counted and credited to these customers.

Further, by using a value of zero for solar output in planning, non-NEM customers are undoubtedly paying more than they should be. Accurately quantifying NEM solar impacts on the distribution system would prevent the Company from overbuilding the system at the expense of ratepayers.

Company Witness Lynch states that while SCE&G is currently setting distribution avoided costs to zero, treatment of solar output in distribution planning "may change in the future as SCE&G has more experience with solar QFs on the system."[17] Witness Lynch made the same assertion last year, and the Company clearly has one more year of experience with solar QFs on its system now. Because of this additional experience, and because avoided costs are quantifiable now, I recommend that the Company be required to commission an independent study of these benefits and file it prior to the next avoided cost filing, so that the value can be vetted before it is included in the tariff rate.

[17] Rebuttal Testimony of Joseph Lynch, Docket No. 2018-2-E at page 26, lines 3-5.

5. AVOIDED LINE LOSSES

Q. How are marginal transmission losses modeled on systems elsewhere and by SCE&G?

A. The American Transmission Company models marginal transmission losses as "twice the overall average loss."[18] Similarly, a Federal Energy Regulatory Commission technical report reviewing a transmission system notes that "marginal losses are about twice the average losses."[19] Consultants and academics also agree that marginal transmission losses are two times the size of average transmission losses.[20,21] In contrast to these experts, "the Company believes that marginal losses should be approximated by average losses."[22] The Company's beliefs are inconsistent with both theory and in-the-field application of marginal transmission loss calculations.

Q. Is SCE&G's transmission system fundamentally different than other transmission systems in the Southeast, on the Eastern Interconnect, or anywhere else in the contiguous United States?

A. No. SCE&G's transmission system, "a network of sources and sinks with power lines connecting them,"[23] is substantially similar to other transmission systems in the region and the country. Therefore, the Commission should require SCE&G to calculate marginal transmission losses as twice average losses, consistent with its industry peers.

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[18] Smith, M. 2012. "ATC Customer Benefit Metric." Page 20. Available at: http://www.atc10yearplan.com/2013/files/2012/08/ATC-Customer-Benefit-Metric_4-4-2012.pdf.

[19] 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.

[20] 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.cesus.com/download/Reports_and_Publications/Losses%20paper%20-%20web.pdf.

[21] Green, R. 2004. "Electricity Transmission Pricing: How much does it cost to get it wrong?" Page 6. Available at: http://ceepr.mit.edu/files/papers/2004-020.pdf.

[22] Rebuttal Testimony of Joseph Lynch, Docket No. 2018-2-E at page 29, line 1.

[23] *Id.* at page 29, line 3.

6. AVOIDED ENVIRONMENTAL COSTS

Q. Has Company Witness Lynch demonstrated that there are no avoided environmental costs in addition to criteria air pollutants?

A. No. Although Witness Lynch stated that “there are no environmental costs that are not already included in the other specific components of the methodology,”[24] he did not point to any Company or third-party study, analysis, or review. He also did not address coal combustion residuals (CCRs), the specific environmental cost I discussed in my direct testimony for which SCE&G can avoid in part when DERs generate energy instead of a Company coal-fired power plant. Witness Lynch also claims to have complied with the Commission’s directive in last year’s proceeding to “address the cost-effectiveness of separately accounting for environmental costs[,]”[25] by pulling out the environmental costs for lime and ammonia and the net profit resulting from SCE&G’s sale of coal ash. He “conclude[s] that the time and resources necessary to separately account for these environmental costs do not result in any additional benefit to the NEM methodology.”[26] However, SCE&G’s exercise of pulling out certain environmental cost components from the energy cost component does not provide adequate transparency regarding the environmental costs associated with particular items. Further, Witness Lynch does not point to any Company or third party information to support the costs he has calculated.

Q. Does this conclude your surrebuttal?

A. Yes.

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[24] *Id.* at page 32, line 2.

[25] Docket 2017-2-E, Order 2017-246 at 39.

[26] Rebuttal Testimony of Joseph Lynch, Docket No. 2018-2-E at page 32-33.

EXHIBITS DCG 3 AND DCG 4 TO SURREBUTTAL 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

DOCKET NO. 2018-2-E

Exhibit No. _(DCG_3)

Synapse calculation of SCE&G's capacity needs with an adjustable reserve margin

SCE&G Forecast of Summer and Winter Loads and Resoures - 2018

(MW)

		YEAR	**2018**		**2019**		**2020**		**2021**		**2022**		**2023**		**2024**		**2025**		**2026**		**2027**		**2028**		**2029**		**2030**		**2031**		**2032**	
			S	**W**	**S**	**W**	**S**	**W**	**S**	**W**	**S**	**W**	**S**	**W**	**S**	**W**	**S**	**W**	**S**	**W**	**S**	**W**	**S**	**W**	**S**	**W**	**S**	**W**	**S**	**W**	**S**	**W**
Load Forecast																																
	1	**Baseline Trend**	5103	5056	5148	5126	5239	5195	5333	5287	5459	5351	5559	5415	5652	5478	5738	5544	5820	5611	5900	5677	5976	5743	6049	5805	6116	5869	6186	5934	6254	5998
	2	**EE/Renewables Impact**	-26	-32	-37	-55	-59	-78	-80	-101	-100	-123	-119	-158	-151	-179	-169	-197	-184	-220	-205	-245	-226	-270	-248	-295	-269	-317	-287	-340	-306	-361
	3	**Gross Territorial Peak**	5077	5024	5111	5071	5180	5117	5253	5186	5359	5228	5440	5257	5501	5299	5569	5347	5636	5391	5695	5432	5750	5473	5801	5510	5847	5552	5899	5594	5948	5637
System Capacity																																
	4	**Existing**	5278	5464	5782	5883	5697	5858	5672	5858	5672	5858	5672	5858	5672	5858	5672	5951	5765	6044	5858	6044	5858	6230	6044	6230	6044	6230	6044	6323	6230	6416
	5	**Existing Solar**	58.73	0	96.36	0	161.6	0	302.79	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0
	6	**Demand Response**	274	222	275	223	276	324	277	325	278	326	280	327	281	328	282	329	283	330	285	331	286	332	287	333	288	333	290	334	291	335
Additions:																																
	7	**Solar Plant**	37.63	0	65.21	0	141.2	0																								
	8	**Peaking/Intermediate**																												93		
	9	**Baseload**		504										0	0																	
	10	**Retirements**			-85		-25																									
	11	**Total System Capacity**	5648.36	6190	6133.57	6106	6250.8	6182	6251.79	6183	6252.8	6184	6254.8	6185	6255.8	6186	6256.8	6280	6350.8	6374	6445.8	6375	6446.8	6562	6633.8	6563	6634.8	6563	6636.8	6750	6823.8	6751
	12	**Firm Annual Purchase**	300	0	0	0	0	0	0	0	0	0	0	0	25	25	0	0	0	0	50	0	0	0	0	0	50	0	0	0	0	0
	13	**Total Production Capability**	5948.36	6190	6133.57	6106	6250.8	6182	6251.79	6183	6252.8	6184	6254.8	6185	6280.8	6211	6349.8	6280	6443.8	6374	6495.8	6375	6632.8	6562	6633.8	6563	6684.8	6563	6729.8	6750	6823.8	6751
Reserves																																
	14	**Margin (L13-L3)**	871	1166	1023	1035	1071	1065	999	997	894	956	815	928	780	912	781	933	808	983	801	943	883	1089	833	1053	838	1011	831	1156	876	1114
	15	**% Reserve Margin (L14/L3)**	17.2%	23.2%	20.0%	20.4%	20.7%	20.8%	19.0%	19.2%	16.7%	18.3%	15.0%	17.7%	14.2%	17.2%	14.0%	17.4%	14.3%	18.2%	14.1%	17.4%	15.4%	19.9%	14.4%	19.1%	14.3%	18.2%	14.1%	20.7%	14.7%	19.8%
		Min Reserve Margin	17%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%	14%	17%
		Capacity Gap	291.73	0	0	0	0	0	0	0	0	0	0	0	15.34	14	91.86	0	74.24	0	46.5	0	108.2	0	0	0	30.78	0	88.06	0	0	0
		Dynamic Peaking Capacity Additions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	93	0	93	0	0	0	186	0	0	0	0	0	93	0	0	0

Winter Reserve Margin	17%
Summer Reserve Margin	14%

Exhibit No. _(DCG_4)

Synapse calculation of SCE&G's capacity needs with an adjustable reserve margin

SCE&G Forecast of Summer and Winter Loads and Resoures - 2018

(MW)

	YEAR	2018		2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	**Baseline Trend**	5103	5056	5148	5126	5239	5195	5333	5287	5459	5351	5559	5415	5652	5478	5738	5544	5820	5611	5900	5677	5976	5743	6049	5805	6116	5869	6186	5934	6254	5998
2	**EE/Renewables Impact**	-26	-32	-37	-55	-59	-78	-80	-101	-100	-123	-119	-158	-151	-179	-169	-197	-184	-220	-205	-245	-226	-270	-248	-295	-269	-317	-287	-340	-306	-361
3	**Gross Territorial Peak**	5077	5024	5111	5071	5180	5117	5253	5186	5359	5228	5440	5257	5501	5299	5569	5347	5636	5391	5695	5432	5750	5473	5801	5510	5847	5552	5899	5594	5948	5637
System Capacity																															
4	**Existing**	5278	5464	5782	5883	5697	5858	5672	5858	5672	5858	5672	5858	5672	5858	5672	5951	5765	6044	5858	6044	5858	6230	6044	6230	6044	6230	6044	6323	6230	6416
5	**Existing Solar**	58.73	0	96.36	0	161.6	0	302.79	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0
6	**Demand Response**	274	222	275	223	276	324	277	325	278	326	280	327	281	328	282	329	283	330	285	331	286	332	287	333	288	333	290	334	291	335
Additions:																															
7	**Solar Plant**	37.63	0	65.21	0	141.2	0																								
8	**Peaking/Intermediate**																												93		
9	**Baseload**		504										0	0																	
10	**Retirements**			-85		-25																									
11	**Total System Capacity**	5648.36	6190	6133.57	6106	6250.8	6182	6251.79	6183	6252.8	6184	6254.8	6185	6255.8	6186	6256.8	6280	6350.8	6374	6445.8	6375	6446.8	6562	6633.8	6563	6634.8	6563	6636.8	6750	6823.8	6751
12	**Firm Annual Purchase**	300	0	0	0	0	0	0	0	0	0	0	0	25	0	0	0	0	0	50	0	0	0	0	0	50	0	0	0	0	0
13	**Total Production Capability**	5948.36	6190	6133.57	6106	6250.8	6182	6251.79	6183	6252.8	6184	6254.8	6185	6280.8	6186	6349.8	6280	6443.8	6374	6495.8	6375	6632.8	6562	6633.8	6563	6684.8	6563	6729.8	6750	6823.8	6751
Reserves																															
14	**Margin (L13-L3)**	871	1166	1023	1035	1071	1065	999	997	894	956	815	928	780	887	781	933	808	983	801	943	883	1089	833	1053	838	1011	831	1156	876	1114
15	**% Reserve Margin (L14/L3)**	17.2%	23.2%	20.0%	20.4%	20.7%	20.8%	19.0%	19.2%	16.7%	18.3%	15.0%	17.7%	14.2%	16.7%	14.0%	17.4%	14.3%	18.2%	14.1%	17.4%	15.4%	19.9%	14.4%	19.1%	14.3%	18.2%	14.1%	20.7%	14.7%	19.8%
	Min Reserve Margin	17%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
	Capacity Gap	291.73	0	0	0	0	0	0	0	0	0	0	0	15.34	0	91.86	0	74.24	0	46.5	0	108.2	0	0	0	30.78	0	88.06	0	0	0
	Dynamic Peaking Capacity Additions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	93	0	93	0	0	0	186	0	0	0	0	0	93	0	0	0

Winter Reserve Margin	14%
Summer Reserve Margin	14%